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Genetic Algorithm Approach to Generation Expansion Planning under Deregulated Environment

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Abstract

This paper presents an application of Improved Genetic Algorithm (IGA) with the support of Optimal Power Flow (OPF) algorithm for the least cost Generation Expansion Planning (GEP) problem under deregulated environment of power system. The proposed GEP model includes the presence of firm bilateral transactions, multilateral transactions and Independent Power Producers (IPP) in the system. The optimal location and size of new generators have also been determined using this model. The performance of the proposed algorithm has been illustrated for 6-year planning period with modified IEEE-30 Bus system. The results of IGA is compared and validated with Dynamic Programming (DP) solutions.

Nomenclature

C_j	is the objective function value of the j^{th} individual attached to the expansion plan
t	is the time in years (1, 2 . T)
T	is the length of the study period (total number of years)
I	is the capital Investment cost
S	is the Salvage value of investment cost
M	is the Maintenance cost of the unit
O	is the Outage cost (Cost of the energy not served)
$[K_t]$	is the vector containing the number of all generating units which are in operation in the year t
$[A_t]$	vector of committed addition of units in year t
$[R_t]$	vector of the retirements of generating units in year t
$[U_t]$	vector of candidate generating units added to the system in year t.
$U_{t, max}$	maximum construction capacity [MW] vector by unit types in year t
D_t	annual demand in the year t in MW
R_{min}	lower bound of reserve margin
R_{max}	upper bound of reserve margin
$\in$	reliability criterion expressed in LOLP
P_g	is the real power of the generating bus
P_L	is the real power of the load bus
Q_g	is the reactive power of the generating bus
Q_L	is the reactive power of the load bus

$P(V,\theta)$	is the real power as a function of voltage and phase angle
$Q(V,\theta)$	is the reactive power as a function of voltage and phase angle
V_i^{min}	is the minimum voltage limit of the i^{th} bus
V_i^{max}	is the maximum voltage limit of the i^{th} bus
f_j	is the fitness function value of the j^{th} individual
α_1	is the penalty factor for reserve margin constraint
Ψ_1	is the amount of reserve margin constraint violation
α_2	is the penalty factor for LOLP constraint
Ψ_2	is the amount of LOLP constraint violation
δ	is the penalty value added for the power flow constraint violation
ν	represents the degree of satisfaction
P	is the vector of online generating capacities of each generating unit
a, b and c	constants (Fuel cost)

Introduction

In developing countries like India, which has one of the largest electrical networks, it is the right time to think about effective utilization of electrical network [1] along with deregulated market developments. The government policy changes permit the Independent Power Producers (IPP) to enter into the bulk transmission network. Furthermore in the wake of pollution arising from usage of oil and coal for the power generation, the non-conventional energy sources (especially wind and solar) are entertained. A large number of private parties are entering into the electrical network by connecting their miniature units at sites selected for non-conventional energy sources and utilizing the power at remote places; known as firm transactions. Some private concerns are interested in utilizing the transmission network alone for their power transactions. In these circumstances, the utility shall have to focus their concentration on the effective utilization of transmission line, to reduce the power cost of the utility consumers.

The Generation Expansion Planning (GEP) problem concentrates mainly on '*When*', '*Where*', and '*Which*' generating units to be committed on line. In the deregulated environment, '*when and where to allow the transactions*' is an important question remains to be answered. This problem is another form of GEP, with both firm bilateral and multilateral wheeling transactions.

The necessity to coordinate both long term and short term planning in thermal systems is illustrated in [2]. The necessity of composite generation and transmission expansion planning has been explained in [3]. An attractive work has also been carried out for optimization of generating unit's location in [4]. A modeling framework is developed which comprises of investment planning, unit commitment and OPF modules for generator bid selection in [5]. The Genetic Algorithm (GA), iterative GA and advanced evolutionary programming are also applied to simple GEP problem successfully [6-8].

