Electrical Power and Energy Systems 64 (2015) 250–259

Contents lists available at ScienceDirect

Electrical Power and Energy Systems

journal homepage: www.elsevier.com/locate/ijepes

Centralized and decentralized optimal decision support for congestion management

Brijesh Singh, R. Mahanty, S.P. Singh *

Department of Electrical Engineering, Indian Institute of Technology (Banaras Hindu University), Varanasi 221005, India

ARTICLE INFO

Article history:
Received 24 July 2013
Received in revised form 18 June 2014
Accepted 6 July 2014

Keywords:
AC optimal power flow
Decentralization
Open access
Optimal pricing
Power market
Security constrained optimal power flow

ABSTRACT

This paper presents a framework to carry out optimal power flow in a coordinated multi-transaction/utilities decentralized system. An AC power flow model has been used in this work for independent optimal dispatch of each utility. The global economic optimal solution of the whole electric energy system with congestion management has also been done in this work using the interior point (IP) optimization procedure. In this approach, each participant tries to maximize its own profit with the help of information announced by the operator which are information related to system security constraints and public issues. The developed algorithm can be run in parallel, either to carry out numerical simulations or to obtain an optimal generation schedule in an actual multi-utility electric system. The study has been conducted on a three utility modified IEEE-30 bus system with two market models and six utility modified IEEE-118 bus system. The results clearly show the effectiveness of the suggested IP optimization based optimal generation schedule in decentralized scenario. It has been demonstrated that the suggested decentralized approach produces improved optimal dispatch solution with enhanced market benefits and can effectively manage the congestion in the system as compared to the centralized approach.

Introduction

The congestion management is one of the most challenging operational problems with open access transmission. The power system is said to be congested if the transmission network is operated at or beyond one or more transfer limits [1]. Because of the present trends of bilateral and multilateral contracts in the electricity market, the role of independent system operator (ISO) is increasing. Under this new scenario, the role of ISO is to create a set of rules that ensure sufficient control over producers and consumers to maintain an acceptable level of power system security and reliability [2]. As such, in a tight pool market, ISO has constraints to operate the system without the violation of operational constraints. Due to this, all the market participants are bound by some rules of coordination. For a better competition in the market, it is essential that all the participants are free to optimize their own profits. Hence, a decentralized decision making based methodology can play a vital role in market competition [3]. As the electric power industry is undergoing restructuring, it results into higher degree of decentralized decision making in the power system. This change has been affecting long term expansion planning of independent investors with less centralized coordination. After the restructuring of the electric power industry, profit generating companies have been developed to deliver electric energy in a competitive market. In such a case, independent regulated transmission system operators (TSOs) manage the operation of the transmission system. The congestion management is one of the central issues of centralized optimal power flow (COPF) [4,5]. The recent trends in electricity market are towards large multinational electricity markets, such as, the internal electricity market (IEM) in Europe. However, there are technical and economic challenges in the operation of a single joint market by combining different regional electricity markets. If an individual market optimizes its own electricity market without coordinating with its neighbouring markets, seam issues arise among regional electricity markets. In multiple market environments, seam issues lead to market inefficiency in the operation of the combined markets. Hence, a decentralized approach is needed to facilitate economically efficient and viable energy trading among regional electricity markets [6].

A decentralized model partitioned by tie-line between individual markets has been proposed for coordinating trading between regional electricity markets [7]. The tie-line information is exchanged at the end of each iteration, until the final convergence is achieved. Different decomposition methods for dividing the interconnected electricity markets into individual markets have also been introduced [8]. After decomposition the single joint

* Corresponding author. Tel.: +91 9415336705.
E-mail addresses: singhb1981@gmail.com (B. Singh), mahantyr@yahoo.co.in (R. Mahanty), spsingh.eee@itbhu.ac.in (S.P. Singh).

