Congestion Management Using Multiobjective Particle Swarm Optimization

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***Abstract*—This paper presents an effective method of congestion management in power systems. Congestions or overloads in transmission network are alleviated by generation rescheduling and/or load shedding of participating generators and loads. The two conflicting objectives 1) alleviation of overload and 2) minimization of cost of operation are optimized to provide pareto-optimal solutions. A multiobjective particle swarm optimization (MOPSO) method is used to solve this complex nonlinear optimization problem. A realistic frequency and voltage dependent load flow method which considers the voltage and frequency dependence of loads and generator regulation characteristics is used to solve this problem. The proposed algorithm is tested on IEEE 30-bus system, IEEE 118-bus system, and Northern Region Electricity Board, India (NREB) 390-bus system with smooth as well as nonsmooth cost functions due to valve point loading effect.**

***Index Terms*—Congestion management, generator rescheduling, multiobjective optimization, pareto optimality, particle swarm optimization.**

I. Introduction

The restructuring in electric power industry has led to intensive usage of transmission grids. In deregulated electricity market, most of the time power system operates near its rated capacity as each player in the market is trying to gain as much as possible by full utilization of existing resources. Congestion or overload in one or more transmission lines may occur due to the lack of coordination between generation and transmission utilities or as a result of unexpected contingencies such as generation outages, sudden increase of load demand, or failure of equipments. Therefore, congestion management is one of the key functions of any system operator (SO) in the restructured power industry.

In the literature, many methods have been reported for congestion management. Sensitivity-based optimum generation rescheduling and/or load shedding schemes to alleviate overloading of transmission lines are reported in [1]–[6]. Optimal power flow (OPF) is arguably the most significant technique for congestion management in a power system with existing transmission and operational constraints [7]. Congestion management methods proposed in [7]–[10] are based on market model.

Congestion management methods based on OPF use the derivative of the objective function to determine the search direction. However, in general, objective function of OPF is nonconvex, nonsmooth, and nondifferentiable [11] because of the valve point loading of thermal units. In recent years, particle swarm optimization (PSO) method proposed by Kennedy and Eberhart [12] has been one of the popular method used for solving complex nonlinear optimization problems such as optimal power flow [13], [14], unit commitment [15], congestion management [16], etc.

Congestion management methods available in the literature consider only one objective and provide only one solution which does not provide any choice to the operator. Moreover, all the methods use simple load flow method which may not provide accurate results due to change in load and generation because of change in voltage and frequency caused by major contingencies like generator outage or tie line outage.

In this paper, a cost-efficient congestion management method is proposed for smooth and nonsmooth cost functions using multiobjective particle swarm optimization (MOPSO) method. A realistic frequency and voltage dependent load flow model is used which considers the voltage and frequency dependence of load and generator regulation characteristics. Two objectives congestion and cost are simultaneously minimized. Generation rescheduling of participating generators is done to overcome the congestion, but if generation rescheduling alone is not sufficient to alleviate overload, then load shedding is done as a last option for the participating loads. The proposed congestion management method provides a set of nondominated pareto optimal solutions. This provides operator with a set of alternative solutions to manage the congestion.

II. Pareto Optimality

Pareto optimality is a measure of efficiency in multicriteria and multiobjective situations. It is a situation which exists when economic resources and output have been allocated in such a way that none of the objectives can be made better off without sacrificing the well-being of at least one objective, i.e., no part of a pareto optimal solution can be improved without making some other part worse. A state X (a set of object parameters) is said to be pareto optimal, if there is no other state Y dominating the state X with respect to a set of objective functions. A state X dominates a state Y, if X is better than Y in at least one objective function and not worse with respect to all other objective functions. Mathematically it can be put as follows.

A decision vector x is said to strictly dominate another vector y (denoted $x \prec y$) iff

$$f_i(x) \leqslant f_i(y), \quad \forall i = 1, \ldots\ldots, n \tag{1}$$

and

$$f_i(x) < f_i(y) \quad \text{for at least one i.} \tag{2}$$

where n is the number of objectives to be optimized.

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III. Particle Swarm Optimization

PSO is a simple and efficient population-based optimization method proposed by Kennedy and Eberhart [12]. PSO is motivated by social behavior of organisms such as fish schooling and bird flocking. In PSO, potential solutions called particles fly around in a multidimensional problem space. Population of particles is called swarm. Each particle in a swarm flies in the search space towards the optimum or a quasi-optimum solution based on its own experience, experience of nearby particles, and global best position among particles in the swarm.

Let us define search space S is n-dimension and the swarm consists of N particles. At time t, each particle i has its position defined by $X_t^i = \{x_1^i, x_2^i, \ldots, x_n^i\}$ and a velocity defined by $V_t^i = \{v_1^i, v_2^i, \ldots, v_n^i\}$ in variable space S. Position and velocity of each particle changes with time. Velocity and position of each particle in the next generation (time step) can be calculated as

$$V_{t+1}^i = w \times V_t^i + c_1 \times \mathrm{rand}() \times (P_t^i - X_t^i) + c_2 \times \mathrm{Rand}() \times \left(P_t^{i,g} - X_t^i\right) \quad (3)$$

$$X_{t+1}^i = X_t^i + V_{t+1}^i \quad i = 1, \ldots\ldots, N \quad (4)$$

where

N	number of particles in the swarm;
n	number of elements in a particle;
w	inertia weight of the particle;
t	generation number;
c_1, c_2	acceleration constant;
rand(), Rand()	uniform random value in the range [0,1];
$P_t^{i,g}$	global best position of particle in the population;
P_t^i	best position of particle i so far.

