Muneender Erukulla[1,*], Vinodkumar D.M[2]

J. Electrical Systems 8-2 (2012): 160-177

Regular paper

Velocity Feedback Adaptive Particle Swarm Optimization for Optimal Congestion Management

JES Journal of Electrical Systems

In a deregulated electricity market one of the most important tasks of System Operator is to manage congestion. One of the most practical and obvious technique of congestion management (CM) is rescheduling the power outputs of generators in the system. The optimal rescheduling of powers in a pool model is formulated as a constrained nonlinear optimization problem. This paper proposes a novel Velocity Feedback Adaptive Particle Swarm Optimization (VFAPSO) for solving the constrained nonlinear optimization problem of the congestion management problem to minimize the Congestion Cost using the optimal rescheduling of reactive power generation of both generator and capacitor along with the rescheduling of active power. In the proposed VFAPSO method the inertia weight is dynamically adjusted using the information of average velocity of swarm as feedback. The proposed method deals with an adaptive strategy for tuning the parameters of Particle Swarm Optimization method based on the analysis of the dynamics of PSO. The effectiveness of the proposed method has been tested on 39-bus New England Test system. The simulation experiments reveal that the proposed method performs better than the Standard Particle Swarm Optimization (SPSO), Linearly Decreasing Inertia Weight PSO and other Evolutionary Algorithms such as Binary Coded Genetic Algorithm (BCGA) and Real Coded Genetic Algorithm (RCGA).

Keywords: Congestion Management, Evolutionary Algorithms, Adaptive PSO, Optimal Power Flow and Transmission Congestion Distribution Factors.

1. Introduction

1.1 Motivation

When the producers and consumers of electric energy desire to produce and consume in amount that would cause the transmission system to operate at or beyond one or more transfer limits, then the system is said to be ‘congested’. One of the most critical and important tasks of System Operator (SO) is to manage congestion. The objective of the congestion management (CM) is to take actions or control measures to relieve the congestion of transmission networks optimally. Several methods of congestion management have been reported in literature [1]. Pool and bilateral contract dispatches and the priority arrangements for line congestion and curtailment strategies are discussed in [2]. Srivastava and Kumar [3] presented an OPF based model for reducing the congestion to minimize the curtailment of contracted power in a power market having bilateral and multilateral contracts. A congestion cluster based method, which identifies the group of system users according to their impact on transmission constraints of interest, has been proposed in [4]. Here clusters of type 1, 2 and higher based on congestion distribution factors have been demarcated, with type 1 cluster consisting of those with strongest and non uniform effects on the transmission constraints of interest. A Zonal model based on AC load flow was proposed in [5]. In these papers the zones/clusters are identified based on transmission congestion distribution factors and the optimal re-dispatch has been solved by CONOPT solver using GAMS software package.

In [6], a technique has been proposed for selection of participating generators based on

* Corresponding author: Muneender Erukulla, National Institute of Technology Warangal, Electrical Engineering Department, E-mail: emuneender.nitw@gmail.com

sensitivity to current flow on congested lines as well as the generation bids. However, an optimal selection of the design variables is essential for regulating the number of participating generators in this work. In [7], congestion alleviation by rescheduling of active power based on Relative Electrical Distance (RED) has been introduced. This method claims to minimize the system losses and maintain better voltage profile and hence more stability margin. However, the bids of individual generation units and costs of rescheduling are not taken in concern. Generators having same RED but different price bids must reschedule their outputs so as to minimize cost of rescheduling is minimum. This problem has not been addressed in this paper.

Sudipta Dutta et al [8] proposed PSO based OPF for the optimal rescheduling of generators for congestion management using generator sensitivities. In this they discussed only the optimal re-dispatch of active power and the reactive power dispatch has not been taken into consideration. But, the reactive power will play a vital role in the congestion management in reducing the congestion cost. Moreover, if the PSO parameters are not properly tuned, it leads to premature convergence to local optima due to the imbalance between global and local searching capabilities [11].

In [9], a fuzzy PSO has been applied for congestion management by optimal rescheduling of active powers of generators selected based on the generator sensitivity to the congested line. This paper has not discussed the impact of reactive power of generator as well as the capacitor reactive support on the congestion management. This paper has not addressed the effect of multi line congestion cases on the congestion cost and the optimal rescheduling of active powers.

In the literature survey on various approaches to congestion management, it is observed that no researcher has made an attempt so far to dynamically adjust the inertia weight of the PSO for Optimal Rescheduling of both Active and Reactive power with capacitor reactive support to relieve the congestion in the congested line optimally.

The main intent of the present paper is to propose the optimal rescheduling of both active and reactive power with capacitor reactive support for congestion management using a novel Velocity Feedback Adaptive Particle Swarm Optimization (VFAPSO). The proposed VFAPSO method deals with an adaptive strategy for tuning the parameters of Particle Swarm Optimization method based on the analysis of the dynamics of PSO. In this method the inertia weight is dynamically adjusted using the information of average velocity of swarm as feedback.

In this paper, the effect of reactive power of both generator and capacitor on the optimal rescheduling of active power of generators and congestion cost. This paper also addressed the impact of multi line congestion cases on the congestion cost and optimal rescheduling of both active and reactive powers. Instead of selecting all the generators to relieve congestion, in this paper it is proposed to select the only those generators from the most sensitive zone based on their active and reactive power transmission congestion distribution factors (PTCDFs and QTCDFs).

In the congestion management problem formulation, first it is required to find the optimal number of generators participating in the congestion alleviation process and then application of one of the available optimal power flow methods to find minimum rescheduling cost or congestion cost to alleviate congestion. The System Operator (SO) can manage congestion effectively by selecting the generators from the most sensitive congestion zones based on their bids in the market.

The effectiveness of the proposed method has been tested on a 39-bus New England Test system and 75-bus Indian Practical System. All the methods for Congestion Management problem have been implemented using MATLAB 7.0 programming. The performance and the effectiveness of the proposed method have been compared with Linearly Decreasing Inertia Weight PSO (LDIW-PSO), Conventional Particle Swarm Optimization (SPSO), Binary Coded Genetic Algorithm (BCGA), Real Coded Genetic Algorithm (RCGA) methods and the methods reported in [5], [7] and [8].

