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Biogeography – Based Optimization for Transmission Network Planning Problem Considering Distributed Generation Impacts

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Abstract

Transmission system is one of the major components in the electric power industry. In this paper, a novel approach is proposed using biogeography-based optimization (BBO) for the solution of Transmission-expansion planning (TEP) long range problem. It applies a constrained BBO algorithm where network stability constraints as lower and upper limits of bus voltage magnitudes and swing angles are included, as well as the AC load flow equations. The cost function is formulated including both fixed and variable costs of planned transmission lines, in addition to energy losses cost. The function is then minimized subject to these constraints. In addition, the proposed method will be employed to study the impacts of distributed generation (DG) on transmission expansion planning. Theoretical details, mathematical model, and the verification of the approach using IEEE 6-BUS and modified 14-BUS test systems are given in the paper.

Index Terms – Transmission expansion planning, biogeography-based optimization, heuristic optimization, distributed generation.

1. Introduction

TEP is a mathematical optimization challenge. The complication arises from the large number of variables involved in the process. TEP planners formulate their objective functions and the corresponding constraints to account for the cost of investment and/or the cost of power loss. When planning a new transmission system, or a system expansion, it is important to think carefully in all the aspects, which can imply in a better performance and also in lower cost. The main objective of the TEP problem is to determine the optimal expansion plan of the electrical system. The planning should specify the circuits (transmission lines or transformers) that have to be built to guarantee adequate operation for a specified planning horizon [1]-[4]. The data available is: base-year topology, candidate circuits, forecast generation and demand of the planning horizon, investment constraints, etc. The planning specifies the location, capacity and when the circuits should be installed.

According to the procedure that was followed to obtain the expansion plan, the synthesis planning models can be classified into two types: heuristic [5]-[8] and mathematical [9]-[15] optimization. However, there are tools that have characteristics of both types of models, and they are termed meta-heuristic. Recently, most reported works for solving TEP problems use the modern meta-heuristic methods such as genetic algorithm (GA) [16]-[18] and particle swarm optimization (PSO) [19]-[21]. A new method have been developed called BBO [22], this method is applied to power problems such as optimal power flow problems [23], and the results was fruitful.

An important issue is the potential large-scale penetration of DG technologies. In recent decades, the large-scale centralized generation model has been criticized for its costs, security vulnerability, and environmental impacts, while DG is now expected to play an increasingly important role in the future provision of electricity supply. However, any large-scale implementation of DG will cause significant changes in the power industry, and also deeply influence the transmission planning process. Therefore, it is important to investigate the impacts of DG on transmission planning and take into account the uncertainty that it brings to the planning process.

In the following sections a novel approach is proposed using the BBO method for the solution of the TEP optimization problem to obtain minimum cost, with studying the impacts of DG. Theoretical details and results of the tests are given.

2. Biogeography-Based Optimization

Actually biogeography is nature’s way of distributing species. Biogeography describes how species migrate from one island to another, how new species arise, and how species become extinct. A habitat is any Island (area) that is geographically isolated from other Islands. The more generic term “habitat” in this paper is used rather than term “island”. Geographical areas those are well suited as residences for biological species are said to have a high habitat suitability index (HSI). Features that correlate with HSI include factors such as rainfall, diversity of vegetation, diversity of topographic features, land area, and temperature. The variables that characterize habitability are called suitability index variables (SIVs). SIVs can be considered the independent variables of the habitat, and HSI can be executed using these variables. Habitats with a high HSI tend to have a large number of species, while those with a low HSI have a small number of species.

Migration of some species from one habitat to other habitat is known as emigration process. When some species enters into one habitat from any other outside habitat is known as immigration process. Habitats with a high HSI have a low species immigration rate because they are already nearly saturated with species. Therefore, high HSI habitats are more static in their species distribution than low HSI habitats. By the same token high HSI habitats have a high emigration rate; the large numbers of species on high HSI islands have many opportunities to emigrate to neighboring habitats. Habitats with a low HSI have a high species immigration rate because of their sparse populations. A good solution is analogous to an island with a high Habitat Suitability Index (HSI), and a poor solution represents an island with a low HSI. High HIS solutions resist change more than low HSI solutions. By the same token, high HSI solutions tend to share their features with low HSI solutions. This does not mean that the features disappear from the high HSI solution; the shared features remain in the high HSI solutions, while at the same time appearing as new features in the low HSI solutions. This is similar to representatives of a species migrating to a habitat, while other representatives remain in their original habitat.

Poor solutions accept a lot of new features from good solutions. This addition of new features to low HSI solutions may raise the quality of those solutions. This new approach to problem solving is known as BBO [22].

Mathematically the concept of emigration and immigration can be represented by a probabilistic model. Let us, consider the probability Ps that the habitat contains exactly S species at time t. Ps changes from time t to time t + Δt as follows:

$$P_s(t+\Delta t) = P_s(t)(1-\lambda_s\Delta t-\mu_s\Delta t)+P_{s-1}\lambda_{s-1}\Delta t+P_{s+1}\mu_{s+1}\Delta t \tag{1}$$

Where (λ_s) and (μ_s) are the immigration and emigration rates when there are (S) species in the habitat. This equation holds because in order to have (S) species at time (t+Δt), one of the following conditions must hold:

1) There were (S) species at time (t), and no immigration or emigration occurred between (t) and (t+Δt);

2) There were (S −1) species at time (t), and one species immigrated;

3) There were (S +1) species at time (t), and one species emigrated.

