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RESERVE CLEARING IN DEREGULATED ENVIRONMENT USING DYNAMIC MULTI-SWARM OF PARTICLE SWARM OPTIMIZER

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Abstract- Reserve clearing is an important part of electricity markets and is done in both aggregated and disaggregated market. The amount of required reserve is determined by using either deterministic or probabilistic methods. In disaggregated market that energy and reserve are cleared separately, we have to optimize the total market cost. In this paper we propose a method to clear energy and reserve markets separately with considering probabilistic approach to determine sufficient amount of required reserve. We use dynamic multi-swarm particle swarm optimizer (DMS-PSO) to solve the proposed model. Constraint handling is based on penalty factors. The IEEE Reliability Test System - 1996 (RTS-96) with 24 buses is used to examine the effectiveness of DMS-PSO in solving problems.

Keywords: Deregulation, Reserve Clearing, Reliability, Dynamic Multi-Swarm, Particle Swarm Optimization.

I. INTRODUCTION

In the last decade, deregulation and restructuring in power system improves the efficiency of power systems. Thus restructuring is increasing in many countries. In the deregulated power system, there are three main parts, generation companies (Genco), transmission companies (Transco), and distribution companies (Disco). One of the most important characteristics of deregulation is competitive environment that causes high efficiency. Some ancillary services such as reactive power are necessary for transmission of power and some are necessary for increasing the reliability and quality and safety of power systems [1].

Spinning reserve (SR), non-spinning reserve, reactive power, voltage regulation and black start are some kinds of ancillary services. For supplying energy and ancillary services, there are two kinds of market framework in deregulated power system; aggregated framework and disaggregated framework. In aggregated framework market, energy market and ancillary services markets are cleared simultaneously; but in disaggregated framework they are cleared sequentially. Disaggregated framework has also two forms; sequential and simultaneous forms [2]. In the sequential form of disaggregated framework, after clearing energy market by market operator (MO), system operator (SO) will clear ancillary services sequentially such that an auction for the best quality ancillary service is carried out first followed by decreasing quality ancillary services auction [3].

In the simultaneous form, all types of ancillary services are cleared simultaneously. This form is also known as rational buyer. Operating reserve is one of the most important ancillary services. In aggregated framework, we achieve higher social welfare than disaggregated one. This is one of the great advantages of aggregated framework but it acts as a "black box" in which justifying schedules and prices are very hard [2].

Disaggregated framework sometimes has no feasible solution for reserve market because its available reserve is less than required reserve. This is because of the fact that when high ramp rate units are accepted in the energy market, they don't have enough capacity to participate in the reserve market. Transparency in clearing energy and reserve market is one of the most important advantageous of disaggregated framework. In [4-6], an approach for procuring operating reserve has been presented using insurance theory. In [7], the generating units have been scheduled such that a given risk index is met. The optimal value of the risk index is determined using cost-benefit analysis. The concept in [7] has been applied to a traditional power system.

In [8], using correlation between capacity and reliability, a scheme for procuring and pricing operating reserve in a deregulated environment has been proposed. A pool-based market clearing algorithm, which is based on the deterministic/probabilistic criterion for application in electricity market, has been introduced in [9]. In this context, the energy and reserve are simultaneously solved and units are committed such that loss of load probability (LOLP) or expected energy not supplied (EENS) is smaller than a predetermined value. Because energy and reserve markets are cleared simultaneously in this framework, like the aggregated framework, it acts as a black box and therefore it is very hard to identify schedules and costs.

A security constrained economic dispatch for optimal reserve allocation and pricing has been formulated in [10]. In [10], a system has been divided into different control sub-areas where it is assumed that the amount of reserve required in each sub-area is predetermined. Then, the optimal spot price of operating reserve has been calculated using the Lagrange multipliers. An integrated energy and spinning reserve market model has been presented in [11], in which market dispatch is carried out so that the total payment including both energy and spinning reserve and expected energy not served (EENS) is minimized. Reserve allocation in deregulated environments has been done in [12] using risk minimization approach. In [13], an approach for spinning reserve allocation considering reliability and cost in the deregulated environments has been proposed.

In [14], the customers in a bilateral model have given the opportunity to purchase spinning reserve according to their needs using a well-being framework. In this proposed model, probabilistic method is used to determine the amount of required reserve. Either single risk criteria or multiple criteria, single risk criteria with system health probability, are used in well-being framework. After clearing energy market, the priority list is formed by combining all accepted units in energy market and then required spinning reserve, SR, is purchased from this priority list. In the case that there isn't enough available SR in the priority list, generating units are rescheduled with a new constraint to increase available SR in the priority list by accepting more generating units.

Rescheduling because of not enough available reserve in the priority list is one of disadvantages of this model. Also this model doesn't warranty minimum reserve procurement cost. Because some units with low bids for energy that are accepted in energy market may have high bids for reserve. So, reserve procurement cost many increase by purchasing reserve among these units. Another disadvantage of this model is that units with high ramp rate are fully accepted in energy market and therefore they can't be used in reserve market. In [15], a method in disaggregated framework is proposed wherein energy and reserve market are cleared separately. This method has advantages of both aggregated and disaggregated framework; and also the total cost is less than disaggregated method.

In this proposed method, the above problems are dealt with using some complementary considerations in reserve market clearing. In this manner, some units are backed down from their accepted values in the energy market and are participated in the reserve market. In this case, the backed down units are eligible to receive opportunity cost. Opportunity cost is paid to units that are backed down from the accepted values in the energy market and are participated in the reserve market with a capacity equal to their reduction in the energy market. Therefore, the payment for these units is the same as the units that are accepted in the reserve market. Due to the consistent balance between load and generation, the backed down portion of the accepted capacity in the energy market should be compensated by other units [15].

Therefore, in this proposed model some accepted units in energy market with high ramp rates and low bids of reserve are backed down from energy market and some others compensate backed down capacities in clearing reserve market. This is because of both achieving higher social welfare and providing required reserve. Therefore minimum SR procurement cost is warranted and there is always a feasible solution in reserve market. Deterministic method is used for determining required SR whereas determining SR by using probabilistic method is more convenient and has more advantageous. In this proposed method, the total cost is less than disaggregated method and always there is a feasible solution in reserve market.

For clearing this proposed method, a method for optimization would be needed. Recently, many evolutionary algorithms (EAs) were proposed for solving various nonlinear optimization problems such as simulated annealing (SA) genetic algorithms (GA) and ant colony optimization (ACO). Among them Particle swarm optimization (PSO) has shown a great effectiveness in solving optimization problem. It was introduced by Kennedy and Eberhart [16, 17]. PSO behaves similar to the behaviors of individual birds in a swarm when they are searching for food. In these behaviors, each individuals search a multidimensional space by moving in it. This Movement velocity of each individual is based on its present velocity, its own previous best performance, and the best previous performance of other individuals. PSO has considerable search performance in solving hard optimization problems with fast and stable convergence rates [18].

PSO algorithm requires few parameters to be tuned, thus it is easily implemented [19]. There are two main variants, global PSO and local PSO. In the local version of the PSO, each particle's velocity is adjusted according to its personal best position (*pbest*) and the best position (*lbest*) achieved so far within its neighborhood. The global PSO learns from the personal best position (*pbest*) and the best position (*gbest*) achieved so far by the whole population [20].