The inertia weight w is an important factor for the PSO's convergence. It is used to control the impact of previous history of velocities on the current velocity. A large inertia weight factor facilitates global exploration (i.e., searching of new area) while small weight factor facilitates local exploration. Therefore, it is wise to choose large weight factor for initial iterations and gradually reduce weight factor in successive iterations [13]. This can be done by using

$$w = w_{\max} - \frac{w_{\max} - w_{\min}}{\mathrm{iter}_{\max}} \times \mathrm{iter} \quad (5)$$

where $w_{\max}$ and $w_{\min}$ are maximum and minimum weight, respectively, $iter$ is iteration number, and $\mathrm{iter}_{\max}$ is maximum iteration allowed.

With no restriction on the maximum velocity $(V_{\max})$ of the particles, velocity may move towards infinity. If $V_{\max}$ is very low, particle may not explore sufficiently, and if $V_{\max}$ is very high, it may oscillate about optimal solution. Velocity clamping effect has been introduced to avoid the phenomenon of "swarm explosion" [17]. In the proposed method, velocity is controlled within a band as

$$V_{\max,t} = V_{\max} - \frac{V_{\max} - V_{\min}}{\mathrm{iter}_{\max}} \times \mathrm{iter} \quad (6)$$

where $V_{\max,t}$ is maximum velocity at generation t, and $V_{\max}$ and $V_{\min}$ are initial and final velocity, respectively.

Acceleration constant c_1 called cognitive parameter pulls each particle towards local best position whereas constant c_2 called social parameter pulls the particle towards global best position. Usually c1 equals to c2 and ranges from 0 to 4 [18].

A. Multiobjective PSO

In this paper, multiobjective PSO proposed by Mostaghim and Teich [19] is used. In this method, a truncated elite archive is maintained which contains a set of nondominated solutions. New nondominated solutions are included in the archive in each iteration, and the archive is updated to make it domination free. The MOPSO algorithm is as follows.

1) Set generation number t = 0.
2) Initialize the size of the population, P_t, and the archive, A_t.
3) Generate particles for population and archive randomly.
4) Calculate fitness values for all the particles in the archive and make the archive domination free by deleting dominated particles with respect to particles inside the archive.
5) Calculate fitness values for all the particles in the population.
6) Compare the fitness values of each particle of population with the fitness values of the members of the archive.
7) Check whether any particle (k) in the population dominates any particle (m) in the archive. If yes, replace the dominated archive particle (m) with the particle (k). If particle k dominates more than one particle in the archive, replace one of them with the particle k and replace others with nondominated particles (with respect to archive members) from the population.
8) For each particle, find the best local guide from the archive, calculate new velocity and position, and update particle's best position.
9) If stopping criterion is not satisfied, increase generation number and go to step 5.
10) Stop simulation.

In the MOPSO method, velocity vector of each particle is updated as follows:

$$V_{t+1}^i = w \times V_t^i + c_1 \times \mathrm{rand}() \times (P_t^i - X_t^i) + c_2 \times \mathrm{Rand}() \times (P_t^{i,l\mathrm{best}} - X_t^i) \quad (7)$$

where $P_t^{i,l\mathrm{best}}$ is the best local guide for particle i. For finding the best local guide for each particle sigma, the method proposed in [19] is used. Each particle is assigned a value σ with coordinate (say, (f_1, f_2) for two objectives as shown in Fig. 1) so that all the points which are on the line $f_2 = af_1$ have same σ value. Therefore, for two objectives, σ is written as

$$\sigma = \left(f_1^2 - f_2^2\right) / \left(f_1^2 + f_2^2\right) \quad (8)$$

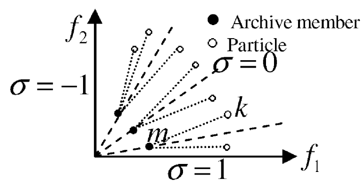

Fig. 1. Finding best local guide for each particle using Sigma method.

where f_1 and f_2 are the fitness values for objective 1 and objective 2, respectively.

Now $\sigma = 0$ if $f_1 = f_2$; $\sigma = -1$ if $f_1 = 0$ and $\sigma = 1$ if $f_2 = 0$. For m objective functions, σ can be calculated as follows:

$$\sigma = \begin{bmatrix} f_1(x)^2 - f_2(x)^2 \\ f_2(x)^2 - f_3(x)^2 \\ \cdot \\ f_m(x)^2 - f_1(x)^2 \end{bmatrix} \Bigg/ (f_1(x)^2 + f_2(x)^2 + \cdot + f_m(x)^2). \quad (9)$$

When two σ values are close to each other, two particles are on two lines which are close to each other. To find out the best local guide for any particle (k) in the population, the archive member (m) having closest sigma value to the sigma value of the particle (k) in population is chosen as best local guide for that particle as shown in Fig. 1.

IV. Problem Formulation

The objective of congestion management is to alleviate the congestion and minimize the cost of generation. Mathematically, this can be represented as in the following.