http://dx.doi.org/10.1016/j.ijepes.2014.07.026
0142-0615/

market, a decentralized approach to congestion management in interconnected markets has been proposed [9,10]. An efficient economic dispatch in competitive electricity market has been analyzed to solve seam problems and establishing the theory of duality and decomposition in mathematical programming [11]. As the demand for deregulation of electric utilities is on the rise, the selection of objective function for optimization of economic system operation is becoming more critical. The conventional benefit optimizations have been mainly based on economic dispatch that enables to achieve cost minimization in a single utility environment [12,13]. Currently, many of these issues are being played out in real time with the privatization of power system. This is particularly relevant in multi-utility or multi-country setting. In order to achieve economical optimal dispatch of the whole power system, a small interchange of information is sufficient among the involved utilities or countries to obtain a global solution instead of setting up a common control centre [14]. Decentralized optimal power flow (DOPF) algorithm is an iterative algorithm in which the TSO of each region iteratively solves a modified optimal power flow (OPF) sub-problem for its own region and exchanges tie-line information with the TSOs of neighbouring regions [14–16]. The congestion pricing and cost allocation based transmission congestion management in decentralized approach to maximize the profit independently has been reported in [17,18].

Recently, researchers have shown interest in including the demand to maximize the market profit. Also, the demand limits are incorporated with objective function of problems. In the early days of deregulation, customers did not have effective participation in power markets, and therefore, they were not able to respond to the prices effectively. However, to have a complete competitive market, there should be enough motivations for customers to participate in power market operations [19–26].

The present investigation deals with the congestion management using decentralized and centralized approaches. The model reported in present work, though similar to [11,22], include transmission losses cost in the objective function; however the solution is obtained by interior point (IP) method. The IP has been applied to solve large-scale OPF problems in recent past [27–34]. In IP based OPF, the computation of gradient, Jacobian and Hessian matrices of objective functions are constraint functions. The basic property of IP to cut the solution space across the interior points has been exploited in this work to achieve faster solution. In this work, the accuracy of the decentralized approach is authenticated by comparing its results with that of centralized approach. Modified IEEE-30 and IEEE-118 bus systems have been used to show the performance of the proposed method. The test results reveal that the proposed method yields superior results as compared to the results reported in [11,22].

Mathematical formulation

Two market models have been proposed for the congestion management in literature, namely COPF and DOPF. In COPF, the lack of transparency of market participants is bounded by centralized authority and thus becomes a superpower. This is not considered as an appropriate approach for a healthy competitive market. On the other hand in DOPF model the participants are free to optimize their own profits. In the following sections of this work, the mathematical models of these two markets have been formulated and discussed.

Centralized optimal power flow market model

In COPF, forward contract market for real power is mainly based on dc load flow based solution. In a perfect competitive market, the ISO adjusts the contracts to maximize the benefit and social welfare to achieve efficient operation with all constraints satisfied. With this assumption, the mathematical model of COPF is given by

$$max\ f(P_{D_j}, P_{G_i}) = \sum_{j=1}^{N_d} B_j(P_{D_j}) - \sum_{i=1}^{N_g} C_i(P_{G_i}) \tag{1}$$

subject to

$$\sum_{i=1}^{N_g} P_{G_i} - \sum_{j=1}^{N_d} P_{D_j} - P_{loss} = 0 \tag{2}$$

$$P_{G_i}^{min} \le P_{G_i} \le P_{G_i}^{max} \tag{3}$$

$$Q_{G_i}^{min} \le Q_{G_i} \le Q_{G_i}^{max} \tag{4}$$

$$P_{D_j}^{min} \le P_{D_j} \le P_{D_j}^{max} \tag{5}$$

$$P_{ij} \le P_{ij}^{max} \tag{6}$$

where N_g is the number of generator buses; N_d is number of demand buses; P_{G_i} is active power output of ith generator; Q_{G_i} is reactive power output of ith generator; P_{D_j} is active power demand of jth consumer; P_{loss} is active power loss; B_j is benefit function of jth consumer; C_i is cost function of generator i; P_{ij} is active power flow of transmission line between buses i and j; and P_{ij}^{max} is the maximum active power flow limit of transmission line between buses i and j in MW.

The objective of (1) is to maximize the total benefit and social welfare of the system. The first term of (1) represents the demand cost and second term represents the generation cost of all generator buses. The equality constraint in (2) denotes the active power balance for each utility considering the losses. The inequality constraints in (3) and (4) denote the output active and reactive power limits of the generators. The demand limits of consumers are represented in (5), which also includes the problem of congestion management. Inequalities constraints represented in (6) denote the line capacity limits. The power flow in lines due to various transactions has been obtained using the power transfer distribution factor used in [35].