In [21, 22, 23, 24, 25] different neighborhood structures were proposed. In [26] and [27] local PSO variants with multi-swarm and subpopulation were proposed respectively. In [28], a dynamic multi-swarm particle swarm optimizer (DMS-PSO) was proposed whose neighborhood topology is dynamic and randomized. DMS-PSO gives a better performance on multimodal problems than some other PSO variants [20]. The dynamic multi-swarm particle swarm optimizer was constructed based on the local version of PSO with a new neighborhood topology [28].

In [29], decomposition technique and PSO algorithm together are used to determine bid prices and quantities in a competitive power market. In [30], modified PSO algorithm is used in power system unit commitment. In [31], particle swarm optimization with improved inertia weight (PSO-IIW) is used to solve economic dispatch. Adaptive PSO in conjunction with simulated annealing are used to optimize the location of FACTs devices in [32]. In [33], optimization of the size and location of DGs is done with PSO algorithm.

In [34], a constrained PSO algorithm is proposed for solving generation and reserve dispatch problem in a competitive pool market with considering valve-point and multi-fuel effect and transmission constraints. In [35], a market clearing mechanism is proposed in which overall payment of energy, spinning reserve and interruption costs are minimized by PSO algorithm. In [36], like [15] energy and reserve markets are cleared by PSO algorithm in both aggregated and disaggregated frameworks. In other words, PSO algorithm is used to solve minimization problem in [36] instead of GAMS software in [15].in disaggregated framework , proposed model in [15] is used for clearing reserve market and results of PSO algorithm are compared with obtained results of GAMS software in [15]. Like [15], deterministic method is used to determine required reserve.

In this paper we want to examine the capability of DMS-PSO in solving the proposed method in [15]. Energy and reserve will be cleared by DMS-PSO in proposed disaggregated market in [15]. In contrast with [15], probabilistic method is used to determine required amount of reserve. Penalty factors are used to handle equality and inequality constraints of objective function. RTS-96 [35] with some assumptions is employed for simulation.

II. PROPOSED METHOD

In this paper a new model is proposed in which energy and reserve markets are cleared separately by using proposed disaggregated framework in [15]. In contrast with [15], probabilistic method is used to determine required SR in this model.

Both of energy and reserve market are based on rational buyer model. In rational buyer model, Gencos submit their energy and reserve bids curves along with their ramp rates and maximum available unit capacity to the market operator. Independent system operator (ISO) that is responsible for power market management determines overall desired system reliability level in the form of expected energy not supplied (EENS) according to desired reliability levels of Discos.

The selection of specific values for the healthy state probability or risk depends on the desired degree of system well-being and the conditions under which the system is being operated. It is a managerial decision and depends largely on the degree to which the reliability level is required [14]. DisCos declare their desired reliability levels. Once the desired reliability levels associated with all DisCos are declared, the overall desired system reliability criterion is determined [14]. This implies that DisCos consequently contribute to the overall system desired reliability levels by choosing their own preferred reliability levels [14].

As mentioned in [14], weighted average of Discos' desired reliability levels can be considered as overall desired system reliability level. ISO calculates overall desired system reliability, overall desired EENS, by using submitted information of both Gencos and Discos; and then clears energy and reserve markets.

Therefore, in our proposed model, in first step, energy market is cleared such that its procurement cost is minimized. After that, capacity outage probability table (COPT) is formed by combating all accepted unit in energy market and EENS is determined. Then, spinning reserve market clearing procedure is begun. In each iteration of this procedure, required spinning reserve increases 1 MW and reserve market is cleared by using proposed disaggregated spinning reserve market in [15] such that its procurement cost is minimized.

After clearing reserve market with this amount of increased required spinning reserve, COPT is reformed by combining all accepted units in both energy and reserve markets and then the new amount of EENS is determined. This procedure, e.g. increment of system's required spinning reserve and resave market clearing with this amount of required spinning reserve, continues until system's EENS becomes less than desired EENS.

In other words, when calculated system's EENS becomes less than desired EENS, increase in required spinning reserve stops. Thus, we are deal with two optimization problems, e.g. minimization of procurement costs of both energy and spinning reserve in energy and reserve markets clearing that introduced DMS-PSO in [28] is used to solve these two optimization problems. Therefore, DMS-PSO is used to clear both energy and reserve markets.

In next section, after description of market-clearing procedure, the formulation of proposed disaggregated market in [15] is also introduced.

III. MARKET CLEARING PROCEDURE

As mentioned before, market-clearing procedure is as follows:

1) Energy market clearing: Energy market is cleared in such a way that energy procurement cost is minimized.

2) Determination of ten-minute available reserve: Maximum available reserve that each unit can deliver in ten minutes is limited by both its ramp rate and its accepted capacity in energy market.

3) Formation of COPT in order to determine EENS: COPT is formed by using outage replacement rate (ORR) of units that are accepted in energy market; and then EENS is determined.

4) Reserve market clearing with increased required reserve: Required reserve increases 1MW more than its previous value and reserve market is cleared again with this new amount of required reserve.

5) Determination of new EENS: COPT is reformed by combining all accepted units in energy and reserve markets, and then new EENS is determined.

6) Continuation of required reserve increment until reaching desired EENS: Required reserve increment, reserve market clearing and determination of new EENS continue until calculated EENS becomes less than desired EENS.

Proposed model flowchart for energy and reserve market clearing is depicted in Figure 1. Some of these steps and also its associated formulation are described in the following sessions.

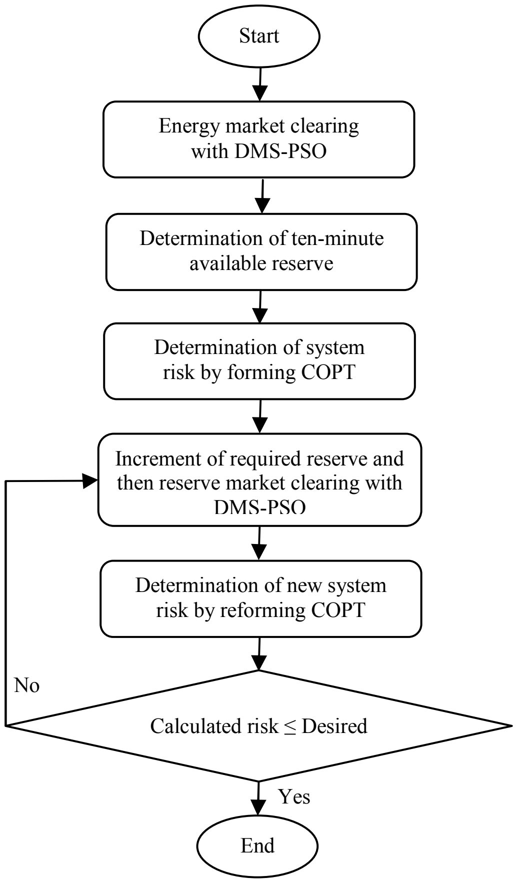

Figure 1. Market clearing flowchart

A. Energy Market Clearing

Energy market is cleared in such a way that energy procurement cost becomes minimized. Thus we deal with an optimization problem that minimizes energy procurement cost. Market operator clears energy market by using Gencos’ submitted information such as unit’s offer curves for energy and their maximum capacities. Energy market objective function that should be minimized in energy market is as follows:

$$\min \sum_{i=1}^{N} EP_i(P_i) \tag{1}$$

subject to

$$\sum_{i=1}^{N} P_i = \text{load} \qquad P_{i,\min} < P_i < P_{i,\max} \tag{2}$$

