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A Novel Genetic-based Optimization for Transmission Constrained Generation Expansion Planning

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Abstract— Transmission constrained generation expansion planning (TC-GEP) problem involves decisions on site, capacity, type of fuel, and etc. of new generation units, which should be installed over a planning horizon to meet the expectations of energy demand. This may lead to adding or lightening transmission lines congestion. This paper presents an application of genetic algorithm (GA) to TC-GEP problem for simultaneously determination of new generation site, capacity and fuel type for a multi-period generation expansion plan. The objective function in this paper is to minimize the total generation cost which is composed of generation capital investment costs, operation and maintenance (O&M) costs, outage cost, transmission losses costs and transmission enhancement costs. In this paper, also a new method is proposed for computing transmission enhancement costs. In addition a new approach is presented in this paper to determine site and number of combined cycle power plants regarding to candidate units. The GA is applied to solve TC-GEP problem for 4 bus test system from Grainger & Stevenson for a planning horizon of one year and the results are compared and validated against Enumeration Method (EM). Then GA is applied to solve TC-GEP problem for IEEE-RTS 24-bus test system for a planning horizon of three years and results are discussed.

Index Terms— Generation Expansion Planning, Genetic Algorithm, Probabilistic Production Simulation, Power Losses Cost, Transmission Constraints

Nomenclature:

T	Study period (in years)
$\overline{IG_t}$	Discounted value of the generation capital investment costs ($) in year *t*
$\overline{IT}_t^{worst}$	Discounted value of the transmission capital investment costs ($) in the period of year *t* with the worst conditions
IG_t	Generation capital investment costs ($) in year *t*
N_p	Total number of different types of power plants
N_k	Total number of different types of units
PG^k	Maximum capacity (MW) of a k[th] type unit
$CIGFT_{p,b}$	Part of $CIGF_{p,b}$ related to technical cost($)
$CIGFL_{p,b}$	Part of $CIGF_{p,b}$ related to land cost($)
$CIGFP_{p,b}$	Part of $CIGF_{p,b}$ related to fuel supply piping cost($)
$CIGFGC_{p,b}$	Part of $CIGF_{p,b}$ related to interconnection cost to the main grid ($)
$CIGVT_{k,b}$	Part of $CIGV_{k,b}$ related to technical cost($)
$CIGVL_{k,b}$	Part of $CIGV_{k,b}$ related to land cost($)
$CIGVP_{k,b}$	Part of $CIGV_{k,b}$ related to fuel supply piping cost($)
$CIGVGC_{k,b}$	Part of $CIGV_{k,b}$ related to interconnection cost to the main grid ($)
IT_t^{worst}	Transmission capital investment costs ($) in worst period of year *t* (period with the worst conditions) of the study period

SR_j	Maximum capacity (MVA) of line j
NL	Total number of lines between buses
N_{per}	Total number of periods considered in each year
M_t	Total cost ($) of operation and maintenance in year t
$HRG_k^{\min}$	Heat rate at the minimum operating level (kcal/MWh) of the k^{th} type plant
$HRG_k^{\max}$	Heat rate at the maximum operating level (kcal/MWh) of the k^{th} type plant
$CFG_{k,b}$	Fuel cost ($/kcal) of the k^{th} type plant unit located at bus b
$Com_{k,b}^{\text{var}}$	Variable O&M cost ($/MWH)of the k^{th} type plant unit located at bus b
$Com_{k,b}^{fix}$	Fixed O&M cost ($/MW) of the k^{th} type plant unit located at bus b
O_t	Outage cost ($)
L_t	Total cost ($) of active Power losses in year t
CLT	Cost of active power loss ($/MW)
RL_j	Resistance (Ω) of line j
$P\left(K_{t,c}\right)$	Installed capacity (MW) of the system in the critical period of year t
$LOLP_t$	Loss of Load Probability (LOLP) in year t
$LOLP_{\max}$	Maximum acceptable LOLP
$FUV_{m,t}^{ex}$	Fuel consumption type m for existing units in year t (liter)
$FUV_{m,i}$	Fuel consumption type m for unit i (liter/MWh)
$EG_{i,t}^{tot}$	Total energy generated by plant unit i in year t
$U_{i,t}$	A binary bit is 1 if the type of fuel consumed at plant unit i in year t is m, otherwise its value is 0
$FUV_{m,t}^{\max}$	Maximum availability of fuel type m for the system in year t
N_{fu}	Total number of fuel types
NU_t	Total number of units added in year t

I. Introduction

Generation Expansion Planning (GEP) is the essential step in long-term planning problems, after properly forecasting the load for a specified future period. Generally, GEP is an optimization problem in which the objective is to decide the new generation plants in terms of what type and capacity they should be, where they should be installed and when to be invested, with the result that the cost function is minimized and various constraints are satisfied. GEP problem may be of a static type (for a specified stage, typically a year) or a dynamic type (for several stages in a specified period), concerning the stages under consideration for the planning horizon [1-3].