2. Notation

Indexes:

P_{ij} and Q_{ij}	:	active and reactive power flow in line between i^{th} and j^{th} bus
P_{ij}^{0} and Q_{ij}^{0}	:	the original real and reactive power flow in line connected between bus-i and bus-j
$P_i + Q_i$	:	the net injected complex power at bus-i
V_i	:	voltage at i^{th} bus
V_i^0	:	initial voltage at i^{th} bus
Y_{ij}	:	Y-matrix element of i^{th} row and j^{th} column
θ_{ij}	:	admittance angle of Y-matrix element of i^{th} row j^{th} column
δ_i	:	voltage angle of i^{th} bus
CC	:	congestion cost
C_{pg}	:	cost of the active power generation
C_{qg}	:	cost of the reactive power generation
C_{qc}	:	production cost on the capital investment of the capacitor
ΔP_g	:	change in active power generation
ΔQ_g	:	change in reactive power generation
ΔQ_c	:	change in reactive power of capacitor

$\Delta P_g^{\min}$ *and* $\Delta P_g^{\max}$	:	*minimum and maximum limit of change in active power generation*
$\Delta Q_g^{\min}$ *and* $\Delta Q_g^{\max}$	:	*minimum and maximum limit of change in reactive power generation*
$\Delta Q_c^{\min}$ *and* $\Delta Q_c^{\max}$	:	*minimum and maximum limit of change in reactive power of capacitor*
$V_i^{\min}$ *and* $V_i^{\max}$	:	*minimum and maximum limit of voltage at* i^{th} *bus*
ΔV_i	:	*change in voltage at* i^{th} *bus*
$S_{ij}^{\max}$	:	*MVA flow limit of line between* i^{th} *and* j^{th} *bus*
$S_{G,\max}$	:	*nominal apparant power of generator*
K	:	*profit rate*
P_L *and* Q_L	:	*active and reactive power loss*
N_l	:	*number of congested lines*
NG	:	*number of generators participating in congestion manangement*
N_b	:	*number of buses*
r_{jk}	:	*resistance of line between* j^{th} *and* k^{th} *bus*
x_{jk}	:	*reactance of line between* j^{th} *and* k^{th} *bus*
$\alpha_{jk}, \beta_{jk}, \gamma_{jk}$ *and* ξ_{jk}	:	*loss coefficients*
a_i, b_i *and* c_i	:	*predetermined cost coefficients of* i^{th} *generator*

2. Congestion Management Problem Formulation

For the optimal number of generators, this paper has utilized two sets of sensitivity indices termed as Real Power Transmission Congestion Distribution Factors (PTCDFs) and Reactive Power Transmission Congestion Distribution Factors (QTCDFs). The procedure for the calculation of PTCDFs and QTCDFs is explained in the following section.

2.1 Transmission Congestion Distribution Factors (TCDFs)

The main objective of the TCDFs is to reduce the computation burden by selecting only few of the generators which are more sensitive to the power flow in the congested line. Transmission congestion distribution factors (TCDFs) are defined as the change in power flow in a transmission line-k connected between *bus-i* and *bus-j* due to unit change in the power injection at *bus-i*. Mathematically the TCDF for the line-k can be written as:

$$\left.\begin{aligned} PTCDF_n^k &= \frac{\Delta P_{ij}}{\Delta P_n} \\ QTCDF_n^k &= \frac{\Delta Q_{ij}}{\Delta Q_n} \end{aligned}\right\} \tag{1}$$

The PTCDF_g^k and QTCDF_g^k given in the above equations represent the real and reactive power flow sensitivities of line $i - j$ with respect to bus real and reactive power injections [5].

The basic power flow equation on the congested line can be written as:

$$\left.\begin{aligned} P_{ij} &= V_i V_j Y_{ij} \cos(\theta_{ij} + \delta_j - \delta_i) - V_i^2 Y_{ij} \cos\theta_{ij} \\ Q_{ij} &= -V_i V_j Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i) + V_i^2 Y_{ij} \sin\theta_{ij} - \frac{V_i^2 Y_{sh}}{2} \end{aligned}\right\} \quad (2)$$

Where V_i and δ_i are the voltage and phase angle respectively at i[th] bus; Y_{ij} is the admittance of the line connected between buses *i* and *j*.

$$\left.\begin{aligned} PTCDF_n^k &= \left(\frac{\Delta P_{ij}}{\Delta \delta_i}\right)\left(\frac{\Delta \delta_i}{\Delta P_n}\right) + \left(\frac{\Delta P_{ij}}{\Delta \delta_j}\right)\left(\frac{\Delta \delta_j}{\Delta P_n}\right) \\ QTCDF_n^k &= \left(\frac{\Delta Q_{ij}}{\Delta V_i}\right)\left(\frac{\Delta V_i}{\Delta P_n}\right) + \left(\frac{\Delta Q_{ij}}{\Delta V_j}\right)\left(\frac{\Delta V_j}{\Delta P_n}\right) \end{aligned}\right\} \quad (3)$$

Where
$$\left.\begin{aligned} a_{ij} &= \frac{\Delta P_{ij}}{\Delta \delta_i} = V_i V_j Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i) \\ b_{ij} &= \frac{\Delta P_{ij}}{\Delta \delta_j} = -V_i V_j Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i) \\ c'_{ij} &= \frac{\Delta Q_{ij}}{\Delta V_i} = -V_j Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i) + 2V_i Y_{ij} \cos(\theta_{ij}) - V_i Y_{sh} \\ d'_{ij} &= \frac{\Delta Q_{ij}}{\Delta V_j} = -V_i Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i) \\ m_{in} &= \frac{\Delta \delta_i}{\Delta P_n} \text{ and } m_{jn} = \frac{\Delta \delta_j}{\Delta P_n} \\ n_{in} &= \frac{\Delta V_i}{\Delta Q_n} \text{ and } n_{jn} = \frac{\Delta V_j}{\Delta Q_n} \end{aligned}\right\} \quad (4)$$

a_{ij}, b_{ij}, c'_{ij} & d'_{ij} are the coefficients which can be obtained using the partial derivatives of active and reactive power flows shown in equation (2).

