OPTIMAL CONGESTION MANAGEMENT IN AN ELECTRICITY MARKET USING VERSATILE PARTICLE SWARM ALGORITHM

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ABSTRACT

Transmission lines in power system network operate close or beyond their thermal limits are said to be congested. In deregulated electricity markets the problem is more likely to occur due to unplanned power exchanges. Congestion management (CM) is accomplished mainly either by generator rescheduling or by load shedding. In load shedding reliability of power supply gets affected so re-dispatching the output of generator is better option to manage congestion while ensuring the system reliability. In generator rescheduling or re-dispatching independent system operators reschedule the generator output so that congestion has gotten rid off. In this operation independent system operator (ISO) commands the generator of low-price area to lower down its output while purchasing power from high price areas this will lead to an additional cost known as rescheduling cost. As rescheduling of generators incurs additional investment, an appropriate CM strategy should be adopted that involve minimum cost of generator rescheduling. This paper presents a versatile particle swarm (VPS) optimization-based CM by optimal rearranging of power generation dependent on the generator sensitivity to the congested line. In VPS algorithm, the parameters such as inertia weight factor and acceleration factors are made adaptive on the basis of objective functions of the current and best solutions. To attest the robustness and effectiveness of CM, the VPS algorithm is examined on IEEE 30-bus system and the results are compared with the particle swarm optimization (PSO) approach. The simulation results demonstrate that the VPS algorithm is successfully minimize the fuel cost in comparison with PSO for optimal rescheduling of generators to relieve congestion in the transmission line.
**NOMENCLATURE**

- **GS**: Generator sensitivity to congested line
- **P_{ij}**: Real power flow on the congested line k
- **P_g**: Real power generated by generator k
- **ΔP_g**: Real power adjustment at bus-g
- **C_g (ΔP_g)**: Incremental and decremental price bids
- **PF_k^0**: Power flow caused by all contracts requesting transmission service
- **PF_k^{max}**: Line flow limit of the line connecting bus-i and bus-j
- **N_G**: Number of online generating units
- **N_g**: Number of participating generators
- **N_l**: Number of transmission lines in the system
- **P_g^{min} and P_g^{max}**: Minimum and maximum limits of generator outputs
- **a_i, b_i, c_i**: Cost coefficients
- **P_i**: Real power output (MW) of ith generator
- **P_{Gi}**: Real power injections at ith bus
- **Q_{Gi}**: Reactive power injections at ith bus
- **P_{Di} & Q_{Di}**: Load demands
- **|Y_{ij} & θ_{ij}|**: Magnitude and angle of bus admittance matrix
- **K**: Line connected between buses i and j
- **G_k**: Conductance
- **P_{Gi}^{min} And P_{Gi}^{max}**: Lower and upper bounds for real power outputs of the ith generator unit
- **Q_{Gi}^{min} And Q_{Gi}^{max}**: Lower and upper bounds for reactive power outputs of the ith generator unit
- **V_{i}^{min} And V_{i}^{max}**: Lower and upper bounds of the voltages
- **NB**: Number of buses
- **NV**: Number of PV buses
- **NL**: Number of lines
- **S_{L}^{max}**: Line flow capacity of Lth transmission line
- **NC**: Number of constraints
- **N**: Number of dimensions in a particle
- **i**: Number of particles
- **W**: Inertia weight factor
- **C_1, C_2**: Acceleration constants
- **rand_1, rand_2**: Uniform random value generated between 0 and 1
- **C_{C_i}^{k-1}**: Objective value of ith solution at (K-1)th iteration
- **C_{C_{pbest}}^{k-1}**: Objective value of pbest solution at (K-1)th iteration
- **C_{C_{gbest}}^{k-1}**: Objective value of gbest solution upto (K-1)th iteration

**INTRODUCTION**

1.1. BACKGROUND

A system is supposed to be congested when makers and customers of electric energy want to deliver and consume in sums that would make the transmission framework to work at or past at least one exchange limits. The primary assessment looked by the independent system operator (ISO) in a deregulated environment is to keep up the security and unwavering quality of the power system by boosting the market proficiency when the framework is clogged. The ISO, hence, needs to make a lot of straightforward and vigorous...
principles that ought not urge forceful entities to abuse clog to make market control and boost benefits at the expense of the market. Congestion in a transmission framework may not be permitted past a brief length since this could prompt falling blackouts with uncontrolled loss of burden.