In this paper, the GEP for 6 years planning period considering the IPPs, firm purchases and other multilateral transactions without violating transmission constraints is explained considering the methods suggested in [2-6]. The planning problem is solved by running Optimal Power Flow (OPF) including the various transactions with load growth. The solving technique includes Dynamic Programming (DP) and Improved Genetic Algorithm (IGA).

Problem Formulation

A. Objective function

The least cost GEP problem is a stochastic, nonlinear, dynamic optimization problem with many constraints [9]. The GEP problem determines a set of best decision vectors over a planning horizon that minimizes the cost (objective function) under several constraints. The cost function for the GEP problem has been formulated by considering the capital cost of the unit to be installed, energy generated by the new units, the capacity charge of the IPPs and the operation and maintenance cost of the existing and the new units.

This problem is started with the addition of IPPs for the various transactions. The various transactions used in this paper are firm transactions, multilateral transactions and multilateral transaction with firm purchase.

In all types of transactions, the private parties use only the transmission lines of the utility. In firm purchase, the private parties operate over a longer period. They inject power at one bus and draw in some other bus. Bilateral transactions can be either firm or non firm. In non-firm transactions, the supplier are not bound to transmit the fixed power all the time and it will vary depending upon system congestion. In multilateral transaction, the private parties inject and/or they may draw the power from more than one point.

The objective function (cost function) for each type j is calculated by the following expression

$$\text{Min } C_j = \sum_{t=1}^{T}\left[I_t - S_t + M_t + O_t\right] \tag{1}$$

The maintenance cost of the unit includes the fixed cost for the maintenance as well as the variable cost. Normally probabilistic production costing method is used to find the expected energy produced by each unit. Equivalent energy function method may be used to find the probabilistic production cost. The generating units are scheduled for operation according to their economic merit order and the energy produced by each generating unit can be calculated. But this method ignores the transmission losses. So in the proposed model, to get an exact cost, the OPF method is used, which include, the generation required (economic dispatch) to meet the load demand as well as the transmission losses. So this proposed method provides better result than the probabilistic production costing method.

B. Constraints

The various constraints that are used in this paper for DP and IGA algorithms are reserve margin, reliability criterion and power flow constraints. If $[K_t]$ is a vector containing the number of all generating units which are in operation in year t for a given expansion plan, then $[K_t]$ must satisfy the following relationship

$$[K_t]=[K_{t-1}]+[A_t]-[R_t]+[U_t] \tag{2}$$

$[A_t]$ and $[R_t]$ are given data, and $[U_t]$ is the system configuration vector which is the vector of newly added units. $[A_t]$ is the committed addition of units in year t. The committed addition of units implies the already selected units in the previous expansion plans which are going to be constructed in the year t. $[R_t]$ is the retirement of the generating units. In this paper, both $[A_t]$ and $[R_t]$ are not considered.

$$0 < [U_t] < [U_{t,max}] \tag{3}$$

i) Reserve margin

The selected units along with the existing units should satisfy the annual demand. To carry out the maintenance activities of the generators and to compensate for the unexpected outage of units, the reserve margin of 20 % to 60 % is used. The selected units should satisfy the minimum and maximum reserve margin given by equation (4). If it is not met, then the error (ψ_1) is calculated by using the equation (5).

$$(1+R_{min})\times D_t \leq \sum [K_t] \leq (1+R_{max})\times D_t \tag{4}$$

$$\Psi_1 = \max(((1+R_{min})\times D_t - \sum[K_t]), (\sum[K_t] - (1+R_{max})\times D_t)) \tag{5}$$

If the minimum or maximum reserve margin is violated, then the proportional penalty value is added with the original objective function value. If the minimum reserve margin is violated, $((1+R_{min}) \times D - \Sigma[K_t])$ of equation (5) becomes positive and $((\Sigma[K_t]) - (1+R_{max}) \times D)$ becomes negative. The maximum of the two terms results in positive value and corresponds to the shortage value of reserve margin. Similarly for maximum reserve margin, if the margin is exceeded, then $((\Sigma[K_t]) - (1+R_{max}) \times D)$ becomes positive and $((1+R_{min}) \times D - \Sigma[K_t])$ becomes negative. The positive value corresponds to the excess of generation capacity. This error term Ψ_1 is used in the penalty function approach.

