International Journal of Computer and Electrical Engineering, Vol. 2, No. 1, February, 2010
1793-8163

Optimal Power Flow based Congestion Management Methods for Competitive Electricity Markets

Ashish Saini and A.K. Saxena

Abstract— **Congestion management is one of the major tasks performed by system operators to ensure the operation of transmission system within operating limits. In the emerging electric power market, the congestion management becomes extremely important and it can impose a barrier to the electricity trading. In the present paper, a concept of transmission congestion penalty factors is developed and implemented to control power overflows in transmission lines for congestion management. Three methods based on optimal power flow are proposed to alleviate congestion in transmission lines and tested. The first two methods require re-dispatching of generators and changes in capacitors' reactive support only. They can be differentiated on the basis of economic cost involved in making required changes to above variables. The third method deals with load curtailment scheme based on *willing to pay* charges paid for different transactions in the system to avoid congestion. The formation of different categories for charging *willing to pay* charges from pool consumers is new feature of this scheme.**

Index Terms— **Adjustment Bids, Congestion Management, Electricity markets and Optimal Power Flow.**

I. INTRODUCTION

Congestion results when power flows in the transmission line are higher than allowed by the operating reliability limits. In a competitive electricity market, congestion occurs when the transmission network is unable to accommodate all of the desired transactions due to violation of system operating limits. Congestion management means the activities of the transmission system operator to relieve transmission constraints in competitive electricity market. In the present day competitive power market, each utility manages the congestion in the system using its own rules and guidelines utilizing a certain physical or financial mechanism. Various congestion management schemes suitable for different electricity market structure have been reported in literature. Hogan proposed the contract network and nodal pricing approach [1] using the spot pricing theory [2] for pool type market. Chao and Peck [3] proposed an alternative approach which is based on parallel markets for link based transmission capacity rights and energy trading under a set of rules defined and administered by the System Operator (SO). A congestion management approach after the deregulation of the Slovenian power system is presented in [4] and [5]. The method is based on countertrade method where the system operator, based on technical and economic data, decides the optimal redispatch that eliminates congestion. Singh et. al. [6] has proposed dynamic security constrained congestion management in an unbundled electric power system. In [7], the zones have been determined based on lines real and reactive transmission congestion distribution factors in a zonal/cluster-based congestion management approach.

Several Optimal Power Flow (OPF) based congestion management schemes for multiple transactions also have been proposed. An approach using the minimum total modification to the desired transactions for relieving congestion is presented in [8]. A variant of this least modification approach [9] used a weighting scheme with the weights being the surcharges paid by the transactions for transmission usage in the congestion-relieved network. In [10], an OPF based approach that minimizes cost of congestion and service costs is proposed. In [11], a new mechanism of congestion management in multilateral transaction networks has been developed based on physical flows.

There are two broad paradigms that may be employed for congestion management. These are the ***cost-free*** means and the ***not-cost-free*** means [12]. The former include actions like outaging of congested lines or operation of transformer taps, phase shifters or FACTS devices. These means are termed as cost-free only because the marginal costs (and not the capital costs) involved in their usage are nominal.

The *not-cost-free* means include:

1) Rescheduling generation

Here, system operator re-dispatches power generation in such a way, that resulting power flows does not overload any line. Every generation unit can bid an increase or decrease of its production in a similar manner as this is done on a balancing market, while the responsibility of system operator is to select bids in efficient way. Somehow, countertrade approach based congestion management can be viewed as simplified optimal power flow problem, where optimization variables are re-dispatch of the active power production and criteria function is minimum of the costs related to this active power re-dispatch.

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2) Prioritization and curtailment of loads/transactions

A parameter termed as *willingness-to-pay-to-avoid-curtailment* was introduced in [9]. This can be an effective instrument in setting the transaction curtailment strategies which may then be incorporated in the optimal power flow framework.

In this paper, section II is a brief introduction of GA-Fuzzy optimization method is given. The GA-Fuzzy OPF is tested and found better than various OPF methods based on classical optimization techniques and GA variants by authors and already reported in reference [13]. In section III, the procedure for determining transmission congestion penalty factors is explained. These transmission congestion penalty factors are helpful in deciding appropriate re-dispatchment of dispatchable resources. Section IV covers congestion management methods on GA-Fuzzy based OPF formulations incorporating *(1)* and hybrid type i.e. both *(1)* and *(2)*, above are presented and tested on IEEE 30-bus system. The function of proposed congestion management methods based on GA-Fuzzy OPF is to modify system dispatch to ensure secure and efficient system operation based on the existing operating condition. It would use the dispatchable resources (i.e. real and reactive power generations and capacitor reactive supports) and controls (i.e. transformer tapings) subject to their limits and determine the required curtailment of transactions to ensure uncongested operation of the power system. A new load curtailment scheme for pool loads is proposed where all connected loads are divided into three different groups depending on their ***willingness to pay*** up to certain load curtailment value.