Decentralized optimal power flow market model

The COPF model (1)–(6) are converted into DOPF model by rewriting them into simpler form by redefining the decision variables of contract $u^k = f(P_{G_i}^k, P_{D_j}^k)$ for kth utility, where $k \varepsilon T$. Taking (7) into consideration, the welfare related to utility k can be defined as

$$w^k(u^k) = \sum_{\substack{j=1 \\ j \in D(k)}}^{N_d} B_j^k\left(P_{D_j}^k\right) - \sum_{\substack{i=1 \\ N_g \neq N_{g\,slack} \\ i \in G(k)}}^{N_g} C_i^k\left(P_{G_i}^k\right) - C_{N_{gslack}}(P_{G_{slack}}) \tag{7}$$

where $D(k)$ is the set of consumers in utility k; $G(k)$ is set of generators in utility k; $N_{g\ slack}$ is slack bus number index; $P_{G_i}^k$ is active power output of ith generator in utility k; $P_{D_j}^k$ is active power demand of jth consumer in utility k; $P_{G_{slack}}$ is active power output of slack bus generator; P_{loss}^k is active power loss due to kth utility; B_j^k is benefit function of jth consumer in utility k; C_i^k is cost function of ith generator in utility k; and $C_{N_{g\,slack}}$ is the cost function of slack bus generator.

In decentralized model, the cost of slack bus generator has been taken separately in order to incorporate the cost of power supplied by the slack bus due to losses in multi-utility market operation. In fact, the losses incurred would be supplied by the slack bus generator. Thus, the last term of the objective function can be utilized for evaluating the cost of losses due to various utilities. The last term of (7) represents the cost of slack bus generation. However, the power loss cost is ignored from the objective function in [11,22]. The generation of various generators in each utility has been optimally allocated in such a way that none of the generators and transmission lines violate their limits. Further all the local constraints of individual contracts are not interactive among utilities. In decentralized market, maximum transfer capability of transmission lines for individual utilities has been allocated using an optimal resource allocation index [11]. If $P_{ij}^{k\,max}$ is maximum allocated transfer capacity of the ijth line due to kth utility then

$$P_{ij}^{k\,max} = P_{ij}^{max} * \alpha_{ij}^{k} \tag{8}$$

where α_{ij}^{k} is the optimal resource allocation index for ijth line due to kth utility which is defined as

$$\alpha_{ij}^{k} = \frac{\partial P_{ij}}{\partial w^{k}} \tag{9}$$

In situations, when the COPF problem changes, the original DOPF model can be presented as

$$max \sum_{k=1}^{T} w^{k}(u^{k}) \tag{10}$$

subject to

$$\sum_{k=1}^{T}\sum_{\substack{i=1\\ i\in G(k)}}^{N_g} P_{g_i}^{k} - \sum_{k=1}^{T}\sum_{\substack{j=1\\ j\in D(k)}}^{N_d} P_{d_j}^{k} - \sum_{k=1}^{T} P_{loss}^{k} = 0 \tag{11}$$

$$P_{g_i}^{k\,min} \le P_{g_i}^{k} \le P_{g_i}^{k\,max} \tag{12}$$

$$Q_{g_i}^{k\,min} \le Q_{g_i}^{k} \le Q_{g_i}^{k\,max} \tag{13}$$

$$P_{d_j}^{k\,min} \le P_{d_j}^{k} \le P_{d_j}^{k\,max} \tag{14}$$

$$\sum_{k=1}^{T} P_{ij}^{k} \le P_{ij\,max} * \alpha_{ij}^{k} \tag{15}$$

$$\sum_{k=1}^{T} \alpha_{ij}^{k} = 1 \tag{16}$$

where T is the total number of utility in the market; and k is the index of each transaction, for all $k \in T$.

The counter flow of power in lines may result into negative α_{ij}^{k}. This equality condition is only true for congested lines.

