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Optimal Generation Costs Considering Modified Sensitivity Factors and Modified Particle Swarm Optimization Version

R.A. El-Sehiemy*[1], and A.A. Abou El- Ela[+]

Abstract – *This paper proposes modified sensitivity factors (MSF) for computing the transmission power flows in terms of buses injected power at different power system events. The proposed MSF are capable for obtaining higher quality solutions. A modified particle swarm optimization (MPSO) version is proposed to solve the power dispatch problem. Comparison studies based on the optimal power dispatch model are performed to show the superiority of the proposed MSF compared to the existed sensitivity factors. In the competitive environment, the use of the proposed sensitivity factors leads to fair allocation of user responsibilities in recovery problems such as loss allocation and transmission usage allocation. The comparison studies are performed using two standard systems, 5-bus and IEEE 57-bus test systems. Also, a real power system as a part of the Unified Egyptian Network (UEN) at Delta region is used to show the superiority of the proposed approach.*

Keywords – Deregulation, emergency, particle swarm optimization, and production cost minimization

1. INTRODUCTION

Electricity markets development has been witnessed through radical changes due to deregulation/ privatization process. The traditional vertically integrated systems were divided into individual companies to provide a suitable reduction level of consumer prices by means of competition. The competition in electricity is constrained by the available transfer capabilities and the level of transmission congestion in a market.

A variety of applications in both planning and operation require repetitive computation of power flows and power losses in transmission lines. Sensitivity factors were presented as the generalized generation distribution factors (GGDF) for obtaining the power flows in transmission lines in terms of the injected power generations [1]. Topological generation and load distribution factors for power flows and transmission losses were presented [2]. A modification of the topological generation and load distribution factors for power flows and transmission power losses was presented [3].

Milano *et al.* [4] presented three main market models namely: centralized markets, standard auction, and spot pricing or hybrid markets. Different electricity market models were presented to maximize the market profit and minimize production costs in [5].

Yamin *et al.* [6] considered the impact of transmission constraints on the security constrained generation scheduling problem in the competitive market. A probabilistic transmission planning model was evaluated the expansion and reinforcement of transmission system by using adequacy linear programming model in the liberalized electricity markets [7].

Modern heuristics optimization techniques were considered as practical tools for non-linear optimization problems [8]-[16]. Particle Swarm Optimization (PSO) technique was invented by Kennedy and Eberhart in 1995. The PSO is a relatively recent heuristic search method whose mechanics are inspired by the swarming or collaborative behavior of biological populations. The PSO technique is considered as a realistic and powerful solution scheme for solving continuous non-linear optimization problems [8]-[15]. Recently, PSO has been successively applied to various fields of power system optimization problems such as for economic dispatch problem considering generation constraint [8], for minimizing the non-smooth cost function of economic dispatch problem [9], scheduling the power generations considering Lagrangian relaxation method [10], reactive power and voltage control [11], optimal design of power system stabilizer [12], optimal power flows [13], state estimation [14] and for unit commitment problem [15]. Reference [16] presented the application of PSO technique to obtain the optimal transmission loss allocation levels at generation and demand buses.

2. GENERATION DISPATCH FORMULATION

The generation dispatch formulation can be represented as:

$$Min \quad PR = \sum_{i=1}^{NG} C_i \left(PG_i \right) \tag{1}$$

Where, PR presents the total generation costs.

PG_i is the generation unit i output.

NG is the number of generation units.

The cost function of unit i $\left(C_i \left(PG_i \right) \right)$ is described as:

* The Arab Contractor (Osman Ahmed Osman and Co.), Marine Construction Department, 10th of Ramadan City, Egypt. Postal Address: P.O. Box 32735 Bakhaty, Shebin El Kom, Minoufiya, Egypt.

+ Minoufiya University, Faculty of Engineering, Shebin El-Kom, Minoufiya , Egypt. E-mail: draaa50@hotmail.com.

1 Corresponding author;
Tel: + 20101281051, Fax: +2015410470.
E-mail: elsehiemy@hotmail.com.

$$C_i\left(PG_i\right)=a_iPG_i^2+b_iPG_i+c_i\,,\quad i=1,2,.....,NG \tag{2}$$

where, a_i, b_i and c_i are the generation cost coefficients.

The objective function (Equation 1) is subjected to the set of system operating constraints including the system security constraints as:

- ***Power balance constraint***

The power balance constraint can be written as:

$$\sum_{i=1}^{NG} PG_i = \sum_{j=1}^{ND} PD_j \tag{3}$$

where, the total power generated should be equal to the system load demand which includes transmission losses.
ND is the number of power demand buses.

- ***Congestion constraint***

The power flow in the transmission line k $\left(PF_k\right)$ must be less than its maximum limit $\left(PF_k^{\max}\right)$ as:

$$\left|PF_k\right| \le PF_k^{\max}, \qquad k=1,2,\ldots,NL, \tag{4}$$

where, NL is the total number of transmission lines.