ii) Reliability criterion

The reliability criterion includes the Loss of Load Probability (LOLP) and the Expected Energy Not Served (EENS). If LOLP (K_t) is the LOLP, every acceptable configuration must satisfy the following constraint.

$$\mathrm{LOLP}(K_t) \leq \in \tag{6}$$

$$\Psi_2 = \mathrm{LOLP}(K_t) - \in \tag{7}$$

Both LOLP and EENS are calculated by the Equivalent energy function method [9].

iii) Optimal power flow constrains

In this paper, in addition to the above constraints, the power flow constraints are also checked and if it satisfies the optimal power flow, then the cost obtained, is included as variable cost. The location of generating units is also considered by assuming the availability of generators at the specified buses.

To check the MVA limits of transmission lines alone, it is enough to use a D.C power flow algorithm. To include additional constraints such as real power flow, reactive power flow, voltage magnitude at each bus, etc A.C power flow algorithm can be used.

The various constraints used to check the optimal power flow are as follows:

The active power balance equation is

$$P_{gi} - P_{Li} - P(V,\theta) = 0 \tag{8}$$

The reactive power balance equation is

$$Q_{gi} - Q_{Li} - Q(V,\theta) = 0 \quad (9)$$

The apparent power flow limit of lines, (*from* side) is

$$\tilde{S}_{ij}^{f} \leq S_{ij}^{max} \quad (10)$$

The apparent power flow limits of lines, (*to* side) is

$$\tilde{S}_{ij}^{t} \leq S_{ij}^{max} \quad (11)$$

The bus voltage limits is

$$V_i^{min} \leq V_i \leq V_i^{max} \quad (12)$$

The active power generation limits is

$$P_{gi}^{min} \leq P_{gi} \leq P_{gi}^{max} \quad (13)$$

The reactive power generation limits is

$$Q_{gi}^{min} \leq Q_{gi} \leq Q_{gi}^{max} \quad (14)$$

The selected units should satisfy all the constraints from (8) to (14). If it satisfies all the constraints, OPF is satisfied, the cost from this OPF is taken as a variable cost. If the constraints are not met, then the OPF is not satisfied and a penalty value (δ) is added to the objective function value.

III. IGA implementation

GA emphasizes the models of chromosome selections as observed in nature, such as crossover and mutation. Each variable used is assumed to be one chromosome and the crossover and mutation are likely to takes place in these chromosomes. The populations are generated and their fitness values are calculated. Then by crossover and mutation, offspring are formed and fitness function values for these offspring are also calculated. GA uses the Darwin principle "Survival of the Fittest". The best individual among the parents and the offspring are selected for the next generation.

In GA, '*penalty function approach*' and '*elitism*' are introduced to improve the effectiveness of the approach.

A. Initialization

The initial population of decision variables which satisfies the upper and lower limits is selected randomly from the set of uniformly distributed population. The distribution of initial population should be uniform. Totally N_p

populations are generated where N_p is the total number of parents selected. The objective function and the fitness function values for each population are calculated.

B. Competition and selection

In IGA, as the crossover and mutation are performed on the parent itself, the total number of offspring created will be equal to N_p. The N_p individuals are not taken directly for the next generation. Some kind of selection methods are used to select the individuals for the next generation. The various selection methods used are i) Ranking selection method, ii) Roulette wheel selection and iii) Tournament selection method. In this paper '*Roulette wheel selection*' method is used, in which, more copies of the best individuals and very few or no worst individuals are copied into the next generations.

C. Crossover

Crossover or recombination means exchanging some portions of the chromosomes of two individuals to yield offspring. Crossover can occur at single point, two points or at multiple points. The various crossover techniques used are tail to tail crossover, head to tail crossover and binary window crossover. '*Uniform binary window*' crossover technique is used in this paper.