II. GA-Fuzzy approach for OPF solution

The GA-Fuzzy optimization technique has been already validated by Saini *et al.*, [13] for OPF on 26-bus power system data, 6-bus power system data and IEEE 30-bus power system data. In this approach the ranges of crossover probability (P_c) and mutation probability (P_m) are divided into LOW, MEDIUM and HIGH membership functions and each function is given some membership values.

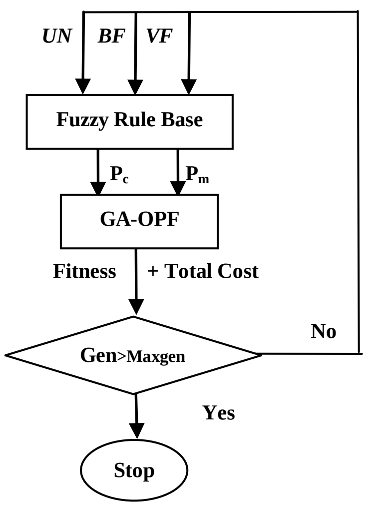

Fig.1 GA-Fuzzy approach for OPF problem solving

Fig. 1 is a diagrammatic representation of an approach to incorporate fuzzy logic to GA based OPF solution. The GA parameters (P_c and P_m) are varied based on the fitness function values as per the following logic:

1) The values of the best fitness for each generation (*BF*) is expected to change over a number of generations, but if it does not change significantly over a number of generations (*UN*) then this information is considered to cause changes in both P_c and P_m.
2) The diversity of the population is one of the factors, which influences the search for a true optimum. The variance of the fitness values of objective function (*VF*) of the population is a measure of diversity which is used to change P_c and P_m.

In this approach the ranges of P_c, P_m, *BF*, *UN* and *VF* are divided into three triangular functions and each is given some membership values.

III. Transmission Congestion Penalty Factors

A concept of transmission congestion penalty factors is developed and implemented to control line overflows in proposed GA-Fuzzy approach for congestion management. Transmission congestion penalty factor for each transmission line is computed which can adopt a suitable value depending upon amount of power flow (in MVA) above/below the maximum limit. Therefore, the congested line/lines and lines near to congested line/lines have higher values of transmission congestion penalty factors than other lines in the system. A base case situation is considered for congestion management. This base case refers to optimal settings of real power generation schedule, transformer tap settings and capacitor reactive support settings under normal state and with these settings now system is subjected to congestion (with one/more than one line limits is/are violated).

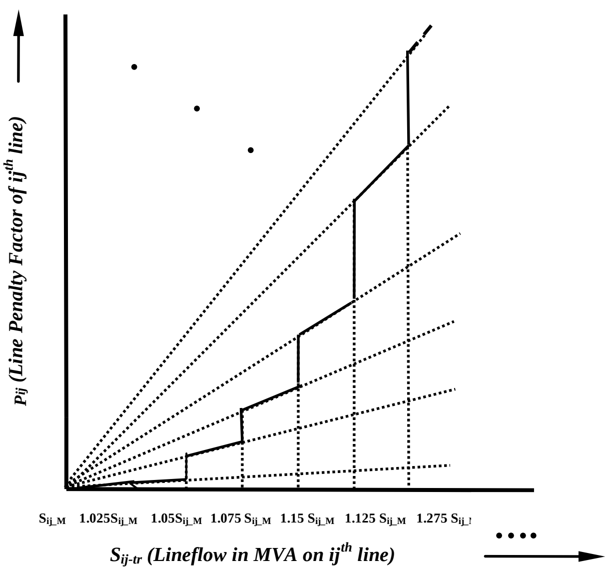

Fig.2 Graphical representation of penalty factors as straight lines

A. Determination of transmission congestion penalty factors

The following steps are followed to compute these penalty factors.

Step 1. Load flow solution and line flows ($S_{ij\text{-}base}$) are obtained for base case.
Step 2. Set the line limits in congestion case ($S_{ij\text{-}M}$).
Step 3. GA-Fuzzy approach [13,15] is used to generate population of different generation schedules satisfying equality and non-equality constraints (except line flows limits).
Step 4. Line flows ($S_{ij\text{-}tr}$) are calculated for each such generation schedule and line penalty factors (P_{ij}, where i and j denote bus nos. between which transmission line is connected) are calculated according to the logic given below:

$$P_{ij} = \begin{cases} 0 & , \ when\ S_{ij-tr} \le S_{ij-M} \\ m_{ij} * S_{ij-tr} & , \ when\ S_{ij-tr} \rangle\ S_{ij-M} \end{cases}$$

where, m_{ij} = slope decided by $S_{ij\text{-}tr}$ and $S_{ij\text{-}M}$ as per Table I.

P_{ij}s are piecewise linear functions which are dependent on overflows on transmission lines (*i.e.* how much times power flow on any transmission line exceeds its maximum limit). Line penalty factors can be graphically represented as shown in Fig.2.