- ***Capacity (physical) constraints***

The physical minimum and maximum limits of each generation unit, $PG_i^{\min}$ and $PG_i^{\max}$, can be expressed as:

$$PG_i^{\min} \le PG_i \le PG_i^{\max}, \quad i=1,2,\ldots NG \tag{5}$$

- ***Demand constraints***

The physical minimum and maximum limits of each power demand, $PD_j^{\min}$ and $PD_j^{\max}$, can be expressed as:

$$PD_j^{\min} \le PD_j \le PD_j^{\max}, \quad j=1,2,\ldots ND \tag{6}$$

3. SENSITIVITY FACTORS

General Generation Distribution Factors (GGDF)

The GGDF are used to compute the power flow in transmission line k as a function of power generation as [1]:

$$PF_k = \sum_{i=1}^{NG}\left(D_{k,i}.PG_i\right) \tag{7}$$

$$D_{k,i}=D_{k,r}+A_{k,j} \tag{8}$$

$$D_{k,r}=\left(PF_k^0-\sum_{\substack{i=1\\ i\ne r}}^{NG}A_{k,i}PG_i\right)\Bigg/\sum_{i=1}^{NG}PG_i \tag{9}$$

Where, $D_{k,i}$ is the GGDF for line k related to bus i,
$D_{k,r}$ is the GGDF for line k related to slack bus r.
$A_{k,j}$ is the generation shift distribution factors for line k related to bus i. and
PF_k^0 is the initial power flow of line k.

Proposed Modified Sensitivity Factors

The proposed MSF (denoted in the following equations by D_m) depend on the actual power system measurements for power flows in transmission lines, corresponding to the power generation, which can be written as:

$$PF = D_m.PG \tag{10}$$

$PF=[PF_1\ PF_2\ PF_3\ .....,PF_k,.....,PF_{NL}]$, k=1,2, ..., NL
$PG=[PG_1\ PG_2\ PG_3.....,PG_i,.....,PG_{NG}]$, i=1,2, ..., NG

The initial power flows in terms of initial power generations can be written as:

$$PF^0 = D_m.PG^0 \tag{11}$$

By multiplying both sides of Equation 11 by $\left(PG^0\right)^t$, it can become:

$$PF^0.\left(PG^0\right)^t = D_m.\left(PG^0\right).\left(PG^0\right)^t \tag{12}$$

Also, by multiplying the both sides of Equation 12 by the inverse of the matrix $\left(\left(PG^0\right).\left(PG^0\right)^t\right)$, the following can be obtained:

$$\begin{aligned}&PF^0.\left(PG^0\right)^t.\left(\left(PG^0\right).\left(PG^0\right)^t\right)^{(-1)} =\\ &D_m.\left(PG^0\right).\left(PG^0\right)^t.\left(\left(PG^0\right).\left(PG^0\right)^t\right)^{(-1)}=D_m\end{aligned} \tag{13}$$

$$\therefore D_m = PF^0.\left(PG^0\right)^t.\left(\left(PG^0\right).\left(PG^0\right)^t\right)^{(-1)} \tag{14}$$

The proposed MSF depend on the actual power systems measurements of the power flows in transmission lines. The power generations as well as the effects of circuit resistances are considered. The power flow $\left(PF_k\right)$ in Equation 4 can be written as:

$$PF_k=\sum_{i=1}^{NG}\left(\left(D_m\right)_{k,i}.PG_i\right) \tag{15}$$

$$\left(D_m\right)_{k,i}=PF_k^0.\left(PG_{k,i}^0\right)^t.\left(\left(PG_{k,i}^0\right).\left(PG_{k,i}^0\right)^t\right)^{(-1)} \tag{16}$$

$\left(D_m\right)_{k,i}$ is the MSF for line k related to generation i.
$\left(PG_{k,i}^0\right)^t$ is the transpose of initial power generation vector $PG_{k,i}^0$.
$PG_{k,i}^0$ is the initial power generator for unit i.

4. MODIFIED PARTICLE SWARM OPTIMIZATION TECHNIQUE

The proposed modified PSO (MPSO) model based on the collected information of self and group experience with respect to the current agent position is considered for solving the security constrained power dispatch problem. The updated formula for each $PG_{i,k}$ at iteration k is computed using the conventional PSO model presented in [8]-[10] as:

$$\Delta PG_{i,k} = W.\Delta PG_{i,k} + C_1 R_1 (PG_{i,k}^{Pbest} - PG_{i,k}) + C_2 R_2 (PG_{i,k}^{Gbest} - PG_{i,k}) \quad (17)$$

$$PG_{i,k+1} = PG_{i,k} + \Delta PG_{i,k} \quad (18)$$

$$W = W^{\max} - \frac{(W^{\max} - W^{\min}).iter}{Iter\max} \quad (19)$$

Both agent position and transition information of each agent transition ($\Delta PG_{k,i}$) are constrained by the minimum and maximum particle transitions, at iteration k for individual i, as:

$$T_{k,i}^{\min} \le \Delta PG_{k,i} \le T_{k,i}^{\max} \quad (20)$$

The minimum and maximum agent transitions can be obtained from:

$$T_{k,i}^{\max} = k_m (PG_{k,i}^{\max} - PG_{k,i}^{\min}), \quad T_{k,i}^{\min} = -k_m (PG_{k,i}^{\max} - PG_{k,i}^{\min}) \quad (21)$$