References [1,4-9] have used decomposition schemes to handle the problem complexity. Usually, such schemes divide the GEP problem into two sub-problems: the first is a single-bus GEP without considering transmission system; the next is a multi-bus GEP in which the transmission system effects are taken into account. WASP-IV is a powerful software product developed by the International Atomic Energy Agency (IAEA). A dynamic programming approach is used in this software to solve single-bus GEP problems [4]. In single-bus GEP problems proposed in [1,4-6,9], it is assumed that total generation capacity and total system load are placed on a particular bus. Single-bus GEP problems are able to determine the total generation capacity required for the network, but unable to geographically distribute and allocate the capacities among the network buses. Consequently, the O&M cost throughout the geographical distribution of the network is presumed to be uniform. This assumption is not practicable in real-world planning; For example, a power plant located far from a fuel resource supply center has higher fuel transmission (piping) costs in respect to closer ones. Furthermore, in single-bus GEP problems, some non-technical factors associated with the investment costs—such as the interconnection cost to the main grid and the cost of land —are uniformly distributed among the network buses. In real-world planning, such supposition reduces precision of the problem. In multi-bus GEP problems [1,7], it is supposed that the total generation requirements as well as the types and capacities of the generating units are pre-specified; here the purpose is to allocate the generation among the network buses to minimize generation investment costs and transmission enhancement requirements. This supposition also decreases the problem precision. All three TC-GEP variables (fuel type, capacity and place of new generation units) affect both O&M costs and investment costs. Consequently in this paper a model is developed to solve TC-GEP problems by simultaneously computing all three of problem variables, making the problem more practical. Objective function is to minimize the total generation cost, which is composed of O&M costs, investment costs, outage costs, transmission enhancement costs and active power loss costs. O&M costs consist of fuel costs and non-fuel operation and maintenance costs which are depending on energy generated by each unit [4,10]. In this paper, a power system probabilistic production simulation (PPS) is implemented for computing the energy generated by each unit and also the expected energy not served (EENS) in each period. Invested costs consist of generation investment costs and transmission enhancement costs. Generation investment costs involve technical costs, land costs, fuel supply piping costs and the interconnection cost to the main grid. Number of power plants is effective on the most nontechnical factors of investment costs such as land costs, fuel supply piping costs and the interconnection costs to the main grid as an alternative of the unit's number. So, in this paper, investment costs are divided into two parts: fixed part costs varying with the number of power plants, and variable part costs varying with the number of plant units. In this paper, an approach is proposed for computing the number and type of power plants relative to the number and type of plant units. It is worth to note that, any of the existing lines may need to be enhanced for a higher capacity, once a generation unit is installed on a bus. Consequently in this paper to improve problem precision, transmission enhancement costs are also considered as an objective function of TC-GEP problem. Note that, in this problem the main emphasis is GEP not the actual transmission enhancement requirements. So to handle the problem complexity, it is supposed that the transmission enhancement requirements are approximately proportional to the length-based overloads [1,11]. Moreover, an AC power flow model is used to compute transmission line loading and active power losses of the transmission system. All costs are discounted to a certain reference date. Besides, salvage values for all plants and transmission equipment are considered in the objective function formulation. Capacity reserve margins, reliability indexes and fuel availability are taken into account as the TC-GEP problem constraints. In this study, a GA is used as the optimization tool for the objective function of the TC-GEP problem. A new method is used for the proposed GA in order to sustain the feasibility of candidate solutions through the GA's operators. Four different types of plant units—natural gas, coal, oil and nuclear— are considered as candidate units for TC-GEP problem. To numerically evaluate the efficiency of the proposed method, simulation results on the 4-bus test system from Grainger & Stevenson for a planning horizon of one year and the IEEE-RTS 24-bus test system for a planning horizon of three years with growing complexity containing 16 and 288 decision variables, respectively, are used. EM is also applied to solve the TC-GEP problem for the Grainger & Stevenson 4-bus test system for a planning horizon of one year; the results of the GA are compared and validated against the EM. The results indicated that the GA is an effective alternative for the solution of the proposed TC-GEP problem.

II. Problem Formulation

In this section, a reconfigured formulation of the TC-GEP problem is presented. The problem is to specify the place, type and capacity of each unit required in each year of the study period from a list of available options. In doing so, besides satisfying different constraints such as meeting load demand, the present value of the total costs incurred should be minimized. The TC–GEP problem is dynamic and it is supposed that the forecasted load will be specified for each stage. The objective function terms as well as the different constraints are presented in the following subsections.

2.1 Capital investment Costs

The capital investment costs along the planning horizon consists of generation investment costs and transmission enhancement costs as:

$$\overline{I_t} = \overline{IG_t} + \overline{IT_t}^{worst} \tag{1}$$

At the following subsections, formulation of generation investment and transmission enhancement costs are discussed.