There are a few techniques to ease congestion, for example, utilizing Flexible AC Transmission Systems (FACTS), tapping transformers, re-dispatching the generation, and abridging pool loads or potentially reciprocal agreements. In a deregulated environment, all the Generating Companies (GENCOs) and Distribution Companies (DISCOs) prepare their transactions in time. In any case, when of execution of exchanges, blockage may as of now be available in a portion of the transmission lines. Henceforth, ISO needs to ease the congestion with the goal that the system stays in a protected state.

1.1.1. POWER MARKET TRANSACTIONS

The different transactions in power market are as follows:

a) Pool transaction

Here the sellers (competitive generators) present their steady and decremental bidding costs in a constant adjusting market. These are then consolidated in the power flow problem to yield the incremental/decremental change in the generator outputs.

b) Bilateral transaction

Here every transaction contract includes a compensation price that the buyer-seller pair is willing to accept if its transaction is curtailed, without third party intervention.

c) Multilateral transaction

Here the purchases and sales agreement between the generation companies (GENCOs) and distribution companies (DISCOs) are supplemented by third parties, such as broker or forward contractors.

1.1.2. MARKET ENTITIES IN DEREGULATED ENVIRONMENT

The restructuring of electricity market has changed the role of traditional entities of the vertically integrated utility and created new entities that can function independently. The market entities can be broadly classified into market participants and ISO.

1.1.3. MARKET PARTICIPANTS

a) GENCOs

GENCOs generate electricity and have the opportunity to sell the electricity to entities with which they have negotiated sales contracts. Generally, GENCOs consist of a group of generating units within a single company ownership structure with the sole objective of producing electrical power. In addition to active power, they may sell reactive power (ancillary services) and operating reserves.

b) Transmission companies (TRANSCOs)

It transports electricity using a high voltage, bulk transmission system from GENCOs to DISCOs/retailers for delivering power to consumers. A TRANSCO has role of building, owning, maintaining and operating the transmission system in a certain geographical region to provide services for maintaining the overall reliability of the electrical power systems and provides open access of transmission wires to all market entities in the system. The investment and operating costs of transmission facilities are recovered using access charges, which are usually paid by every user within the area/region, and transmission usage charges based on line flows contributed by each user.

c) DISCOs

A DISCO distributes the electricity, through its facilities, to customers in a certain geographical region. They buy wholesale electricity either through the spot markets or through direct contracts with GENCOs and supply electricity to the end user customer. A DISCO is a regulated utility that constructs and maintains distribution wires connecting the transmission grid to the end user customer. A DISCO is responsible for building and operating its electric system to maintain a desired degree of reliability and availability.
d) ISO  
   The part of an ISO in a serious market is to encourage the total dispatch of the power which becomes contracted among the market players. Thus, maximizing market efficiency with prime importance towards maintain the security and reliability of line or grid.

1.1.4. CM TECHNIQUES  
   ISO essentially utilizes two sorts of strategies to remove congestion. These are recorded underneath.

   Cost free methods are classified as:
   - Out-maturing of blocked lines,
   - Functioning of transformer taps/ shifters, and
   - Functioning of FACTS

   Non-cost-free methods are classified as:
   - Re-dispatching of generation in a way not quite the same as the regular settling purpose of the market. A few generators down, while others increment their output. Thus, generators at this point do not work at equivalent incremental expenses.
   - Curtailment of burdens and the activity of (non-cost free) load interference choices.

1.2. LITERATURE SURVEY  
   In a deregulated power system TRANSCOs, GENCOs and DISCOs are under differential organizations. To maintain the coordination between them there will be one system operator in all types of deregulated power system models, generally he is ISO. Several utilities join together to form a pool, with a central broker in place, to co-ordinate the operations on an hour-to-hour basis. In a pool market GENCOs and DISCOs submit the sell and purchase decisions in the form of sell and buy bids to the market operator, who, in turn, clears the market using an appropriate market-clearing procedure.