Solution by interior point method

This method is also known as Karmarkar interior point method [27]. The conventional optimization methods require a large number of iterations to reach to the optimum solution. In fact, in conventional optimization methods for nonlinear programming (NLP), some extreme points are visited before the optimum solution is reached. In the IP based optimization method, a polynomial-time algorithm is used, wherein in the solution process, it cuts across the interior of the solution space resulting into increased effectiveness for extremely large linear programming (LP) [28–31]. In the present work, the idea of the IP method has been used in NLP to formulate a non-linear optimization problem [34]. The problem expressed in (1)–(6) can be expressed as follows for the purpose.

$$\left.\begin{array}{ll} Minimize & f(x) \\ Subject\ to & h(x) = 0 \\ and & g_{min} \le g(x) \le g_{max}. \end{array}\right\} \tag{17}$$

where $f(x)$ represents the social welfare of the system as stated earlier. The function $h(x)$ represents the power flow equations and the function $g(x)$ represents relevant inequality constraints.

The KKT optimal condition of (17) can be written as

$$\Delta_x L = \nabla f(x) - \nabla h(x)^T \lambda + \nabla g(x)^T \pi_1 - \nabla g(x)^T \pi_u = 0 \tag{18}$$

$$\Delta_\lambda L = -h(x) = 0 \tag{19}$$

$$\Delta \pi_1 L = -(-g(x) + z_1 + g_{min}) = 0 \tag{20}$$

$$\Delta \pi_u L = -(g(x) + z_u - g_{max}) = 0 \tag{21}$$

$$\Delta_{z_1} L = Z_1 \pi_1 = 0 \quad \pi_1, Z_1 > 0 \tag{22}$$

$$\Delta_{z_u} L = Z_u \pi_u = 0 \quad \pi_u, Z_u > 0 \tag{23}$$

where z_1, z_u are slack variables and λ, π_1, π_u are the vectors of Lagrange multipliers.

Applying complimentary conditions of (22) and (23), (18)–(21) can be solved by introducing a perturbation factor, $\mu > 0$ in Lagrangian function using a logarithmic barrier given by

$$L_\mu = f(x) - \mu \sum (\ln z_1 + \ln z_u) - \lambda^T h(x) - \pi_1^T (g(x) - z_1 - g_{min}) - \pi_u^T (g(x) + z_u - g_{max}) \tag{24}$$

When the KKT conditions are applied to (24), then (22) and (23) are transformed as

$$\Delta_{z_1} L_\mu = Z_1 \pi_1 - \mu e = 0 \tag{25}$$

$$\Delta_{z_u} L_\mu = Z_u \pi_u - \mu e = 0 \tag{26}$$

where $e = [1, 1, 1, \ldots, 1]^T$ and μ is known as the barrier parameter.

The original complementary conditions are satisfied by forcing the value of μ from a non-zero value to zero value as the iteration proceeds. After including the barrier parameter in (18)–(21), (25) and (26), they are called the perturbed KKT conditions which on applying Newton's method gives

$$\begin{bmatrix} \pi_1 & 0 & Z_1 & 0 & 0 & 0 \\ 0 & \pi_u & 0 & Z_u & 0 & 0 \\ -Z_1 & 0 & 0 & 0 & \nabla_{g(x)}^T & 0 \\ 0 & Z_u & 0 & 0 & -\nabla_{g(x)}^T & 0 \\ 0 & 0 & \nabla_{g(x)} & -\nabla_{g(x)} & \nabla_x^2 L_\mu & -\nabla h(x)^T \\ 0 & 0 & 0 & 0 & \nabla h(x) & 0 \end{bmatrix} \times \begin{bmatrix} \Delta Z_1 \\ \Delta Z_u \\ \Delta \pi_1 \\ \Delta \pi_u \\ \Delta x \\ \Delta \lambda \end{bmatrix} = - \begin{bmatrix} \nabla_{z_1} L_\mu \\ \nabla_{z_u} L_\mu \\ \nabla_{\pi_1} L_\mu \\ \nabla_{\pi_u} L_\mu \\ \nabla_x L_\mu \\ \nabla_\lambda L_\mu \end{bmatrix} \tag{27}$$

where $\nabla_x^2 L_\mu = \nabla_x^2 f(x) - \nabla_x^2 h(x)^T \lambda + \nabla_x^2 g(x)^T \pi_1 - \nabla_x^2 g(x)^T \pi_u$.