A. Generation Capital Investment Costs

Generation investment costs in each year can be computed as:

$$IG_t = \sum_{b=1}^{N_b} \left[\begin{array}{l} \sum_{p=1}^{N_p} \left(X_{p,b} \times CIGF_{p,b} \right) + \\ \sum_{k=1}^{N_k} \left(Y_{k,b} \times CIGV_{k,b} \times PG^k \right) \end{array} \right] \tag{2}$$

In Formula (2), $X_{p,b}$ is the number of type-p power plants placed on bus b; $CIGF_{p,b}$ denotes the fixed portion of the generation capital investment cost which is dependent on the number of power plants. $CIGF_{p,b}$ can be determined as:

$$CIGF_{p,b} = CIGFT_{p,b} + CIGFL_{p,b} + CIGFP_{p,b} + CIGFGC_{p,b} \quad (3)$$

The terms in formula (3) refer to parts of $CIGF_{p,b}$ which are concerning to technical, land, fuel piping costs and costs of interconnection into the main grid, respectively. Power plants composed of distributed units on network buses follow these rules:

Gas, steam and nuclear units placed on a bus where there is no other unit of the same type make up a new power plant.

Two gas units with a steam unit make up a combined-cycle power plant.

Maximum total capacity of each power plant is considered to be equal to 1,300MW.

In formula (2), $Y_{k,b}$ denotes the number of type-k units placed on bus b; $CIGV_{k,b}$ is the part of generation capital investment costs which is variable with the number of units. $CIGV_{k,b}$ can be calculated from formula (4).

$$CIGV_{k,b} = CIGVT_{k,b} + CIGVL_{k,b} + CIGVP_{k,b} + CIGVGC_{k,b} \quad (4)$$

The terms in (4) refer to parts of $CIGV_{k,b}$ which are concerning to technical, land, fuel piping costs and costs of interconnection into the main grid, respectively.

B. Transmission Enhancement Costs

As aforementioned, transmission enhancement requirements are considered proportional to the length-based overloads and are determined for a period of one year under the worst conditions (i.e., a period with the minimum reserve capacity). It is worthwhile to note that the transmission system model proposed in this paper is approximated and is not the only way to observe this point. The investment cost of transmission enhancement requirements is obtained from formula (5);

$$IT_t^{worst} = \sum_{j=1}^{NL} \left(Z_j \times (SL_j - SR_j) \times CIT_j \right) \quad (5)$$

Where CIT_j is the investment cost ($/MVA) of line j that requires to be enhanced; SL_j denotes power flow (MVA) through transmission line j under the worst conditions; Z_j is set to 1 only if line j is overloaded, otherwise Z_j is set to zero; Two objective functions generation investment costs and transmission enhancement costs have conflicts in distributing units among the buses. Increasing the number of power plants throughout distributing units among the network buses will increase the generation investment costs, whereas the transmission enhancement costs will be reduced by decreasing length-based overloads.

2.2 O&M Costs of Generation

O&M costs in each year consist of fuel costs and non-fuel O&M costs of generation. O&M costs can be calculated as:

$$M_t = \sum_{f=1}^{N_{per}} \sum_{b=1}^{N_b} \sum_{k=1}^{N_k} \left(\sum_{i=1}^{m_{k,b,f}} \left[\begin{array}{l} (HRG_k^{\min} \times EG_i^{base} + \\ HRG_k^{\max} \times EG_i^{peak}) \times CFG_{k,b} \\ + Com_{k,b}^{var} \times EG_i^{tot} \\ + Com_{k,b}^{fix} \times PG^k \end{array} \right] \right) \quad (6)$$

where $m_{k,b,h}$ denotes the total number of type-k plant units placed on bus b, in period f of year t of the study period. EG_i^{base}, EG_i^{peak} and EG_i^{tot} are the energy generated in base and peak capacity, and total energy generated by the type-k i^th plant unit located at bus b, in period f of year t of the study period ,respectively. In this paper, PPS is used for power system generation expansion planning as well as laying seasonal operation plans for existing power systems. Doing so, the PPS not only calculates the output of every generating unit and performs cost analysis from the perspective of optimization, but also provides important data for dealing with different problems arising during operation. The equivalent load duration curve (ELDC) is the most important concept confirmed in the development of PPS technology. It ingeniously integrates a generating unit's random outage with the random load model and is the core of PPS [12]. Indices of ${}^{base}EG_i^{k,b,f,t}$, ${}^{peak}EG_i^{k,b,f,t}$ and ${}^{tot}EG_i^{k,b,f,t}$ are computed using an ELDC for the PPS. Formula (7) shows the equation of the ELDC used for fixed and candidate units:

$$f^{(i)}(x) = p_i f^{(i-1)}(x) + q_i f^{(i-1)}(x - c_i) \quad (7)$$

Where P_i is the operation rate of generating unit i and $q_i=1-p_i$ indicates the unit's Forced Outage Rate (FOR); c_i is generating capacity for unit i in $p.u$; energy generated by each unit is calculated by formula (8)

$$E_{gi} = Tp_i \int_{x_{i-1}}^{x_i} f^{(i-1)}(x)dx \quad (8)$$

Where x_i is equal to $\sum_{j=1}^{i} C_j$.