where $EP_i(P_i)$, which denotes energy bid of ith generating unit. N is the number of generator and P_i is energy generation of ith generator before clearing reserve market. Each generating company submits individual bidding blocks both for energy and reserve as follows:

$$\begin{aligned} &[E_i^j, BE_i^j] \qquad j = 1,2,\ldots,n_{ei} \\ &[R_i^k, BR_i^k] \qquad k = 1,2,\ldots,n_{ri} \end{aligned} \tag{3}$$

where E_i^j is the energy quantity offered by the ith generating company for the jth band, BE_i^j is the energy price offered by the ith generating company for the jth band, R_i^k is the capacity reservation quantity offered by the ith generating company for the kth band, BR_i^k is the capacity reserve price offered by the ith generating company for the kth band, n_{ei} is the number of energy bid bands offered by the ith generating company, and n_{ri} is the number of reserve bid bands offered by the ith generating company. Energy price function can be a step function as expressed below:

$$\begin{aligned} &EP_i(P_i) = \sum_{j=1}^{c} E_i^j \cdot BE_i^j + \left(P_i - \sum_{j=1}^{c} E_i^j\right) \cdot BE_i^{c+1} \\ &\sum_{j=1}^{c} E_i^j \le p_i \le \sum_{j=1}^{c+1} E_i^j \end{aligned} \tag{4}$$

where E_i^j is the energy quantity of the ith band and BE_i^j is the energy price of the ith band that was offered by the generating unit.

B. Determination of Ten-Minute Available Reserve

Maximum available reserve that each unit can deliver in ten minutes, also is known as ten-minute available capacity, should be determined before clearing reserve market. This value is limited by both unit’s ramp rate and its accepted capacity in energy market. Maximum total reserve that can be supplied by system is equal to the summation of all units’ ten-minute available reserves. In order to determine available reserve of each unit, its residual capacity should be determined before. Residual capacity and available reserve of each unit are calculated according to the following equations:

$$\begin{aligned} &Residual\ Capacity_i\left(ResCap_i\right) = P_i^{\max} - P_i \\ &Available\ Reserve_i(AR_i) = \min\left[ResCap_i\ ,\ 10 \times RR_{\mathrm{i}}\right] \end{aligned} \tag{5}$$

where RR_{i} is the ramp rate of ith unit.

C. Formation of COPT in order to Determine EENS

After clearing energy market, EENS is determined to represent for system reliability level. COPT is formed by combining all accepted units in energy market, and then EENS is determined. As mentioned in [14], based on Markov model, each unit is represented by two states, e.g. operating state and failed state. The repair process is neglected in determining the time dependent probabilities of generating units [14]. The probability of the unit being in the failed state during a time period (TP) is known as outage replacement rate (ORR) and is expressed as follows [36]:

$$P(\text{failed}) = ORR \cong \frac{\lambda.TP}{8760} \tag{6}$$

In the market model used in this paper, the auction is assumed to be an hourly auction. The time period is therefore considered to be 1 hour [14]. Formation procedure of COPT by using units’ *ORR* and also determination procedure of EENS are described in [36].

D. Reserve Market Clearing with Increased Required Reserve

In this step, required reserve increases 1 MW more than its previous value and reserve market is cleared with this new amount of required reserve. Proposed disaggregated reserve market in [15] is used to clear reserve market. As required reserve increases, EENS decreases and so system reliability level nears to the desired system reliability level.

As mentioned before, after clearing energy market the maximum available reserve in the reserve market may be less than the required reserve. Thus, to overcome this problem and to achieve highest social welfare, some units are backed down from their accepted values in the energy market and are participated in the reserve market. In this case, the backed down units are eligible to receive opportunity cost. Opportunity cost is paid to units that are backed down from the accepted values in the energy market and are participated in the reserve market with a capacity equal to their reduction in the energy market. Therefore, the payment for these units is the same as the units that are accepted in the reserve market.

Due to the consistent balance between load and generation, the backed down portion of the accepted capacity in the energy market should be compensated by other units [15]. Although backed down units are eligible for receiving opportunity cost, they shouldn't be paid for their backed down capacities in the energy market, any more. Therefore, the cost of reserve market is the summation of the following cost minus reduction of energy payment associated to the backed down units.

a) Reserve payment to the accepted units in the reserve market.

b) Energy payment from those units that compensate backed down capacities.

c) Opportunity cost payment for backed down units.

Therefore, the cost of reserve market clearing that should be minimized in the reserve market is as follows:

$$\min\sum_{i=1}^{N} RP_i(R_i,\rho)+\sum_{i=1}^{N} EP_i(P_i')+ \\ +\sum_{i=1}^{N} OC_i((P_i-\overline{P}_i),\rho)-\sum_{i=1}^{N} REP_i(P_i,\overline{P}_i) \tag{7}$$

subject to

$$\sum_{i=1}^{N} R_i+\sum_{i=1}^{N}\left(P_i-\overline{P}_i\right)=Required\ Reserve$$

$$\sum_{i=1}^{N} P_i'=\sum_{i=1}^{N}\left(P_i-\overline{P}_i\right) \tag{8}$$

$$P_i+R_i+P_i'\le P_i^{\max}$$

$$R_i+\left(P_i-\overline{P}_i\right)\le 10\times RR_i$$

In the following four sub sections, each terms of this objective function are described.

1) *Reserve payment*: Delivering power in real-time is related to the contingency probability factor (CPF) [15]. The CPF is strongly related to the reliability of generating units [36]. In this paper, it is assumed that this factor is specified according to ISO's experience, before. Therefore, ISO announces the CPF for GENCOs to consider this factor in their energy and reserve bidding for maximizing their profits before closing the market [15].

The $RP_i(R_i,\rho)$ is the reserve payment (*RP*) to the *i*th generating unit with R_i is accepted capacity in the reserve market and with CPF equal to ρ. Reserve cost function of each unit can be also a step function with only one step. Therefore $RP_i(R_i,\rho)$ has a following equation:

$$RP_i(R_i,\rho)=R_i\cdot BR_i+\rho\left[EP_i(P_i+R_i)-EP_i(P_i)\right] \tag{9}$$

where BR_i is capacity reserve price of *i*th generating unit.

2) *Energy payment in the reserve market*: P_i' is the amount of energy that is accepted in the reserve market clearing in addition to P_i from the *i*th unit to compensate backed down capacities. $EP_i(P_i')$ is the energy payment to the *i*th unit for generating higher than P_i. This payment is calculated as follows:

$$EP_i(P_i')=EP_i(P_i'+P_i)-EP_i(P_i) \\ \text{subject to} \\ P_i'\le ResCap_i \tag{10}$$

3) *Opportunity cost*: $\overline{P}_i$ is the accepted value of the *i*th generating unit in the energy market after clearing the reserve market [15]. P_i was the accepted value of the *i*th generating unit in the energy market after clearing the energy market. So, $\overline{P}_i$ is equal to P_i for units that wasn't backed down and $\overline{P}_i$ is less than P_i for units that was backed down. Thus, $(P_i-\overline{P}_i)$ is the backed down capacity of the *i*th generating unit for participating in the reserve market. Units that are backed down participate in the reserve market with a capacity equal to their reduction in the energy market. So the payment to these units should be the same as the units that are accepted in the reserve market. As mentioned before, Reserve Cost function of each unit can be assumed to be a step function with only one step. Thus as [15], the opportunity cost is assumed to be equal to the capacity reservation bid as follows:

$$OC_i((P_i-\overline{P}_i),\rho)=(P_i-\overline{P}_i)\cdot BR_i+\rho\left[EP_i(P_i)-EP_i(\overline{P}_i)\right] \\ \text{subject to} \\ \overline{P}_i\le P_i \tag{11}$$

4) *Reduction of energy payment in the reserve market:* $REP_i(P_i,\overline{P}_i)$ is reduction of energy payment of *i*th generating unit. As mentioned before, when the *i*th generating unit was backed down energy payment to this unit should be reduced as follows:

$$REP_i(P_i,\overline{P}_i)=EP_i(P_i)-EP_i(\overline{P}_i) \tag{12}$$

Constraint (8) denotes that provided reserve in reserve market, summation of backed down capacities and accepted reserve capacities, should be equal to required reserve. Also constraint (8) says that summation of backed down capacities should be equal to summation of compensated capacities. Summation of backed down capacity and accepted reserve capacity of *i*th unit should be less than or at last equal to ten minutes reserve of that unit. We use deterministic criteria like [15] in determining reserve requirements.