A strategy for reducing the searching space for generation limits is performed by searching between the minimum and maximum individual limits to new space searching space. This strategy helps the agent in the detection of early convergence of the optimality problem. The maximum and minimum individual limits can be updated from:

$$\begin{cases} (PG_{k,i}^{\max} = PG_{k,i}^{\max} - \delta(PG_{k,i}^{\max} - PG_{k,i}^{Gbest}) \\ PG_{k,i}^{\min} = PG_{k,i}^{\min} + \delta(PG_{k,i}^{Gbest} - PG_{k,i}^{\min}) \end{cases} \quad (22)$$

Equations 17 to 22 are used for updating the current, personal best and global positions of Nind-individuals. The need to adjust the learning coefficient leads us to modify the conventional PSO to MPSO version. The MPSO reduces the conventional PSO to a single experience term. The proposed updating formula of the MPSO can be written as:

$$\Delta PG_{i,k} = W.\Delta PG_{i,k} + C_m \left(PG_{i,k} / PG_{i,k}^{Gbest} \right) ((PG_{i,k}^{Gbest} + PG_{i,k}^{Pbest} - 2PG_{i,k}) \quad (23)$$

where, $PG_{k,i}$ is the power generator i at iteration k.

$\Delta PG_{k,i}$ is the change in power generator i at iteration k.

$PG_{i,k+1}$ is the power generator i at iteration k+1.

$PG_{k,i}^{Pbest}$ is the personal best of power generator i, iteration k.

$PG_{k,i}^{Gbest}$ is the global best of power generator i at iteration k.

$PG_{k,i}^{\max}$ is the maximum limit of generation i at iteration k.

$PG_{k,i}^{\min}$ is the minimum limit of power generator i at iteration k.

$T_{k,i}^{\max}$ is the maximum transition of power generator i at iteration k.

$T_{k,i}^{\min}$ is the minimum transition of power generator i at iteration k.

k_m is the transition factor.

δ is the reduction space factor.

W is the inertia factor of updating formula.

$W^{\min}$ and $W^{\max}$ are the minimum and maximum inertia factors.

Iter is the iteration number.

Iter max is the maximum iteration number.

C_1, C_2 and C_m are the learning coefficients of the self experience, the group experience and the modified experience terms, respectively.

R_1 and R_2 are random values in the range (0,1).

Nind is the number of individuals of the PSO versions.

5. APPLICATIONS

Test Systems

The 5-bus [18], and IEEE 57-bus test systems [19] are used for an extensive study of the proposed modified techniques. The power flow calculations are performed using MATPOWER 3.0 [19]. The line diagram for the 5-bus test system is illustrated in Figure 1 [18]. While, the transmission lines and buses data are presented in Tables 1 and 2, respectively. A real system of the Unified Egyptian Network (UEN) is also used to show the capability of the proposed technique. The Delta network consists of 52-bus and 108 transmission lines. Eight generation substations are located at buses 1-8. The system data for buses and transmission lines are reported in the Appendix. MATPOWER version 3.0 package [19] and MATLAB 6.5 Software are used to perform the required computation.

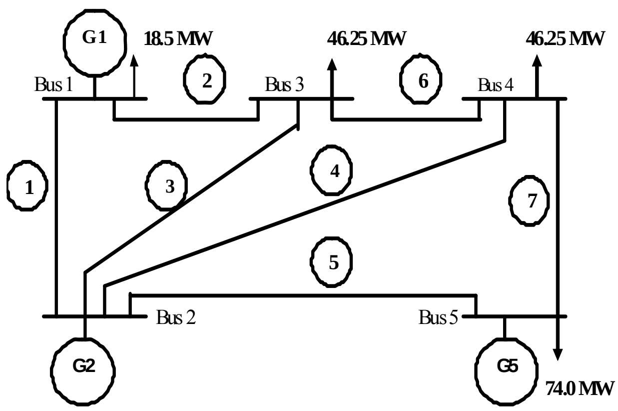

Fig. 1. The line diagram for the 5-bus test system

Table 1. Five-bus test system transmission line data

Line No.	From	To	Impedance Z	Line Charge Y/2
1	1	2	0.02+j 0.06	j 0.030
2	1	3	0.08+j 0.24	j 0.025
3	2	3	0.06+ j 0.18	j 0.020
4	4	2	0.06+j 0.18	j 0.020
5	2	5	0.04+j 0.12	j 0.015
6	3	4	0.01+j 0.03	j 0.010
7	4	5	0.08+j 0.24	j 0.025

Table 2. Five-bus test system bus data

Bus No.	PG (MW)			Load Demand (MW)
	Maximum	Minimum	Initial	
1	120	10	90.44	18.5
2	90	10	60	0
3	0	0	0	46.25
4	0	0	0	46.25
5	60	10	40	74.0

6. RESULTS AND COMMENTS

Table 3 shows a comparison between the GGDF [1] and the proposed MSF applied on 5-bus test system. The proposed MSF re-allocates the responsibilities of the individual generation in the power flows of transmission lines. Using the GGDF, the power flow in transmission line 1 is affected by 64.03% of G_1 only. The power flow components due to generations G_2 and G_5 are in the opposite direction of the power flow in this line due to G1. While, the power flow in transmission line 1 is affected by 20.58%, 12.79% and 15.35% due to G_1, G_2 and G_5, respectively. Only line No. 7 has negative MSF for all generators according to the direction of flow in that line. The proposed MSF allocates different levels of responsibility that related to the direction of the power flows in transmission network.