2.3 Outage Cost

FOR of a generating unit represents the percentage of time the unit maybe unavailable due to unexpected outages. A generating unit maybe tripped at a rate given by it's FOR. Some portion of the energy demand cannot be served owing to the FORs of the units and based on demand and available reserves. EENS is computed from formula (9) and cannot be equal to 0; rather, it should be minimized as a cost term called outage cost, specified by formula (10):

$$EENS = T \int_{C_t}^{x_{\max}+C_t} f^{(n)}(x)dx \tag{9}$$

$$O_t = \left[\begin{array}{l} a + b \times \left(\sum_{f=1}^{N_{per}} EENS^f \right) \\ +C \times \left(\sum_{f=1}^{N_{per}} EENS^f \right)^2 \end{array} \right] \tag{10}$$

Where $EENS^{f,t}$ denotes EENS (MWH) in period f, and year t of the study period; c_t is the total capacity of all of the active generating units during the time interval; a, b and c are constants; and ELDC of the PPS is also used to calculate EENS and loss of load probability(LOLP) used in the constraint objective[12]. LOLP can be calculated from formula (11).

$$LOLP = f^{(n)}(C_t) \tag{11}$$

2.4 Transmission Losses Costs

The costs of active power losses can be calculated as:

$$L_t = \left[CLT \times \sum_{j=1}^{NL} \left(RL_j \times \left(IL_j \right)^2 \right) \right] \tag{12}$$

Where IL_j denotes the current of line j which is calculated by solving the AC load flow for the system involving candidate units. As aforementioned, in this model, it is assumed that the network load is uniformly increased between the network load buses according to the forecasting load for each year.

2.5 Objective Function of the Proposed Method

As aforementioned, the discounted value of the total generating costs is considered as the objective function, which is represented by formula (13):

$$Min \quad C = \sum_{t=1}^{T} \left[\overline{I_t} + \overline{M_t} + \overline{O_t} + \overline{L_t} - \overline{S_t} \right] \tag{13}$$

Where the first and second terms refer to present-worth values of capital investment costs and O&M costs, respectively. In addition, the third and fourth terms represent the present-worth value of outage costs and power active loss costs, respectively. $\overline{S_t}$ is the salvage value of the investment costs, which is deducted from the capital investment costs. In order to calculate the present-worth value of the cost components of formula (13), it is supposed that the full capital investment for a plant or a transmission equipment added by the expansion plan are made at the beginning of the year in which it goes into the service. As a matter of fact, the present-worth factors are specified with this assumption.

2.6 Constraints of the Proposed Method

Two types of constraints are considered in the proposed TC-GEP problem: fuel constraints and technical constraints.

A. Fuel Constraints

As can be seen from formula (14), each fuel supply center is able to supply a maximum amount of generation capacity.

$$\begin{array}{l} FUV_{m,t}^{ex} + \sum_{i=1}^{NU_t} \left(FUV_{m,i} \times EG_{i,t}^{tot} \times U_{i,t} \right) \le FUV_{m,t}^{\max} \\ \forall m = 1,...,N_{fu}, t = 1,...,T \end{array} \tag{14}$$

B. Technical Constraints

There are uncertainties that may cause generation units to trip unexpectedly at any time. Consequently generation capacity should be adequate in satisfying the load requirements. The following two constraints, then, should be taken into account:

$$\begin{array}{l} \left(1 + a_t\right) D_{t,c} \ge P\left(K_{t,c}\right) \ge \left(1 + b_t\right) D_{t,c} \\ \forall t = 1,...,T \end{array} \tag{15}$$

$$\begin{array}{l} LOLP_t \le LOLP_{\max} \\ \forall t = 1,...,T \end{array} \tag{16}$$

Where c is the critical period. It denots the period of the year in which the difference between the relevant available generating capacity and the peak demand has the smallest value. Formula (15) clearly implies that the installed capacity in the critical period must lie between the given maximum and minimum reserve margins—a_t and b_t, respectively—above the peak demand ($D_{t,c}$) during the critical period of the year.

In the proposed TC-GEP problem, the reliability of the system is computed in terms of the LOLP index for each period of the year, as in formula (16). The LOLP of each period is specified as the average annual LOLP, where the sum of the LOLP of the periods is divided by the total number of periods.

III. Solution Methodology

As previously mentioned, the purpose of this problem was to find the optimum number, type and location of the candidate generating units. The objectives are described in Section 2.In the following section, a GA is employed to the proposed method.

3.1 Applying a GA to the Proposed Method

In nature, each species must adapt itself for the maximum likelihood of survival in a challenging environment. Species with improved characteristics tend to survive overtime. In fact, species with higher fitness levels survive longer. This type of phenomenon, which occurs in nature, is the basis for the evolutionary-based GA [1,13-15].To solve a TC-GEP problem using a GA problem, variables are combined and represented as mixed integer coding in each chromosome. The data structure of the chromosome can be depicted, as shown in Figure 1. As can be seen from this figure, each three genes of the chromosome refer to the number of type-k plants on bus *b*, in year *t* of the study period. In the proposed GA, candidate solutions of the initial population are randomly selected between all solutions to satisfy the constraints in formula (15), and new solutions are obtained through the GA's operators (selection, crossover, and mutation) which are checked to sustain feasibility.