In this technique, a binary mask having only 0's and 1's are created. Equal number of 1's and 0's are created and are called by the name uniform binary window crossover. If there exist 1 in the mask then the elements in individuals are swapped and are illustrated in Table 1.

Table 1 Uniform binary window crossover

Parent 1	1	0	2	2
Parent 2	2	1	1	1
Binary Mask	1	0	1	0
Child 1	2	0	1	2
Child 2	1	1	2	1

D. Mutation

In IGA, the mutation involves selecting a string with bit position at random and altering its value. The number of bits and the number of populations to be mutated depends upon the mutation probability. After mutation, the fitness function value for the populations generated by crossover and mutation are calculated. The next generation starts with selection of the individuals.

E. Fitness function evaluation (penalty function approach)

The objective function value is evaluated for each of the individuals in the generation by equation (1) and constraints are checked. The constraints include reserve margin, reliability criterion and OPF constraints. If the constraints are violated, then proportional penalty value is added to the objective function value to get the fitness function value. As a result of this, the parent with minimum fitness (minimum penalty) value will be the better individual. The formula for calculating the fitness function value is given as

$$f_j = [C_j + \alpha_1 \Psi_1 + \alpha_2 \Psi_2 + \delta] \tag{15}$$

In Dynamic programming (DP), only those combinations satisfying the constraints are considered for calculating the objective function value using equation (1). But in GA, the initial solution starts with infeasible combinations (Infeasible combinations are those which do not satisfy the constraints) and later it converged to the optimal solution. The infeasible solutions at the initial iterations are made feasible in the subsequent iterations by adding the proportional penalty value with the original objective function value using equation (15). If the constraints are satisfied, then the corresponding penalty term becomes zero.

F. Elitism

In IGA, as the crossover and mutation are performed on the parent itself, there is a possibility for the better individual in the previous solution to be lost. To avoid this situation, a mechanism called, elitism is introduced. Elitism retains one or more copies of the previous generation's best individual. As a result of this, the best solution does not lost in the subsequent generations. The process is repeated with the competition and selection process.

G. Convergence

The maximum generation can be used as a terminating condition for IGA. In another way, the ratio of the average to the maximum objective function of the population is computed. The generations are repeated until ν should be very close to 1, which represents the degree of satisfaction

$$\left(f_{ave} \;/\; f_{max}\right) \geq \nu \tag{16}$$

Test Results

The proposed techniques for the GEP problem were implemented using MATLAB in a PC with Pentium III, 500 MHz processor.

A. T*est system description*

To illustrate the performance of various transactions within transmission limit, the modified IEEE-30 Bus system is being used. The hypothetical generator cost is assumed for IPP. By iteration process, the beneficial additional generator buses are being identified. The units of IPP connected in the same buses are being assumed identical. The forecasted load demand is assumed to be 20% increment for every two years in all buses. The firm and other transaction are selected randomly.

The generator data for modified IEEE-30 Bus system is given in Table 2 and the generator data of IPPs is given in Table 3. The third column in the table shows the forced outage rate (F.O.R) for the generating units.

Table 2 Modified IEEE 30 Bus system

Generator No.	Bus No.	F.O.R	P_g max (MW)	P_g min (MW)	Q_g max (MVar)	Q_g min (MVar)	Price Rs/MWh
1	1	0.005	200	50	150	-20	1000
2	2	0.007	80	20	60	-20	1500
3	5	0.008	50	15	62.5	-15	2000
4	8	0.010	35	10	48.7	-15	2200
5	11	0.010	30	10	40	-10	2500
6	13	0.009	40	12	44.7	-15	2800

Table 3 IPPs generator data

IPP No.	Bus No.	No.of Units	F.O.R	P_g (MW)		Q_g (MVar)		Price Rs/MWh	Cap. Charge Rs/KW
				Min	Max	Min	Max		
1	18	2	0.010	5	40	0	20	3000	2600
2	15	2	0.010	5	40	0	20	3200	2400
3	21	2	0.007	5	60	0	40	3400	2200
4	27	2	0.010	5	30	0	20	3600	2000

B. Parameters for GEP

There are several parameters to be pre-determined, which are related to the GEP problem. The lower and upper bounds for reserve margin are set as 20% and 60%. Additionally the following parameters are needed and they are used in solving the GEP problem. The cost of expected energy not served was the penalty value given by the utility to the customer for not serving the energy. The unserved energy (EENS) cost is assumed a low value as 0.05 Rs. / KWh. It can also be increased.