Table 3. A compassion between GGDF and suggested MSF for 5-bus test system

Line No.	GGDF			Proposed MSF		
	G_1	G_2	G_3	G_1	G_2	G_3
1	0.6403	-0.2061	-0.1506	0.2058	0.1279	0.1535
2	0.2660	0.1077	0.0500	0.1906	0.1185	0.1421
3	0.1315	0.2026	0.1071	0.1736	0.1079	0.1295
4	0.1553	0.2120	0.0910	0.1827	0.1136	0.1363
5	0.3395	0.3673	-0.3609	0.1537	0.0955	0.1147
6	0.1435	0.0572	-0.0957	0.0554	0.0344	0.0413
7	0.0523	0.0237	-0.2497	-0.0614	-0.0382	-0.0458

Table 4 compares the power flows computed using the GGDF and the proposed MSF applied to 5-bus test system with the results of load flow solution solved by the NR method [18]. The power flows computed with the proposed MSF are near to the power flows calculated by the NR method for small changes in the power generation.

Table 4. A comparison between the load flow solution using different methods for 5-bus system

Line No.	NR Load flow	GGDF	MSF
1	15.956	20.667	15.919
2	27.711	28.702	27.647
3	29.514	29.257	29.446
4	30.98	30.812	30.908
5	33.369	33.485	33.292
6	8.9514	9.4903	8.9307
7	-6.9425	-6.7605	-6.9264

Tables 3 and 5 show comparison studies between the proposed MSF and the GGDF for different emergency conditions. So, the proposed MSF can be considered as alternative sensitivity factors instead of the GGDF.

Table 5. A compassion between GGDF and suggested MSF for 5-bus test system when line 2 is outage

Line No.	GGDF			MSF		
	G_1	G_2	G_5	G_1	G_2	G_5
1	0.900	-0.105	-0.108	0.250	0.310	0.137
2	0.000	0.000	0.000	0.000	0.000	0.000
3	0.251	0.250	0.128	0.222	0.275	0.122
4	0.251	0.250	0.108	0.218	0.271	0.120
5	0.385	0.384	-0.355	0.234	0.291	0.129
6	0.000	-0.001	-0.122	-0.024	-0.030	-0.013
7	0.000	0.000	-0.263	-0.051	-0.064	-0.028

Tables 4 and 6 show the power flows computed by the GGDF and the proposed MSF compared to NR load flow method for 5-bus test system with the results of load flow solution which based on NR method. The power flows computed by the proposed MSF are close to the power flows calculated by the NR power flow method for small incremental changes in the power generation.

Table 6. A comparison between the load flow solution using different methods when Line 2 is outage

Line No.	NR Load flow	GGDF	MSF
1	44.186	49.428	43.98
2		Outage	
3	42.048	42.113	41.852
4	41.165	41.23	40.973
5	38.978	39.076	38.796
6	-5.6016	-5.6001	-5.5755
7	-12.001	-12.001	-11.945

Table 7. A comparison between GGDF and suggested MSF when Line 6 is outage

Line No.	GGDF			MSF		
	G_1	G_2	G_5	G_1	G_2	G_5
1	0.689	-0.189	-0.192	0.120	0.150	0.067
2	0.210	0.084	0.084	0.126	0.157	0.070
3	0.042	0.167	0.167	0.119	0.150	0.066
4	0.250	0.249	0.026	0.200	0.251	0.111
5	0.384	0.383	-0.396	0.224	0.280	0.124
6			Outage			
7	0.000	0.001	-0.222	-0.042	-0.053	-0.024

Tables 7 and 8 compare the power flows computed by the GGDF and the proposed MSF with the NR load flow method when line 6 is outage from the 5-bus test system. The power flows computed with the proposed MSF are close to the power flows computed by the NR power flows for small incremental changes in the power generation.

Table 8. A comparison between the load flow solution using different methods when Line 6 is outage

Line No.	NR Load flow	GGDF	MSF
1	19.693	24.622	19.649
2	23.952	24.743	23.899
3	23.738	23.143	23.685
4	37.169	37.367	37.087
5	36.724	37.029	36.643
6		Outage	
7	-10.032	-10.03	-10.009

Tables 9 and 10 show the effects of MPSO on the convergence and optimal dispatch solution of the generation costing model considering the MSF. In Table 9A, the optimal dispatch results are presented based on the MPSO at total load demand equals to 180 MW considering the both of GGDF and MSF factors for 5-bus test system It is founded that, more economical solutions are achieved with the proposed MSF factors. The optimal generation costs are 372.12 $/hr using the MSF. The use of GGDF leads to generation costs of 384.25 $/hr. More reserve levels are obtained from transmission network that can be used to remove the effects of different congestion events. It is found that, the security of power flows margin is increased compared to their limits.