E. Determination of New EENS

In this step, after 1 MW increment of required reserve, COPT is reformed by combining all accepted units in energy and reserve markets; and then new EENS is determined from COPT. As mentioned before, formation of COPT by using units' ORR and also determination of EENS are described in [36].

IV. ORIGINAL DMS-PSO

Particle swarm optimization (PSO) was proposed by Kennedy and Eberhart in 1995 [16, 17]. PSO is a stochastic global optimization method which is inspired by the emergent motion of a bird flock when they are searching for food. Scientists found that in other to find food, each bird determined its velocity by two factors, its own best previous location and the best location of all other birds. In PSO there are a number of individuals called particles that constitute a population called swarm. Each particle represents a potential solution for the optimization problem and moves in search space and looks for global minimum. As said before, there are two main variants for PSO, global PSO and local PSO. In the global PSO, each particle's velocity is adjusted according to its personal best position (*pbest*) and the best position (*gbest*) achieved so far by the whole population; whereas in the local version of the PSO, each particle's velocity is adjusted according to its personal best position (*pbest*) and the best position (*lbest*) achieved so far within its neighborhood as follows:

$$v_{i,d} = \omega . v_{i,d} + c_1 . r_1 . \left(pbest_{i,d} - x_{i,d} \right) + \\ + c_2 . r_2 . \left(lbest_{i,d} - x_{i,d} \right) \tag{13}$$

where $lbest_i=(lbest_{i,1}, \ldots, lbest_{i,D})$ is the best position achieved within ith particle's neighborhood and $Pbest_i=(pbest_{i,1}, \ldots, pbest_{i,D})$ is ith particle's previous best location.

The dynamic multi-swarm particle swarm optimizer (DMS-PSO) was constructed based on the local version of PSO with a new neighborhood topology that is dynamic and randomized. As reported in [21, 22], PSO with small neighborhoods performs better on complex problems. So, in the DMS-PSO, small neighborhoods are used in order to slow down convergence speed and to increase diversity; therefore better results are achieved in multimodal problems.

In DMS-PSO, The population is divided into small sized swarms called sub-swarm. Each sub-swarm searches for better regions in the search space with its own members. These sub-swarms are searching using their own best historical information; so they easily converge to a local optimum because of PSO's speedy convergence behavior. Also Because of maximum information exchange among the particles, the diversity of the particles is increased.

In DMS-PSO, a randomized regrouping schedule is introduced to make the particles have a dynamically changing neighborhood structures. Therefore, every R generations, the population is regrouped randomly and then searches the search space using a new configuration of small swarms. R is called regrouping period. Thus, the obtained information by each swarm is exchanged among the swarms, and the diversity of the population is increased. DMS-PSO performs better on complex multimodal problems because of its new neighborhood structure.

Procedure of regrouping the whole population into new swarms is shown in Figure 2. As can be seen, nine particles are divided into three swarms randomly in each regrouping period. This Procedure is continued until a stop criterion is satisfied.

With the randomly regrouping schedule, particles from different swarms are grouped in a new configuration so that each small swarms search space is enlarged and better solutions are possible to be found by the new small swarms [28]. In the end of the search, in order to perform a better local search, all particles form a single swarm to become a global PSO version [28]. Flowchart of the original DMS-PSO introduced in [28], is also shown in Figure 3. As can be seen, we run original global PSO after regrouping phase of DMS-PSO.

The ω is inertia factor that balance between global and local exploration. We damped this inertia factor linearly from $\omega_{\max}$ to $\omega_{\min}$ in DMS-PSO algorithm. As proposed in [28], we set $\omega_{\max}$ and $\omega_{\min}$ equal to 0.9 and 0.2 respectively.

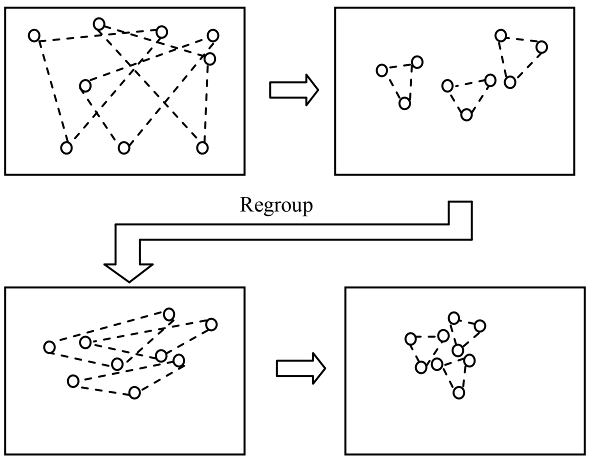

Figure 2. DMS-PSO's regrouping phase [28]

The c_1 and c_2 are accelerations constants and it is found out that setting them equal to 1.49445 gets the best overall performance in regrouping phase of DMS-PSO; therefore, like some latter versions of DMS-PSO such as [20], we set them equal to 1.49445 in regrouping phase of DMS-PSO. The r_1 and r_2 are uniform value in the range [0,1]. The particle velocity is limited by maximum value, $V_{\max}=(v_{\max,1}, \ldots, v_{\max,D})$. It was set 20 % of range of the variable on each dimension.

Except these common parameters, each swarm's population size m and regrouping period R are set to 3 and 5 respectively. As mentioned in [28], three particles achieve the balance between local and global search abilities, and the swarms show better global search ability [28]. Therefore, m=3 gives better performance for more complex multimodal problems. Also, for most test functions the better results are achieved when R=5 [28].

In original PSO, each particle adjusts its velocity towards its own previous best position (*pbest*) and the best previous position of whole swarm (*gbest*). When a particle discovers a better position than what has found previously, previous *pbest* will replace with this new position. The ith particle vector at tth iteration is represented as $X_i=(x_{i,1}, \ldots, x_{i,D})$. $V_i=(v_{i,1}, \ldots, v_{i,D})$ is the velocity vector of ith particle at the tth iteration . The velocity and position of each particle are updated with the following two equations.

$$v_{i,d} = \omega . v_{i,d} + c_1 . r_1 . \left(pbest_{i,d} - x_{i,d} \right) + + c_2 . r_2 . \left(gbest_{i,d} - x_{i,d} \right) \tag{14}$$

$$x_{i,d} = x_{i,d} + v_{i,d} \tag{15}$$

where $gbest=(gbest_1 ,\ldots, gbest_D)$ is the best position achieved so far by the whole population. Flowchart of the original PSO is also shown in Figure 4. Commonly, c_1 and c_2 are set to 2 in order to get the best overall performance in global PSO.