If time Δt is small enough so that the probability of more than one immigration or emigration can be ignored then taking the limit of equation (3.1) as Δt →0 gives the following equation:

$$P_S = \begin{cases} -(\lambda_s+\mu_s)P_s + P_{s+1}\,\mu_{s+1} & s=0 \\ -(\lambda_s+\mu_s)P_s + P_{s+1}\,\mu_{s+1} + P_{s-1}\,\lambda_{s-1} & 1\le s\le s_{max}-1 \\ -(\lambda_s+\mu_s)P_s + P_{s-1}\,\lambda\mu_{s-1} & s=s_{max} \end{cases} \tag{2}$$

From the straight-line graph of Fig. 3.1, the equation for emigration rate (μ_k) and immigration rate (λ_k) for (k) number of species is derived as per following way:

$$\mu_k = \frac{Ek}{n} \tag{3}$$

$$\lambda_k = I\left(1-\frac{k}{n}\right) \tag{4}$$

When E = I , $\mu_k + \lambda_k = E$ (5)

Where, (E) and (I) are the maximum emigration rate and maximum immigration rate respectively, (n) is the total number of species in the habitat. For details regarding migration and mutation process refer to [22].

3. Distributed generation

Distributed Generation is defined as a source of electric energy located very close to the demand [24], [25]. Usually, DG investments are not more economic than conventional generation. Nevertheless, important contributions of DG occur when: energy transmission and distribution costs are avoided, demand uses it for peak shaving, losses are reduced, network reliability is increased, or when it lead to investment deferral in transmission and distribution systems [26]-[29]. DG seems a plausible means of improving the traditional way of driving the expansion of the transmission systems. The fact of considering DG projects as new decision alternatives within the TEP, involves the incorporation of additional parameters such as investment and production costs of DG technologies, firm power, etc. Based on the typical short lead times of DG projects and their lower irreversibility, the uncertainty present in DG project investment decisions and investment costs can be neglected.

In recent decades, the large-scale centralized generation model has been criticized for its costs, security vulnerability, and environmental impacts, while DG is now expected to play an increasingly important role in the future provision of electricity supply. However, any large-scale implementation of DG will cause significant changes in the power industry, and also deeply influence the transmission planning process. For example, DG can reduce local power demand, and thus, it can potentially defer investments in the transmission and distribution sectors. On the other hand, when the penetration of DG in the market reaches a certain level, its suppliers will have to get involved in the spot market and trade the electricity through the transmission and distribution networks, which may then need to be further expanded. Therefore, it is important to investigate the impacts of DG on transmission planning and take into account the uncertainty that it brings to the planning process.

3.1 DG impact on transmission planning

Increasing efforts have been made recently to investigate the impacts of DG on all aspects of the power market. Generally speaking, distributed generation is defined as the presence of generation units that are connected to the power grid either on the customer side or into the distribution network [37]. The size of a typical DG system usually ranges from 1 KW to 5 MW, while a large DG system can reach a capacity up to 300 MW [37]. DG can be categorized as renewable, such as wind or solar power, or nonrenewable, such as the internal combustion engine (ICE) and micro-turbines. Since the market penetration of DG is still low in most countries, a number of studies [30], [31] have been conducted to investigate the barriers to DG penetration and the factors that can contribute to DG deployment. A number of economic analyses [32], [33] have also been conducted to study the market performance of DG systems. In addition, since DG is usually connected at the distribution level, extensive research [34] has been conducted to investigate the impacts of DG on distribution network planning. These studies have usually focused on determining the optimal size and location of DG units in the distribution network from the distribution company's point of view. Some studies [35], [36] also have been performed to understand the impacts of DG on the system side, such as on reliability, system security, and power quality.

3.2 DG valuation

DG units can be valued in two different ways. When the market share of DG is small, a DG unit is usually modeled as a negative load in the distribution network and a distribution company implements it only if its cost is lower than the cost of buying electricity from the market. If so, it expands the distribution network correspondingly [34]. However when the market penetration of DG reaches a certain level and the electric utilities implement DGs as standard investments in generation capacity [37], then it will be necessary to get involved in the spot market and sell power through the transmission network. This will possibly require modifications to the current market dispatch mechanism [38].

4. Formulation of transmission planning problem

The following model is for long-range transmission planning as it is an AC load flow model to obtain optimal solution satisfies load demand, both active and reactive power limitations, the system security and operational constraints. Installation, variable, and energy losses costs are included in the cost function in terms of time and both interest and inflation rates. The model present worth cost function could be formulated as follows [39]:

Minimize

$$\mathrm{Cost} = \sum_{i=1}^{N_t}\left[P_0^i\, E^i + \sum_{j=1}^{N_L}\sum_{k=1}^{N_p^j}\{R_{j,k}^i\, \alpha_{j,k}^i + C_{j,k}^i\, \beta_{j,k}^i\}\right] \tag{6}$$