The Newton's direction is obtained by solving (22) directly or by solving the reduced system as

$$\begin{bmatrix} H & -J_h^T \\ -J_h & 0 \end{bmatrix} * \begin{bmatrix} \Delta x \\ \Delta \lambda \end{bmatrix} = - \begin{bmatrix} \psi \\ h(x) \end{bmatrix} \tag{28}$$

After finding Δx and $\Delta \lambda$, the variables ΔZ_1, ΔZ_u, $\Delta \pi_1$ and $\Delta \pi_u$ are given by

$$\left.\begin{array}{l} \Delta Z_1 = \nabla g(x)^T \Delta x - \nabla_{\pi_1} L_\mu \\ \Delta Z_u = -\nabla g(x)^T \Delta x + \nabla_{\pi_u} L_\mu \\ \Delta \pi_1 = Z_1^{-1}(-\pi_1 \Delta Z_1 - \nabla_{z_1} L_\mu) \\ \Delta \pi_u = Z_u^{-1}(-\pi_u \Delta Z_u + \nabla_{z_u} L_\mu) \end{array}\right\} \tag{29}$$

Using (29); H, J_h and ψ are reformed as

$$\left.\begin{aligned} &H = \nabla_x^2 L\mu + \nabla g(x)(Z_1^{-1}\pi_1 - Z_u^{-1}\pi_u)\nabla g(x)^T \\ &J_h = \nabla h(x) \\ &\psi = -\nabla_x L_\mu - \nabla g(x)(Z_1^{-1}\pi_1 - Z_u^{-1}\pi_u)\nabla g(x)^T + Z_1^{-1}\nabla_{z_1} L_\mu - Z_u^{-1}\nabla_{z_u} L_\mu \end{aligned}\right\} \tag{30}$$

After computing (30), and then applying the new primal and dual variables theory, the value of μ and the variables $\Delta x, \Delta\lambda, \Delta Z_1, \Delta Z_u, \Delta\pi_1$ and $\Delta\pi_u$ are updated. These updated variables are as follows:

$$\left.\begin{aligned} x^{k+1} &= x^k + \chi_p^k \Delta x \quad & \lambda^{k+1} &= \lambda^k + \chi_d^k \Delta\lambda \\ z_1^{k+1} &= z_1^k + \chi_p^k \Delta z_1 \quad & \pi_1^{k+1} &= \pi_1^k + \chi_d^k \Delta\pi_1 \\ z_u^{k+1} &= z_u^k + \chi_p^k \Delta z_u \quad & \pi_u^{k+1} &= \pi_u^k + \chi_d^k \Delta\pi_u \end{aligned}\right\} \tag{31}$$

where χ_p^k and χ_d^k are step length parameters. The maximum step length has been determined by Newton's direction as follows:

$$\chi_p^k = min\left\{1, \gamma min\left\{-\frac{z_1^k}{\Delta z_1}\Big/\Delta z_1 < 0, -\frac{z_u^k}{z_u}\Big/\Delta z_u < 0\right\}\right\} \tag{32}$$

$$\chi_d^k = min\left\{1, \gamma min\left\{-\frac{\pi_1^k}{\Delta\pi_1}\Big/\Delta\pi_1 < 0, -\frac{\pi_u^k}{\Delta\pi_u}\Big/\Delta\pi_u < 0\right\}\right\} \tag{33}$$

To ensure that the next point satisfies the strict positivity conditions, γ is used as a safety factor. To reduce the complementary gap, the value of μ should be proportional to this gap and can be described as

$$\mu^{k+1} = \sigma^k \frac{\rho^k}{2p} \tag{34}$$

where p is the number of inequality constraints, $\rho^k = (Z_1^k)^T \pi_1^k + (Z_u^k)^T \pi_u^k$ is complementary gap, and σ^k is the centering parameter given by $\sigma^k = max\{0.99\sigma^{k-1}, 0.1\}$ with $\sigma^0 = 0.2$.