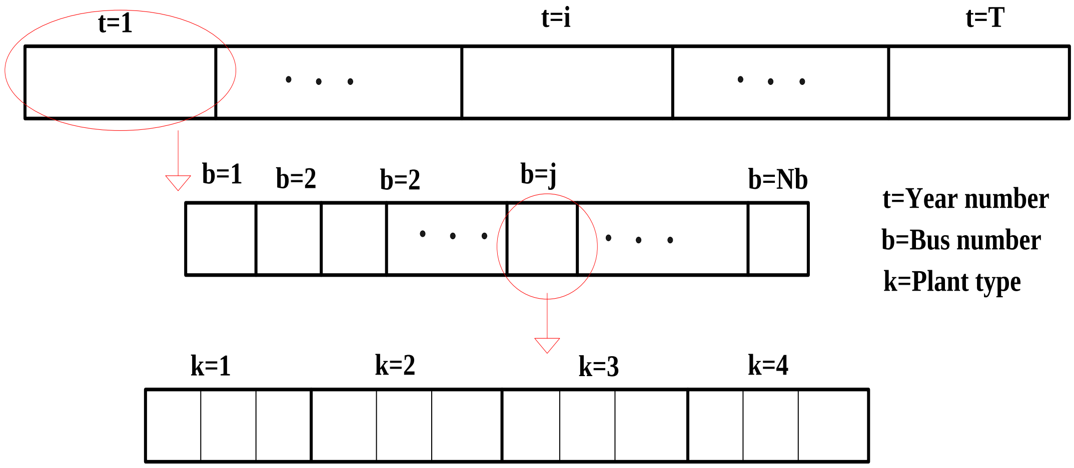

Fig. 1: Data structure of each chromosome of GA

IV. Simulation

In order to demonstrate the effectiveness of the proposed approach, it is applied to the 4-bus test system from Grainger & Stevenson for a planning horizon of one year and an IEEE-RTS 24-bus test system for a planning horizon of three years with growing complexity. For these case studies, chromosomes containing 48 and 864 genes, respectively, are considered (see Figure 1). In this study, candidate plants for generation expansion planning are selected from four different types of natural gas units, coal units, oil units and nuclear units. Two case studies and their results are presented in the following subsections.

4.1 Case Study 1

In this first case, the problem is applied to a 4-bus, 1-generator case from Grainger & Stevenson [16]. The figure of this system is presented in Figure 2.

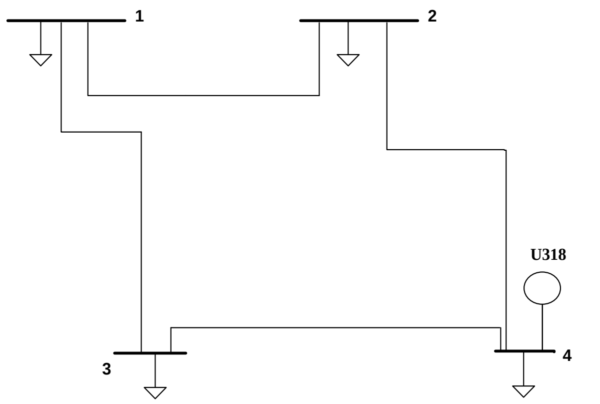

Fig. 2: Case study 1: 4 bus test system from Grainger & Stevenson

As can be seen from this figure, there is only one fixed nuclear unit of 318MW nominal capacity, and 8% FOR, which is placed on bus 4; total network load is 500MW. For this case study, the TC-GEP problem is solved for a planning horizon of one year. First, a GA is used as the optimization tool, then the Enumeration Method (EM) is used to solve the problem for all feasible chromosomes, satisfying formula (15).

It is noteworthy that the proposed expansion plans by the GA and EM are the same. The total objective function is evaluated for this case study, as described in Section 2. A PPS is also employed for calculating the energy generated by each unit and also the expected energy not served in each period for this case study; Figure 3 shows the ELDC of the PPS for the proposed expansion plan by the GA for case study 1. As can be seen, the ELDC is evaluated for six fixed and candidate units with respect to their FORs. The proposed expansion plan for case study 1, generated energy and O&M costs of generation of each unit during the first period for this expansion plan is presented in Table 1.

As can be seen, the candidate plants are distributed on buses 1 and 3. Capital investment costs related to various factors (technical, land, fuel piping and interconnection to the main grid) of the candidate units for the expansion plan proposed for Case study 1 are presented in Table 2. As can be seen from this table, two steam and natural-gas power plants are developed by distributing candidate units between buses 1 and 3. Also, the expected energy not served, overload, active power losses and the discounted value of all of the cost terms of the objective function for the proposed expansion plan for case study 1 are presented in Table 3. Total objective function for case study 1 is equal to \$1,059,931,580. The GA converges at the 4th iteration.