Where N_t is the number of planning time periods, P_0^i is the total annual power loss in the system during planning time period (i), E^i is the present worth value of energy losses cost per unit power over planning time period (i), N_L is the number of available right-of-ways in the system, N_p^j is the number of permitted parallel lines in right-of-way (j), $R_{j,k}^i$ is the present worth value of variable cost of line (k) in right-of-way (j) over planning time period (i), $\alpha_{j,k}^i$ is an integer equals (1) if parallel line (k) of right-of-way (j) is used in planning time period (i), and equals (0) if not, $C_{j,k}^i$ is present worth value of installation cost of line (k) in right-of-way (j) if installed during planning time period (i), and $\beta_{j,k}^i$ is an integer equals (1) if line (k) in right-of-way (j) is installed in planning time period (i), and equals (0) if not. It should be pointed out here that each present worth value; E^i, $R_{j,k}^i$, and $C_{j,k}^i$ is a function in the time at which planning time period (i) starts and the length of its operating time interval, as well as in interest and inflation rates. The above cost function has then to be minimized subject to the system operational and security constraints in (Eqns. 7-11):

$$P_{mk}^l = \left(V_{mr}^l V_{kr}^l + V_{mi}^l V_{ki}^l\right)G_{mk}^l + \left(V_{mi}^l V_{kr}^l - V_{mr}^l V_{ki}^l\right)B_{mk}^l \le w_{mk} P_{mk,max}^l;$$
$$l = 1,2 \ldots, N_t;\ m = 1,2 \ldots, N_b;\ k = 1,2 \ldots, N_b;\ m \ne k \tag{7}$$

$$V_{k,min} \le \left|V_k^l\right| = \sqrt{V_{kr}^2 + V_{ki}^2} \le V_{k,max}; l = 1,2 \ldots, N_t;\ k = 2,3 \ldots, N_b \tag{8}$$

$$\delta_{k,min} \le \left|\delta_k^l\right| = \tan^{-1}\left(\frac{V_{ki}^l}{V_{kr}^l}\right) \le \delta_{k,max}; l = 1,2 \ldots, N_t;\ k = 2,3 \ldots, N_b \tag{9}$$

$$\sum_{k=1}^{N_b}\{\left(V_{mr}^l V_{kr}^l + V_{mi}^l V_{ki}^l\right)G_{mk}^l + \left(V_{mi}^l V_{kr}^l - V_{mr}^l V_{ki}^l\right)B_{mk}^l\} \le P_m^l;$$
$$l = 1,2 \ldots N_t;\ m = 1,2 \ldots N_b \tag{10}$$

$$\sum_{k=1}^{N_b}\{\left(V_{mi}^l V_{kr}^l - V_{mr}^l V_{ki}^l\right)G_{mk}^l - \left(V_{mr}^l V_{kr}^l + V_{mi}^l V_{ki}^l\right)B_{mk}^l\} \le Q_m^l;$$
$$l = 1,2 \ldots N_t;\ m = 1,2 \ldots N_b \tag{11}$$

Where P_{mk}^l is the active power flow from bus (m) to bus (k) during planning time period (l), $P_{mk,max}^l$ is the active power capacity limit of the right-of-way connecting bus (m) to bus (k) during planning time period (l), w_{mk} the weighting factor for active power capacity of the right-of-way connecting bus (m) to bus (k), V_{kr}^l is the real part of bus (k) voltage during planning time period (l), V_{ki}^l is the imaginary part of bus (k) voltage during planning time period (l), $V_{k,min}$ is the lower limit on bus (k) voltage magnitude, $V_{k,max}$ is the upper limit on bus (k) voltage magnitude, G^{l}_{mk} is the conductance of element (m , k) in the bus admittance matrix during planning time period (l), B^{l}_{mk} is the susceptance of element (m , k) in the bus admittance matrix during planning time period (l), P^{l}_{m} is the net injected active power at bus (m) during planning time period (l), Q^{l}_{m} is the net injected reactive power at bus (m) during planning time period(l), and N_b is the number of buses in the system. Eqn. 7 introduces a capacity limit on active power flow through each right-of-way in the system which varies with each planning time period according to the planner decision of number of parallel lines to be used in this right-of-way during each period. Based on the planner decisions, the elements of the system bus admittance matrix also vary with planning time periods. In order to minimize the cost function presented by (Eqn. 6), the weighting factor (w_{mk}) allows either power capacity reserve $(w_{mk} < 1)$ or overloading $(w_{mk} > 1)$ for the right-of-way between buses (m) and (k). (Eqns. 8 and 9) represent the system security constraints in each planning time period. Both real and imaginary parts of the system different bus voltages, at the different planning time periods, are obtained by solving the ac power flow (Eqns. 10 and 11) iteratively, for example, using Gauss-Seidel method-as solved in this paper.

5. Tests and results

To prove the validity of the proposed technique, it is applied to the IEEE 6-BUS and modified 14-BUS test systems.

5.1 Testing the IEEE 6-Bus test system

The IEEE 6-BUS test system is widely used in literature [40]-[44]. Fig. 1 shows the initial configuration of the system. To check the capability of the model of handling the system security constraints, an upper and lower limit of ± 30 ° are imposed on the swing angles of all buses, and an upper limit of 1.1 p.u and a lower limit of 0.9 p.u are also imposed on voltage magnitudes of load buses. Bus 6 is considered the slack bus of the system with voltage 1.04 < 0 ° p.u, while voltage magnitudes of voltage controlled buses 1 and 3 are assigned the values 1.02 and 1.04 p.u, respectively. Also, $w_{mk} = 0.9$ to avoid overloading of the system lines. The proposed technique is applied to the system in two cases. The method is applied in static mode of planning with an installation cost of $240,000/km for any new right-of-way, with a single line between its terminal buses, and $150,000/km for any additional line in an existing and/or future right-of-way. An annual operation and maintenance cost of $800/km is assumed. The cost of energy losses is also assumed to be 0.1/kW/year. The optimal plan has been obtained with the configuration shown in Fig. 2. Both active and reactive power flow, obtained from the model output is also shown in Table 1. An installation cost of $47,040,000 is obtained assuming the new facilities are to be added at the time of planning. For an assumed 10 years operating time period for the system, an operation and maintenance cost of $1,477,452 and energy losses cost of $17,720.1043 are also obtained. An interest rate of 12% and an inflation rate of 4% are used in the study. An installation time period of 1 year is considered for any new facility. Both variable and losses costs are computed according to equations used in [40]. Comparing the results using this BBO based model to the results using GA technique in [38], the installation, operation and maintenance, and losses costs are lower.