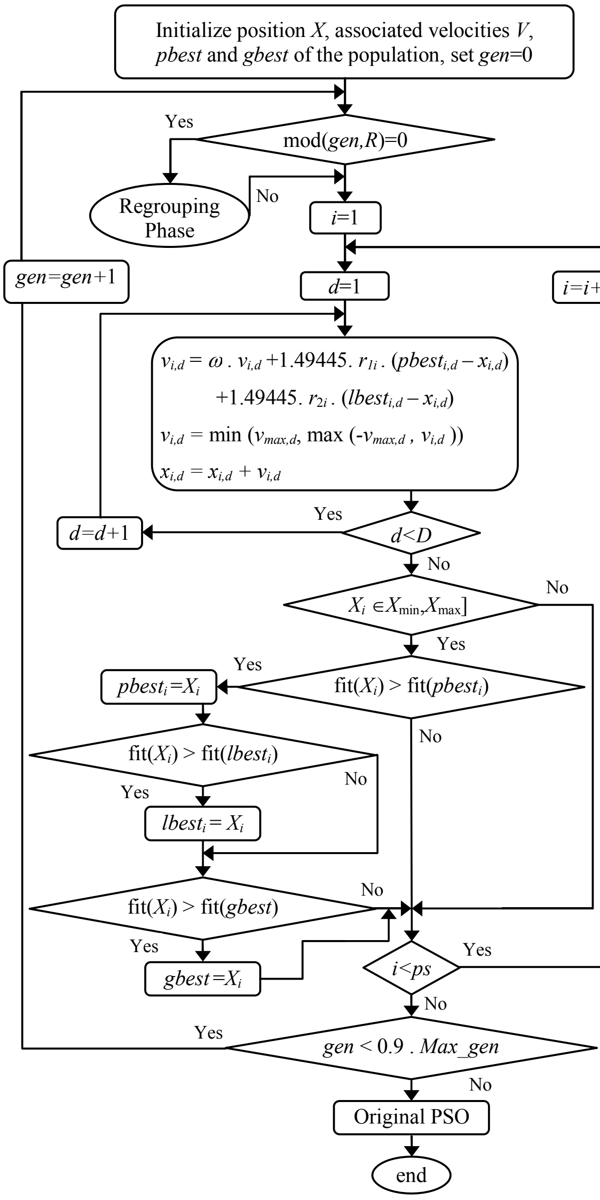

Figure 3. Flowchart of the original DMS-PSO

V. CONSTRAINT HANDLING

Generally, an objective function that we want to be minimized has some equality and inequality constraints as follows:

$$\min f\left(X\right) \qquad X = \left(x_1, \ldots, x_n\right) \tag{16}$$

subject to

$$g_j\left(X\right) \le 0 \qquad j = 1, \ldots, q$$
$$h_k\left(X\right) = 0 \qquad k = 1, \ldots, r \tag{17}$$

where q is the number of equality constraints and r is the number of inequality constraints. To handle these constraints, they are added to objective function with penalty factors and a new objective function is made as follows:

$$\min F\left(X\right) = f\left(X\right) + \sum_{j=1}^{q} Pn_j \times \max(0, g_j(X))^2 + + \sum_{k=1}^{r} Pn_k \times h_k(X)^2 \tag{18}$$

This new objective function will be minimized by PSO algorithm. Pn_j and Pn_k are penalty factors that are chosen large number enough to minimize objective function. If they are chosen very large, minimum of objective function may not be occurred.

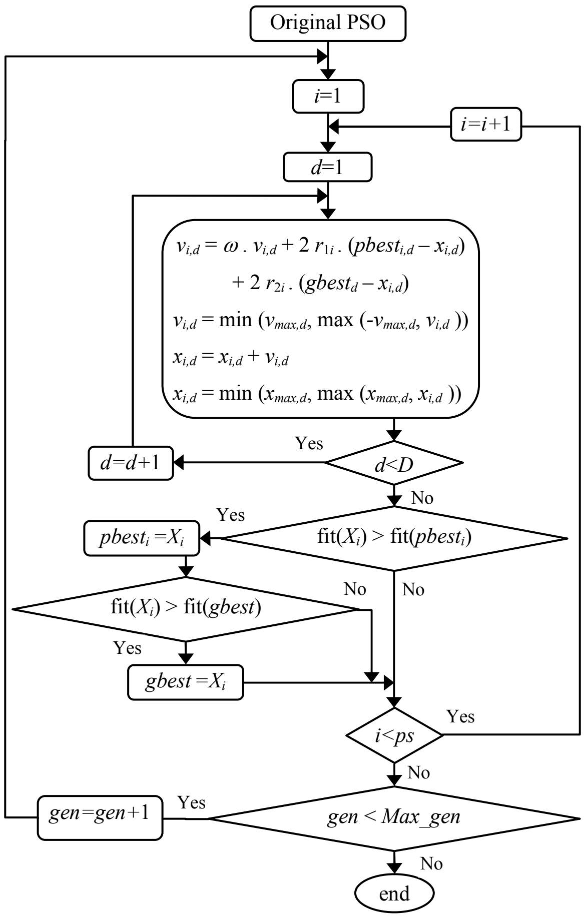

Figure 4. Flowchart of the original PSO

VI. SIMULATION RESULT

The IEEE Reliability Test System - 1996 (RTS-96) with 24 buses is used to examine the capability of DMS-PSO in solving our proposed model. This system is shown in Figure 5. The system peak load is assumed to be 2850 MW. System characteristics such as load of each bus, number and type of units at each bus, size of units, MTTF of each unit, heat rate and incremental heat rate of each unit, and ramp rate of each unit are given in [35]. As proposed in [39] Updated fuel costs are used in the cost model of the generators to reflect recent prices in the energy market. The generator fuel cost listed in Table 1.

The operating costs of each generator per hour are modeled with a quadratic function of the power as follows [37]:

$$z(P_i) = a + bP_i + cP_i^2 \quad (19)$$

The quadratic cost comes from two different contributions [37]: 1) operating and maintenance (O&M) costs and 2) fuel costs. We used The O&M linear cost coefficients provided in [40]. The O&M linear cost is as follows:

$$z_{OM}(P_i) = a_{OM} + b_{OM} P_i \quad (20)$$

Table 1. Units’ characteristics [39]

	U12 (#6 Oil)	U20 (#2 Oil)	U50 (Hydro)	U76 (Coal)	U100 (#6 Oil)	U155 (Coal)	U197 (#6 Oil)	U350 (Coal)	U400 (Nuclear)
P_{min} (MW)	2.4	16	10	15.2	25	54.25	68.95	140	100
P_{max} (MW), Base (MVA)	12	20	50	76	100	155	197	350	400
λ (per year)	2.98	19.5	4.42	4.47	7.30	9.13	9.22	7.62	7.96
O&M: a_{OM} (\$/h)	13.7	0.685	0.001	86.8	97.0	124	112	180	228
O&M: b_{OM} (\$/MWh)	0.9	5	0.001	0.9	0.8	0.8	0.7	0.7	0.3
Fuel cost (\$/MBtu)	5.5	10	0	1.5	5.5	1.5	5.5	1.5	0.60
Fuel cost: a_1 (\$/h)	72.7	400	0	126	684	258	720	485	217
Fuel cost: b_1 (\$/MWh)	55.7	125	0	15.2	42.9	11.6	47.9	11.2	5.35
Fuel cost: c_1 (\$/MW/MWh)	0.328	0	0	0.0141	0.0527	0.00834	0.00717	0.00490	0.000276
Cost: $a=a_{OM}+a_1$ (\$/h)	86.4	401	0.001	213	781	382	832	665	445
Cost: $b=b_{OM}+b_1$ (\$/MWh)	56.6	130	0.001	16.1	43.7	12.4	48.6	11.9	5.65
Cost: $c=c_1$ (\$/MW/MWh)	0.328	0	0	0.0141	0.0527	0.00834	0.00717	0.00490	0.000276