Table 9A. Results of generation dispatch using MPSO Model for 5-bus test system at total power demand equals to 180 MW

Variables	Maximum limits	GGDF	MSF
PG_1 (MW)	120	89.655	113.09
PG_2 (MW)	90	61.828	64.41
PG_5 (MW)	60	36.017	10.00
PF_1 (MW)	40	37.69	14.37
PF_2 (MW)	32	31.762	27.40
PF_3 (MW)	30	27.678	29.62
PF_4 (MW)	45	29.763	31.25
PF_5 (MW)	45	39.54	38.72
PF_6 (MW)	40	12.624	9.90
PF_7 (MW)	12	-3.075	-4.60
Gen. Costs $/hr		384.25	372.12

Table 9B. Results of generation dispatch using MPSO Model for 5-bus test system at total load demand equals 180 MW and Line 6 outage

Variables	Maximum limits	GGDF	MSF
PG_1 (MW)	120	83.52	94.65
PG_2 (MW)	90	62.05	56.04
PG_5 (MW)	60	41.94	36.81
PF_1 (MW)	40	37.44	17.32
PF_3 (MW)	30	20.37	21.75
PF_4 (MW)	45	37.07	35.62
PF_5 (MW)	45	39.54	39.71
PF_6 (MW)	40	Outage	
PF_7 (MW)	12	-8.73	-7.51
Gen. costs $/hr		387.98	379.98

Also, Table 9B compares the results of the optimal power dispatch of generation companies considering the outage of line 6, while, the total power demand equals to 180 MW. The use of the proposed MSF leads to minimize the total generation costs (379.98 $/hr) compared to the GGDF (387.98 $/hr) for 5-bus test system.

In Table 10, the BMPSO version is used to minimize the production costs for 57-bus test system. The use of the proposed MSF leads to minimize the total generation costs from (65056.0 $/hr) to (63207$/hr) using the GGDF. While, the use of the proposed MPSO version considering the proposed MSF leads to the more reduction in the total generation costs from (63720.0 $/hr) to (61528 $/hr) calculated by the GGDF. Added to that solution, the power flow constraints are satisfied and the congestion constraints are considered for transmission network.

Table 10. A comparison between generation dispatch using BPSO and MPSO at total load demand equals to 1630.8 MW

Variables (MW)	Max limits	BPSO		MPSO	
		GGDF	MSF	GGDF	MSF
PG_1	350	299.72	154.080	334.79	81.869
PG_2	200	146.36	156.290	119.71	129.790
PG_5	300	186.36	196.290	159.71	169.790
PG_8	200	146.36	156.290	119.71	129.790
PG_9	450	295.66	401.540	367.15	579.790
PG_{11}	200	146.36	156.290	119.71	129.790
PG_{13}	410	410.00	410.000	410.00	410.000
PF_1	350	311.67	254.890	343.43	250.19
PF_2	250	-106.84	-153.66	-101.79	-184.96
PF_3	60	44.249	-1.983	39.424	-45.594
PF_4	150	-104.07	-125.690	-101.06	-139.240
PF_{78}	75	-11.051	-12.498	-11.563	-14.330
PF_{79}	50	-2.845	-2.694	-2.960	-2.721
PF_{80}	100	-27.142	-34.421	-28.210	-41.687
Gen. Cost $/hr		65056	63207	63720	61528

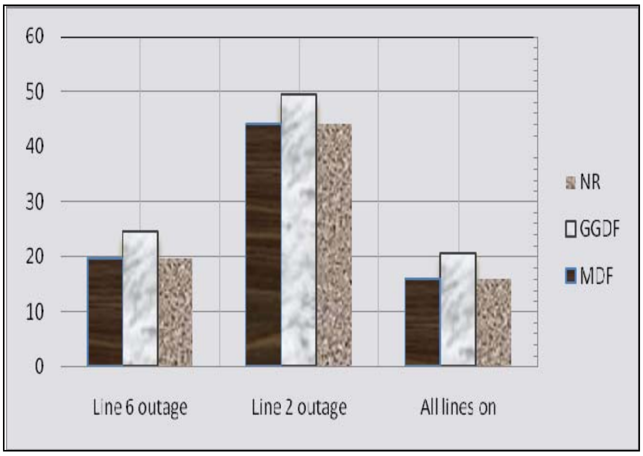

Fig. 2. Comparison between the power flows in Line 1 for different operating conditions