   Vinod kumar et al. [1] clarified in detail the CM and felt that regulating the transmission framework so the move limits are watched. In a liberated environment, all the GENCOs and DISCOs prepare of time. However, when of execution of exchanges there might be congestion in a portion of the transmission lines. Thus, ISO needs to ease the clog so the system stays in secure state. Meena and Selvi [2] introduced an open transmission dispatch in which pool and respective/multi horizontal dispatches exist together and continued to build up a CM approach for this situation. Dutta et al. [3] introduced CM methods applied to different sorts of power markets. Kennady and Eberhart [4] explored widely the procedures of CM and concluded that the CM is one of the significant errands performed by ISOs to guarantee the activity of transmission framework within the limits. In the rising electric markets, the CM turns out to be critical and it can force a boundary to the power exchanging. Tooth and David [5] proposed an effective zonal CM approach utilizing real and reactive power rescheduling dependent on AC transmission congestion distribution factors addressing about the ideal distribution of reactive power. The effect of ideal rescheduling of generators and capacitors has been shown in CM.

   Ashwani kumar et al. [6] depicted a planning procedure between power producing organizations and system administrator for CM utilizing Benders cuts. Lamont et al. [7] presented two methodologies for CMs because of voltage unsteadiness and thermal over burden in a liberated environment. Hazra and Sinha [8] examined a consolidated casing work for service estimation and the CM while another methodology was employed to recognize the services of reactive help and real power misfortune for overseeing blockage utilizing the upper bound cost minimization.

   Chen and Zhang [9] introduced the Particle Swarm Optimization (PSO) idea as far as its forerunners, quickly investigating the phases of its advancement from social reenactment to enhancer and examined the utilization of the approach to the neural network training. Shi et al. [10] introduced the PSO in five classifications viz. approaches, topology, parameters, modified PSO approaches and applications.
The hunt process of a PSO approach ought to be a cycle comprised of both constriction and extension so it could be able to escape from nearby minima, and inevitably discover adequate arrangements. Yamina and Shahidehpour [11] surveyed the PSO strategies and their applications to power system optimization issues. Snider et al. [12] developed the PSO for settling Optimal Power Flow (OPF) with which CM in pool market is basically executed on IEEE 30 Bus framework. Kumar and Srivastava [13] proposed cost proficient rescheduling of generation and additionally load shedding approach for CM in transmission lattices utilizing Chaotic PSO (CPSO) technique.

Fattahi and Ehsan [14] proposed a procedure for decreasing the quantity of partaking generators and ideal rescheduling of their yields while overseeing blockage in a pool at least rescheduling cost and investigated the capacity of PSO method in tackling the CM issue. An ideal solution for static CM utilizing PSO based OPF technique. Here, the blockage has been made in the transmission line by stacking the lines and it is soothed by putting a static synchronous series compensator in an ideal place in the transmission line. Masoud Esmaili et al. [15] developed an adjusted blenders strategy for understanding the CM in power markets. Dutta and Singh [16] exhibited the transformation of the PSO approach to tackle different kinds of economic dispatch (ED) issues in power systems viz. multi-region ED with tie line limits, ED with various fuel choices, consolidated economic and emission dispatch of generators with precluded working zones. The effectiveness of the PSO technique proved that it tends to be implemented to a wide range of optimization problems.

Christie and Wollenberg [17] PSO technique for taking care of the ED issue with the generator requirements and exhibited that the PSO strategy can evade the inadequacy of premature convergence of Genetic Algorithm (GA) technique while getting more excellent solution with better calculation effectiveness and union property.

In the recent years particle swarm optimization (PSO) has gained much popularity in different kind of applications because of its simplicity, easy implementation and reliable convergence. PSO is computationally inexpensive in terms of memory requirement and CPU times. PSO has been found to be robust in solving continuous non-linear optimization problems. However, the traditional PSO highly depends on its parameter and often suffers the problem of being trapped in local optima. Sakthivel et al. [19] introduced adaptive particle swarm optimization (APSO) to overcome the above problems.