Computation procedure of quadratic fuel costs for one plant from the provided measurements of power output and heat consumption in the original IEEE 24-bus RTS are described in [39]. This quadratic fuel costs for one plant is obtained as follows:

$$z_1(P_i) = a_1 + b_1 P_i + c_1 P_i^2 \quad (21)$$

The operating cost coefficients, fuel cost coefficients, and O&C cost coefficients are listed in Table 1. Also, maximum output, minimum output, and failure rate of each unit are given in this table. We suppose that each unit bids for energy and reserve in three blocks and one block, respectively.

In bidding for energy and in first block, each unit offers 30% of its capacity with a unique price that is equal to operating cost of this quantity of energy e.g. $z(0.3P_{max})$; in second block, each unit offers another 40% of its capacity with a unique price that is equal to operating cost of this quantity of energy e.g. $z(0.7P_{max})$; and in third block, each unit offers residual 30% of its capacity with a unique price that is equal to operating cost of this quantity of energy e.g. $z(P_{max})$. In bidding for reserve, each unit offers all of its capacity with a unique price that is equal to operating cost of 40% of its capacity e.g. $z(0.4P_{max})$.

Units’ characteristics such as energy and reserve bidding block, ramp rates, and ORR are given in Table 2. We merge similar units to decrease total number of independent variable. Two cases are studied in this paper. In first case, transmission constraints are ignored, and in second case, test system is divided into two sub-areas, and transmission constraint between them is taken into account. These cases are studied in the following sections.

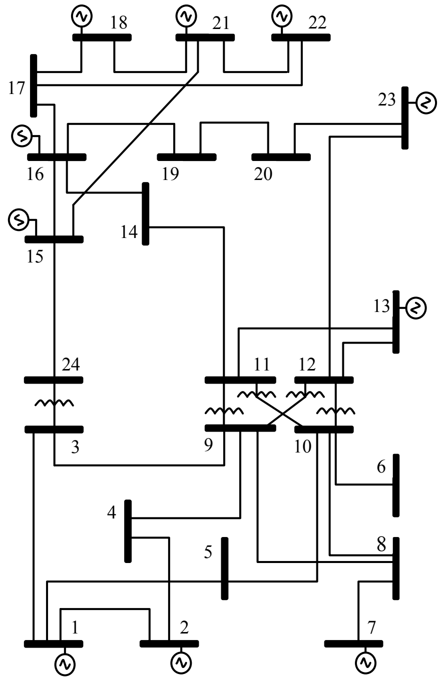

Figure 5. Single line diagram of RTS-96 [37]

In these cases we use DMS-PSO to minimize objective functions. We let $c_1=c_2=2$, $m=3$ and $R=5$. ω decreases from 0.9 to 0.2 with increasing iterations. In regrouping phase, we let $c_1=c_2=1.49455$, $m=3$ and $R=5$. In original global PSO phase, we let $c_1=c_2=2$. ω decreases from 0.9 to 0.2 with increasing iterations. V_{max} is set to 20% of range of the variable on each dimension in both phases. Size of population is set to 300 and 450 in case one and two, respectively. Also, the number of iterations (*Max_gen*) is set to 2500 and 50000 in these cases.

Table 2. Test System Characteristics [15]

Unit size	Unit No	Energy offer						Reserve offer		RR (MW/min)	ORR (f)
		Band 1		Band 2		Band 3		Band 1			
		MW	Price ($)	MW	Price ($)	MW	Price ($)	MW	Price ($)		
20	4	6	1181	8	2221	6	3001	20	1441	3	0.0022222
76	4	22.8	587.40974	30.4	1109.4264	22.8	1518.0416	76	715.47066	2	0.0005102
100	3	30	2139.43	40	4098.23	30	5678	100	2613.32	7	0.00083333
197	3	59.1	3729.3034	78.8	7670.2877	59.1	10684.461	197	4706.2017	3	0.0010526
12	5	3.6	294.41088	4.8	584.98368	3.6	812.832	12	365.63712	1	0.00034014
155	4	46.5	976.63316	62	1825.5806	46.5	2504.3685	155	1182.859	3	0.0010417
400	2	120	1126.9744	160	2048.6384	120	2749.16	400	1356.0656	20	0.00090909
350	1	105	1968.5225	140	3874.6225	105	5430.25	350	2427.04	4	0.00086957
50	6	15	0.016	20	0.036	15	0.051	0	0	0	0.0005102

A. Case 1: One Area without Considering Transmission Constrains

In this case, transmission constraint is ignored. The unconstrained objective function in energy market that should be minimized by PSO is as follows:

$$\min \sum_{i=1}^{N} EP_i(P_i) + Pn.\left(\sum_{i=1}^{N} P_i - \text{load}\right)^2 \tag{22}$$

where equality constraints were added to the cost function of energy market by penalty factor Pn. This penalty factor is set to 100000000 that is about twenty times of constrained objective function's value.

As said before, we merge similar units to decrease number of state variable. Here, state variables are P_i for i=1-8 that DMS-PSO finds them in such a way to minimize above objective function. We assume that hydro units are fully accepted in energy market; therefore P_9 is not a state variable. DMS-PSO algorithm was run five times and mean, standard deviation, and best of the results were given in Table 3. As can be seen, standard deviations of the results are equal to zero in each case. In Table 4, the best result of DMS-PSO e.g. minimum cost of energy market clearing was compared with result of GAMG. As can be seen, DMS-PSO can successfully find minimum of objective function as GAMS. Desired expected energy not supplied is assumed to be 0.78082 MWh per hour. The proposed disaggregated market in [15] was used for achieving optimal solution in reserve market. The unconstrained objective function in reserve market is as follows:

$$\begin{aligned}
&\min \sum_{i=1}^{N} RP_i(R_i,\rho) + \sum_{i=1}^{N} EP_i(P_i') + \\
&+\sum_{i=1}^{N} OC_i((P_i - \overline{P}_i),\rho) - \sum_{i=1}^{N} REP_i(P_i,\overline{P}_i) + \\
&+Pn_1 \cdot \left(\sum_{i=1}^{N} R_i + \sum_{i=1}^{N}\left(P_i - \overline{P}_i\right) - Required\ Reserve\right)^2 + \\
&+Pn_2 \cdot \left(\sum_{i=1}^{N} P_i' - \sum_{i=1}^{N}\left(P_i - \overline{P}_i\right)\right)^2 + \\
&+Pn_3 \cdot \left(\sum_{i=1}^{N} \max\left(0, P_i + R_i + P_i' - P_i^{\max}\right)^2\right) + \\
&+Pn_4 \cdot \left(\sum_{i=1}^{N} \max\left(0, R_i + \left(P_i - \overline{P}_i\right) - 10 \times RR_i\right)^2\right)
\end{aligned} \tag{23}$$

where equality and inequality constraints are added to cost function of reserve market clearing by penalty factors Pn_1, Pn_2, Pn_3, and Pn_4. All penalty factors are set to 5000000 that are about ten times of constrained objective function's value of reserve market. CPF is assumed to be 0.35. State variables are ΔP_i and R_i for i=1-8 that DMS-PSO finds them in such a way to minimize above objective function. We assume that hydro units are fully accepted in energy market and don't participate in reserve market; therefore ΔP_9 and R_9 is not a state variable. After finding ΔP_i, $\overline{P}_i$ and P_i' are calculated as follows:

$$\overline{P}_i = \min\left(P_i, P_i + \Delta P_i\right) \quad , \quad P_i' = \max\left(0, \Delta P_i\right) \tag{24}$$