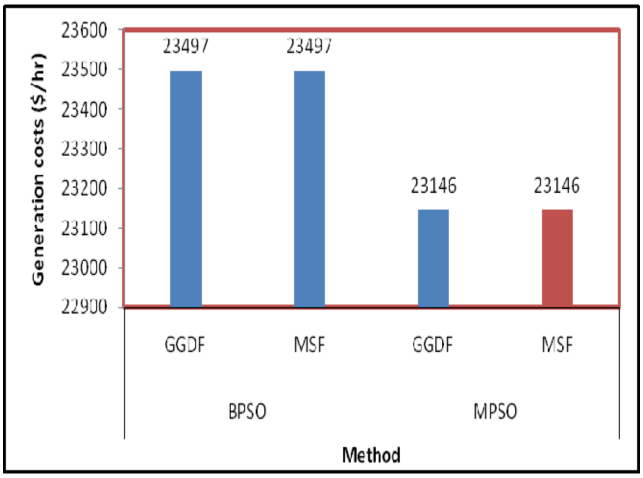

Fig. 3. A comparison between the total generation costs using different methods for real system

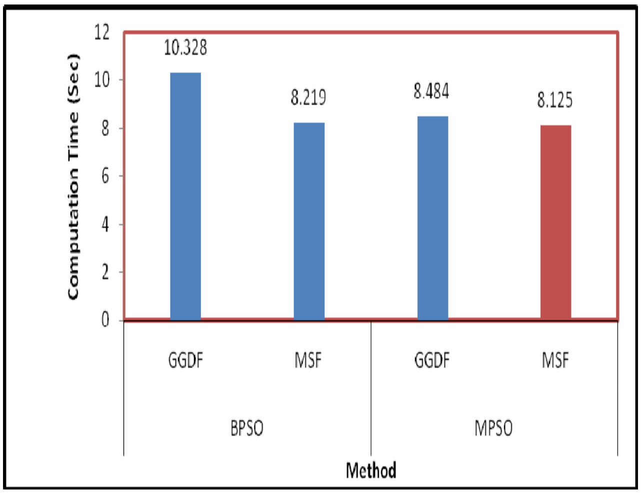

Fig. 4. A comparison between the computation times using different methods for real system

Application to Real System UEN (Delta 66 KV)

To show the superiority of the proposed MSF, a real application is carried out using a part of the Unified Egyptian Network (UEN) at Delta region. The full data of the Delta region network are reported in the appendix. The MPSO model is successively applied to solve the optimal power dispatch model to obtain economic solutions using the proposed sensitivity factors. At the same time, the power flows in the transmission circuits are within their maximum limits.

Table 11 shows the results of the proposed PSO versions for the real system. It is founded that: the appropriate selection of PSO parameters for the values of coefficients C_1, C_2 , C_m , k and δ leads to more economic solutions. The optimal dispatch results are presented based on the MPSO for the real system at total power demand of 889.76 MW considering the both of GGDF and MSF. However, more economical solution are achieved using the proposed MPSO related to the MSF compared with GGDF. The generation costs are minimized to be 23456 $/hr using the MSF compared to that obtained using the GGDF (23156 $/hr). More reserve levels are obtained from the transmission network using the MPSO of different congestion events. A minimum computation time is (8.125 sec) using the MPSO compared to the BPSO (8.48 sec).

Table 11. The results for the real system at total load demand equals to 889.76MW

Variables	BPSO		MPSO	
	GGDF	MSF	GGDF	MSF
PG_1	179.76	179.76	251.39	251.39
PG_2	84.758	84.758	44.911	44.911
PG_3	179.76	179.76	251.39	251.39
PG_4	84.758	84.758	44.911	44.911
PG_5	179.76	179.76	251.39	251.39
PG_6	84.758	84.758	44.911	44.911
PG_7	86.188	86.188	-9.1413	-9.1413
PG_8	10	10	10	10
PF_1	45.365	57.511	72.793	65.211
PF_4	26.103	41.114	43.614	46.619
PF_5	14.377	13.54	14.377	15.353
PF_{24}	-12.92	-18.58	-33.12	-21.07
PF_{25}	9.85	9.28	9.85	10.52
PF_{47}	23.63	26.38	15.23	29.91
PF_{48}	-23.49	-3.91	-62.87	-4.44
PF_{65}	14.62	14.14	14.54	16.03
PF_{66}	27.50	26.45	27.39	29.99
PF_{96}	11.48	14.94	2.81	16.94
PF_{97}	1.00	5.07	-7.72	5.75
PF_{100}	-1.57	2.63	-10.64	2.98
PF_{104}	11.95	11.34	12.88	12.86
PF_{105}	4.62	4.38	4.93	4.97
PF_{108}	0.05	0.05	0.13	0.06
Costs $/hr	23497	23497	23146	23146
Time Sec	10.33	8.22	8.48	8.125

7. CONCLUSION

In this paper, accurate modified distribution factors have been successively presented to compute the transmission power flows in terms of the buses injected power. The proposed MDF have been efficiently applied to optimal power dispatch problem. The advantages of the proposed MDF are: simplicity, dependent on the actual measurements of power flows and injected power, independent on the selection of the slack bus, dependent on the actual bus voltages and considering the line resistance. The use of the proposed MDF leads to fair allocation of the responsibility of different network users in the deregulated power systems. Also, a MPSO version has been successively applied to solve the optimal power dispatch problem. The MPSO version reduces experience terms to single compact term which leads to more economic solutions at lower computation time compared to BPSO version.