After the calculation of PTCDFs and QTCDFs, these will be utilized for identifying congestion clusters (zones) for a given system. The congestion cluster of type-1 has been defined as the zone having large and non uniform Transmission Congestion Distribution Factors (TCDFs) and the congestion cluster of type 2 and higher has been defined as those having small or similar TCDFs. The transactions in the congestion Zone-1 have critical and unequal impact on the line flow. The congestion zones of type 2, 3 and higher are farther from the congested line of interest. Therefore, any transaction outside the most sensitive Zone-1 will contribute very little to the line flow. If more than one line congestion conditions are present in the system, the congestion zones can be obtained by superimposing the zones corresponding to the individual line congestion. Thus, the identification of congestion zones will reduce the computational burden, considerably, in both re-dispatching and physical curtailments necessary for the transmission loading relief

(TLR) in case of emergency and the adjustment of system users themselves under normal conditions.

2.2 Optimization problem for Congestion Management

The optimal re-scheduling of active and reactive powers for Congestion Management in a pool model is formulated as a constrained nonlinear optimization problem as follows:

$$Min\ CC = \sum_{g}^{NG} C_{pg}(\Delta P_g)\Delta P_g + \sum_{g}^{NG} C_{qg}(\Delta Q_g)\Delta Q_g + \sum_{c}^{NC} C_{qc}(\Delta Q_c)\Delta Q_c \tag{5}$$

Subject to

$$\Delta P_g^{min} \le \Delta P_g \le \Delta P_g^{max} \quad g = 1, 2, ... NG \tag{6}$$

$$\Delta Q_g^{min} \le \Delta Q_g \le \Delta Q_g^{max} \quad g = 1, 2, ... NG \tag{7}$$

$$\Delta Q_c^{min} \le \Delta Q_c \le \Delta Q_c^{max} \quad c = 1, 2, ... NC \tag{8}$$

$$V_i^0 - V_i^{min} \le \Delta V_i \le V_i^{max} - V_i^0 \quad i = 1, 2 .... N_b \tag{9}$$

$$\left(P_{ij}^0 + \sum_g PTCDF_g^k * \Delta P_g\right)^2 + \tag{10}$$

$$\left(Q_{ij}^0 + \sum_g QTCDF_g^k * \Delta Q_g + \sum_c QTCDF_c^k * \Delta Q_c\right)^2 \le (S_{ij}^{max})^2 \quad ij \in N_l$$

$$\sum_{g}^{NG} \Delta P_g - \sum_{g}^{NG} \frac{\partial P_L}{\partial P_g}\Delta P_g - \sum_{g}^{NG} \frac{\partial P_L}{\partial Q_g}\Delta Q_g - \sum_{c}^{NC} \frac{\partial P_L}{\partial Q_c}\Delta Q_c = 0 \tag{11}$$

$$\sum_{g}^{NG} \Delta Q_g - \sum_{g}^{NG} \frac{\partial Q_L}{\partial Q_g}\Delta Q_g - \sum_{g}^{NG} \frac{\partial Q_L}{\partial P_g}\Delta P_g - \sum_{c}^{NC} \frac{\partial Q_L}{\partial Q_c}\Delta Q_c = 0 \tag{12}$$

Where

C_{pg} is the cost of active power generation and is modeled by quadratic function as follows:

$$C_{pg}(\Delta P_g) = a_g(\Delta P_g)^2 + b_g(\Delta P_g) + c_g \tag{13}$$

The second term in the objective function shown in (5) is the opportunity cost of the generator and it can be determine approximately as follows [10]:

$$C_{qg}(\Delta Q_g) = \left[C_{pg}(S_{G,\max}) - C_{pg}\left(\sqrt{S_{G,\max}^2 - \Delta Q_g^2}\right)\right]K \tag{14}$$

K is the profit rate of active power generation taken between 5% and 10%.

The third term in the objective function shown in (5) is the equivalent production cost for capital investment return on the capital investment of the capacitors, which is expressed as their depreciation rates for the life-span of 15 years as follows [10]:

$$C_C(\Delta Q_C) = Q_C \times \frac{Investment\ Cost}{Operating\ Hours}$$
$$= Q_C \times \frac{(\$11,600\ /\ MVar)}{(15 \times 365 \times 24 \times h)h} \qquad (15)$$
$$= Q_C \times \$13.24\ /\ (100MVarh)$$

Where, *h* represents the average usage rate of capacitors taken as 2/3. Q_c is in per unit on the 100MVA base.

$$P_L = \sum_{j=1}^{N_b}\sum_{k=1}^{N_b}\left[\alpha_{jk}(P_jP_k + Q_jQ_k) + \beta_{jk}(Q_jP_k - P_jQ_k)\right] \qquad (16)$$

$$Q_L = \sum_{j=1}^{N_b}\sum_{k=1}^{N_b}\left[\gamma_{jk}(P_jP_k + Q_jQ_k) + \xi_{jk}(Q_jP_k - P_jQ_k)\right] \qquad (17)$$

$$\alpha_{jk} = \frac{r_{jk}}{V_jV_k}\times\cos(\delta_j - \delta_k);\ \beta_{jk} = \frac{r_{jk}}{V_jV_k}\times\sin(\delta_j - \delta_k) \qquad (18)$$

$$\gamma_{jk} = \frac{x_{jk}}{V_jV_k}\times\cos(\delta_j - \delta_k);\ \xi_{jk} = \frac{x_{jk}}{V_jV_k}\times\sin(\delta_j - \delta_k) \qquad (19)$$

$P_L\ and\ Q_L$ are the total real and reactive power loss respectively. The second, third and forth terms in (11) and (12) incorporates the change in the losses in the system occurring due to re-dispatch of the generators and capacitors. The real and reactive power loss sensitivity with respect to change in real and reactive power injections can be derived by using (16) and (17).