Step 5. Another parameter, *line_flow_sum* representing cumulative effect of penalty factors and transmission line flows in congestion is computed as follows:

$$line\_flow\_sum = \sum_{l=1}^{n_l} P_{ij} * S_{ij-tr}$$

where n_l = No. of transmission lines.

These new types of transmission congestion penalty factors have two advantages. First, separate slope for penalty factor of each transmission line is determined depending upon power overflow above rated line flow value of that transmission line. It means that line with lesser power overflow will have lower value of slope, and thus will result small value of penalty factor. Similarly, it is understood that line with comparatively higher power overflow will have higher value of penalty factor. This adaptive feature is helpful in finding right solution (optimal values of control parameters e.g. real power generation, transformer tapping and capacitors values) by search techniques such as GA. Secondly, only single logic mentioned in step-4 works for determining these congestion penalty factors based on magnitude of power overflow in the line/lines. Therefore, no difficulty arises in choosing suitable values of penalty factors.

IV. Proposed Methods for Congestion Management

Three methods are proposed with different objectives using GA-Fuzzy optimal approach and are explained below:

Method-1. Objective of minimization of line overflows only.

Method-2. Objective of minimization of line overflows alongwith (real power generation + reactive power generation) redispatch cost and change in capacitor support cost.

Method-3. Objective of minimization of line overflows along with (real power generation + reactive power generation) redispatch cost, change in capacitor support cost and load curtailment.

Mathematical functions representing redispatch cost of real power generation, reactive power generation and change in capacitor support cost are given below. The *real power redispatch cost* $C_{adj}(\Delta P_{g,k\text{-}m})$ is computed by adjusting generation of each generating unit less or more than base case value, with the help of *adjustment bids characteristics curves* shown in Fig. 3. These curves are decided by special *adjustment bids* $C_{adj,Pg,k\text{-}m}$ invited from all the generator units for generating power less or more than base case values. Therefore, *real power redispatch cost* can be expressed as:

$$C_{adj}(\Delta P_{g,k\text{-}m}) = C_{adj,Pg,k\text{-}m} * \Delta P_{k\text{-}m} \quad \$/hr \tag{1}$$

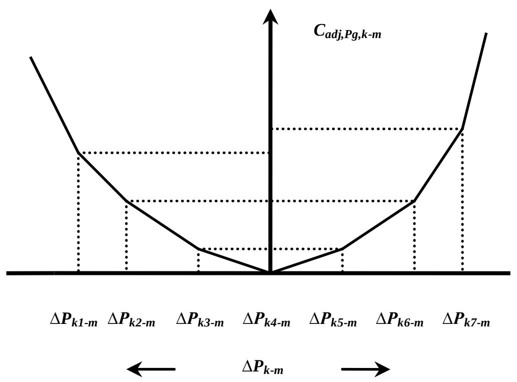

Fig.3 Adjustment bid characteristic representing cost function of the change of active power production at the kth generator

The reactive power cost of generator is also called opportunity cost [14]. The reactive power output of a generator will reduce its active power generation capability which can serve at least as spinning reserve, and the corresponding implicit financial loss to generator is modeled as an opportunity cost. Therefore *reactive power redispatch cost* $C_{adj}(\Delta Q_{g,k\text{-}m})$ of generator as defined by [7] is:

$$C_{adj}(\Delta Q_{g,k-m}) = \left[C_{pg}(S_{G,\max k-m}) - C_{pg}\left(\sqrt{S^2_{G,\max k-m} - \Delta Q^2_{g,k-m}}\right)\right] kprofit \quad \$/hr \tag{2}$$

where, $C_{pg}(P_{G,k-m}) = a_k + b_k P_{G,k-m} + c_{km} P^2_{G,k-m}$

i.e the cost of active power generation is modeled by above quadratic function. Where a_k, b_k and c_k are costs coefficients of k^{th} generator and $S_{G,\max k-m}$ is the nominal maximum apparent power of generation assumed that $P_{G_{\max},k-m} \approx S_{G_{\max},k-m}$ and *kprofit* is the profit rate of active power generation taken between 5-10% [14].

The equivalent cost for return on the capital investment of the capacitors, which is expressed as their depreciation rates (the life span of capacitors is assumed as 15 years) is computed as

$$C\ (Q_{C,kc-m}) = Q_{C,kc-m}\frac{(\$11600/M\text{ var})}{(15*365*24*h)\ hour} = Q_{C,kc-m} * \$13.24/(100\ M\text{ var}\,hour) \tag{3}$$

where h is the average usage rate of capacitors taken as 2/3. Equation (3) is a linear cost function with the slope of $\frac{dC_{adj,kc-m}(Q_{C,kc-m})}{dQ_{C,kc-m}} = \frac{\$13.24}{(100M\text{ var}\ hour)}$, which can be approximately represented as:

$$C_{adj}(\Delta Q_{C,kc-m}) = \Delta Q_{C,kc-m} * (13.24/100)\ \$/hr \tag{4}$$

Method-1. Objective of minimization of line overflows only

Step 1. Real power generation redispatch $\Delta P_{g,k-m}$, reactive power generation redispatch $\Delta Q_{g,k-m}$ and change in capacitor reactive support $\Delta Q_{C,kl-m}$ are computed for each valid generation schedule in population, where k = generating unit no., kc = capacitor unit no. and m = no. of generation schedule in population.