Here the convergence of solution is terminated when the norm of right hand side vector scaled by summation of all variables and the complementary gap is sufficiently small. This method is also known as primal dual interior point method.

IPOPF based decentralized congestion management

In optimal resource allocation based method using IPOPF, the ISO tries to optimally allocate the capacity on the basis of the line index for each utility. In the proposed mathematical model, on the basis of initial contracts between all the utilities, the line flow caused by utilities in the congested lines are determined by ISO using PTDF calculations [35]. Then, the ISO determines the resource allocation index α_{ij}^k such as that $\sum_{k=1}^{T}\alpha_{ij}^k = 1$ on the basis of load flow results, wherein the value of α_{ij}^k is initially same for all utilities. Then it is send by ISO to all utilities, out of which the first utility optimizes its own generations and demands using the IP based OPF algorithm. Subsequently, the next utility starts optimizing its own generations and demands schedule after optimizing the first utility. Similarly, each utility optimizes its own schedule and this process continues till all the utilities complete their optimization procedure [17,23].

Test results and discussions

The proposed algorithm is implemented in MATLAB on Intel (R), Core 2 Duo and 2.66 GHz processor. In order to show the effectiveness of the proposed algorithm, a modified multi-utility IEEE-30 bus and IEEE-118 bus systems have been studied.

Market model M_1

In order to make a multi-utility system, the above mentioned modified IEEE-30 bus system is partitioned into three utilities T1, T2 and T3. It is assumed that each utility have three loads and two generators. In this way there are nine demand and six generation bidders altogether. The marginal cost functions of generators and marginal benefit functions of consumers are listed in Table 1 [11], where in generators of buses 13, 27 and load of buses 3, 4, 7 belong to utility T1; generators of buses 1, 22 and load of buses 12, 15, 17 belong to utility T2; and generators of buses 23, 2 and load of buses 24, 26, 27 belong to utility T3 as shown in Fig. 1. It is assumed that remaining generators and load buses of the system are not participating in the market operations. Therefore, the generation or demands of these buses are neglected in the problem formulation. Each utility has its own resource information and all of them have the right to access the information base to obtain the biddings of all the demands for optimizing their own generations.

In this market model, the branches 2–5, 4–12, 6–7 and 25–27 have transfer limits 130, 65, 130 and 16 MW respectively. The transfer limits of these branches are assumed to be reduced to 10, 30, 10 and 10 MW for observing congestion. In this system topology, the congested branches are 2–5, 4–12, 6–7 and 25–27 as given in Table 2 for both types of approaches (decentralized and centralized). The line flows in these branches obtained after application of proposed congestion management methodology are also shown in Table 2 for decentralized and centralized markets. It can be observed that the proposed IP method has succeeded in managing the congestion in lines using DOPF and COPF approaches. For optimizing the generators power individually to meet the demand bids, the suggested IP optimization approach is applied to centralized and decentralized markets, before and after congestion in lines as shown in Tables 3 and 4.

The results of these cases have been obtained by centralized formulation of the market structure and the solution has been obtained by the proposed IP method in order to authenticate the obtained results of the decentralized approach. It has been observed from Tables 3 and 4 that the generators output are different in the two approaches. In the proposed method, losses are also

Table 1
Cost and benefit function of market model M_1.

Utility	Generator bus	Generation cost function ($/h)	Consumer bus	Consumer benefit function in ($/h)
T1	13	$20P + 0.2P^2$	3	$38.8D - 0.3D^2$
	27	$17.5P + 0.1P^2$	4	$38D - 0.5D^2$
			7	$38D - 0.2D^2$
T2	1	$17.5P + 0.25P^2$	12	$38D - 0.4D^2$
	22	$30P + 0.25P^2$	15	$39.5D - 0.2D^2$
			17	$37D - 0.2D^2$
T3	23	$18P + 0.625P^2$	24	$36D - 0.3D^2$
	2	$23P + 0.283P^2$	26	$38D - 0.4D^2$
			7	$37D - 0.2D^2$