The initial period is two years. The investment cost is assumed to occur in the beginning of the year. The maintenance cost is then calculated using the OPF algorithm. The OPF algorithm basically conducts economic dispatch by satisfying all the power flow constraints (MVA limits, voltage, etc) and finds the online generating capacity of each generating units. The maintenance cost is calculated by the following equation

$$M = aP^2 + bP + c \qquad \text{(Fuel cost equation)} \tag{17}$$

The maintenance cost is assumed to occur in the middle of the year. The salvage cost is assumed to occur at the end of the planning period. The outage cost is calculated using EENS indices [1, 2].

C. Parameters for IGA technique

There are several parameters to be pre-determined, which are selected through experiments is given in Table 4.

Table 4 Parameters for IGA implementation

Parameters	IGA
Population size	50
Maximum generation	50
String length	15
Selection method	Roulette wheel selection
Crossover method	Uniform binary window crossover
Crossover probability	0.6
Mutation probability	0.01
No. of Elite strings	2
Constraints	Reserve margin, LOLP and power flow constraints

D. Numerical results and discussion

The problem is illustrated with five cases. The results for 6 year planning horizon using DP, IGA for five different cases are given in Table 5 to Table 9. The execution time, cost and the percentage of error for each algorithm are also given. The result obtained by DP will be the optimal solution and it is taken as a reference for calculating the errors.

Case 1: Entertaining IPP for the forecasted 20% demand incrementation every 2 years for 6 years planning period in the modified IEEE-30 Bus system.

Table 5 Simple IPP

Year	% of load	Loss (MW)	Cost (Rs) × 10^{10}	Bus			
				18	15	21	27
2002	120	13.14	2.6745	0	0	0	1
2004	140	14.75	5.3352	1	0	0	0
2006	160	14.99	7.9980	0	0	1	0

The utility will purchase from IPP and it will serve the customers directly. To meet 20 % increase in load, one generating unit is selected at Bus No. 27. To meet 40 % increase in load another generating unit at Bus No. 18 is selected. The investment cost for the period is doubled. To meet 60 % increase in load, another generating unit at Bus No. 21 is selected. The increase in loss is negligible from 40 % to 60 % of increase in load.

Case 2: Firm transaction of 25 MW generating unit at Bus No.3 and 25MW load at Bus No.22 including Case 1.

Table 6 IPP with firm purchase (real power alone)

Year	% of load	Loss (MW)	Cost (Rs) × 10^{10}	Bus			
				18	15	21	27
2002	120	14.08	3.1899	0	0	1	1
2004	140	14.46	6.3407	0	0	0	0
2006	160	15.13	9.4949	1	1	0	0

The number of additional units required is different for simple IPP and IPP with various transactions. From the Table 5 and 6, the number of units required for simple IPP is different from IPP with firm purchase. The addition of transaction either increases or decreases the losses.

Case 3: Firm transaction of 25 MW generating unit at Bus No. 3 and load 25 MW + 5 MVAR at Bus No. 22, including Case 1.

Table 7 IPP with firm purchase (real and reactive power)

Year	% of load	Loss (MW)	Cost (Rs) × 10^{10}	Bus			
				18	15	21	27
2002	120	14.09	3.2511	0	0	1	1
2004	140	14.50	6.4578	0	0	0	0
2006	160	15.24	9.6699	1	1	0	0

The number of units taken in Table 6 and Table 7 are same but the cost is different because the power produced by each generator is different for the above two transactions. The cost variation is due to different operating level for the generating units, based on the OPF algorithm.