3. Proposed Velocity Feedback Adaptive PSO (VFAPSO)

In the Standard or Conventional PSO (SPSO) system, particles fly around in a multidimensional search space [11]. The updated velocity of individual ith particle of jth dimension is given in (20).

$$v_{ij}^{k+1} = w \times v_{ij}^{k} + c_1 \times rand_1() \times (pBest_{ij}^{k} - x_{ij}^{k}) + c_2 \times rand_2() \times (gBest_{j}^{k} - x_{ij}^{k}) \qquad (20)$$

Where i=1, …,m, and m is the size of the swarm; j=1,…, n, where n is the size of space of a given problem; v_{ij}^k is the velocity of ith individual of jth dimension at iteration k, *w* is the inertia weight, c_1, c_2 the acceleration factors, $rand_1(\ )$, $rand_2(\ )$, the uniform random numbers between 0 and 1, x_{ij}^k, the position of ith individual of j^{th} dimension at iteration k, $pBest_{ij}^k$, the best position of i^{th} individual of j^{th} dimension at iteration k and $gBest^k$, the best position of j^{th} dimension in group of particles until iteration k. Each individual moves from the current position to the next one with the modified velocity as in (21).

$$x_{ij}^{k+1} = x_{ij}^{k} + v_{ij}^{k+1} \tag{21}$$

As evolution goes on, the swarm might undergo an undesired process of diversity loss. Some particles become inactive while they lose both global and local searching capabilities in the next generations. Considering Equations (20) and (21), there are three problem-dependent parameters, the inertia weight of the particle (w) and two trust parameters (c_1 and c_2). The inertia controls the exploration properties of the algorithm, with larger values facilitating a more global behavior and smaller values facilitating a more local behavior. The trust parameters indicate how much confidence the particle has in itself (c_1) and how much confidence it has in swarm (c_2). Therefore, for better performance, the inertia weight should be nonlinearly and dynamically changed to have better dynamics of balance between global and local searching abilities. Shi and Eberhart proposed an efficient strategy for tuning the parameters of PSO [14]. This method is called Linearly Decreasing Inertia Weight PSO (LDIWPSO). In this method, the value of the parameter w (inertia weight) is large at the beginning of search process, whereupon it gradually becomes smaller as the iteration advances. For example $w=0.9$ (at the beginning of search process), $w=0.4$ (at the end of search process) However, the search ability of LDIWPSO is reduced when the scale of the problem becomes large, because the search finishes before the phase of searching shifts from diversification to intensification.

Although the search ability of LDIWPSO declines when it is applied to a large scale problem, the strategy of LDIWPSO, that is the phase of searching gradually shifting from diversification to intensification with a progress of iteration, appears to be effective for optimization. Thus a new algorithm is proposed in which the parameters are tuned adaptively in order to maintain the ideal velocity as shown in Figure 1.

The particle transfers by using transfer vector v_{ij} generated from the equation (20), therefore $\left|v_{ij}\right|$ is the transfer size. Since in this equation randomness is included, the transfer vector v_{ij} fluctuates due to this randomness. The average velocity of all the particles can be used as an index to understand the activity of all the particles [12].

$$v_{avg} = \frac{1}{m.n}\sum_{i}^{m}\sum_{j}^{n}\left|v_{ij}\right| \tag{22}$$

The value v_{avg} can express the activity of a swarm, and provide useful information for constructing adaptive PSO.

If the values of parameters are not appropriate, the absolute value of velocity $\left|v_{ij}\right|$ can increase or decrease rapidly. Neither of these cases is desirable for the search process. If the parameter setting is appropriate, the average velocity gradually decreases, a good solution tends to be obtained. On the other hand, if the parameters have a divergent character, the average velocity gradually increases, and the search ends in the failure. And if the parameters are over convergent, the particles become almost static after few iterations. The w controls the speed of the convergence and divergence. If w<1, the speed of convergence is high, while if w>1, the speed of divergence is high. In this paper the w is controlled based on the average velocity (v_{avg}) of the swarm, which is used as feedback, for good convergent characteristic of particles. In this algorithm, c_1=c_2=1.3 are constant. If v_{avg} is smaller than the ideal velocity (or goal velocity, v_{goal}), w shifts to 0.9; this is a divergent value and v_{avg} will increase. Otherwise, w shifts to 0.8; this is convergent value and v_{avg} will decrease [12]. In the Figure 1, the proposed goal velocity is reaches 0 before the end of searching, because it is intended to search intensively in the final stage of the search process. While proposed method does not require that parameters be determined before the search process begins, V_{start} in the Figure 1 must be determined. For the present problem V_{start} is selected based on the generator active power limits, generator reactive power limits and capacitor reactive power limits. The difference between the minimum and maximum limits of active and reactive power may be selected as V_{start}.

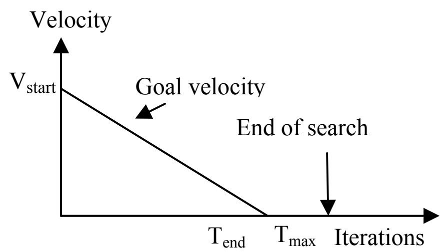

Figure 1. Goal Average velocity of swarm for the proposed method

4. System Studies and Simulation Results

4.1 39-bus New England system

The 39-bus system is simplified representation of the 345-KV transmission system in the New England region having 10 generators and 29 load buses. The congestion cost has been determined for a pool based model by considering the reactive power support provided by the generators and the optimally placed capacitors apart from real power scheduling of generation. The values of the generator PTCDFs and QTCDFs for congested line 34-14 of 39-bus system are shown in Table 1 and 2 respectively. It is observed that Zone-1 and 2 have the non-uniform values of PTCDFS and QTCDFs to the congested line power flow. The magnitudes of the sensitivity values are also much larger. Thus the generators G3, G8 and G10 are selected for the congested line 34-14 from the most sensitive zones Zone-1 and 2 to participate in the congestion management based on the qualifying bids in the market. The capacitor has been located optimally on bus-14 based on its most negative reactive power flow sensitivity index value which has been found to be -0.3601. Whereas, the reactive power flow sensitivity indices at other buses are found to be less than the index at bus-14. In the multi line congestion case, the two lines 34-14 and 36-21 have been found to be congested. For managing the congestion, the generators G3, G4, G6, G8 and G10 have been selected from the most sensitive Zone-1 and 2 based on the qualifying bids in the market.