Step 2. Correspondingly, redispatch costs of real power generation $C_{adj}(\Delta P_{g,k-m})$, reactive power generation $C_{adj}(\Delta Q_{g,k-m})$ and change in capacitor reactive support $C_{adj}(\Delta Q_{C,kc-m})$ are computed as per equations (1), (2) and (4) respectively.

Step 3. Fitness of each generation schedule in a population is calculated as:

$$Fitness = \frac{1}{A * line\_flow\_sum} \quad (5)$$

where, A= Numerical constant

Step 4. Finally values of real and reactive power generation schedule, transformers tapping values, bus voltages, capacitor reactive support values and line flows calculated in last generation of GA-Fuzzy based optimization approach.

<u>Method-2.</u> *Objective of minimization of line overflows alongwith (real power generation + reactive generation) redispatch cost and change in capacitor support cost*

1) Step1 and Step 2 of Method-1 are followed.
2) Fitness of each generation schedule in a population is calculated as:

$$Fitness = \frac{e^{-B\times(\sum_{g}^{NG} C_{adj}(\Delta P_{g,k-m}) + \sum_{g}^{NG} C_{adj}(\Delta Q_{g,k-m}) + \sum_{c}^{NC} C_{adj}(\Delta Q_{C,kl-m}))}}{A\times line\_flow\_sum} \quad (6)$$

where A and B are numerical constants.

3) Step 4 of Method-1 is followed.
4) Fitness of each generation schedule in a population is calculated as:

$$Fitness = \frac{e^{-B\times(\sum_{g}^{NG} C_{adj}(\Delta P_{g,k-m}) + \sum_{g}^{NG} C_{adj}(\Delta Q_{g,k-m}) + \sum_{c}^{NC} C_{adj}(\Delta Q_{C,kc-m}) + \sum_{i=1}^{3} K_i(\sum_{kl}^{NL}(P_{d,kl-m,gr-i}) - \sum_{kl}^{NL}(P_{d,kl-m,base-i}))^2)}}{A\times line\_flow\_sum} \quad (7)$$

where A, B and K_i are numerical constants.

5) Step 4 of Method-1 is followed.

V. Results and Discussion

The proposed methods are implemented on IEEE 30 bus system. The busdata, linedata including generator cost coefficients are taken from [15,16]. The bilateral and multilateral transactions details are given in Appendix and [17] also. Line (8,28) get congested (exceeding flow limit of 12 MVA) if outage of line (6,28) is considered.

Figures 4, 5 and 6 show the convergence of different parameters alongwith crossover probability and mutation probability variations. The line flow at line (8,28) violates line limit of 12 MVA under congestion state (16.64 MVA). The results tabulated in Table II-III show that although Method-1 controls better (11.921 MVA) than Method-2 (11.921 MVA, when kprofit = 5%) but congestion relief charges are less for Method-2 than Method-1. The high congestion relief charges of Method-1 are resulted mainly due to high real power generation redispatch cost because fitness function does not take total (real + reactive) redispatch cost into account. In Method-2 a controlling action to check power overflow is dominant over economic redispatchment cost feature throughout the GA-Fuzzy based optimization procedure.

As per Table IV, Method-2 has slightly lesser load bus voltage variation (i.e. between maximum and minimum load bus voltages) with very small increment in average system voltage value (i.e. average of all bus voltages of the system). It means that from voltage point of view Method-2 is not inferior than Method-1, although this particular aspect requires verification for other power systems also.

In Method-3, a load curtailment feature is also added in fitness function by mathematical modeling. This feature enables pool customers to pay extra charges in order to avoid congestion. This method can be applicable in deregulated environment as it seems to be fair, transparent and consumer satisfaction to great extent. In Fig. 6, convergence of total load curtailment cost and line flow in line (8,28) are shown.

As per Table V, Load Group-3 has maximum and Load Group-1 has minimum load curtailment among all three load groups. This kind of priority is set up by selection parameter K_i (refer equation (7)) in fitness function for each load group. The Load Group-1 has highest value and Load Group-3 has lowest value of $K_{i.}$ respectively.

VI. Conclusion

The transmission congestion management is one of the critical and important task of the ISO for the smooth functioning of competitive electricity market. The ISO in a competitive electricity market is responsible for determining the necessary actions to ensure that violations of the grid constraints occur. A hybrid strategy based having two stages is also formed on the basis of three methods developed and tested on IEEE 30 bus system. In first stage, Method-1 or Method-2 can be used. If congestion is still not avoidable then under second stage Method-3 with load-curtailment and willingness to pay feature can be used. With reference to the proposed congestion management methods, setting priorities (such as economic re-dispatch cost of generators, effect on operating cost due to changes in transformer tapings and load curtailment schemes) in a GA-Fuzzy optimization framework can be extension of this work.