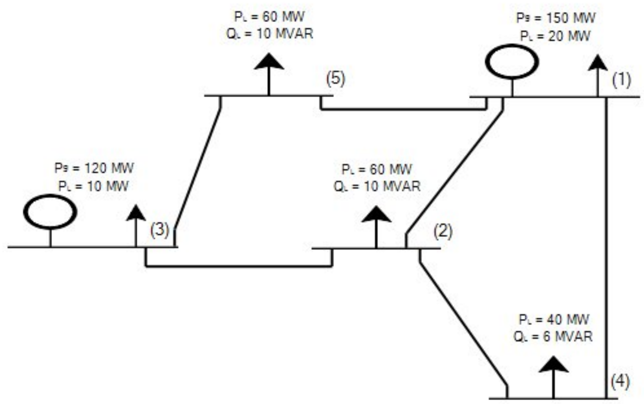

Fig. 1 The 6-BUS test system: Initial Configuration.

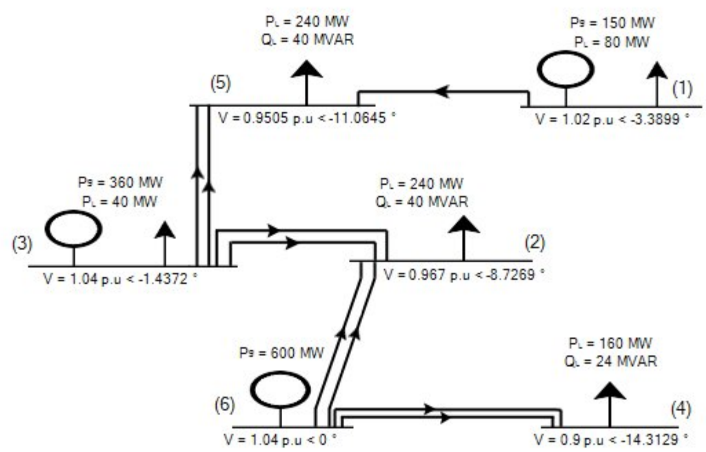

Fig. 2 Optimal plan for 6-BUS test system.

Table 1: The sending and receiving active and reactive power flow for optimal plan for 6-BUS test system.

Lines		**Power flow from optimal plan**			
From bus	To bus	Ps (MW)	Pr (MW)	Qs(MVAR)	Qr (MVAR)
6	2	54.75138	52.37691	14.57984	5.67557
6	2	54.75138	52.37691	14.57984	5.67557
3	2	69.93753	67.39828	24.52875	14.37173
3	2	69.93753	67.39828	24.52875	14.37173
1	5	70.29319	67.68111	22.22778	11.77948
6	4	86.50519	80.05648	35.14977	10.96711

6	4	86.50519	80.05648	35.14977	10.96711
3	5	90.38706	86.16842	30.91826	14.04371
3	5	90.38706	86.16842	30.91826	14.04371

To study the impact of the presence of the DG as a new option for supplying the loads of the system, considering the input data such as percentage of contribution of DG in supplying total load demand (760 MW) and the predetermined buses that can accept the installation of DG units at (for this system, buses 2 and 4), the problem is solved in two cases:

Case1: There will be a 10% share of installed DG units on the load buses (10 % of total load demand = 76 MW and installed at bus 2). We assumed that DG units are nondispatchable and their power is only consumed locally, therefore they can be modeled as negative loads. The optimal plan for this case has been obtained with the configuration shown in Fig. 3. For the assumed data, an installation cost of $39,840,000 is obtained. Also, an operation and maintenance cost of $1,275,982 and energy losses cost of $15,650.1132 are obtained.

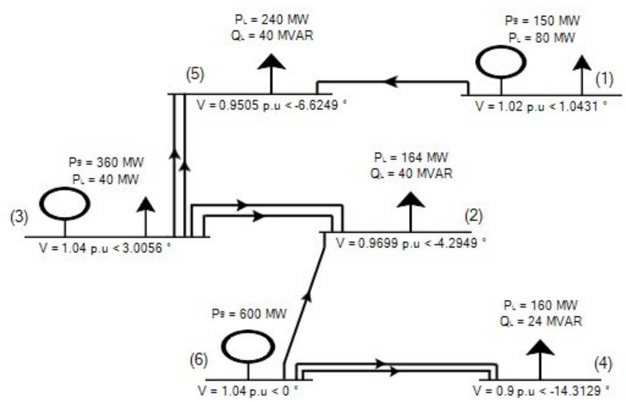

Fig. 3 Optimal plan for 6-Bus system with 10% share of DG in supplying system loads.

Case2: There will be a 30% share of installed DG units on the load buses (30 % of total load demand = 228 MW and installed at bus 4). DG units are assumed to be dispatchable and traded through the spot market. The optimal plan for this case has been obtained with the configuration shown in Fig. 4. For the assumed data, an installation cost of $21,120,000 is obtained. Also, an operation and maintenance cost of $1,141,668 and energy losses cost of $11,686.5334 are obtained.