Objective 1:

$$\min \sum_{i=1}^{\mathrm{NL}} (\mathrm{LF}_i - L_{\mathrm{capi}}) \quad (10)$$

where

NL	number of overloaded lines;
LF_i	MVA flow on line i;
L_{capi}	MVA capacity of line i.

Objective 2: For smooth cost functions:

$$\min \left(\sum_{i=1}^{\mathrm{NG}} \left(p_i + q_i P_{gi} + r_i P_{gi}^2\right) + \sum_{k=1}^{\mathrm{PL}} \left(p'_k + q'_k L_{\mathrm{shd},k} + r'_k L_{\mathrm{shd},k}^2\right) \right). \quad (11)$$

For nonsmooth cost functions considering valve-point effect [13], see (12) at the bottom of the page, where

NG	number of participating generators;
PL	number of participating loads;
P_{gi}	generation of ith generator;
p_i, q_i, r_i	cost coefficients of generator i;
$L_{\mathrm{shd},k}$	amount of load shed at bus k;
p'_k, q'_k, r'_k	cost coefficients of load shedding at bus k;
e_i, f_i	coefficients of generator i reflecting valve point effect.

Subjected to:

Equality Constraints:

$$P_{gi} - P_{di} = \sum_{j=1}^{\mathrm{NB}} |V_i||V_j||Y_{ij}| \cos(\delta_i - \delta_j - \theta_{ij}) \quad (13)$$

$$Q_{gi} - Q_{di} = \sum_{j=1}^{\mathrm{NB}} |V_i||V_j||Y_{ij}| \sin(\delta_i - \delta_j - \theta_{ij}) \quad (14)$$

where

NB	number of buses;
Y_{ii}	self-admittance of node i;
Y_{ij}	mutual admittance between node i and j;
δ_i, δ_j	bus voltage angle of bus i and bus j, respectively;
θ_{ij}	impedence angle of line between buses i and j.

Inequality Constraints:

$$P_{\min i} \leqslant P_{gi} \leqslant P_{\max i} \quad (15)$$

$$Q_{\min i} \leqslant Q_{gi} \leqslant Q_{\max i} \quad (16)$$

$$V_{\min i} \leqslant V_i \leqslant V_{\max i} \quad (17)$$

where

P_{gi}, Q_{gi}	real and reactive power generation at bus i;
P_{di}, Q_{di}	real and reactive power demand at bus i;
$P_{\min i}, P_{\max i}$	minimum and maximum active power generation limits at bus i;
$Q_{\min i}, Q_{\max i}$	minimum and maximum reactive power generation limits at bus i;
$V_{\min i}, V_{\max i}$	minimum and maximum voltage limits at bus i.

Fitness Functions: Fitness functions used for the congestion management MOPSO are as follows.

$$\min \begin{bmatrix} \sum_{i=1}^{\mathrm{NG}} \left(p_i + q_i P_{gi} + r_i P_{gi}^2\right) + |e_i \times \sin(f_i \times (P_{gi} - P_{\min i}))| \\ + \sum_{k=1}^{\mathrm{PL}} \left(p'_k + q'_k L_{\mathrm{shd},k} + r'_k L_{\mathrm{shd},k}^2\right) \end{bmatrix} \quad (12)$$

Fitness Function 1:

$$f_1 = \sum_{i=1}^{\mathrm{NL}} (\mathrm{LF}_i - L_{\mathrm{capi}})^2. \tag{18}$$

Square of the objective 1 is used to avoid any masking effect.

Fitness Function 2: Cost function as given in (11) or (12) is used as appropriate.

V. Load Flow Model

A. Load Characteristics

Both real and reactive power loads are assumed to be composed of three parts. One part is constant, independent of change in voltage, another part is proportional to the voltage, and third part changes as square of the voltage. Loads are also assumed to change with change in frequency. Frequency and voltage dependent loads are expressed as [20]

$$P_{di} = P_{doi}(1 + k_i\Delta f)\left(a_i + b_iV_i + c_iV_i^2\right) \tag{19}$$
$$Q_{di} = Q_{doi}(1 + k_i'\Delta f)\left(a_i' + b_i'V_i + c_i'V_i^2\right) \tag{20}$$

where

k_i, k_i' coefficients of frequency dependent active and reactive load, respectively, at bus i;

a_i, b_i, c_i coefficients of voltage dependent active load at bus i with $a_i + b_i + c_i = 1$;

a_i', b_i', c_i' coefficients of voltage dependent reactive load at bus i with $a_i' + b_i' + c_i' = 1$.

With suitable choice of these coefficients, different types of load characteristics can be obtained.

B. Generator Characteristics

Any real power imbalance in system results in a change in system frequency. This frequency deviation causes generator speed governor control to adjust generator real power output so as to reduce the frequency deviation. This can be modeled as

$$P_{gi} = \sum_{k=1}^{\mathrm{ng}i} P_{gik} = \sum_{k=1}^{\mathrm{ng}i}\left(P_{\mathrm{setik}} - \frac{P_{\max ik}}{R_{\mathrm{ik}}}\Delta f\right) \tag{21}$$
$$P_{\min ik} \leqslant P_{gik} \leqslant P_{\max ik} \tag{22}$$

where,

ng$i$ number of generators at bus i;

$P_{\max ik}, P_{\min ik}$ maximum and minimum real power generation of generator k at bus i;

R_{ik} regulation constant of kth generator at bus i.