The different cases taken for the study are:
Case-1: CM using optimal re-scheduling of active power generation.
Case-2: CM using optimal re-scheduling of active power generation without capacitor reactive power support.
Case-3: CM using optimal re-scheduling of active power generation with capacitor reactive power support.
The Congestion Cost (CC) for all of the cases is presented in Table 3 and Figure 2. The congestion cost determined using the method discussed in Ref [5] is also shown in Table 3 for comparison. It is observed that the CC with the proposed method is much smaller (3454.211 $/Hr) compared with all the LDIWPSO, SPSO, BCGA, RCGA methods and the method discussed in Ref [5] (3485.540 $/Hr).

Form the Figure 2 and Table 3, it is also further observed that the congestion cost is found to be minimum with both generator and capacitors giving reactive power support in the system. And the capacitor reactive support is more effective in reducing congestion cost as compared to generator reactive support. The performance of all the algorithms statistical measures such as best, mean, worst, standard deviation and computation time over 25 independent trials are reported in Table 4. The standard deviation for method VFAPSO is found to be less compared to the other methods, which proves that VFAPSO is more robust. VFAPSO took less time compared to the other methods. This may be due to the fact that the optimal placement of capacitors meets the reactive power requirement of the zone directly without involving the flow of reactive power through lines.
From the Table 5 and 6, it is found that the generators are subjected to a lower magnitude of rescheduling in the presence of reactive support provided by the generators and capacitors. The congestion cost for the multi line congestion case along with those for Case-1 is shown in Figure 3. It is observed that the CC is significantly high for the multi congestion case. The unconstrained power flow of 2.67 pu is recorded before Congestion Management (CM) in line 34-14 whose power flow limit is 2.5 pu.

The line flows in the congested line after congestion management for various methods is shown in Figure 4. It is observed that the line flow using the proposed VFAPSO method is found to be minimum compared to the other method. Figure 5 shows the comparison of convergence characteristics of all the methods. From this figure it is observed that VFAPSO is better compared to other algorithms in terms of solution quality and consistency. From the above, it is observed that VFAPSO provides the best global optimum solution with less computation time compared to other methods.

3.1 Algorithm for the VFAPSO can be described as follows:

Step 1: a) Initialize a population of particles with random positions $\left(x_{ij}\right)$ and velocities $\left(v_{ij}\right)$.

a) Initialize $T_{\max}$, V_{start} & T_{end}

b) Set goal velocity $v_{goal} = V_{start}$ and K=0, where K is an iteration counter.

Step 2: Evaluate the objective values of all particles. Let $pBest_i$ of each particle and its objective value be equal to its current position and objective value, and let $gBest$ and its objective value be equal to the position and objective value of the best initial particle.

Step 3: Update the velocity and position of each particle according to equation (21) and (22).
Step 4: Evaluate the objective values of all particles.
Step 5: For each particle, compare its current objective value with the objective value of its $pBest_i$. If the current value is better, then update $pBest_i$ and its objective value with the current position and objective value.
Step 6: Determine the best particle of the current swarm with the best objective value. If the objective value is better than the objective value of $gBest$, then update $gBest$ and objective value with the position and objective value of the current best particle.
Step 7: Calculate the average velocity v_{avg} using equation (22). And compare the current v_{avg} with v_{goal}. If $v_{avg} > v_{goal}$, shift the parameters w, C1, C2 to convergent values. Otherwise, shift the parameters to divergent values.
Step 8: Modify the goal velocity according to the following equation: $v_{goal}^{k+1} = v_{goal}^{k} - \frac{V_{start}}{T_{end}}$.
Step 9: If stopping criterion is met, then output $gBest$ and its objective value; otherwise go back to Step 3.

3.2 The complete algorithm for optimal congestion management:

Step 1: Run the base case power flow using Fast Decoupled Power Flow method.
Step 2: Determine PTCDF and QTCDF using equations (3) to (5).
Step 3: Form the Zones / Clusters and select the most sensitive generators for congestion management as explained in section (2).
Step 4: Iteration count starts K=1.
Step 5: Solve the Optimization problem shown in equations (6) to (13) with the proposed method explained in section 3.1 and find the optimal reschedule of active and reactive powers ΔP_g, ΔQ_g *and* ΔQ_c.

Step 6: Update Powers using $P_g^{new} = P_g^{old} + \Delta P_g$, $Q_g^{new} = Q_g^{old} + \Delta Q_g$ *and* $Q_c^{new} = Q_c^{old} + \Delta Q_c$.

Step 7: Determine the line flows and check if any line is congested. If any line is congested, K=K+1 and go to step 5. Otherwise go to step 8.
Step 8: Record the optimal values of Congestion Cost (CC), change in powers ΔP_g, ΔQ_g *and* ΔQ_c, line flows voltage profile, Ploss, and computation time.

The effectiveness of the PTCDFs and QTCDFs can be observed from the Table 7. According to [7], all of the ten generators take part in congestion management, whereas, in [8] six generators take part for congestion management. However, based on the method proposed in the present paper, using PTCDFs and QTCDFs, it is apparent that only three generators are sufficient to manage congestion successfully without exceeding the generation limits of generators. As can be seen the proposed method generates better results as it suggests lower amounts of re-scheduled generation of generators. From Table 7, it can be clearly seen that the system losses are lower and voltage profile obtained is better by the proposed method compared to the methods reported in [7] and [8].