1.3. Contributions and organization of the paper

The main contribution of research paper is to tackle the CM issue by ideal rescheduling of active power of the generators dependent on their sensitivities to the clogged line utilizing VPS approach and the results are compared with the PSO approach. The merit of this methodology of easing the clog in the blocked line is very proficient as it is a non-cost-free procedure. The suggested approach exhibits the adequacy of the proposed technique on the CM issue considering IEEE 30-bus system.

This paper is organized as follows: Section 2 details the problem formulation of optimal power flow (OPF) and congestion management by rescheduling the active power in participating generators. An insight into the swarm intelligence algorithms, such as PSO and VPS are explained in Section 3. Section 4 deals the methodology of implementation of the VPS algorithm for CM problems. The effectiveness of the proposed VPS algorithm on the IEEE 30 is illustrated in Section 5. Section 6 concludes the findings of the paper and provides suggestions for further research work in this area.

PROBLEM FORMULATION

2.1. OPF PROBLEM FORMULATION

In a power system, the economic operation of generating utilities is always preferred. In the deregulated market environment, the first part of the power dispatch
problem is to find out the preferred schedule using OPF and the second part is rescheduling the generation for removing the congestion.

The OPF problem is about minimizing the fuel cost of generating units for a specific period of operation so as to accomplish optimal generation dispatch among operating units and in return satisfying the system load demand, generator operation constraints and line flow limits.

The objective function is corresponding to the production cost can be approximated to be a quadratic function of the active power outputs from the generating units. Symbolically, it is represented as

\[
\text{Minimize } F_i^{\text{cost}} = \sum_{i=1}^{N_G} f_i(P_i)
\]  

where \( f_i(P_i) = a_i P_i^2 + b_i P_i + c_i \), \( i = 1, 2, \ldots, N_G \) is the expression for cost function corresponding to ith generating unit and \( a_i, b_i, c_i \) are its cost coefficients. \( P_i \) is the real power output (MW) of ith generator. \( N_G \) is the number of online generating units. This constrained OPF problem is subjected to a variety of constraints depending upon assumptions and practical implications. These include power balance constraints to take into account the energy balance; feasibility of real and reactive power generation, voltage limits at load buses and line flow limits.

### 2.2 POWER BALANCE CONSTRAINTS
This constraint is based on the principle of equilibrium between total system generation and total system loads. That is given by set of non-linear power flow equations as

\[
P_{G_i} - P_{D_i} - \sum_{j=0}^{n} |V_{i}| |V_{j}| \cos(\theta_{g} - \delta_i - \delta_j) = 0
\]

\[
Q_{G_i} - Q_{D_i} - \sum_{j=0}^{n} |V_{i}| |V_{j}| \sin(\theta_{g} - \delta_i - \delta_j) = 0
\]

The real power loss in the system can be modeled a

\[
P_{\text{loss}} = \sum_{k=1}^{N_k} g_k |V_i|^2 + |V_j|^2 - 2|V_i||V_j|\cos(\delta_i - \delta_j)
\]  

### 2.3 GENERATOR CONSTRAINTS
The output power of each generating unit has a lower and upper bound so that it lies in between these bounds. This constraint is represented by a pair of inequality constraints as follows.

\[
P_{G_i}^{\text{min}} \leq P_{G_i} \leq P_{G_i}^{\text{max}}
\]

\[
Q_{G_i}^{\text{min}} \leq Q_{G_i} \leq Q_{G_i}^{\text{max}}
\]

### 2.4 VOLTAGE LIMITS
The voltage magnitudes of the each and every load bus after conducting the load flow simulation should be verified between its bounds. This voltage magnitude is having its own lower and upper bound and mathematically represented by

\[
V_i^{\text{min}} \leq V_i \leq V_i^{\text{max}}
\]

### 2.5 TRANSMISSION LINE LOADINGS
The line flows of all the transmission lines should be within its line capacity given by MVA ratings. This can be given as

\[
S_L \leq S_L^{\text{max}}
\]

### 2.6 OPF CONSTRAINTS HANDLING
The equality and inequality constraints of the power dispatch problem are considered in the fitness function \( J_{\text{error}} \) itself by incorporating a penalty function. 