Appendix

Bilateral and Multilateral transactions for IEEE 30-bus system.

Bilateral Transactions			Multilateral Transactions			
From bus	To bus	Size (MW)	From bus	Size (MW)	To bus	Size (MW)
9	13	5	6	4	11	2
22	25	5	7	2	13	3
					14	1

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TABLE I. Slope determination for lines representing penalty factors

S.No.	$S_{ij\text{-}tr}$	Angle in degrees (θ)	Slope of line (tanθ)
1.	$\le S_{ij\text{-}M}$	0	0
2.	$> S_{ij\text{-}M}$ & $\le 1.025\ S_{ij\text{-}M}$	2.25	0.039
3.	$>1.025\ S_{ij\text{-}M}$ & $\le 1.05\ S_{ij\text{-}M}$	4.5	0.079
4.	$>1.05\ S_{ij\text{-}M}$ & $\le 1.075\ S_{ij\text{-}M}$	6.75	0.118
5.	$>1.075\ S_{ij\text{-}M}$ & $\le 1.1\ S_{ij\text{-}M}$	9.00	0.158
6.	$>1.1\ S_{ij\text{-}M}$ & $\le 1.125\ S_{ij\text{-}M}$	11.25	0.199
7.	$>1.125\ S_{ij\text{-}M}$ & $\le 1.15\ S_{ij\text{-}M}$	13.5	0.240
8.	$>1.15\ S_{ij\text{-}M}$ & $\le 1.175\ S_{ij\text{-}M}$	15.75	0.282
9.	$>1.175\ S_{ij\text{-}M}$ & $\le 1.2\ S_{ij\text{-}M}$	18.00	0.325
10.	$>1.2\ S_{ij\text{-}M}$ & $\le 1.225\ S_{ij\text{-}M}$	20.25	0.369
11.	$>1.225\ S_{ij\text{-}M}$ & $\le 1.25\ S_{ij\text{-}M}$	22.50	0.414
12.	$>1.25\ S_{ij\text{-}M}$ & $\le 1.275\ S_{ij\text{-}M}$	24.75	0.461
13.	$>1.275\ S_{ij\text{-}M}$ & $\le 1.3\ S_{ij\text{-}M}$	27.00	0.510
14.	$>1.30\ S_{ij\text{-}M}$ & $\le 1.325\ S_{ij\text{-}M}$	29.25	0.560
15.	$>1.325\ S_{ij\text{-}M}$ & $\le 1.35\ S_{ij\text{-}M}$	31.50	0.613
16.	$>1.35\ S_{ij\text{-}M}$ & $\le 1.375\ S_{ij\text{-}M}$	33.75	0.660
17.	$>1.375\ S_{ij\text{-}M}$ & $\le 1.4\ S_{ij\text{-}M}$	36.00	0.727
18.	$>1.4\ S_{ij\text{-}M}$ & $\le 1.425\ S_{ij\text{-}M}$	38.25	0.788
19.	$>1.425\ S_{ij\text{-}M}$ & $\le 1.45\ S_{ij\text{-}M}$	40.50	0.854
20.	$>1.45\ S_{ij\text{-}M}$ & $\le 1.475\ S_{ij\text{-}M}$	42.75	0.916
21.	$>1.475\ S_{ij\text{-}M}$ & $\le 1.5\ S_{ij\text{-}M}$	45	1.000
22.	$>1.5\ S_{ij\text{-}M}$ & $\le 1.525\ S_{ij\text{-}M}$	47.25	1.082
23.	$>1.525\ S_{ij\text{-}M}$ & $\le 1.55\ S_{ij\text{-}M}$	49.5	1.171
24.	$>1.55\ S_{ij\text{-}M}$ & $\le 1.575\ S_{ij\text{-}M}$	51.75	1.269
25.	$>1.575\ S_{ij\text{-}M}$ & $\le 1.6\ S_{ij\text{-}M}$	54.00	1.376
26.	$>1.6\ S_{ij\text{-}M}$ & $\le 1.62\ S_{ij\text{-}M}$	56.25	1.497
27.	$>1.625\ S_{ij\text{-}M}$ & $\le 1.65\ S_{ij\text{-}M}$	58.50	1.632
28.	$>1.65\ S_{ij\text{-}M}$ & $\le 1.675\ S_{ij\text{-}M}$	60.75	1.786
29.	$>1.675\ S_{ij\text{-}M}$ & $\le 1.7\ S_{ij\text{-}M}$	63.00	1.963
30.	$>1.7\ S_{ij\text{-}M}$ & $\le 1.725\ S_{ij\text{-}M}$	65.25	2.169
31.	$>1.725\ S_{ij\text{-}M}$ & $\le 1.75\ S_{ij\text{-}M}$	67.50	2.414
32.	$>1.75\ S_{ij\text{-}M}$ & $\le 1.775\ S_{ij\text{-}M}$	69.75	2.711
33.	$>1.775\ S_{ij\text{-}M}$ & $\le 1.8\ S_{ij\text{-}M}$	72.00	3.078
34.	$>1.80\ S_{ij\text{-}M}$ & $\le 1.825\ S_{ij\text{-}M}$	74.25	3.546
35.	$>1.825\ S_{ij\text{-}M}$ & $\le 1.85\ S_{ij\text{-}M}$	76.50	4.165
37.	$>1.85\ S_{ij\text{-}M}$ & $\le 1.875\ S_{ij\text{-}M}$	78.75	5.027
38.	$>1.875\ S_{ij\text{-}M}$ & $\le 1.9\ S_{ij\text{-}M}$	81.00	6.314
39.	$>1.9\ S_{ij\text{-}M}$ & $\le 1.925\ S_{ij\text{-}M}$	83.25	8.449
40.	$>1.925\ S_{ij\text{-}M}$ & $\le 1.95\ S_{ij\text{-}M}$	85.50	12.706
41.	$>1.95\ S_{ij\text{-}M}$ & $\le 1.975\ S_{ij\text{-}M}$	87.75	25.452