C. Real Power Load Flow Equations

Change in bus voltage angles and change in frequency are predominantly influenced by the change in real power injections. Without loss of generality, bus n is assumed as reference bus with $\delta_n = 0$, and therefore, change in real power injections can be written as [21]

$$\begin{bmatrix} \frac{\Delta fp_1'}{|V_1|} \\ \frac{\Delta fp_2'}{|V_2|} \\ \cdot \\ \frac{\Delta fp_n'}{|V_n|} \end{bmatrix} = \begin{bmatrix} -B_{11} & -B_{12} & \cdot & \sum_{k=1}^{\mathrm{ng}1} \frac{P_{\max 1k}}{R_{1k}|V_1|} + b_1k_1P_{do1} \\ -B_{21} & -B_{22} & \cdot & \sum_{k=1}^{\mathrm{ng}2} \frac{P_{\max 2k}}{R_{2k}|V_2|} + b_2k_2P_{do2} \\ \cdot & \cdot & \cdot & \cdot \\ -B_{n1} & -B_{n2} & \cdot & \sum_{k=1}^{\mathrm{ng}n} \frac{P_{\max nk}}{R_{\mathrm{nk}}|V_n|} + b_nk_nP_{on} \end{bmatrix} \times \begin{bmatrix} \Delta\delta_1 \\ \Delta\delta_2 \\ \cdot \\ \Delta(\Delta f) \end{bmatrix} \tag{23}$$

where

$$\Delta fp_i' = \Delta fp_i - P_{\mathrm{doi}} \times k_i \times (a_i + c_i|V_i|^2)\Delta(\Delta f)$$
$$\Delta fp_i = P_i - (P_{gi} - P_{di}).$$

D. Reactive Power Load Flow Equations

Change in bus voltage magnitude is predominantly influenced by the change in reactive power injections. Therefore, change in reactive power injections can be written as [21]

$$\begin{bmatrix} \Delta fq_1'/|V_1| \\ \Delta fq_2'/|V_2| \\ \cdot \\ \Delta fq_n'/|V_n| \end{bmatrix} = \begin{bmatrix} -B_{11} & -B_{12} & \cdot & -B_{1n} \\ -B_{21} & -B_{22} & \cdot & -B_{2n} \\ \cdot & \cdot & \cdot & \cdot \\ -B_{n1} & -B_{n2} & \cdot & -B_{nn} \end{bmatrix} \begin{bmatrix} \Delta V_1 \\ \Delta V_2 \\ \cdot \\ \Delta V_n \end{bmatrix} \tag{24}$$

where

$$\Delta fq_i' = \Delta fq_i - [Q_{\mathrm{doi}}(1 + k_i'\Delta f)(b_i' + 2c_i'V_i)]\Delta V$$
$$\Delta fq_i = Q_i - (Q_{gi} - Q_{di}).$$

VI. Congestion Management Strategy

In deregulated market, pool operator provides congestion-free schedule of load and generation based on submitted bids of GenCos and DisCos. Still, during operation of power system congestion in transmission grids may occur due to uncertainty of load demand or due to contingencies. In case of congestion during operation, all the generators may not participate in congestion management. This paper proposes a method of congestion management where congestion is managed by rescheduling generations of participating generators. If congestion cannot be removed only by generation rescheduling, load shedding is done at the participating load buses. Per unit active power generations of participating generators and/or per unit active power loads of participating load buses are taken as state variables for this problem. Active power inequality constraints are handled during

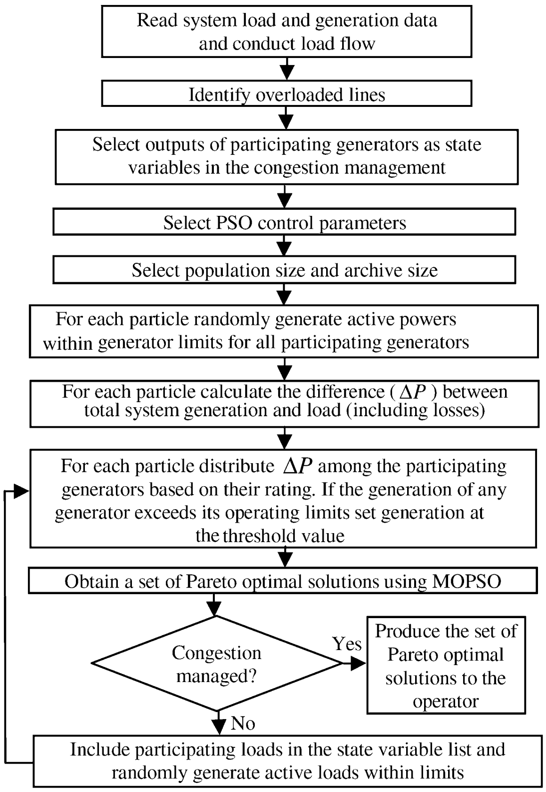

Fig. 2. Congestion management flow chart.