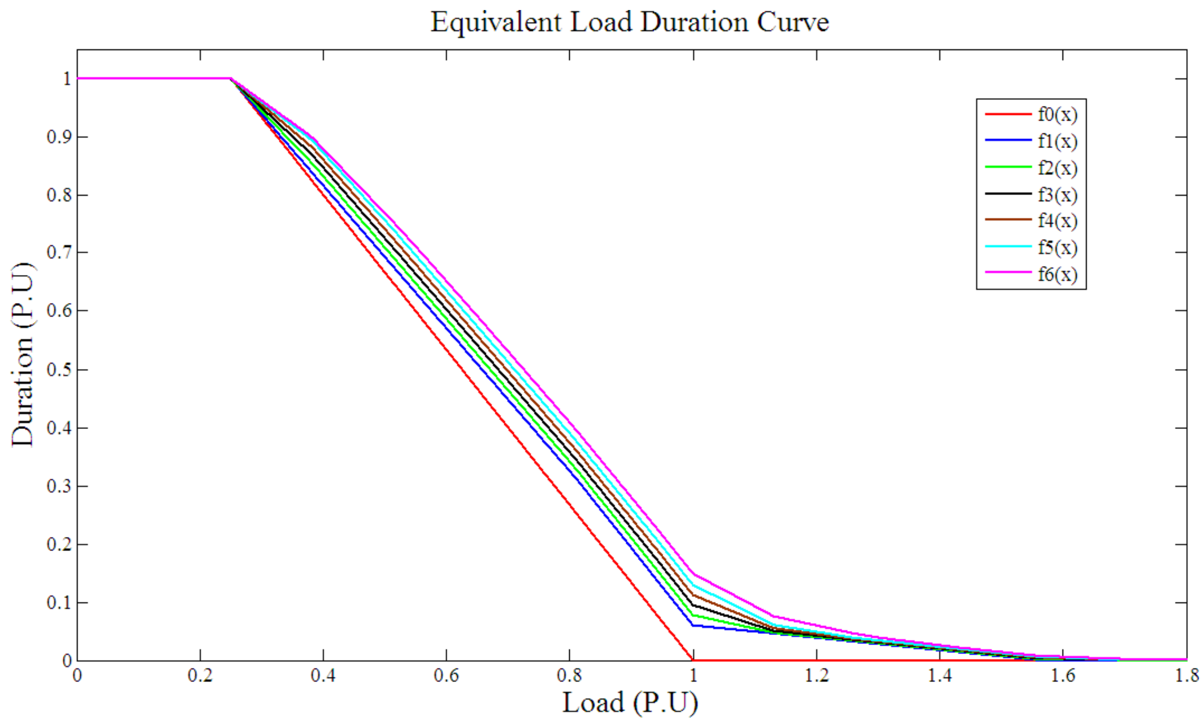

Fig. 3: ELDC for case study 1

Table 1: Generated Energy and O&M costs of generation of each unit during first period for proposed expansion plan by GA for Case study 1

Unit number	Unit type	Bus Number	Unit Type	Total Generated Energy (GWH)	Generated Energy in base Capacity (GWH)	Fuel costs (K\$)	Non-fuel O&M costs (K\$)	O&M cost involving fuel costs (K\$)
1	Fixed	4	U318	567.95	181.33	7951.35	737.63	8688.99
2	Candidate	3	F-CC	79.96	40.28	1193.65	246.41	1440.07
3	Candidate	3	F-CC	58.46	36.2			
4	Candidate	1	FOIL	35.96	32.11	6925.83	1657.07	8582.9
5	Candidate	1	FOIL	16.4	4.1			
6	Candidate	1	FOIL	16.24	10.43			
7	Candidate	1	FOIL	4.04	1.01			
Total	-	-	-	779.01	305.46	16070.83	2641.11	18711.96

Table 2: Capital investment costs for Case study 1

Terms/ Power Plant Number	Power Plant type	Bus Number	Unit Number	Technical costs (K$)		Land costs (K$)		Fuel piping costs (K$)		Costs of interconnection to the main grid (K$)		Fixed costs (K$)	Investment Costs (K$)
				Depreciable	Non-depreciable	Depreciable	Non-depreciable	Depreciable	Non-depreciable	Depreciable	Non-depreciable		
1	NGAS	3	2	893.6	0	80	0	135	0	82	0	150781.82	153163.02
			3	893.6	0	80	0	135	0	82	0		
2	STEAM	1	4	2960.4	148	310	155	15.27	7.63	35	0	103818.18	118343.38
			5	2960.4	148	310	155	15.27	7.63	35	0		
			6	2960.4	148	310	155	15.27	7.63	35	0		
			7	2960.4	148	310	155	15.27	7.63	35	0		
Total				13628.8	592	1400	620	331.08	30.52	304	0	254600	271506.3