Studying the above two cases, it is observed that a 30% share, which provides a dispatchable power, reduces the future network expansion costs more than the 10% share of nondispatchable power.

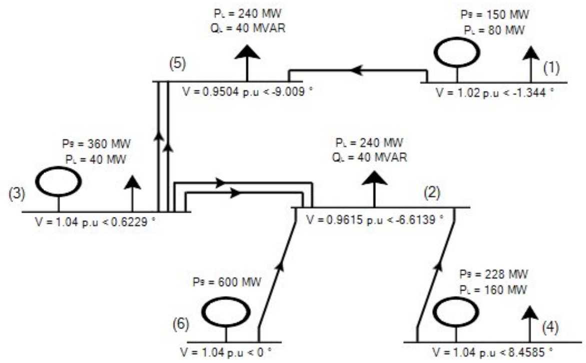

Fig. 4 Optimal plan for 6-Bus system with 30% share of DG in supplying system loads.

5.2 Testing the IEEE modified 14-Bus test system

The IEEE modified 14-BUS test system is widely used in literature [45] and [46]. The system has 5 existing generator buses 1, 2, 3, 6 and 8 with generation capacities of 150, 150, 100, 100, and 100 MW, respectively, along with local demands of 0, 21.7, 21.74, 11.2 and 0 MW, respectively. The system also has load buses 4, 5, 7, 9, 10, 11, 12, 13, and 14 with active power demand 47.8, 7.6, 21.69, 29.5, 9, 3.5, 6.1, 13.5, and 14.9 MW, respectively, and assumed reactive power demand of 17.39, 1.6, 5.21, 16.6, 5.8, 1.8, 1.6, 5.8 and 5 MVAR, respectively. The system in its initial configuration has the 20 single 3-phase lines 1-2, 1-5, 2-3, 2-4, 2-5, 3-4, 4-5, 4-7, 4-9, 5-6, 6-11, 6-12, 6-13, 7-8, 7-9, 9-10, 9-14, 10-11, 12-13 and 13-14, shown in Fig. 5. A future increase in demand by a factor of 2.5 is expected and accordingly, the total future demand will be 520.575 MW. In future, seven additional lines between buses 2-4, 3-4, 4-9, 6-11, 6-13, 7-8, and 7-9 are allowed.

To check the capability of the model of handling this system using the previous values for the security constraints, Bus 2 is considered the slack bus of the system with voltage 1.045 < 0 ° p.u, while voltage magnitudes of voltage controlled buses 1, 3, 6, and 8 are assigned the values 1.06, 1.01, 1.07, and 1.09 p.u respectively. The optimal plan has been obtained with the configuration shown in Fig. 6. For the assumed data, an installation cost of $30,067,200 is obtained. Also, an operation and maintenance cost of $3,858,703 and energy losses cost of $15008.1146 are obtained.

To study the impact of the presence of the distributed DG, the predetermined buses that can accept the installation of DG units are buses 4, 7, 9, 13, and 14; the problem is solved in three cases:

Case1: There will be a 5% share of installed DG units on the load buses (5 % of total load demand = 26.02875 MW and installed at bus 9), DG units are assumed nondispatchable and modeled as negative loads. The optimal plan for this case has been obtained with the configuration shown in Fig. 7. For the assumed data, an installation cost of $22,884,000 is obtained. Also, an operation and maintenance cost of $3,845,204 and energy losses cost of $13559.0406 are obtained.

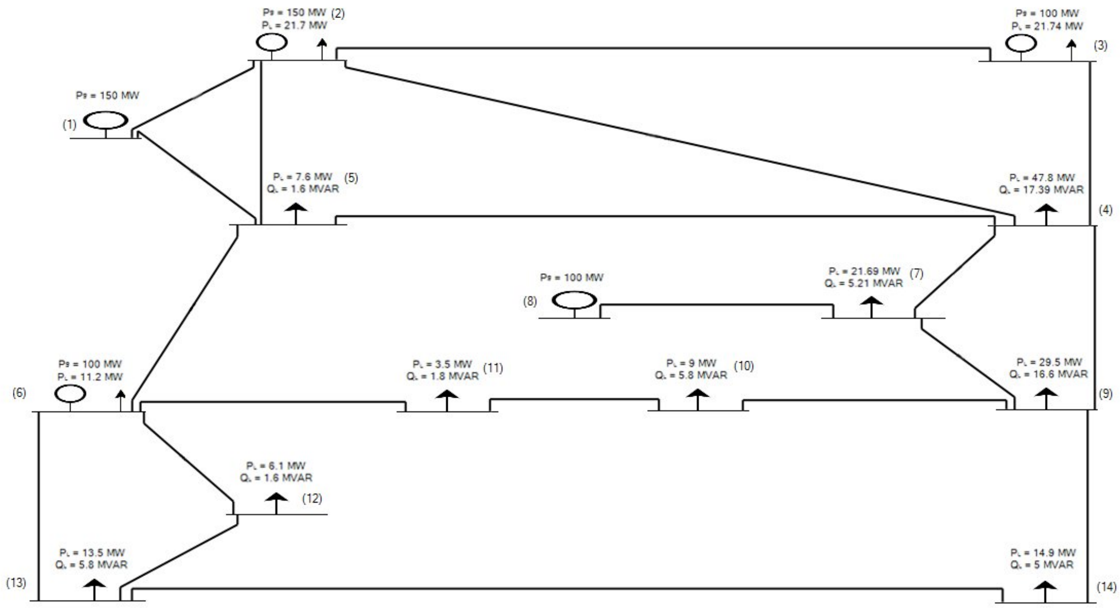

Fig. 5 The modified 14-BUS test system: Initial Configuration.