PSO iteration after generation of new position of each particle. These constraints are handled as follows:

$$\text{if } P_{gi} < P_{\min i}, \quad P_{gi} = P_{\min i};$$
$$\text{if } P_{gi} > P_{\max i}, \quad P_{gi} = P_{\max i}.$$

Voltage and reactive power generation inequality constraints are handled during load flow solution. During load flow solution if for any PQ bus, voltage magnitude gets violated, voltage control using reactive power generation at generators and/or transformer taps are adjusted to bring the bus voltage within limits. If reactive power generation of any PV bus gets violated, then PV bus is treated as PQ bus fixing reactive power generation at the threshold value. Flow chart of the proposed congestion management scheme is given in Fig. 2.

VII. Simulation Results and Discussions

To verify the effectiveness of the proposed congestion management method, simulations were carried out on the IEEE 30-bus test system, IEEE 118-bus test system, and 390-bus Northern Region Electricity Board, India (NREB) system (having 754 transmission lines, 205 transformers, 323 generators, 1 SVS, and one HVDC bipolar link).

For simulation purpose, generator regulation $(\mathrm{R_i})$ is taken as 5% for all the generators. Coefficients of active and reactive load characteristic for all the loads are taken as [21]

$$a = .85 \quad b = .10 \quad c = .05 \quad k = 1.5$$
$$a' = .80 \quad b' = .15 \quad c' = .05 \quad k' = 1.5.$$

TABLE I
Simulated Cases

Test system	Simulated cases	
IEEE 30 Bus	1A	Overload simulation by reducing capacity of line 1-2 from 130 MW to 50 MW
	1B	Overload simulation by reducing capacity of lines 12-13 and 12-15 from 130 MW to 20 MW and 65 MW to 15 MW respectively
	1C	Overload simulation for outage of unit 3 at bus 5 and by reducing capacity of line 2-5 from 130 MW to 50 MW
IEEE 118 Bus	2A	Outage of transformer 68-69
NREB 390 Bus	3A	Outage of a double ckt. tie line 7427-4061
IEEE 30 Bus Using non-smooth cost curves	4A	Overload simulation by reducing capacity of line 1-2 from 130 MW to 85 MW
	4B	Outage of line 1-2
	4C	Outage of unit 3 at bus 5 and reducing capacity of line 5-7 from 130 MW to 10 MW

TABLE II
Effects of Parameters in MOPSO

Case	C_1, C_2	$w_{\max}$, $w_{\min}$	$V_{\max}$, $V_{\min}$	Best Cost (Rs./Hr)	Worst cost (Rs./Hr)	Avg. cost (Rs./Hr)
1	1, 1	1.2, 6	.5, .20	7136329	7144966	7139101
2	1, 1	.5, .4	.4, .15	7135014	7142414	7136637
3	1, 1.5	1, .5	.4, .10	7134544	7137854	7136188
4	1.5, 2	.9, .4	.35, .10	7133841	7134745	7134153
5	1.5, 2	.9, .4	.25, .02	7133700	7134337	7133941
6	1.5, 2	.8, .4	.25, .05	7133736	7134570	7134011
7	**1.5, 2**	**.8, .5**	**.25, .02**	**7133570**	**7133875**	**7133686**
8	2, 1.5	.7, .3	.2, .05	7135512	7139710	7137234
9	2, 2	.8, .3	.25, .02	7133598	7133911	7133734
10	2, 2	.9, .4	.2, .01	7133617	7134361	7133956
11	2, 2	.9, .4	.2, .05	7133573	7133885	7133716

Both smooth and nonsmooth cost curves for generators were used. Generation rescheduling and load shedding cost curves (smooth) used in this simulation are same as given in [6]. Coefficients of nonsmooth cost curves are given in Appendix A for all six generator units of the IEEE 30-bus system. Details of the simulation tests carried out on the three test systems are given in Table I. Line over loads are simulated by either taking reduced value for the line flow limits of a few lines and/or by simulating line or generator outage. It is assumed that initially, the systems are operating with economic dispatch.

Parameters (cognitive parameter $(\mathrm{C_1})$, social parameter $(\mathrm{C_2})$, maximum inertia weight $(\mathrm{W_{max}})$, minimum inertia weight $(\mathrm{W_{min}})$, initial velocity $(= \mathrm{V_{max}})$, and final velocity $(= \mathrm{V_{min}})$) for multiobjective PSO were selected through experiment. Results for tests carried out on the IEEE 118-bus test system with smooth cost curves [6] are discussed here. For different combination of parameters, MOPSO was carried out using a swarm of 100 particles. For each set of parameters, 250 independent trials were carried out; the best, worst, and average costs obtained are given in Table II. From Table II, it is seen that case 7 $(\mathrm{C_1} = 1.5, \mathrm{C_2} = 2; \mathrm{w_{max}} = .8, \mathrm{w_{min}} = .5; \mathrm{V_{max}} = .25$ and $\mathrm{V_{min}} = .02)$ gives best results. Similar results were obtained for IEEE 30-bus and NREB systems; therefore, these parameters were used throughout the simulations. A study was also made on the selection of optimum number of particles for each test system using the selected parameters. Optimum numbers of particles in the population for IEEE 30-bus system,

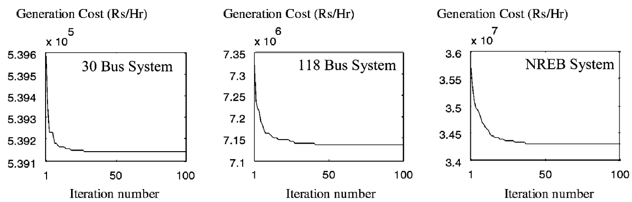

Fig. 3. Convergence characteristics of MOPSO using the selected parameters.