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APPENDIX

Real System (West Delta region 66 KV) Data

A real system at delta region is a part of the Unified Egyptian Network which consists of 52-bus, 8 generation buses and 108 transmission lines. In Table A1, the initial power generation, minimum and maximum limits and the generation cost function coffients are presented. Table A2 presents the buses power demand and the initial bus voltages. While,the data of the transmission lines are reported in Table A3. The KV base is 66 while the MVA base is 100.

Table A1. Real system generation data

Bus No.	$PG^{(o)}$ MW	PG^{max} MW	PG^{min} MW	a	b	c
1	99.56	250	10	0.00921	18	0
2	157.4	250	10	0.00617	25	0
3	139.31	250	10	0.00617	20	0
4	113.69	250	10	0.00617	20	0
5	166.48	375	10	0.00617	35	0
6	31.71	250	10	0.00522	30	0
7	92	250	10	0.00921	32.5	0
8	122.49	250	10	0.00921	32.5	0

Table A2. Real system region bus data

Bus No.	PD (MW)	QD (MVAR)	Voltage (pu)	Angle (deg)
1	0	0	1.05	0
2	12.57	3	1	-1.219

3	38.71	18.48	1	-0.80829
4	36.14	34.84	1	1.0391
5	20.07	5.22	1	-10.888
6	31.71	20.85	1	-10.787
7	89.86	46.82	1	-9.2957
8	0	0	1	-9.8774
9	15	12.75	1.048	-0.09402
10	15	12.75	1.047	-0.13753
11	1.94	0.58	1.021	-1.4166
12	15	12.75	1.035	-0.44825
13	13.09	9.96	0.981	-4.2631
14	8.92	6.38	1	-1.0482
15	3.76	2.32	0.991	-1.9414
16	5	2.31	0.99	-1.4932
17	15.41	8.1	0.995	-1.0318
18	29.8	18.85	0.974	-2.5344
19	24.57	15.03	0.971	-1.8647
20	29.25	17.59	0.977	-2.6198
21	26.64	14.25	0.978	-2.6958
22	2.71	1.55	0.99	-2.0367
23	20.94	13.43	0.998	0.060535
24	24.34	17.17	0.989	0.81652
25	9.4	7.99	0.987	0.78873
26	20.6	17.51	0.999	1.0059
27	24.96	16.17	1	1.0384
28	16.95	9.4	1.005	-2.2084
29	6.25	5.05	0.99	-3.3245
30	2.9	1.42	0.96	-6.9659
31	23.06	13.37	0.971	-10.007
32	12.96	5.92	0.936	-7.8098
33	39.24	33.354	0.96	-11.595
34	0.09	0.14	0.976	-11.733
35	15.17	7.51	0.945	-12.146
36	30.2	16.38	0.982	-11.455
37	14.93	7.2	0.991	-11.37
38	6.84	3.61	0.979	-11.634
39	24.96	16.17	0.979	-11.438
40	13.57	6.8	0.99	-10.703
41	6.2	2.9	0.991	-10.867
42	17.31	8.22	0.993	-9.9955
43	25	18	0.963	-10.952
44	21.86	8.94	0.954	-11.294
45	5.42	1.1	0.953	-11.351
46	18.02	12.03	0.952	-11.507
47	16.17	9.06	0.978	-10.613
48	8.3	3.8	0.899	-13.619
49	15.14	7.3	0.86	-15.31
50	9.7	4	0.861	-15.33
51	0.12	0.06	0.999	-9.9196
52	4	1.6	0.991	-10.301

Table A3. Real system transmission lines data

Line No.	from	to	r (p. u.)	X (p. u.)	Y/2 (p. u.)	Maximum Limits (MW)
1	1	11	0.0405	0.1173	0.0032	120
2	1	11	0.0405	0.1173	0.0032	120
3	1	12	0.0471	0.2231	0.0062	200
4	1	12	0.0471	0.2231	0.0062	200
5	1	10	0.0087	0.0402	0.0029	80
6	1	9	0.0087	0.0402	0.0023	80
7	2	13	0.0436	0.2095	0.0115	200
8	2	13	0.0436	0.2095	0.0115	200
9	2	12	0.0785	0.3977	0.0310	200
10	2	12	0.0785	0.3977	0.0310	200
11	2	14	0.0105	0.0482	0.0028	200
12	2	14	0.0105	0.0482	0.0028	200
13	3	17	0.0080	0.0370	0.0026	200
14	3	17	0.0080	0.0370	0.0026	200
15	3	16	0.0270	0.1245	0.0071	200
16	3	16	0.0270	0.1245	0.0071	200
17	3	14	0.0803	0.3696	0.0106	200
18	3	14	0.0803	0.3696	0.0106	200