Table 1: PTCDFs of 39-bus New England Test System
for congested line 34-14 in different Zones

Zone 1		Zone 2		Zone 3		Zone 4	
Gen No.	PTCDFs	Gen No.	PTCDFs	Gen No.	PTCDFs	Gen No.	PTCDFs
1	-0.0891	2	-0.1201	9	-0.0599	4	0.0621
3	0.1691	8	-0.1069			5	0.0621
		10	-0.128			6	0.0629
						7	0.0629

Table 2: QTCDFs of 39-bus New England Test System
for congested line 34-14 in different Zones

Zone 1		Zone 2		Zone 3		Zone 4	
Gen No.	QTCDFs	Gen No.	QTCDFs	Gen No.	QTCDFs	Gen No.	QTCDFs
1	-0.0499	2	-0.1221	9	-0.0566	4	0.0538
3	0.1590	8	-0.1049			5	0.0538
		10	-0.1248			6	0.0531
						7	0.0538

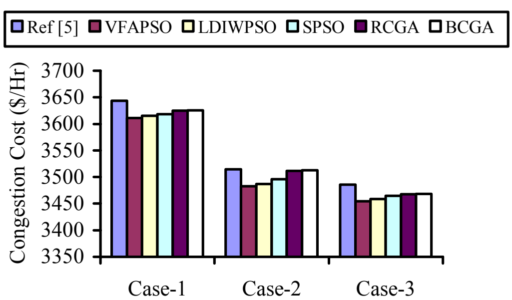

Figure 2: Comparison of Congestion cost
between all the methods for different cases

Table 3: Congestion Cost ($/Hr) for 39-bus New England System for different cases for single line congestion case

	Ref [5]	VFAPSO	LDIW PSO	SPSO	RCGA	BCGA
Case-1	3643.8	3611.1	3615.4	3618.3	3624.9	3625.6
Case-2	3497.9	3482.8	3487.0	3496.1	3511.2	3512.8
Case-3	3485.5	3454.2	3458.4	3464.5	3467.4	3468.1

4.2 75-bus system:

The 75-bus Indian practical system represents a reduced network of Uttar Pradesh State Electricity Board's (UPSEB) network comprising of 400-kV and 200-kV buses with 15 generators, 24 transformers and 97 lines. In this test system, congestion occurred in line 26-41 as it is already overloaded. To participate in the Congestion Management (CM), the generators G3, G12 and G13 are selected for the congested line 26-41 from the most sensitive zone based on the qualifying bids in the market, where as in the multi line congestion case line 26-41 and 19-36 are found to be congested and G3, G9, G12 and G13 have bee4n selected for CM. However, the capacitor reactive support is not considered for this test system. The different cases taken for the study are:

Case-1: CM using optimal rescheduling of active power generation.

Case-2: CM using optimal rescheduling of active and reactive power generation.

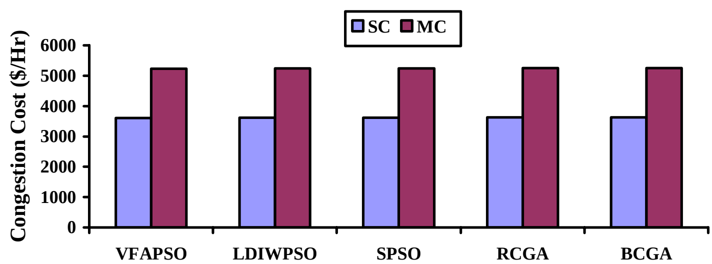

Figure 3: Comparison of Congestion Cost between SC and MC cases for 39-bus system

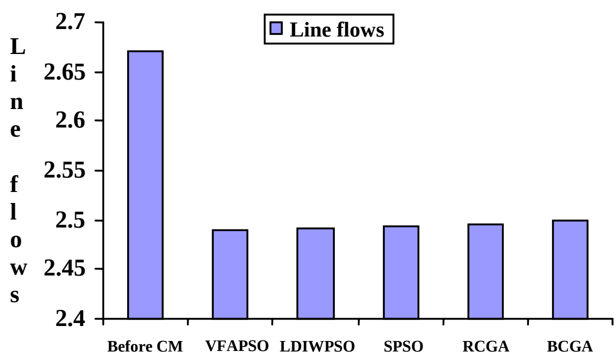

Figure 4: Line flows in congested line 34-14

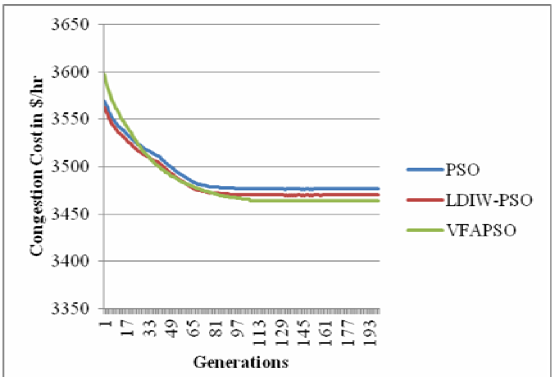

Figure 5: Comparison of Convergence Characteristics of VFAPSO with other methods

The Congestion Cost (CC) for all of the cases is presented in Table 8 and Figure 6. It is observed that the CC with the proposed method is much smaller compared with all LDIWPSO, SPSO, BCGA, RCGA methods.

From the Figure 6 and Table 8, the congestion cost in Case-2 is found to be less than that Case-1. From Table 9 and 10, it is also observed that the generators are subjected to a lower magnitude of rescheduling in the presence of reactive support provided by the generators.