Table 3: Value of all cost terms of objective function for the expansion plan proposed by GA for Case studies 1 and 2

Terms/ Expansion plan proposed by GA	Year number	Expected energy not served (GWH)	Overload (MVA)	Active power losses (MW)	O&M cost (K$)	Capital investment cost (K$)	Salvage value of capital investment cost (K$)	Outage cost (K$)	Transmission enhancement cost (K$)	Active power losses cost (K$)	Objective function (K$)
Case study1	1	3.217	74.943	5.81317	69561.669	1621617.09	1403320.0396	64710.098	123460.24	1511.63	**1059931.58**
Case study 2	1	0.318438	13.472128	54.7463	288180.33	860016.872	604981.32	43801.159	14618.101	14235.99	615871.127
	2	0.096564	411.6279	131.461	348381.41	1044793.611	801774.432	11660.672	415628.523	31077.014	1049766.803
	3	0.08349	682.3472	258.482	334248.126	601305.334	531660.627	9147.969	827778.368	55549.241	1296368.412
	Total	0.4984	1107.44	444.689	970809.871	2506115.818	1938416.387	64609.801	1258024.993	100862.246	**2962006.343**

4.2 Case Study 2

An IEEE-RTS 24-bus test system is selected as the second case study to which the TC-GEP problem is applied for a planning horizon of three years with growing complexity [17-18]. Figure 4 shows this test system. As can be seen from this figure, there are 32 fixed units of 3,405MW total nominal generating capacity. Total network load is 2,850MW, and it is assumed that the network load would uniformly increased between the network load buses.

The proposed GA that is validated for case study 1 and compared with the EM is also employed to solve the TC-GEP problem for this case study. The expansion plan suggested by the GA for case study 2 is shown in Table 4. As can be seen, 8 power plants consisting of 18 units each are distributed between buses 7, 11, 12 and 17.

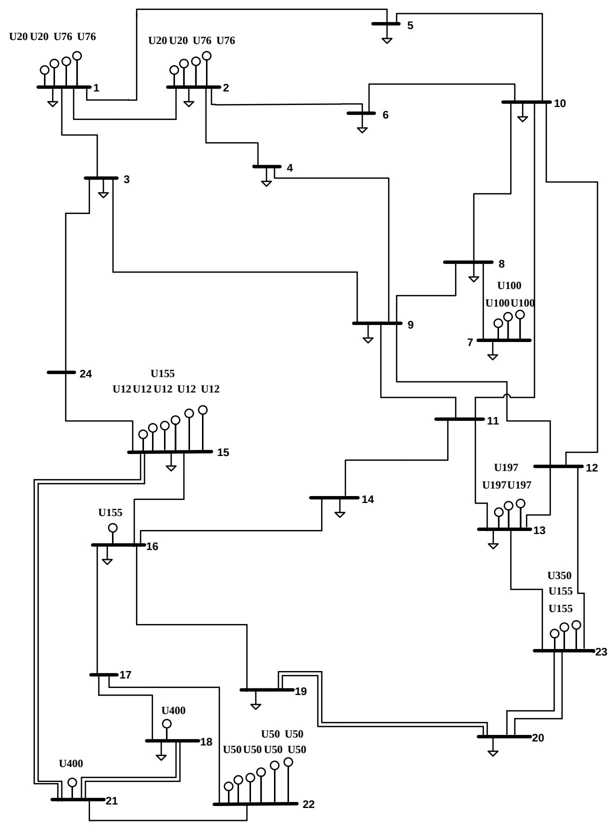

Fig. 4: Case study 2: IEEE-RTS 24-bus test system

Table 4: Specification of expansion plan proposed by GA for Case study 2

Year number	Power plant number	Power plant type	Power plant capacity	Bus number	Unit number	Unit type
1	1	STEAM	280	11	1	FCOA
	2	NGAS	174	11	2	F-CC
	3	CCYC	628	12	3	F-CC
					4	F-CC
					5	FCOA
2	4	CCYC	454	7	6	F-CC
					7	FOIL
	2	NGAS	348	11	8	F-CC
	3	CCYC	983	12	9	FOIL
					10	FCOA
	5	NGAS	174	17	11	F-CC
	6	NUCL	400	17	12	NUCL
3	4	CCYC	529	7	13	FOIL
	7	STEAM	355	7	14	FOIL
					15	FCOA
	1	STEAM	355	11	16	FOIL
	3	CCYC	1263	12	17	FCOA
	8	STEAM	35	17	18	FOIL

Four of these power plants are of the steam type, three are natural-gas power plants, one is nuclear and five are combined-cycle power plants. Five of the candidate units are entered into the network during the first year of the study period, seven of them are entered during the second year and six are entered during the third year of the study period. Fuel and non-fuel O&M costs and capital investment costs related to various factors (e.g., technical, land, fuel piping and interconnection to the main grid) of the candidate units for the expansion plan proposed by the GA for case study 2 are presented in Table 5. All terms are computed for each year of the study period separately. Also, the expected energy not served, overload, active power losses and the discounted value of all of the cost terms of objective function for each year of the study period of the proposed expansion plan for case study 2 are presented in Table 3. The total objective function for case study 2 is equal to $ 2,962,006,343. The GA convergence for case study 2 is shown in Figure 5. As can be seen, the GA converges at the 32^{th} iteration.