Case 4: Multi lateral transaction of 10 MW generating unit at Bus No. 7 and 10 MW Generating unit at Bus No.12; 5 MW load at Bus No. 6, 5 MW load at Bus No. 23 and 10 MW load at Bus No. 20 including Case 1.

Table 8 IPP with multilateral transactions

Year	% of load	Loss (MW)	Cost (Rs) × 10^{10}	Bus			
				18	15	21	27
2002	120	15.02	3.0301	0	0	0	1
2004	140	15.66	6.1073	1	0	0	0
2006	160	16.29	9.2061	0	0	1	0

The cost is reduced for all the 20 %, 40 % and 60 % increase in loads when compared with case 2 and case 3. This transaction will be more beneficial to the utility than case 2 and case 3. The cost is high compared to case 1. The additional cost may be collected as transmission charges by the utility from the transactions.

Case 5: Multi lateral transaction of 5 MW generating unit at Bus No. 20, 2 MW load at Bus No. 7, and 3 MW load at Bus No. 12 including Case 1 and Case 2.

Table 9 IPP with multilateral transactions and firm purchase

Year	% of load	Loss (MW)	Cost (Rs) × 10^{10}	Bus			
				18	15	21	27
2002	120	14.15	3.2933	0	0	1	1
2004	140	14.23	6.5700	1	0	0	0
2006	160	15.57	9.8619	0	1	0	1

The investment cost required by the utility gets increased when transactions are permitted. Sometimes these transactions help the utilities to reduce their losses and may give improved system performance in addition to the earnings from transmission charges. The cost of multilateral with firm purchase is very high when compared with other transactions. These results may be useful to fix up the transmission charges.

E. Comparison of DP and IGA results

The total cost and the execution time for DP and IGA method are compared in Table 10.

Table 10 Comparison of DP and IGA results

Sl. No	Case	Total Cost × 10^{10}		Execution Time (Hours)	
		DP	IGA	DP	IGA
1.	Case 1	7.9980	7.9980	3.0977	3.1560
2.	Case 2	9.4949	9.4949	3.6592	3.9562
3.	Case 3	9.6699	9.6699	1.0692	1.6674
4.	Case 4	9.2061	9.2061	2.5142	3.2672
5.	Case 5	9.8619	9.8619	1.3481	2.7960

The total cost obtained by both the methods DP and IGA are same. The execution time for the 6 year planning horizon by IGA method is relatively higher than DP. If the planning horizon is further increased, or if more numbers of IPPs bid for transactions, DP may take long execution time in addition to the well known drawback of "curse of dimensionality". The test system used here is modified IEEE-30 Bus system to illustrate the concepts. In real world the practical system may be having very high number of buses and generators. For longer planning horizon and if the number of transactions are more, the IGA may be a suitable algorithm to find the best solution.

The convergence characteristics for simple IPP using IGA technique is given in Fig. 1. The optimal solution for simple IPP is obtained in 12th generation itself. The convergence characteristic of IGA for various transactions such as firm purchase (real power alone), firm purchase (real and reactive powers), multilateral transactions and multilateral transactions with firm purchase is given in Fig. 2.