TABLE III
SIMULATION RESULTS FOR OPF USING MOPSO

Test System	Best Minima (Rs/Hr)	Worst Minima (Rs/Hr)	Average Minima (Rs/Hr)	Method in [22] (Rs/Hr)
IEEE 30 Bus	539185	539313	539235	539232
IEEE 118 Bus	7133570	7133875	7133686	7138396
NREB 390 Bus	34274028	34302451	34288356	34276606
IEEE 30 Bus*	547556	547995	547675	No solution

* with non-smooth cost functions

IEEE 118-bus system, and for NREB system are 20, 30, and 50 respectively.

To verify the convergence characteristics of the MOPSO with the selected parameters, OPF simulation was carried out with the optimum number of particles for each system for 100 iterations; the variation in cost with iteration number is shown in Fig. 3. It can be seen that for all the systems (IEEE 30-bus system, IEEE 118-bus system, and NREB 390-bus system), MOPSO converges in less than 50 iterations.

Optimal power flow study without congestion is carried out for all the three systems using smooth and nonsmooth cost curves for 250 independent trials. Best minima, worst minima, and average minima for 250 independent trials are given in Table III. Results are compared with the conventional gradient-based OPF [22]. Table III shows that the proposed method gives reasonable suboptimal solution all the time. The method in [22] fails in case of nonsmooth cost curves in objective function. Taking average minima as base cost, cost variations in p.u. for 250 trials are plotted in Figs. 4 and 5 for the IEEE 30-bus test system with smooth and nonsmooth cost curves, respectively. It shows that for smooth cost functions, cost variation band (0.024%) between best minima and worst minima is less compared the cost variation band (0.08%) for nonsmooth cost curves. This is because of higher nonlinearity caused by nonsmoothness in cost function due to valve point loading. It also shows that MOPSO like any other population-based optimization method does not converge to the same optimal point, but it provides a suboptimal solution which is very close to the optimal point.

Table IV presents the congestion management solutions for the IEEE 30-bus system with smooth cost curves.

For case 1A, congestion is managed by changing active power rescheduling of four participating generators. Three nondominated solutions from the truncated archive are presented here. If the operator wants to alleviate the overload completely, he will choose solution 1, and for this case, generation cost will increase by Rs 1986 per hour. However, if the operator allows some overload and takes solution 2, generation cost changes by

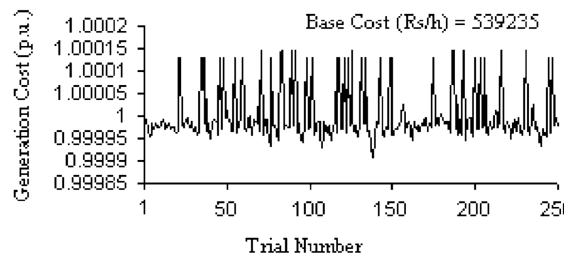

Fig. 4. Performance of MOPSO-based OPF for IEEE 30-bus system with smooth cost curve.

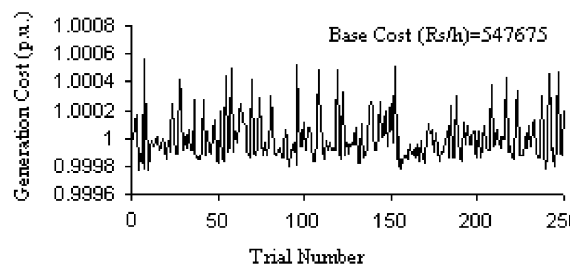

Fig. 5. Performance of MOPSO-based OPF for IEEE 30-bus system with non-smooth cost curve.

Rs 1634 per hour and for solution 3 it changes by only Rs 708 per hour. This shows that if the operator wants to alleviate the overload completely, he has to sacrifice cost to some extent.

For case 1B, overload alleviation is not possible by only rescheduling of generators. Therefore, load shedding has to be carried out on participating loads at buses 4, 15, 18, and 23 based on cost of load shedding. In this case, if the operator chooses solution 1, he needs to increase the generation at bus 2 by 13.28 MW, decrease the generation at bus 13 by 17.35 MW, and shed 4.5 MW (2.33 MW at bus 15 and 2.17 MW at bus 23) load (see Appendix B for load shedding scheme) to manage the congestion completely; in this case generation cost increases by Rs 3280 per hour, whereas for solutions 2 and 3, generation cost increase by Rs 2461 per hour and Rs 1865 per hour, respectively, but congestion is not relieved completely.

In case of 1C, when generator at bus 5 trips, system frequency drops down from 50.00 Hz to 49.61 Hz. As system frequency drops, total system load also reduces from 283.4 MW to 280.6 MW; this reduces generation cost by Rs 1115 per hour, but the load served is also reduced by 2.8 MW. In this case, line 2–5 gets overloaded and load shedding is necessary to alleviate the overload. For this case, 38.8 MW (27.04 MW at bus 5 and 11.76 MW at bus 7) load shedding is required to alleviate the overload completely.