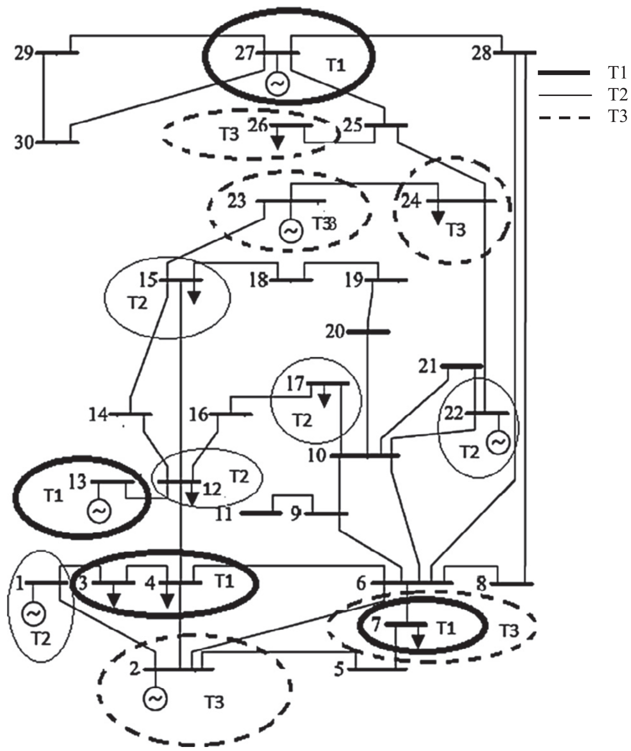

Fig. 1. Modified IEEE-30 bus system for market model M_1.

incorporated with the output of generators. In the decentralized approach, the generator of utility T1 at bus 13 has been considered as a slack bus. The losses due to other utilities have been incorporated with this generator. Therefore, the additional cost of loss is including with this generator and the total generation cost becomes more as shown in Table 3. The generator rescheduling has been adopted by OPF solution for congestion management. It may also be observed from Tables 3 and 4 that the costs obtained by decentralized and centralized approaches are very close.

Table 4
Generation and demand in centralized market model M_1.

Generator bus	Generation (MW)	
	Before congestion management	After congestion management
13	31.9570	26.8237
27	43.6640	33.7781
1	5.5648	14.7388
22	5.5648	0.0850
23	3.6259	1.7442
2	21.4244	34.6303
Loss	4.28	3.54
Total	116.0809	115.3401
Load bus	Demand (MW)	
3	12.6452	17.5605
4	7.7871	10.7431
7	16.7678	27.1803
12	8.4839	3.9341
15	20.7178	8.0891
17	14.4678	12.7441
24	7.9785	4.9234
26	8.4839	5.4553
7	14.4678	21.1701
Total	111.7998	111.8000

Market model M_2

Similar to market model M_1, another modified IEEE-30 bus system has been considered, named as market model M_2 for the

Table 2
Line flows in market model M_1 (MW).

Lines	Maximum limit	Decentralized approach								Centralized approach	
		Before congestion management				After congestion management				Before congestion management	After congestion management
		T1	T2	T3	Total	T1	T2	T3	Total		
2–5	10	2.58	4.23	6.70	13.51	1.58	4.08	4.33	9.99	9.62	6.61
4–12	30	12.62	16.25	1.60	30.47	7.33	15.98	4.89	28.2	32.10	27.67
6–7	10	3.60	6.30	5.95	15.85	3.98	3.04	2.58	9.60	14.02	9.08
25–27	10	5.86	9.12	1.01	15.99	4.46	4.46	1.35	9.69	17.45	9.035

Table 3
Generation and demand in decentralized market model M_1.