Table 4: Comparison of Congestion cost ($/Hr) and computation time (sec) of 39-bus system for single congestion case (for *Case-3*)

Method	Congestion Cost ($/Hr)				Time (sec)
	Best value	Worst value	Mean value	Standard Deviation	
VFAPSO	**3453.211**	3453.213	3453.212	**2.342×10^{-2}**	22.12
LDIWPSO	**3458.480**	3458.491	3458.482	**1.801×10^{-3}**	25.64
SPSO	**3464.513**	3464.521	3464.518	**3.321×10^{-3}**	26.55
RCGA	**3467.412**	3467.420	3467.417	**5.410×10^{-2}**	32.23
BCGA	**3468.102**	3468.112	3468.108	**7.210×10^{-2}**	40.12

Table 5: Change in active power generation in pu for 39-bus system

	VFAPSO	LDIW PSO	SPSO	RCGA	BCGA
Case-1					
ΔPg_3	-0.7261	-0.7277	-0.7278	-0.7294	-0.7289
ΔPg_8	0.3326	0.3330	0.3334	0.3335	0.3341
ΔPg_{10}	0.3981	0.3988	0.3987	0.3996	0.4003
Case-2					
ΔPg_3	-0.6983	0.7054	-0.7061	-0.7063	-0.7064
ΔPg_8	0.3105	0.3135	0.3136	0.3144	0.3142
ΔPg_{10}	0.3950	0.3985	0.3993	0.3998	0.3998
Case-3					
ΔPg_3	-0.6987	-0.6994	-0.6999	-0.7014	-0.7022
ΔPg_8	0.3068	0.3070	0.3077	0.3080	0.3083
ΔPg_{10}	0.3985	0.3985	0.3995	0.3996	0.3998

Table 6: Change in active and reactive power generation in pu for 39-bus system

	VFAPSO	LDIW PSO	SPSO	RCGA	BCGA
Case-2					
ΔQg_3	-0.4938	-0.4982	-0.4986	-0.5001	-0.5001
ΔQg_8	0.6512	0.6579	0.6573	0.6594	0.6588
ΔQg_{10}	-0.2425	-0.2446	-0.2452	-0.2457	-0.2457
Case-3					
ΔQg_3	-0.3866	-0.3871	-0.3870	-0.3883	-0.3882
ΔQg_8	0.3405	0.3413	0.3415	0.3422	0.3420
ΔQg_{10}	-0.3984	-0.3987	-0.3987	-0.3995	-0.3999
ΔQc_{14}	0.3244	0.3246	0.3250	0.3255	0.3254

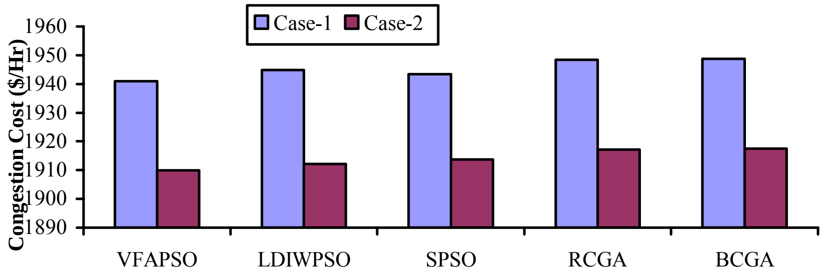

Figure 6: CC comparisonfor 75-bus system

Table 7: system parameters before and after rescheduling for 39-bus system

System parameter	Pre-rescheduling	Post-rescheduling		
		Results reported in [7]	Results reported in [8]	Proposed VFAPSO method
Ploss (MW)	59.35	58.00	57.31	57.28
Vmin (pu)	0.929	0.932	0.945	0.9501
No. of Generators participated in CM	10	10	6	3
Total Reschedulin g in pu	------	5.1845	5.542	1.4568

Table 8: Congestion Cost ($/Hr) for 39-bus New England System for different cases for single line congestion case

	VFAPSO	LDIW PSO	SPSO	RCGA	BCGA
Case-1	1941.0	1943.4	1944.9	1948.4	1948.8
Case-2	1909.9	1912.2	1913.7	1917.2	1917.5

Table 9: Change in active power generation in pu for 75-bus system for Single line congestion

	VFAPSO	SPSO	LDIW PSO	RCGA	BCGA
Case-1					
$\Delta Pg3$	0.2039	0.2040	0.2039	0.2046	0.2046
$\Delta Pg12$	-0.4214	-0.4230	-0.4220	-0.4236	-0.4236
$\Delta Pg13$	0.1993	0.1996	0.1993	0.1997	0.1999
Case-2					
$\Delta Pg3$	0.1992	0.1996	0.1994	0.2001	0.2001
$\Delta Pg12$	-0.4088	-0.4099	-0.4103	-0.4108	-0.4107
$\Delta Pg13$	0.1992	0.1994	0.1997	0.2000	0.1999

Table 10: Change in reactive generation in pu 75-bus system (*case-2)*

	VFAPSO	LDIW PSO	SPSO	RCGA	BCGA
$\Delta Qg3$	-0.4978	-0.4985	-0.4993	-0.4994	-0.4996
$\Delta Qg12$	0.0345	0.0345	0.0345	0.0346	0.0346
$\Delta Qg13$	0.3848	0.3858	0.3860	0.3865	0.3869

5. Conclusion

This paper has presented an optimal power dispatch model for congestion management and minimization of congestion cost using proposed VFAPSO. Generators are selected from the most sensitive zones formed based on the PTCDFs and QTCDFs calculations. The proposed method has been tested on 39-bus New England Test system and 75-bus Indian practical system.

From the results presented in this paper, following main conclusions can be made.

- The Congestion Cost with the proposed VFAPSO method is found to be smaller as compared to the LDIWPSO, SPSO, RCGA and BCGA methods and the method proposed in [5].
- The standard deviation of the proposed method is found to be less compared to the other methods, which proves that the proposed method is more robust.
- The computation time for the proposed method is less as compared to the other methods.
- The congestion costs for cases employing reactive power support from generators and capacitors are considerably less than the cases without any reactive support.
- The amount of rescheduling of real power transactions is reduced in the presence of reactive support considered in the system for congestion management.
- The Congestion Cost is significantly higher for multi line congestion case than single line congestion case.

Thus, the optimal rescheduling of active and reactive power using the proposed VFAPSO is more effective in reducing the congestion cost and it offers best optimal solution to the congestion management as compared to the other methods reported in the literature.

References

[1] A.Kumar, S.C. Srivastava, S.N. Singh, “Congestion management in competitive power market: A bibliographical survey”, Electric Power Systems. Res. 76, pp. 153–164, 2005.