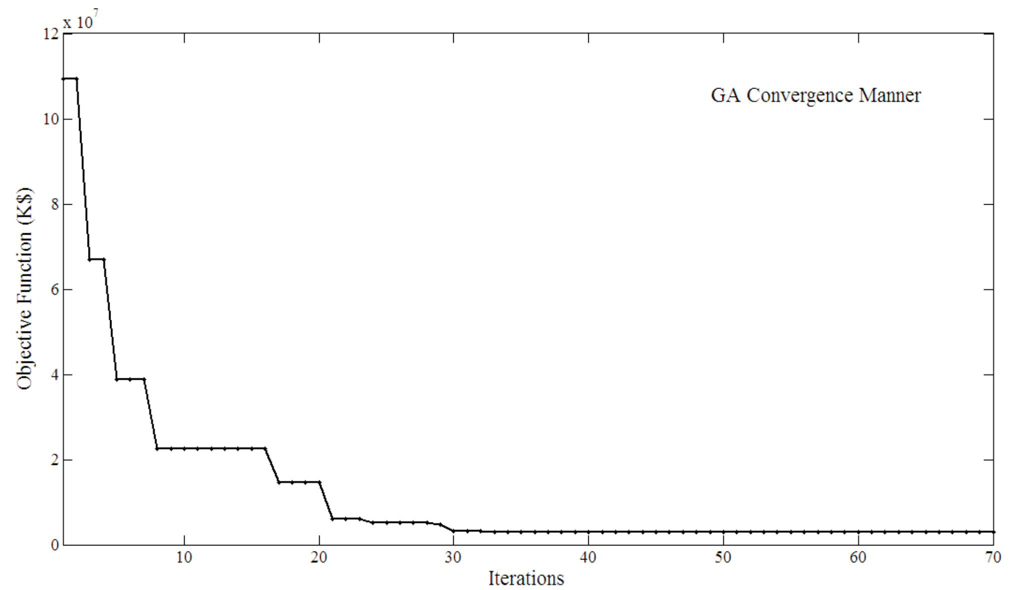

Fig. 5: GA convergence manner for Case study 2

Table 5: O&M capital investment costs of candidate units for the expansion plan proposed by GA for Case study 2

Terms/Year number	Fuel costs (K$)	Non-fuel O&M costs (K$)	O&M cost involving fuel costs (K$)	Technical costs (K$)		Land costs (K$)		Fuel piping costs (K$)		Costs of interconnection to the main grid (K$)		Fixed costs (K$)	Investment costs (K$)
				Depre-ciable	Non-depreciable	Depreciable	Non-depre-ciable	Depre-ciable	Non-depreciable	Depre-ciable	Non-depreciable		
1	285685.879	46784.809	332470.688	240689.76	16119.6	24948	14870.8	20745.2	9872.8	7364.4	0	611408	946018.56
2	381485.183	60784.4587	442269.642	539880.75	9971.9	34936	9318.95	16581.725	5179.725	6856.9	0	682000	1304725.95
3	390233.168	76499.263	466732.432	280092.5	20461.9	23010	17178.15	12089.125	10003.725	4002	0	433500	800337.4
Total	1057404.23	184068.53	1241472.762	1060663.01	46553.4	82894	41367.9	49416.05	25056.25	18223.3	0	1726908	3051081.91
				1107216.41		124261.9		74472.3		18223.3			

V. Conclusions

Usually, in order to solve GEP problems, the expansion problem is divided into two sub-problems. The first is a single-bus GEP in which the transmission system is ignored, and the next is a multi-bus GEP in which transmission system effects are considered. This classification is not practicable in real-world planning. In order, then, to make TC-GEP problems more practicable, the study presented here is developed in order to solve such problems by simultaneously determining the location, type and capacity of each unit needed in each year of the study period. The objective function is used to minimize total generation costs which are composed of O&M costs, investment costs, outage costs, transmission enhancement costs and active power loss costs. Power system PPS is used to calculate the energy generated by each unit and also the expected energy not served in each period. The 4-bus test system from Grainger & Stevenson and the IEEE-RTS 24-bus test system are used as test systems to numerically evaluate the efficiency of the proposed method. Simulation results are provided for the test systems for a planning horizon of one year and a planning horizon of three years with growing complexity, respectively. The results of the GA are compared and validated against the EM in solving the TC-GEP problem for the Grainger & Stevenson 4-bus test system. The results indicate that the GA is an effective alternative to the solution of the proposed TC-GEP problem.

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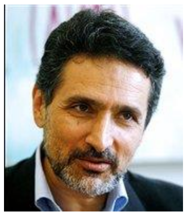

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