Case2: There will be a 10% share of installed DG units on the load buses (10 % of total load demand = 52.0575 MW and installed at bus 4), DG units are assumed nondispatchable and modeled as negative loads. The optimal plan for this case has been obtained with the configuration shown in Fig. 8. For the assumed data, an installation cost of \$27,189,600 is obtained for this case. Also, an operation and maintenance cost of \$3,797,388 and energy losses cost of \$13,828.7665 are obtained.

Case3: There will be a 15% share of installed DG units on the load buses (15 % of total load demand = 78.08 MW and installed at buses 7 (10 MW), 13 (18.08 MW), and 14 (50 MW)). The excess power at bus 14 will be dispatchable. The optimal plan for this case has been obtained with the configuration shown in Fig. 9. For the assumed data, an installation cost of \$27,364,800 is obtained for this case. Also, an operation and maintenance cost of \$3,828,751 and energy losses cost of \$7759.61613 are obtained.

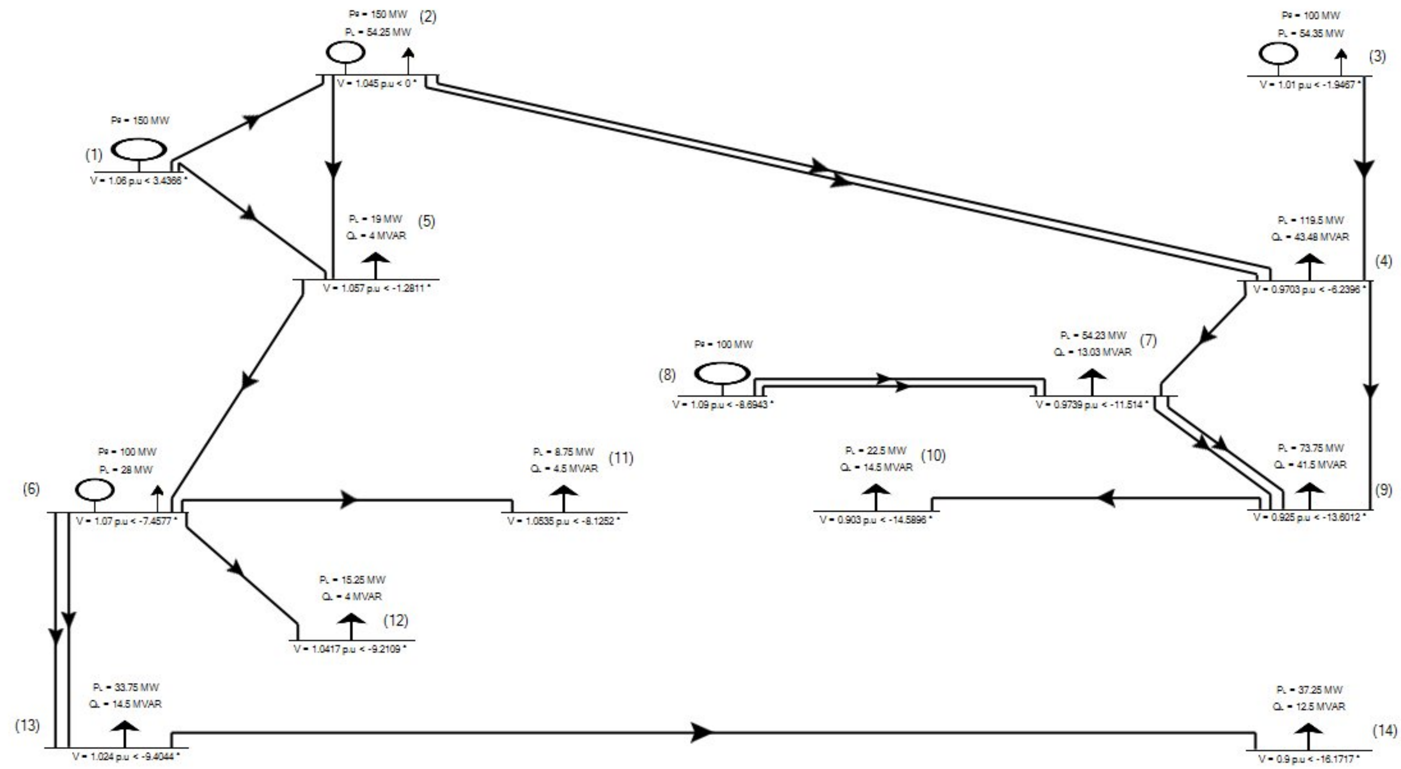

Fig. 6 Optimal plan for modified 14-BUS test system.

Studying the above three cases, it is observed that a 10% share of nondispatchable power and 15% share of dispatchable power reduce future network expansion costs. However, the cost reductions in installation cost are much lower than in the 5 % nondispatchable power case. These results are reasonable because when the DG units share is larger or are involved in the dispatch process, their electricity will be traded through the transmission network, which potentially can cause network congestion and provide incentives for network expansion. However, compared with the base case, larger penetration level of DG can still reduce the transmission investments to some extent.

Generally, studying the above optimal solutions reveals the following:

- None of the system lines has ever been overloaded.
- None of the system security constraints has been violated at any time.
- Some of the existing lines have been removed in the optimal plans, which is an advantage for this BBO based model since it allows the removal of any of the existing facilities if this helps in achieving the optimal plan.
- Computation time needed to get optimum solution using BBO model is short.