Required reserve is increased 1 MW and then reserve market is cleared with this increased value of required reserve in each iteration. DMS-PSO algorithm is run five times to clear reserve market with this increased value of required reserve and its best result, e.g. the result that has minimum cost for reserve procurement, is chosen as the answer of reserve market. When required reserve is increased to the 128 MW, EENS becomes less than desired EENS, e.g. about 0.7748 MWh. Therefore minimum system required reserve for achieving desired EENS is about 128 MW; whereas if we use deterministic criteria to determine required reserve such as ten percent required reserve criteria, we need 285 MW required reserve. Reserve market is cleared with DMS-PSO for supplying this amount of reserve; DMS-PSO algorithm was run five times and mean, standard deviation, and best of the results were given in Table 3. The best answer of reserve market clearing with 128 MW required reserve is given in Table 5, and was compared with result of GAMG. As can be seen, DMS-PSO can successfully find minimum of objective function as GAMS.

B. Case 2: Two Sub-Areas with Considering Transmission Constraint

In this case we divide the original IEEE 24-bus RTS into two sub-areas and transmission capacity constraint between these two sub-areas is taken into account. 20, 76, and 100 MW Units belong to sub-area A and other units belong to sub-area B. In this case, the total load levels in A and B sub-areas are 1332 and 1518 MW, respectively. Required reserve in A sub-area is determined such that EENS of this sub-area becomes less than desired EENS whereas A sub-area and B sub-area are considered as assisted system and equivalent assisting unit respectively.

Similarly, required reserve in B sub-area is determined such that EENS of this sub-area becomes less than desired EENS whereas B and A sub-areas are considered as assisted system and equivalent assisting unit respectively, too.

Required reserves in both A and B sub-areas increase 1 MW more than their previous values and then reserve market is cleared with these new amounts of required reserves by using DMS-PSO. After that, A sub-area EENS is determined whereas B sub-area acts as an equivalent assisting unit; and similarly, B sub-area EENS is determined whereas A sub-area acts as an equivalent assisting unit. Required reserve increment of each sub-area continues until its EENS becomes less than desired EENS. Procedure of modeling an area as an assisting unit is described in [38].

Transmission capacity between two sub-areas is assumed to be 2400 MW. The unconstrained objective function of energy market that is minimized by DMS-PSO algorithm is as follows:

$$\begin{aligned}\min\ & \sum_{i=1}^{N} EP_i(P_i) + Pn_1 . \left(\sum_{i \in A} P_i - A_{load} - E_{AB} \right)^2 + \\ & + Pn_2 . \left(\sum_{i \in B} P_i - B_{\text{load}} + E_{AB} \right)^2 \end{aligned} \tag{25}$$

Penalty factors, Pn_1 and Pn_2, are set to 100000000 that is about twenty times of constrained objective function's value of energy market. In this section, we also merge similar units to decrease number of state variable. State variables are P_i for i=1-8 and E_{AB} that DMS-PSO finds them in such a way to minimize above objective function. We also assume that hydro units are fully accepted in energy market; therefore P_9 is not a state variable.

Like the previous case, DMS-PSO was run five times and mean, standard deviation, and best of the results were given in Table 3. In Table 6 the best result of DMS-PSO e.g. minimum cost of energy market clearing was compared with result of GAMG. As can be seen, DMS-PSO can successfully find minimum of objective function as GAMS. Because energy procurement cost in B sub-area is cheaper than A sub-area, 738 MW energy flows from B sub-area to A sub-area. Desired EENS for A and B sub-areas are assumed to be 0.3649 and 0.4159 MWh per hour, respectively in this case. The non-constrained objective function of reserve market can be minimized with DMS-PSO and expressed as following:

$$\begin{aligned}\min\ & \sum_{i=1}^{N} RP_i(R_i,\rho) + \sum_{i=1}^{N} EP_i(P_i') + \\ & + \sum_{i=1}^{N} OC_i((P_i - \bar{P}_i),\rho) - \sum_{i=1}^{N} REP_i(P_i,\bar{P}_i) + \\ & + Pn_1 \cdot \left(\sum_{i \in A} R_i + \sum_{i \in A} \left(P_i - \bar{P}_i\right) - A_{Required\ Reserve} - R_{AB} \right)^2 + \\ & + Pn_2 \cdot \left(\sum_{i \in B} R_i + \sum_{i \in B} \left(P_i - \bar{P}_i\right) - B_{Required\ Reserve} + R_{AB} \right)^2 + \\ & + Pn_3 \cdot \left(\sum_{i \in A} P_i' + \sum_{i \in A} \bar{P}_i - A_{load} - E_{AB} \right)^2 + \\ & + Pn_4 \cdot \left(\sum_{i \in B} P_i' + \sum_{i \in B} \bar{P}_i - B_{load} + E_{AB} \right)^2 + \\ & + Pn_5 \cdot \left(\sum_{i=1}^{N} P_i' - \sum_{i=1}^{N} \left(P_i - \bar{P}_i\right) \right)^2 + \\ & + Pn_6 \cdot \left(\sum_{i=1}^{N} \max\left(0, P_i + R_i + P_i' - P_i^{\max}\right)^2 \right) + \\ & + Pn_7 \cdot \left(\sum_{i=1}^{N} \max\left(0, R_i + \left(P_i - \bar{P}_i\right) - 10 \times RR_i\right)^2 \right) + \\ & + Pn_8 \cdot \left(\max\left(0, E_{AB} + R_{AB} - LinCap\right)^2 \right) + \\ & + Pn_9 \cdot \left(\max\left(0, -LinCap - R_{AB} - E_{AB}\right)^2 \right) \end{aligned} \tag{26}$$

Equality and inequality constraints are included in non-constrained objective function with penalty factors $Pn_1 - Pn_9$. These penalty factors are set to 22000000, 20000000, 18000000, 16000000, 14000000, 26000000, 24000000, 10000000, and 12000000, respectively that are about ten to twenty times of constrained objective function's value of reserve market.