\[
P_{F_i} = \begin{cases} 
K_i(U_i - U_i^{\text{min}})^2 & \text{If violated} \\
0 & \text{otherwise}
\end{cases}
\]  \( K_i \) (9)

Now the final solution should not contain any penalty for the constraint violation. Therefore, the objective of the problem is the minimization of generation cost and penalty function due to any constraint violation as defined by the following equation.

\[
J_{\text{error}} = F_{\text{cost}} + \sum_{i=0}^{nc} P_{F_i}
\]  (10)

2.7 DETERMINATION OF GENERATOR SENSITIVITY FACTOR

The generators in the system under consideration have different sensitivities to the power flow on the congested line. An adjustment in real power stream in a transmission line \( k \) associated between \( i \)th bus and \( j \)th bus because of progress in power generation by generator \( g \) can be named as generator sensitivity (GS) to clogged line. Mathematically, GS for line \( k \) can be written as

\[
GS_g = \frac{\Delta P_{ij}}{\Delta P_g}
\]  (11)

2.8 CONGESTION MANAGEMENT PROBLEM

It is advisable to select the generators having non uniform and large magnitudes of sensitivity values as the ones most sensitive to the power flow on the congested line and to participate in congestion management by rescheduling their power outputs. Based on the bids received from the participant generators, the amount of rescheduling required is computed by solving the following optimization problem.

\[
C_c = \min \left\{ \sum_{g} C_g (\Delta P_g) \Delta P_g \right\}
\]  (12)

Subject to

\[
\sum_{g} ((GS_g \Delta P_g) + PF_k^0) \leq PF_k^{\text{max}}
\]  (13)

\[
\Delta P_g^{\text{min}} \leq \Delta P_g \leq \Delta P_g^{\text{max}}
\]  (14)

\[
\Delta P_g^{\text{min}} = P_k^{\text{min}} - P_g^{\text{min}}
\]  (15)

\[
\Delta P_g^{\text{max}} = P_g^{\text{max}} - P_g^{\text{min}}
\]  (16)

\[
\sum_{g=1}^{N_g} \Delta P_g = 0
\]  (17)

where \( \Delta P_g \) is the real power adjustment at bus-\( g \) and \( C_g (\Delta P_g) \) are the incremental and decremented price bids submitted by generators and these generators are willing to adjust their real power outputs. \( PF_k^0 \) is the power flow brought about by all agreements mentioning the transmission administration. \( PF_k^{\text{max}} \) is the line flow limit of the line joining the \( i \)th bus and \( j \)th bus. \( N_g \) is the number of participating generators, \( N_l \) is the number of transmission lines in the system, \( P_g^{\text{min}} \) and \( P_g^{\text{max}} \) denotes respectively the minimum and maximum limits of generator outputs. It can be seen that the power flow solutions are not required during the process of optimization.
VPS OPTIMIZATION

3.1 PSO

Kennedy and Eberhart first introduced the PSO in the year 1995[4]. PSO is motivated from the simulation of behavior of Social systems such as fish schooling and birds flocking. The PSO algorithm requires less computation time and less memory because of the simplicity inherent in the above systems. The basic assumption behind the PSO algorithm is, birds find food by flocking and not individually. This leads to the assumption the information is owned jointly in flocking. Basically, PSO was developed for two-dimension solution space by Kennedy and Eberhart [4]. The position of each individual is represented by XY axis position and its velocity is expressed by $V_x$ in x direction and $V_y$ in y direction. Modification of the individual position is realized by the velocity and position information.

PSO algorithm for N-dimensional problem formulation based on the above concept can be described as follows. Let P be the in a search ‘particle’ coordinates (position) and V its speed (velocity) in a search space. Consider i as a particle in the total population (swarm). Now the ith particle position can be represented as $P_i = (P_{i1}, P_{i2}, P_{i3}... P_{iN})$ in the N-dimensional space. The best previous position of the ith particle is stored and represented as $P_{best_i} = (P_{best_{i1}}, P_{best_{i2}}... P_{best_{ij}})$. All the $P_{best_i}$ are evaluated by using a fitness function, which differs for the different problems. The best particle among all $P_{best_i}$ is represented as $g_{best}$.