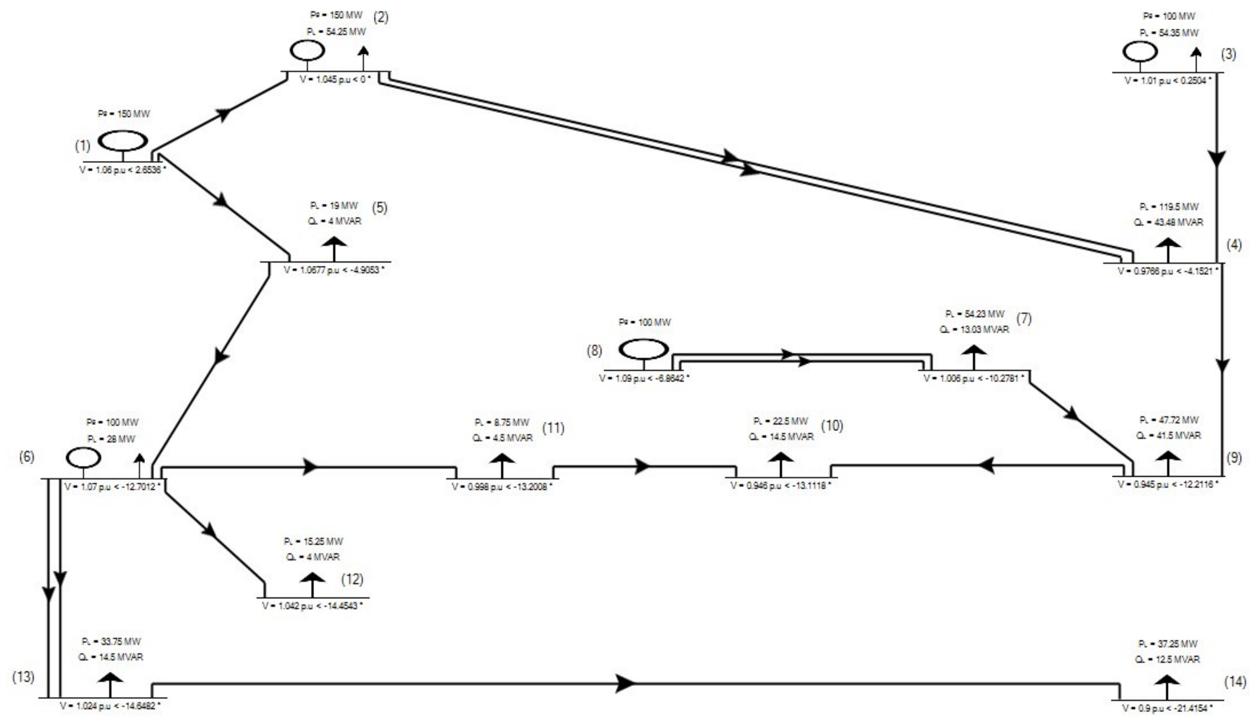

Fig. 7 Optimal plan for modified 14-Bus with 5% share of DG in supplying system loads.

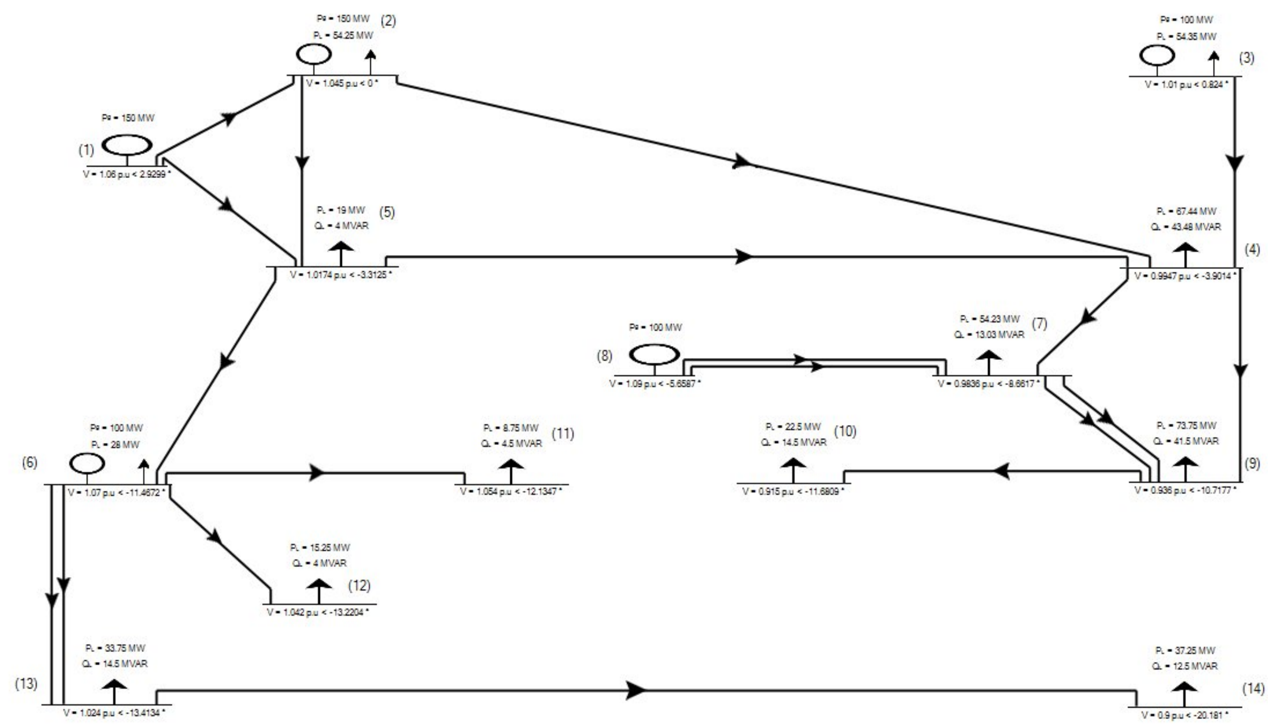

Fig. 8 Optimal plan for modified 14-Bus with large 10% of DG in supplying system loads.