[2] A.K. David, R.S. Fang, “Congestion management of electric power systems under transmission open access”, Proceedings of the 4th International Conference on Advances in Power System Control, Operation, and Management, vol. 2, APSCOM, Hong Kong, pp. 469–474, November 1997.

[3] S.C. Srivastava, P. Kumar, “Optimal power dispatch in deregulated market considering congestion Management”, Proceedings of International Conference on Electric Utility Deregulation and Restructuring and Power Technologies, DRPT, April 4–7, 2000, pp. 53–59.

[4] C.-N.Chien-Ning Yu and M. Ilic, “Congestion clusters-based markets for transmission management”, Proceedings of IEEE PES, Winter Meeting, New York, NY, pp. 821–832, January 1999.

[5] A.Kumar, S.C. Srivastava, S.N. Singh, “A zonal congestion management approach using real and reactive power rescheduling”, IEEE Trans. Power Systems. , vol. 18, pp. 554–562, Feb 2004.

[6] B. K. Talukdar, A. K Sinha, S. Mukhopadhyay, and A. Bose, “A Computationally simple method for cost-efficient generation rescheduling and load shedding for congestion management”, Int. J. Elect. Power Energy Syst., vol 27, No.5, pp.379-388, jun-july, 2005.

[7] G. Yesuratnam and D. Thukaram, "Congestion Management in open access based on relative electrical distances using voltage stability criteria", *Elect. Power Syst. Res.*, vol.77, pp. 1608-1618, 2007.
[8] Sudipta Dutta , S. P. Singh, " Optimal Rescheduling of Generators for Congestion Management Based on Particle Swarm Optimization", IEEE Trans. Power Systems. Vol. 23, No. 4, pp. 1560-1568, Nov 2008.
[9] Ch Venkaiah, and D. M. Vinod Kumar, "Fuzzy PSO Congestion Management using sensitivity based optimal active and reactive re-scheduling of generators", Journal of Electrical Engineering & Technology, Vol.3, pp123-132, 2008.
[10] Y. Dai, Y. X. Ni, C. M. Shen, F. S. Wen, Z. X. Han and Felix F. Wu, "A study of reactive power marginal price in electricity market", Electrical Power Systems Research, Vol. 57, pp. 41-48, 2001.
[11] J. Kennedy and R. Eberhart, "Paricle Swarm Optimization", Proceedings of the IEEE international conference on Neural Networks, Vol.4, pp.1942-1948, Dec 1995.
[12] Keiichiro Yasuda and Nobuhiro Iwasaki, Adaptive Particle Swarm Optimization Using Velocity Information of Swarm, Proceedings of IEEE International Conference on Systems, Man & Cybernetics Proceedings, Vol.4, pp.3475-3481, Oct 2004.
[13] Deb K.: 'Multiobjective Optimization Using Evolutionary Algorithms', Wiley, Chichester, UK, 2001.
[14] Shi Y., J. Kennedy and R.C. Eberhart, "Swarm Intelligence", Morgan Kaufmann Publishers (2001).

Appendix

7.1 Real Coded Genetic Algorithms

Owing to the adaptive capability, Simulated Binary Crossover (SBX) and Tournament selection is used as selection mechanism in order to avoid premature convergence [13]. SBX crossover and non-uniform polynomial mutation are given below.

Simulated Binary Crossover (SBX):

In SBX crossover, two children solutions are created from two parents as follows: Choose a random number $u_i, \in [0,1]$ and calculate β_{qi} as given in (23)

$$\beta_{qi} = \begin{cases} (2u_i)^{\frac{1}{\eta_c+1}} & , u_i \le 0.5 \\ \left(\dfrac{1}{2(1-u_i)}\right)^{\frac{1}{\eta_c+1}} & , \text{otherwise} \end{cases} \tag{23}$$

A spread factor β_{qi} is defined as the ratio of the absolute difference in offspring values to that of the parents. η_C is the crossover index. Then compute the offspring $x_i^{(1,t+1)}$ and $x_i^{(2,t+1)}$ as

$$\left.\begin{aligned} x_i^{(1,t+1)} &= 0.5\left[(1+\beta_{qi})x_i^{(1,t)} + (1-\beta_{qi})x_i^{(2,t)}\right] \\ x_i^{(2,t+1)} &= 0.5\left[(1-\beta_{qi})x_i^{(1,t)} + (1+\beta_{qi})x_i^{(2,t)}\right] \end{aligned}\right\} \tag{24}$$

Non-uniform polynomial mutation:

Newly generated offspring undergoes polynomial mutation operation. Like in the SBX operator, the probability distribution can also be a polynomial function, instead of a normal distribution. The new offspring $y_i^{(1,t+1)}$ is determined as follows

$$y_i^{(1,t+1)} = x_i^{(1,t+1)} + (x_i^U - x_i^L)\overline{\delta_i} \tag{25}$$

x_i^U and x_i^L are the upper and lower limit values.

Where the parameter $\overline{\delta_i}$ is calculated from the polynomial probability distribution.

$$P(\delta) = 0.5(\eta_m + 1)(1 - |\delta|)^{\eta_m} \qquad \overline{\delta} = \begin{cases} (2r_i)^{1/(\eta_m+1)} - 1, & \text{if } r_i < 0.5 \\ 1 - \left[2(1-r_i)\right]^{1/(\eta_m+1)}, & \text{if } r_i \geq 0.5 \end{cases} \tag{26}$$

Where, η_m is the mutation index.

7.2 Parameter Selection:

Crossover probability P_C is varied between 0.4 and 0.9 in steps of 0.1 and for each P_C the performance is analyzed. Other parameters such as mutation probability (*Pm*), crossover index (η_c), mutation index (η_m) and penalty factor (*PF*) are selected as recommended by Deb [13]. *Pc=0.8*; *Pm=1/n*; η_c *=5*; η_m *=20; PF=100.* In SPSO, after series of experiments conducted, it is found that the following parameter setting produces the best result in terms of best and mean. *Vmax=0.2;* $C_1=C_2=1$*; PF=100*; *w*=0.4.