The velocity of the ith particle is represented as $V_i = (V_{i1}, V_{i2}... V_{ij})$. The modified velocity of each particle can be calculated using the following information:

- the current velocity
- the distance between the current position and $P_{best_i}$, and
- the distance between the current position and $g_{best}$.

This can be formulated as an equation

$$
V_{ij}^{(iter+1)} = W \ast V_{ij}^{(iter)} + c_1 \ast rand_1 \ast (P_{best_{ij}} - P_{ij}^{(iter)}) + c_2 \ast rand_2 \ast (g_{best_{ij}} - P_{ij}^{(iter)})
$$

(18)

$$
P_{ij}^{(iter+1)} = P_{ij}^{(iter)} + V_{ij}^{(iter+1)} \quad I = 1, 2... N \text{ and } j = 1, 2... N
$$

(19)

The use of linearly decreasing inertia weight factor $W$ has provided improved performance in all the applications. Its value is decreased linearly from about 0.9 to 0.4 during a run. Suitable selection of the inertia weight provides a balance between global and local exploration and exploitation, results in fewer iterations on average to find a sufficiently optimal solution, its value is set according to the following equation:

$$
W = \frac{W_{max} - (W_{max} - W_{min}) \times iter}{iter_{max}}
$$

(20)

In Eq. 18, the first term indicates the current velocity of the particle, second term represents the cognitive part of PSO where the particle changes its velocity based on its own thinking and memory. The third term represents the social part of the PSO where the particle changes its velocity based on the social psychological adaption of knowledge.

3.2 VPS OPTIMIZATION

In the classical PSO, the inertia weight factor is made constant for all the particles in a single generation and the acceleration factors are made constant for all the particles in the whole generation. But these factors are very important parameters that move the current position of the particle towards its optimum position. In order to increase the search ability, the algorithm should be modified in which the movement of the swarm should be controlled by the objective function. In the proposed VPS algorithm, the particle position is adjusted such that the highly fitted particle moves slowly when compared to the lowly fitted particle. This can be achieved by using adaptive parameter values for each particle according to their objective functions of the current and best solutions.

The adaptive inertia weight factor (AIWF) is obtained as follows:
So, the inertia weight for the best particle is set to the minimum value and vice versa. The adaptive acceleration factors are determined as follows:

\[ w_i^k = w_{\text{min}} + \frac{C_{c, \text{pbest}}^{k-1} \times |C_i^{k-1} - C_i^{k-1}|}{C_{c, \text{gbest}}^{k-1} \times |C_i^{k-1} - C_i^{k-1}|} \]  

(24)

It is concluded from Eqs. 25 and 26 that C1 and C2 values are greater than or equal to one. Higher acceleration factors are obtained for higher objective function and vice versa. Use of Eqs. 24, 25 and 26 in Eq. 18 is expected to provide better optimum solution compared to classical PSO.

The VPS algorithm can be summarized as follows:

Step 1: Initialization of the swarm: For a particle size m, the particles are randomly generated between the minimum and maximum limits.

Step 2: Defining the fitness function: A suitable fitness function should be used for constraints handling based on the current.

Step 3: Initialization of pbest and gbest: The fitness values obtained above for the initial particles of the swarm are set as the initial pbest values of the particles. The best value among all the pbest values is identified as gbest.


Step 5: Evaluation of velocity: The new velocity for each particle is computed.

Step 6: Update the swarm: The particle position is updated using Eq. 19. The values of the fitness function are calculated for the updated positions of the particles. If the new value is better than the previous pbest, the new value is set to pbest. Similarly, gbest value is also updated as the best pbest.

Step 7: Stopping criteria: A stochastic optimization algorithm is usually stopped either based on the tolerance limit or when maximum number of generations are reached. The number of generations is used as the stopping criterion in this paper.

The flowchart of VPS algorithm is displayed in Fig. 1.
APPLICATION OF VPS ALGORITHM FOR CM PROBLEM

The computational procedure for VPS algorithm-based CM problem is described hereunder:

Step 1: Read line parameters, upper and lower limits for active and reactive powers of the generators, voltage limits for the load buses and maximum line loading limits, active powers produced at the generator buses and active and reactive powers consumed at the load buses as determined by market clearing procedure.