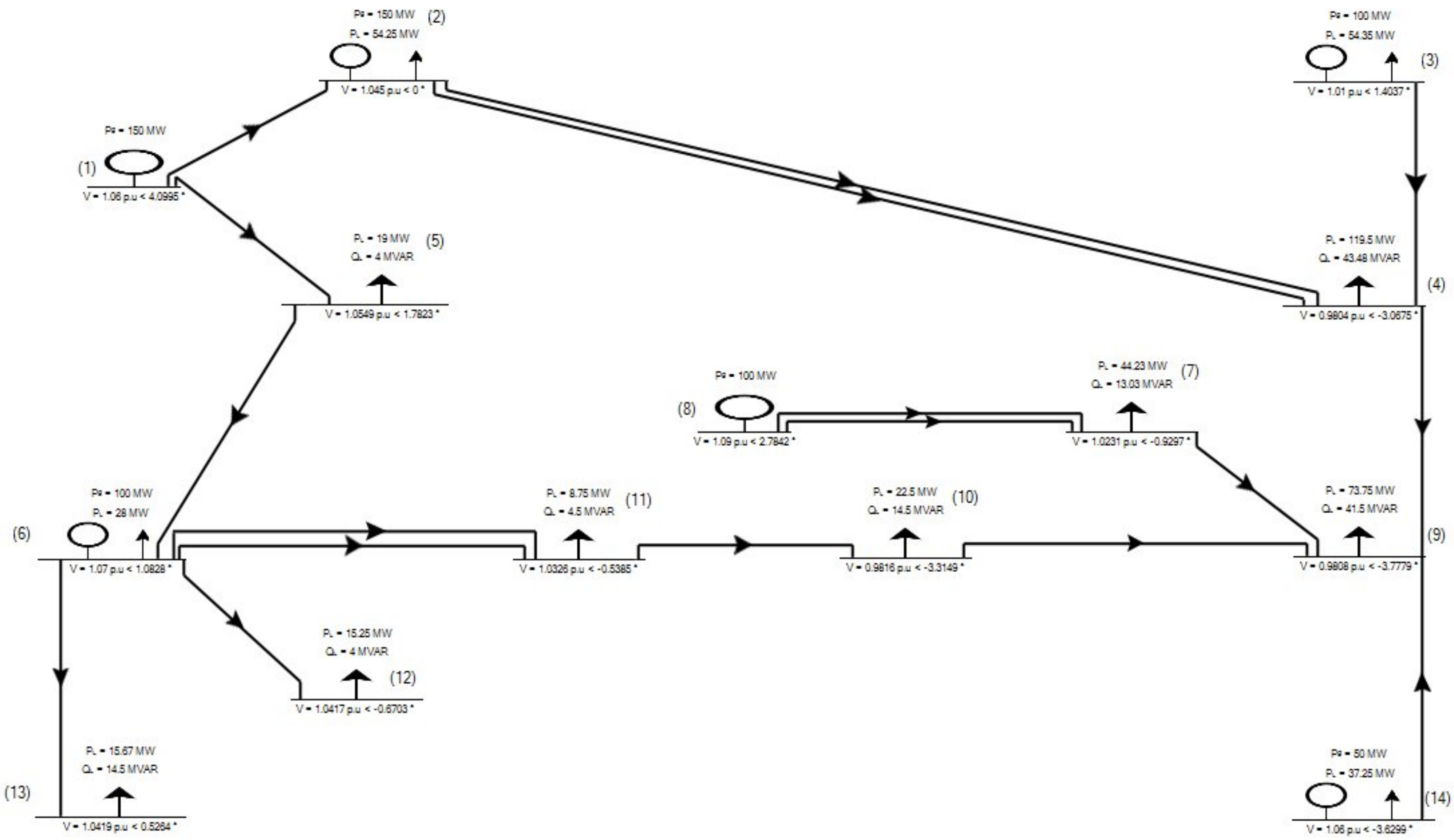

Fig. 9 Optimal plan for modified 14-Bus with large 15% of DG in supplying system loads.

6. Conclusions

A new BBO long range transmission planning model is developed and introduced in this paper with studying the DG impacts on the planning. This model is capable of handling both static and dynamic modes of planning. It ensures the feasibility of the optimal plan obtained since it applies the accurate AC load flow as well as the system operational and security constraints easily. It also allows the removal of any existing facilities if it is not needed and can account for their assets value in the objective function. The model cost function accurately includes the present worth value of all system installation, operation and maintenance, and energy losses costs with the consideration of their change with time according to inflation and interest rates. The results obtained from the proposed approach were reasonable compared to those reported in the recent literature. It has been observed that the BBO has the ability to converge to a better quality solution and possesses good convergence characteristics and robustness than other techniques. Also, the effect of DG as a new option for supplying the loads of the system, on the TEP costs was modeled mathematically and evaluated. The results showed that the use of DG units in the TEP provides more economical plans.

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