19	3	15	0.0919	0.4234	0.0181	200
20	3	15	0.0919	0.4234	0.0181	200
21	4	25	0.0929	0.1414	0.0092	50
22	4	24	0.0465	0.0707	0.0046	50
23	4	23	0.0349	0.1676	0.0092	200
24	4	23	0.0349	0.1676	0.0092	200
25	4	26	0.0014	0.0040	0.0002	150
26	4	26	0.0014	0.0040	0.0002	150
27	4	27	0.0087	0.0402	0.0029	150
28	5	36	0.0723	0.2095	0.0143	150
29	5	36	0.0723	0.2095	0.0143	150
30	5	33	0.0871	0.1326	0.0086	80
31	5	33	0.0871	0.1326	0.0086	80
32	5	34	0.0651	0.1885	0.0103	150
33	5	34	0.0651	0.1885	0.0103	150
34	5	31	0.0477	0.1398	0.0057	200
35	5	31	0.0477	0.1398	0.0057	200
36	5	37	0.0345	0.1591	0.0045	80
37	5	37	0.0345	0.1591	0.0045	80
38	6	40	0.0304	0.1085	0.0024	80
39	6	40	0.0304	0.1085	0.0024	80
40	6	36	0.0174	0.0503	0.0041	150
41	6	36	0.0174	0.0503	0.0041	150
42	6	41	0.0148	0.0683	0.0059	200
43	6	41	0.0148	0.0683	0.0059	200
44	6	42	0.0349	0.1607	0.0092	200
45	6	42	0.0349	0.1607	0.0092	200
46	7	43	0.0201	0.0924	0.0066	200
47	7	43	0.0201	0.0924	0.0066	200
48	7	42	0.0145	0.0419	0.0023	80
49	7	42	0.0145	0.0419	0.0023	80
50	8	41	0.0209	0.0964	0.0055	200
51	8	41	0.0209	0.0964	0.0055	200
52	8	52	0.0017	0.0080	0.0005	200
53	8	52	0.0017	0.0080	0.0005	200
54	8	46	0.0688	0.1994	0.0082	150
55	8	46	0.0688	0.1994	0.0082	150
56	8	47	0.0116	0.0335	0.0009	150
57	8	47	0.0116	0.0335	0.0009	150
58	11	28	0.0231	0.0670	0.0055	150
59	11	28	0.0231	0.0670	0.0055	150
60	13	29	0.0607	0.1687	0.0096	150
61	13	29	0.0607	0.1687	0.0096	150
62	13	30	0.0521	0.1446	0.0062	150
63	13	30	0.0521	0.1446	0.0062	150
64	15	22	0.0080	0.0370	0.0026	200
65	15	22	0.0080	0.0370	0.0026	200
66	16	18	0.0436	0.2009	0.0086	200
67	16	18	0.0436	0.2009	0.0086	200
68	17	19	0.0521	0.1508	0.0083	150
69	17	19	0.0521	0.1508	0.0083	150
70	18	20	0.0340	0.1567	0.0112	200
71	18	20	0.0340	0.1567	0.0112	200
72	20	21	0.0427	0.1969	0.0141	200
73	20	21	0.0427	0.1969	0.0141	200
74	21	22	0.0584	0.2692	0.0231	200
75	21	22	0.0584	0.2692	0.0231	200
76	23	14	0.0602	0.2772	0.0238	200
77	23	14	0.0602	0.2772	0.0238	200
78	24	25	0.0465	0.0643	0.0037	50
79	28	29	0.0492	0.1424	0.0098	150
80	28	29	0.0492	0.1424	0.0098	150
81	30	32	0.0304	0.0880	0.0072	200
82	30	32	0.0304	0.0880	0.0072	200
83	30	31	0.0523	0.2410	0.0069	150
84	30	31	0.0523	0.2410	0.0069	150
85	35	36	0.1394	0.2121	0.0110	80
86	35	36	0.1394	0.2121	0.0110	80
87	37	38	0.1162	0.1768	0.0115	80
88	37	38	0.1162	0.1768	0.0115	80
89	38	39	0.1162	0.1768	0.0115	80
90	38	39	0.1162	0.1768	0.0115	80
91	40	42	0.0434	0.1257	0.0052	80

92	40	42	0.0434	0.1257	0.0052	80
93	41	39	0.0171	0.0787	0.0056	150
94	41	39	0.0171	0.0787	0.0056	150
95	43	44	0.0072	0.0209	0.0014	150
96	43	44	0.0072	0.0209	0.0014	150
97	44	45	0.0064	0.0184	0.0010	150
98	44	45	0.0064	0.0184	0.0010	150
99	45	46	0.0723	0.2095	0.0143	150
100	45	46	0.0723	0.2095	0.0143	150
101	47	48	0.0680	0.1969	0.0162	150
102	47	48	0.0680	0.1969	0.0162	150
103	48	49	0.0492	0.1424	0.0098	150
104	48	49	0.0492	0.1424	0.0098	150
105	49	50	0.0523	0.2410	0.0138	80
106	49	50	0.0523	0.2410	0.0138	80
107	49	51	0.0174	0.0803	0.0034	150
108	49	51	0.0174	0.0803	0.0034	150