Step 2: Compute the APSO parameters such as inertia weights, and acceleration coefficients and set particle size, population size, initial weight factor and number of iterations.

Step 3: Create congestion in the network intentionally. The line outages are occurred and load is incremented.

Step 4: Run load flow using Newton Raphson (NR) method where the generation, load and loss are satisfied according to the equality constraint Eqs. (2) and (3)

Step 5: Determine the excess power flow in line and bus voltage violation using the results of NR. And calculate the sensitivity of all the generators with respect to excess power
flow in line and change in the output of the generators from the committed generator data that is already given.

**Step 6:** Determine the number of the generators participating in the process of rescheduling from the value of their sensitivity.

**Step 7:** Generate randomly the particles between the maximum and the minimum operating limits of the generators.

**Step 8:** Determine the minimum cost of rescheduling using the objective function Eq. (12) for each particle. These values are set as the \( P_{best} \) value of the particles.

**Step 9:** The best value among all the \( P_{best} \) values, \( g_{best} \), is identified.

**Step 10:** New adaptive inertia weight factor and velocities for all the dimensions in each particle are calculated using Eqs. (20) and (18) respectively.

**Step 11:** The position of each particle is updated using Eq. (19).

**Step 12:** The objective function values are calculated for the updated positions of the particles. If the new value is better than the previous \( P_{best} \), the new value is set to \( P_{best} \). If the stopping criteria are met, the positions of particles represented by \( g_{best} \) are the optimal solution. Otherwise, the procedure is repeated from Step 9.

**PARAMETER SELECTION OF VPS ALGORITHM**

Some parameters must be assigned before VPS algorithm is used to solve the CM problem as follows:

- Particle size = 6 and population size = 20.
- The inertia weight and acceleration factors are computed using Eqs. (24), (25) and (26).

**RESULTS AND DISCUSSIONS**

The effectiveness of the VPS algorithm has been tested for IEEE-30 bus system as shown in Fig. 2 and compared with PSO algorithm. The IEEE 30 bus system description has been given in Tables 1 and 2. The algorithms are implemented in Matlab-7.12 programming language and the developed software code is executed on 1.67 GHz, 2 GB RAM INTEL(R) ATOM (TM) CPU (N455), DELL computer.

The preferred generation schedule corresponding to the particular load condition is obtained by running optimal power flow to minimize the generation cost alone and is given in Table 3. The generator outputs except the slack bus generator are considered as the variable for running optimal power flow. The PSO and VPS algorithms are used to optimize the generation cost. It is giving the minimum generation cost values as 801.842 $/h by VPS algorithm. The corresponding power generation is taken as the preferred schedule to meet the normal load demand. The bidding cost coefficients are given in Table 4. The congestion is created in the system by loading at load Bus-14 and is occurred in Line-26 connecting Bus-10 and Bus-17. The real power flow of the Line-26 before and after the congestion management is given in Table 5 and shown in Fig. 3. The real power flow obtained in the congested line (line-26) is 7.01 MW. But the real power flow limit of the line is 6.99 MW.

The computed generator sensitivities for the congested Line-26 are shown in Fig. 4. From the Figure it is noticed that all the generators are having strong influence on the congested line. The VPS algorithm is used for finding the necessary change in power generation to remove this congestion on Line 26. The results of rescheduling the generation by PSO, and VPS algorithms are reported in Table 6. The 20 trail is made with both the algorithms and result of best cost, worst cost and mean value of cost is presented in the same table.