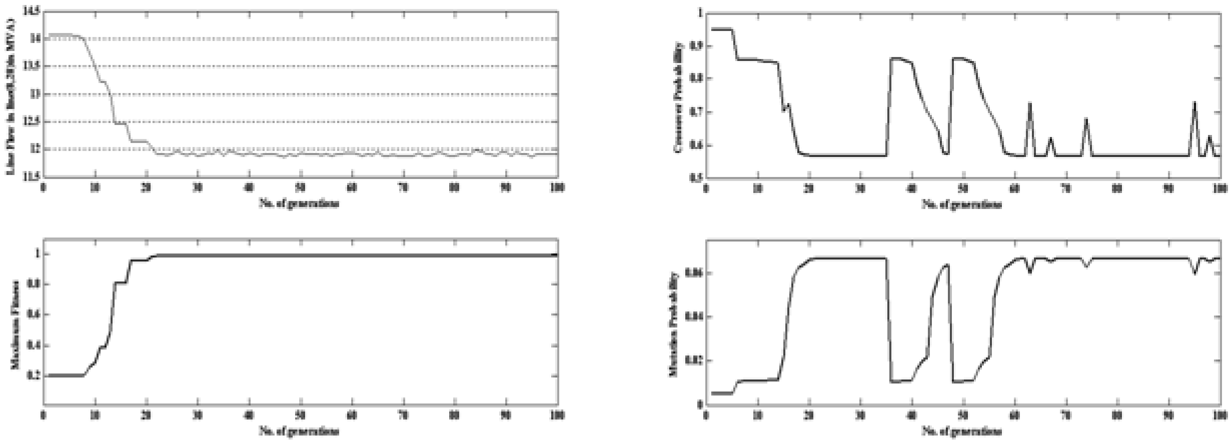


Fig.4 Convergence of different parameters, crossover probability and mutation probability variations using GA-Fuzzy approach for Method-1

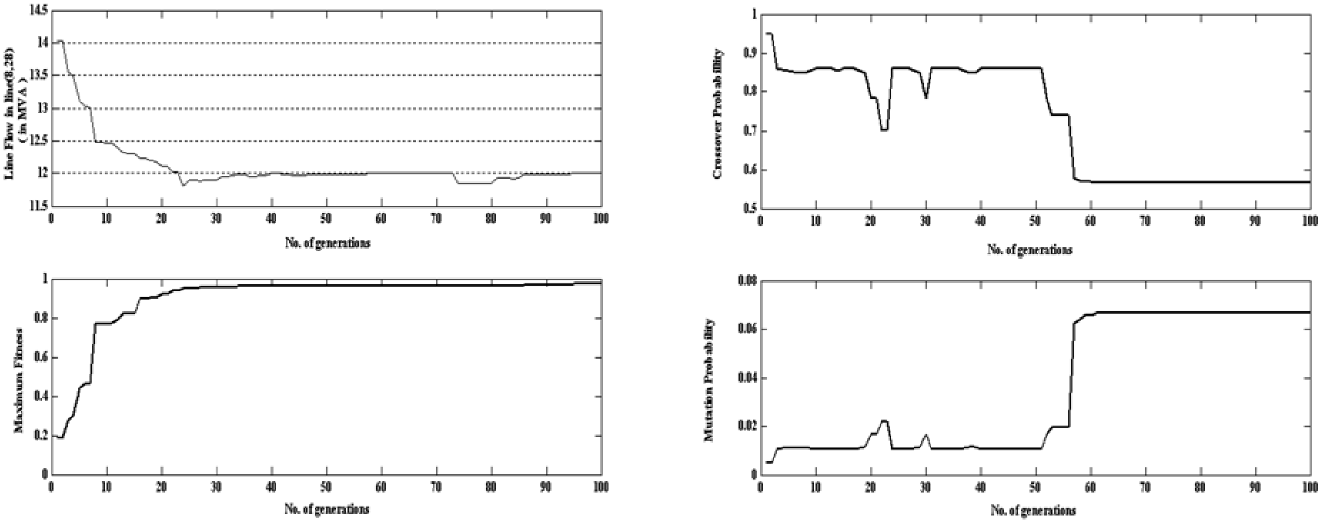
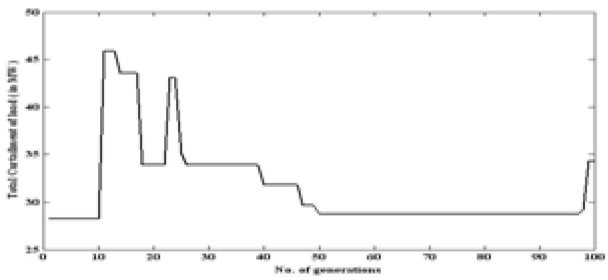