Table 3. Cases' Results

Case		Mean	Standard Deviation	Minimum	Number of Iterations
1	Energy Cost($)	5670871.8539	0	5670871.8539	2500
	Reserve Cost($)	577957.8608	0	577957.8608	50000
2	Energy Cost($)	5670871.7802	0	5670871.7802	2500
	Reserve Cost($)	1231600.1089	0	1231600.1089	50000

Table 4. Energy market clearing result without considering transmission constraints

System load (MW)	Unit size	PSO				GAMS			
		P_i	$ResCap_i$	AR_i	Energy cost ($)	P_i	$ResCap_i$	AR_i	Energy cost ($)
2850	20	20	0	0	5670871.8539	20	0	0	5670871.9276
	76	76	0	0		76	0	0	
	100	70	30	7		70	30	7	
	197	68.95	128.05	3		68.95	128.05	3	
	12	12	0	0		12	0	0	
	155	155	0	0		155	0	0	
	400	400	0	0		400	0	0	
	350	269.15	80.85	4		269.15	80.85	4	
	50	50	0	0		50	0	0	

Table 5. Reserve market clearing result using the proposed method without considering transmission constraints

System load (MW)	System Reserve (MW)	Unit size	PSO				GAMS			
			P_i'	R_i	$P_i - \overline{P}_i$	Reserve cost ($)	P_i'	R_i	$P_i - \overline{P}_i$	Reserve cost ($)
2850	128	20	0	0	0	577957.8608	0	0	0	577959.6600
		76	0	0	0		0	0	0	
		100	2.3e-13	29.3332	0		0	30,30,28 [a]	0	
		197	0	0	2.66e-13		0	0	0	
		12	0	0	0		0	0	0	
		155	0	0	0		0	0	0	
		400	0	0	0		0	0	0	
		350	0	39.9998	0.00027149		0	40	0	
		50	0	0	0		0	0	0	

a. Three similar 100 MW units have 30, 30, and 28 MW reserve, respectively.

Table 6. Energy market clearing result with considering transmission constraints

Sub-area load (MW)	Unit size	PSO				GAMS			
		P_i	$ResCap_i$	AR_i	Energy cost ($)	P_i	$ResCap_i$	AR_i	Energy cost ($)
1332	20	20	0	0	5670871.7802	20	0	0	5670871.9276
	76	76	0	0		76	0	0	
	100	70	30	7		70	30	7	
1518	197	68.95	128.05	3		68.95	128.05	3	
	12	12	0	0		12	0	0	
	155	155	0	0		155	0	0	
	400	400	0	0		400	0	0	
	350	269.1499	80.8501	4		269.15	80.85	4	
	50	50	0	0		50	0	0	

Table 7. Reserve market clearing result using the proposed method with considering transmission constraint

Sub-area Reserve (MW)	Sub-area EENS	Unit size	PSO				GAMS			
			P_i'	R_i	$P_i - \overline{P}_i$	Reserve cost ($)	P_i'	R_i	$P_i - \overline{P}_i$	Reserve cost ($)
1332	7.8e-6	20	0	0	4	1231600.1089	0	0	0,4,4,4[b]	1233128.9469
		76	0	0	4e-14		0	0	0	
		100	1.3e-5	30	0		0	30	0	
1518	0.4141	197	20.3831	1.1e-13	2.66e-13		29.1,16.025,16.025[a]	0	0	
		12	0	0	9.7e-17		0	0	0	
		155	0	0	21.4999		0	0	0	
		400	0	0	4.3e-14		0	0	0,90[c]	
		350	40.8501	40	0		40.85	40	0	
		50	0	0	0		0	0	0	

a. Three similar 197 MW units compensate 29.1, 16.025, and 16.025 MW of backed down capacity, respectively.
b. Four similar 20 MW units backed down 0, 4, 4, and 4 MW, respectively.
c. Two similar 400 MW units backed down 0 and 90 MW, respectively.

Because transmitted energy from B sub-area to A sub-area is assumed as a firm purchase, and also units in A sub-area have high reliability, some reserve is required for achieving desired EENS in this sub-area. Whereas, if we use deterministic criteria to determine required reserve such as ten percent required reserve criteria, we will need 133.2 MW and 151.8 MW required reserve for A and B sub-areas, respectively; that causes A sub-area to have reserve more than its required reserve and B sub-area to have reserve less than its required reserve.

We merge similar units to decrease number of state variable. Therefore, State variables are E_{AB}, R_{AB}, ΔP_i and R_i for i=1-8 that DMS-PSO finds them in such a way to minimize above objective function. Similarly, we assume that hydro units are fully accepted in energy market and don't participate in reserve market; therefore ΔP_9 and R_9 are not state variables. DMS-PSO is run five times to clear reserve market with increased required reserves of B sub-area; and its best result, e.g. the result that has minimum cost for reserve procurement, is chosen as the answer of reserve market clearing. When required reserves in A and B sub-areas increase to 6 and 226 MW respectively, their EENS becomes less than their desired values.

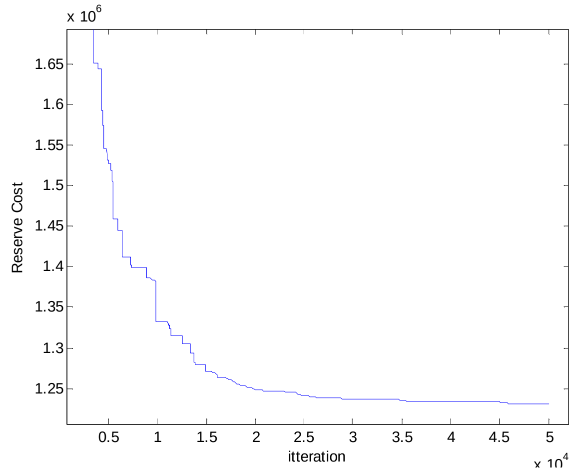

Figure 6. The *gbest*'s convergence graph of best answer of DMS-PSO

DMS-PSO was also run five times to clear reserve market with these required reserves of A and B sub-areas; and mean, standard deviation, and best of the results were given in Table 3. The best result of DMS-PSO e.g. minimum cost for reserve procurement is compared with result of GAMG in Table 7; and its convergence graph is illustrated in Figure 6. As can be seen, DMS-PSO has found minimum of objective function better than GAMS has. However, we don't merge same units when solving our problems with GAMS.

The maximum available reserve in both sub-areas is 220 MW, which is less than summation of required reserves in these sub-areas e.g. 232 MW; therefore, there is no feasible solution without using the proposed disaggregated method in [15] for reserve market clearing. For supplying this amount of required reserves with minimum cost, some units with low reserve bid e.g. 20 MW units and 155 MW units are backed down about 102 MW; and, 197 MW units and 350 MW unit compensate this backed down capacity. 100 MW units and 350 MW unit supply last 130 MW of required reserve. In contrast with energy market, because reserve procurement cost in A sub-area is cheaper than B sub-area, 100 MW reserve capacity of B sub-area is provided from A sub-area to minimize reserve procurement cost.

VII. CONCLUSIONS

In this paper DMS-PSO was used to solve energy and reserve market in disaggregated framework with considering probabilistic method in determining the amount of system required reserve. Proposed method in [15] is used to clear energy and reserve market. In this proposed method, some units with high ramp rates are backed down from energy market and participate in reserve market to both supply required reserve and minimize reserve procurement cost. Because probabilistic method is more convenient than deterministic method, in contrast with [15], probabilistic method was used for determining system required reserve. We studied two cases; with and without considering transmission constraint. In each case, we had several equality and inequality constraints that were added to the objective function with penalty factors. RTS-96 was used for simulation. DMS-PSO not only successfully found the minimum of objective function as well as GAMS in each case, but also it has found better result than GAMS in last case. Therefore DMS-PSO has high performance in solving mixed integer programming (MIP) problem. It has simple concept and can easily be implemented. DMS-PSO can find global optimum even if there are many state variables and constraints. It found our global minimum in each case study as GAMS. So, we can simply use DMS-PSO in optimization problem instead of mathematical algorithms and other heuristic optimization problem such as GAMS software.

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