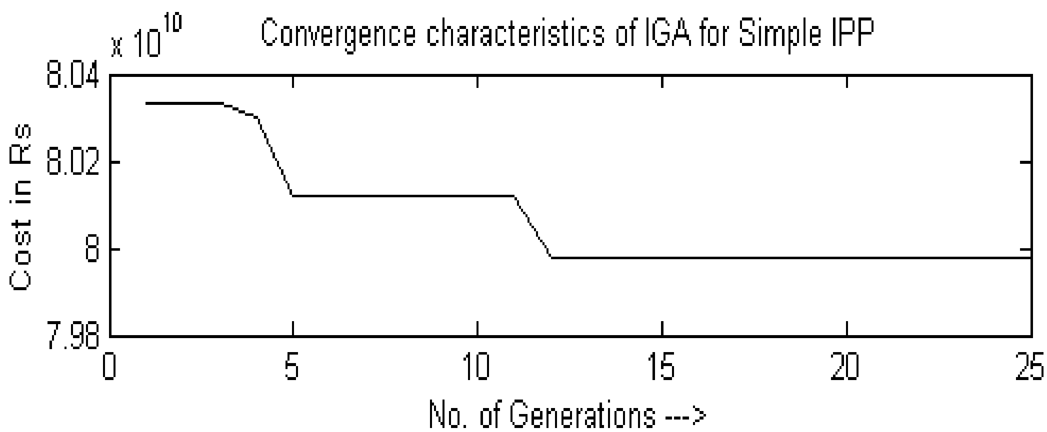

Fig. 1 Convergence characteristics of IGA for simple IPP

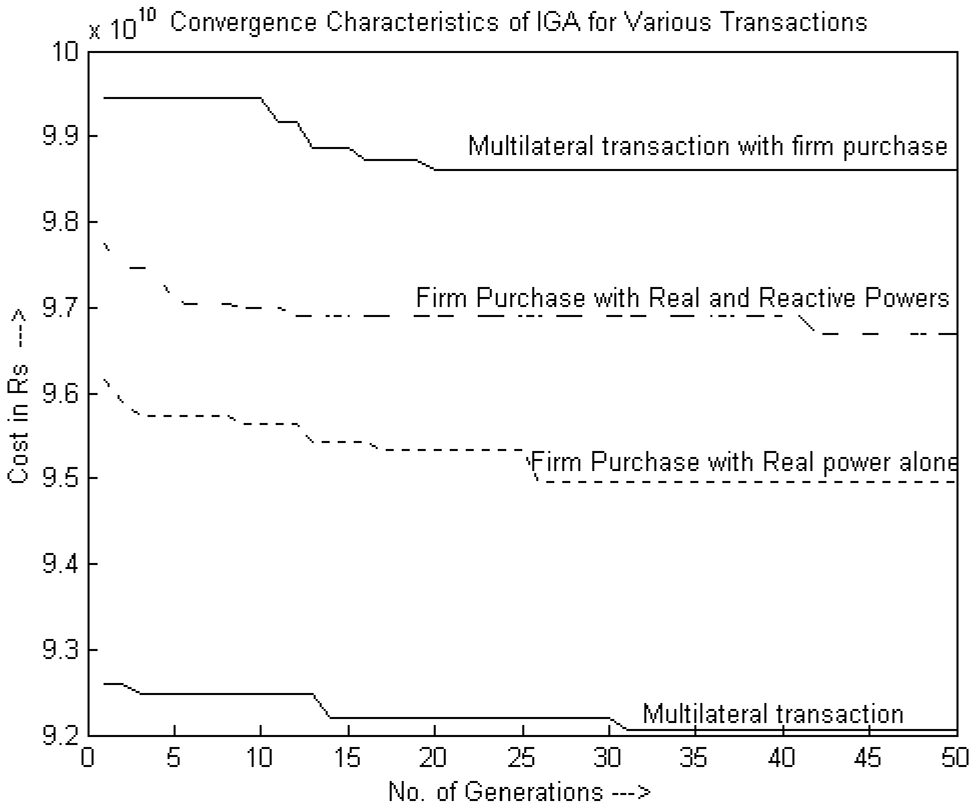

Fig. 2 Convergence characteristics of IGA for various transactions

Conclusions

This paper proposed the IGA method for least-cost generation expansion planning problem by considering OPF and the location of the generating units for a fixed transmission line system. The IGA results are compared with DP. To check the power flow constraint OPF algorithm was used. The execution time of DP was less than that of IGA for smaller planning horizon. The IGA technique may be effective for problems with longer planning horizon. The execution time of DP grows exponentially whereas for IGA it grows linearly. IGA can produce better result in a reasonable time when compared with DP. Introduction of IPP, firm and other transactions changes the line losses. The number of additional units required depends upon the type of transactions, the real and reactive power demands permitted in the system.

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