Fig.5 Convergence of different parameters, crossover probability and mutation probability variations using GA-Fuzzy approach for Method-2



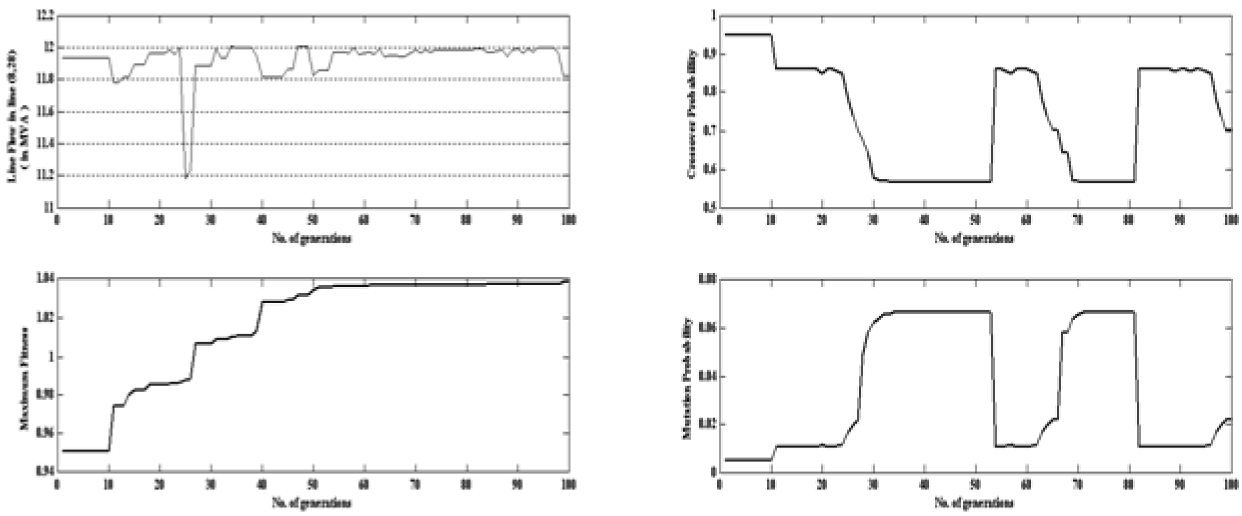


Fig.6 Convergence of different parameters, crossover probability and mutation probability variations using GA-Fuzzy approach for Method-3

TABLE II. Comparison of re-dispatchment of (Real Power + Reactive Power Generation), change in Capacitor Reactive power Support and Line flow at line (8,28) for Method-1 and Method-2

S.No.	Generation at	In Congestion state		Congestion Management Method			
				Method-1		Method-2	
		P_g (in MW)	Q_g (in MVAr)	P_g (in MW)	Q_g (in MVAr)	P_g (in MW)	Q_g (in MVAr)
1.	Bus 1	175.165	4.624	156.568	72.914	163.962	32.23
2.	Bus 2	48.941	29.345	33.647	-4.262	41.882	39.692
3.	Bus 5	21.176	28.21	33.941	25.8	20.765	33.403
4.	Bus 8	22.647	40.559	12.549	29.386	11.667	27.073
5.	Bus 11	12.588	17.124	26.706	8.078	26.471	22.08
6.	Bus 13	12.00	10.263	28.8	6.634	28.031	-8.37
Total		*292.517*	*130.125*	*292.211*	*138.551*	*292.778*	*146.107*
S.No.	Capacitor at	In Congestion state		Congestion Management Method			
				Method-1		Method-2, when kprofit = 5%	
		Q_C(in MVAr)		Q_C(in MVAr)		Q_C(in MVAr	
1.	Bus 10	3.982		1.585		2.299	
2.	Bus 12	0.02		2.916		1.037	
3.	Bus 15	4.149		0.998		4.354	
4.	Bus 17	4.99		3.043		1.937	
5.	Bus 20	4.432		1.526		2.114	
6.	Bus 21	4.354		0.802		0.773	
7.	Bus 23	4.54		3.503		1.155	
8.	Bus 24	4.687		4.237		1.791	
9.	Bus 29	2.097		4.355		3.387	
Total		*33.251*		*22.965*		*18.847*	
Line flow at line (8,28) (in MVA)		*16.64*		*11.921*		*11.993*	