Fig. 5 shows the cost of congestion management obtained by PSO and VPS algorithms. It is observed from Fig. 5 that the VPS algorithm obtains minimum cost for rescheduling of active power of participating generators to alleviate congestion.
Figure – 2: One line diagram of standard IEEE-30 bus data

Table – 1: Description of the Test system

<table>
<thead>
<tr>
<th>Variables</th>
<th>30 bus system</th>
</tr>
</thead>
<tbody>
<tr>
<td>Buses</td>
<td>30</td>
</tr>
<tr>
<td>Branches</td>
<td>41</td>
</tr>
<tr>
<td>Generators</td>
<td>6</td>
</tr>
</tbody>
</table>

Table – 2: Generator cost co-efficient

<table>
<thead>
<tr>
<th>Bus No.</th>
<th>Real power output limit of generator (MW)</th>
<th>Cost co-efficient</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Min</td>
<td>Max</td>
</tr>
<tr>
<td>1</td>
<td>50</td>
<td>200</td>
</tr>
<tr>
<td>2</td>
<td>20</td>
<td>80</td>
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<td>35</td>
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<td>11</td>
<td>10</td>
<td>30</td>
</tr>
<tr>
<td>13</td>
<td>12</td>
<td>40</td>
</tr>
</tbody>
</table>

Table – 3: Active power generation before congestion management

<table>
<thead>
<tr>
<th>Generator Bus No.</th>
<th>Active power generation before congestion management (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PSO</td>
</tr>
<tr>
<td>1</td>
<td>176.93</td>
</tr>
<tr>
<td>2</td>
<td>48.72</td>
</tr>
<tr>
<td>5</td>
<td>21.44</td>
</tr>
<tr>
<td>8</td>
<td>21.60</td>
</tr>
<tr>
<td>11</td>
<td>12.10</td>
</tr>
<tr>
<td>13</td>
<td>12.0</td>
</tr>
</tbody>
</table>
Table – 4: *Bidding cost*

<table>
<thead>
<tr>
<th>GEN. NO.</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
</tr>
</thead>
<tbody>
<tr>
<td>BIDS</td>
<td>11</td>
<td>17</td>
<td>19</td>
<td>20</td>
<td>15</td>
<td>10</td>
</tr>
</tbody>
</table>

Table – 5: *Comparison of line flow before and after congestion management*

<table>
<thead>
<tr>
<th>Branch power flow</th>
<th>Before congestion management active power flow (MW)</th>
<th>After congestion management active power flow (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>From bus</td>
<td>To bus</td>
<td>PSO</td>
</tr>
<tr>
<td>10</td>
<td>17</td>
<td>7.01</td>
</tr>
</tbody>
</table>

Table – 6: *Active power generation after congestion management*

<table>
<thead>
<tr>
<th>Generator Bus No.</th>
<th>Active power generation before congestion management (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PSO</td>
</tr>
<tr>
<td>1</td>
<td>176.15</td>
</tr>
<tr>
<td>2</td>
<td>47.55</td>
</tr>
<tr>
<td>5</td>
<td>21.45</td>
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<tr>
<td>8</td>
<td>24.50</td>
</tr>
<tr>
<td>11</td>
<td>14.5</td>
</tr>
<tr>
<td>13</td>
<td>12.0</td>
</tr>
<tr>
<td>Best cost (Rs/MWh)</td>
<td>226.53</td>
</tr>
<tr>
<td>Worst cost (Rs/MWh)</td>
<td>290.11</td>
</tr>
<tr>
<td>Mean cost (Rs/MWh)</td>
<td>260.73</td>
</tr>
</tbody>
</table>

Figure – 3: *Active power flows in Line 26*

Figure – 4: *Generator sensitivity factors of Line 26*
CONCLUSIONS

In this paper, the congestion management problem has been solved through optimal rescheduling of active powers of generators utilizing PSO and VPS algorithms. The generators have been chosen based on the generator sensitivity to the congested line. The rescheduling has been carried out by taking minimization of cost and satisfaction of line flow limits into consideration. The results obtained by VPS algorithm has been tested on the IEEE 30-bus and compared with conventional PSO. Based on the results, VPS algorithm is the most cost-efficient solution to the congestion management problem compared with conventional PSO.

The following features are being suggested as future research work to be carried out.
- The effect of reactive power of generators may be considered in managing congestion.
- The VPS algorithm may be extended to solve dynamic congestion management problem.
- In recent years, the usage of renewable energy sources like wind energy and solar energy has increased drastically. So, their cost functions and constraints may be included in the OPF problem to simulate congestion management.

REFERENCES