Tables V–VII present some of the pareto optimal solutions for the congestion cases for the IEEE 118-bus system and NREB system with smooth cost curves and for the IEEE 30-bus system with nonsmooth cost curves, respectively.

For case 2A, as soon as the transformer 68-69 trips, network topology changes and line flow (109.25 MW) through the transformer is shared by other lines. As power flow on some line changes, power loss increases from 51.64 MW to 56.96 MW. Therefore, generation costs increase by Rs 9978 per hour from the optimal solution (7 133 570 Rs/h).

TABLE IV
SIMULATED CASES FOR IEEE 30-BUS SYSTEM WITH SMOOTH COST CURVES (TOTAL LOAD 283.4 MW)

CASE	OVER LOADED CONDITION			INITIAL GENERATION/ LOAD* AT PARTICIPATING BUSES			PARETO OPTIMAL SOLUTIONS								
							SOLUTION I			SOLUTION II			SOLUTION III		
	Line	MVA Flow	MVA Cap	Bus code	P_g or P_d MW	Cost (Rs/h)	MVA Flow	P_g or P_d MW	Cost (Rs/h)	MVA Flow	P_g or P_d MW	Cost (Rs/h)	MVA Flow	P_g or P_d MW	Cost (Rs/h)
1	1-2	63.62	50	1	96.70		49.16	80.65		53.12	86.39		54.95	86.86	
A				2	48.04	539185		77.66	541171		75.35	540819		64.05	539893
				5	49.87			46.72			44.64			48.21	
				8	35.00			24.83			23.67			30.59	
1	12-13	29.63	20	2	48.04		12.31	61.32		12.90	61.09		12.86	62.48	
B	12-15	19.74	15	13	29.49		14.99	12.14		15.82	12.79		16.36	12.78	
				4*	7.60	539185		7.60	542465		7.60	541646		7.60	541050
				15*	8.20			5.87			7.25			8.20	
				18*	3.20			3.20			1.10			2.12	
				23*	3.20			1.03			2.90			2.01	
1	2-5	69.88	50	1	127.5	538070	49.82	125.0	565979	52.15	130.8	563366	54.71	118.5	559514
C				2	60.39	Freq		31.79	Freq		30.00	Freq		47.98	Freq
				5*	94.20	49.61		67.16	49.99		71.30	49.99		71.70	50.00
				7*	22.80	Hz		11.04	Hz		10.57	Hz		15.78	Hz

TABLE V
SIMULATED CASES FOR 118-BUS SYSTEM WITH SMOOTH COST CURVES (TOTAL LOAD 4242 MW)

CASE	OVERLOADED CONDITION			INITIAL GENERATION/ LOAD* AT PARTICIPATING BUSES			PARETO OPTIMAL SOLUTIONS								
							SOLUTION I			SOLUTION II			SOLUTION III		
	Line	MVA Flow	MVA Cap	Bus code	P_g or P_d MW	Cost (Rs/h)	MVA Flow	P_g or P_d MW	Cost (Rs/h)	MVA Flow	P_g or P_d MW	Cost (Rs/h)	MVA Flow	P_g or P_d MW	Cost (Rs/h)
2	65-68	112	100	49	147		10	145		105	150		108	148	
A				61	124		0	130			126			128	
				62	34	7143548		30	7143303		40	7142483		40	7142232
				65	222			223			215			225	
				66	221			221			226			222	
				69	325			288			291			287	
				70	30			35			24			21	
				77	36			28			42			41	
				80	337			348			346			347	
				116	24			53			41			41	

TABLE VI
SIMULATED CASES FOR NREB 390-BUS SYSTEM WITH SMOOTH COST CURVES (TOTAL LOAD 18 996 MW)

CASE	OVERLOADED CONDITION			INITIAL GENERATION/ LOAD* AT PARTICIPATING BUSES			PARETO OPTIMAL SOLUTIONS								
							SOLUTION I			SOLUTION II			SOLUTION III		
	Line	MVA Flow	MVA Cap	Bus code	P_g or P_d MW	Cost (Rs/h)	MVA Flow	P_g or P_d MW	Cost (Rs/h)	MVA Flow	P_g or P_d MW	Cost (Rs/h)	MVA Flow	P_g or P_d MW	Cost (Rs/h)
3	8419-	279	250	2217	566		245	538		262	548		274	589	
A	8424			4219	180			155			157			169	
				8238	558	34312403		506	35878255		371	35334305		516	34763485
	8419-	279	250	8207	558		245	211		262	452		274	530	
	8424			8222	376	Freq.		374	Freq		380	Freq		408	Freq
				7472	362	49.91 Hz		861	50.00 Hz		841	50.00 Hz		939	50.00 Hz
	8424-	705	600	7265	284		585	244		589	248		637	267	
	7446			3232	588			831			969			770	
				3129*	196			0.0			86			196	
	3230-	242	200	3230*	237		170	100		199	237		215	195	
	3207			3213*	39.2			0.0			25			39.2	
				7245*	281			119			101			237	
				3240*	58.1			2.6			25			34	