TABLE III. Comparison of congestion relief charges for Method-1 and Method-2

S.No.		Congestion Management Method			
		Method-1		Method-2	
		$C(\Delta P_g)$ (in \$/hr)	$C(\Delta Q_g)$ (in \$/hr)	$C(\Delta P_g)$ (in \$/hr)	$C(\Delta Q_g)$ (in \$/hr)
1.		-59.823	2.0764	-36.0217	0.3343
2.		-48.4633	1.6359	-23.3393	0.1525
3.		58.2958	0.0211	-1.3936	0.0978
4.	Bus 8	-35.7547	0.3496	-38.7967	0.515
5.	Bus 11	55.1735	0.3117	54.1465	0.0925
6.	Bus 13	67.8	0.0412	64.5317	1.1247
Total (in \$/hr)		*37.2283*	*4.4359*	*19.1269*	*2.3169*
S.No.	Capacitor at	Method-1		Method-2	
		$C(\Delta Q_c)$ (in \$/hr)		$C(\Delta Q_c)$ (in \$/hr)	
1.	Generation at	-0.3174		-0.2228	
2.		0.3834		0.1347	
3.		-0.4172		0.0271	
4.	Bus 1	-0.2578		-0.4042	
5.	Bus 2	-0.3848		-0.3069	
6.	Bus 5	-0.4703		-0.4741	
7.	Bus 23	-0.1373		-0.4482	
8.	Bus 24	-0.0596		-0.3834	
9.	Bus 29	0.299		0.1708	
Total (in \$/hr)		*-1.3619*		*-1.9071*	
Grand Total (in \$/hr)		*40.3023*		*19.5367*	

TABLE IV. Comparison of maximum and minimum voltage levels at Load buses for all the three methods

		Method-1	Method-2	Method-3
Load Bus	Maximum	Bus 12: 1.048 p.u.	Bus 9: 1.049 p.u.	Bus 9: 1.047 p.u.
	Minimum	Bus 30: 0.95 p.u.	Bus 30: 0.956 p.u.	Bus 30: 0.959 p.u.
	Difference	0.098 p.u.	0.093 p.u.	0.088 p.u.
Average value of system voltage		1.005533 p.u.	1.0139 p.u.	1.0135 p.u.

TABLE V. Re-dispatchment of (Real Power + Reactive Power Generation), Change in Capacitor Reactive power Support, Load curtailment and Line flow at line (8,28) for Method-3

Generation at	Method-3	
	P_g (in MW)	Q_g (in MVAr)
Bus 1	150.747	13.316
Bus 2	42.353	32.196
Bus 5	19.529	30.004
Bus 8	10.098	31.131
Bus 11	15.02	13.246
Bus 13	19.027	23.381
Total	*256.774*	*143.273*
Capacitor at	Q_C(in MVAr)	
Bus 10	2.329	
Bus 12	2.808	
Bus 15	1.693	
Bus 17	0.401	
Bus 20	1.986	

Bus 21	1.027
Bus 23	1.115
Bus 24	1.115
Bus 29	3.16
Total	*15.636*

Load P_l (in MW)								
Load Group-1	In Congestion	Method-3	Load Group-2	In Congestion	Method-3	Load Group-3	In Congestion	Method-3
Bus 7	22.8	21.6232	Bus 4	7.6	7.0116	Bus 2	21.7	14.56
Bus 8	30.0	28.4516	Bus 5	94.2	86.9071	Bus 3	2.4	1.6103
Bus 17	9.0	8.5355	Bus 15	8.2	7.5652	Bus 10	5.8	3.8916
Bus 18	3.2	3.0348	Bus 16	3.5	3.229	Bus 12	11.2	7.5148
Bus 26	3.5	3.3194	Bus 21	17.5	16.1452	Bus 14	6.2	4.16
Bus 29	2.4	2.2761	Bus 23	3.2	2.9523	Bus 19	9.5	6.3742
Bus 30	10.6	10.0529	Bus 24	8.7	8.0265	Bus 20	2.2	1.4761
Total	*81.5*	*77.2935*	*Total*	*142.9*	*131.8369*	*Total*	*59.0*	*39.587*
Line flow at line (8,28) (in MVA)						*11.823*		

Group 1- Load group 1, Group G2- Load group 2, Group 3- Load group 3