In case 3A, a 400-KV double circuit tie line between Gorakhpur (NREB) and Muzaffarpur (Eastern Region Electricity Board, India) is tripped. Through this tie line, NREB was importing 800 MW power (400 MW on each circuit) from the Eastern region. Due to the tripping, NREB system gets isolated, and the imbalance of 800 MW is met by real power control of the generators in NREB according to their regulation characteristics. As a result of this system, frequency drops from 50.00 Hz

TABLE VII
SIMULATED CASES FOR IEEE 30-BUS SYSTEM WITH NONSMOOTH COST CURVES (TOTAL LOAD 283.4 MW)

CASE	OVER LOADED CONDITION			INITIAL GENERATION/ LOAD* AT PARTICIPATING BUSES			PARETO OPTIMAL SOLUTIONS								
							SOLUTION I			SOLUTION II			SOLUTION III		
	Line	MVA Flow	MVA CAP	Bus code	P_g or P_d MW	Cost (Rs/h)	MVA Flow	P_g or P_d MW	Cost (Rs/h)	MVA Flow	P_g or P_d MW	Cost (Rs/h)	MVA Flow	P_g or P_d MW	Cost (Rs/h)
4	1-2	98	85	1	149.4		84.92	130.9		86.82	132.8		93.50	144.9	
A				2	57.40	547556		59.02	559573		57.41	556651		61.38	556641
				5	35.97			36.18			35.94			36.19	
				8	10.18			25.70			25.69			10.34	
4	1-3	153	100	1	153.2		96.39	96.39		97.35	97.35		99.79	99.79	
B	3-4	145	100	2	58.90	574499	91.02	80.00	576007	91.93	80.00	574638	94.27	78.17	572422
				5	36.90			50.00			50.00			49.73	
				8	10.83			25.89			25.89			25.68	
				13	30.22			30.02			29.16			29.43	
4	5-7	23.1	10	1	168.2	591659	6.70	149.9	575592	7.00	150.4	575574	11.00	141.7	575409
C				2	64.88	Freq		57.42	Freq		57.98	Freq		56.85	Freq
				8	13.45	49.76		10.26	49.996		10.00	50.00		25.24	50.00
				5*	94.20	Hz		59.38	HZ		60.00	HZ		65.57	

to 49.91 Hz, four transmission lines get congested, and total system load is reduced from 18 996 MW to 18 952 MW. The change in generation causes the cost to increase by Rs 38 375 per hour from the optimal solution (34 274 028 Rs/h). Solution 1 in Table VI gives a congestion-free solution for this problem, but generation cost increases by 1 604 227 Rs/h from the optimal solution whereas for solution 2 and 3, generation cost increases by 1 060 277 Rs/h and 489 457 Rs/h, respectively, which are attractive from economic point of view with acceptable congestion (less than 10%).

Simulation results for the IEEE 30-bus system in Table VII show that due to nonsmooth cost function caused by the valve point loading, optimal generation cost increases by Rs 8371 per hour as compared to smooth cost functions for same loading condition. For case 4A and 4B, congestions are managed without load shedding. For case 4C, load shedding is required to alleviate the overload completely. If 34.82 MW load is shed at bus 5, then line flow through 5–7 reduces to 6.7 MVA and system frequency improves to 49.996 Hz.

VIII. CONCLUSION

This paper presents a method for congestion management in transmission grids using cost-efficient generation rescheduling and/or load shedding. A realistic frequency and voltage dependent modified fast decoupled load flow method is used with multiobjective PSO technique to solve this complex problem. Though MOPSO (with limited number of iterations) does not guarantee global optimal solution, it provides a very close suboptimal solution for smooth as well as nonsmooth objective functions. This method also provides a set of pareto optimal solutions for any congestion problem, giving the system operator options for judicious decision in solving the congestion.

APPENDIX

A. *Cost Coefficients of Steam Turbine Generators of IEEE 30-Bus System*

Unit	Bus No.	Pmax	Pmin	e	f
1	1	200	50	15,000	.063
2	2	80	20	14,000	.084
3	5	50	15	12,000	.15
4	8	35	10	10,000	.20
5	11	30	10	10,000	.25
6	13	40	12	12,000	.18

B. *Load Shedding Scheme*

Load can be shed in a two stage procedure: 1) operator may switch off some of the distribution feeders or transformers to shed approximately the amount of load shedding required (coarse adjustment), and 2) for fine adjustment, operator can adjust the bus voltage (as loads are voltage dependent) by changing the transformer tap position.

For example, in case 1B, solution 1, operator needs to shed 2.33 MW load at bus 15. Initially, operator will switch off the feeders/transformers to shed that amount of load coarsely. Let us say that by switching feeders/transformers, operator is able to shed 2.28 MW load. Now for fine adjustment, operator can control the bus voltage as follows.

As change in active load is very small, frequency variation will be negligible; therefore, (19) can be written as

$$P_{d15} = P_{do15}\left(a_{15} + b_{15}V_{15} + c_{15}V_{15}^2\right).$$

Now $P_{do15} = (8.2 - 2.28) = 5.92$ MW as 2.28 MW load is already shed, $P_{d15} = 5.87, a_{15} = .85, b_{15} = .1$ and $c_{15} = .05$.

Solving above $V_{15} = .957$ p.u.

Now adjusting tap, voltage at bus 15 can be made .957 p.u. Similarly, desired voltage can also be calculated if the amount of coarse load shedding is more than the desired value.

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