Utility	Before congestion management				After congestion management			
	Generator bus	PG (MW)	Load bus	PD (MW)	Generator bus	PG (MW)	Load bus	PD (MW)
T1	13	15.2801	3	11.6637	13	20.6072	3	20.4974
	27	21.6573	4	7.1982	27	18.0702	4	12.1128
			7	15.4955			7	1.7472
	Total	36.9374	Total	34.3574	Total	38.6774	Total	34.3574
	Loss	0.60			Loss	1.58		
T2	1	33.5672	12	8.1768	1	40.1679	12	8.1768
	22	8.5671	15	20.1037	22	1.9664	15	20.1037
			17	13.8537			17	13.8537
	Total	42.1343	Total	42.1342	Total	42.1343	Total	42.1342
	Loss	1.08			Loss	1.18		
T3	23	13.8203	24	9.3872	23	12.7974	24	14.5268
	2	21.6880	26	9.5404	2	22.7109	26	13.0998
			7	16.5808			7	7.8817
	Total	35.5083	Total	35.5084	Total	35.5083	Total	35.5083
	Loss	0.90			Loss	1.56		

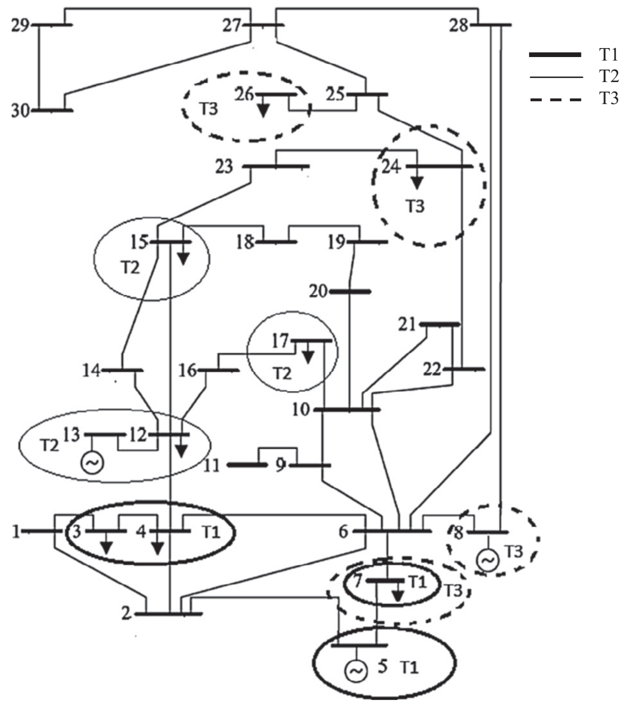

Fig. 2. Modified IEEE-30 bus system for market model M_2.

Table 5
Cost and benefit function of market model M_2.

Utility	Generator bus	Generation cost function ($/h)	Consumer Bus	Consumer benefit function in ($/h)
T1	5	$45P + 0.01P^2$	3	$47.8D - 0.03D^2$
			4	$47.8D - 0.05D^2$
			7	$47.8D - 0.02D^2$
T2	13	$48P + 0.01P^2$	12	$49.0D - 0.04D^2$
			15	$48.5D - 0.02D^2$
			17	$49.7D - 0.02D^2$
T3	8	$40P + 0.01P^2$	24	$49.0D - 0.03D^2$
			26	$48.8D - 0.04D^2$
			7	$48.8D - 0.02D^2$

Table 7
Generation and demand in decentralized market model M_2.

Utility	Before congestion management				After congestion management			
	Generator bus	PG (MW)	Load bus	PD (MW)	Generator bus	PG (MW)	Load bus	PD (MW)
T1	5	38.6200	3	11.9355	5	38.8396	3	10.1234
			4	7.1610			4	5.5231
			7	17.9035			7	22.1631
		Total		37.0000		Total		37.8096
		Loss		0.53		Loss		0.13
T2	13	12.0000	12	1.0000	13	12.0000	12	0.9321
			15	1.0000			15	1.1000
			17	10.0000			17	9.9679
		Total		12.000		Total		12.00
		Loss		0.20		Loss		0.27
T3	8	35.0000	24	13.0769	8	35.0000	24	15.1723
			26	7.3077			26	7.7319
			7	14.6154			7	12.0958
		Total		35.000		Total		35.0000
		Loss		0.89		Loss		0.63

Table 8
Generation and demand in centralized market model M_2.

Generator bus	Generation (MW)	
	Before congestion management	After congestion management
5	38.4800	38.5900
13	12.0000	12.0000
8	35.0000	35.0000
Total	85.4800	85.5900
Loss	1.8700	1.5900
Load bus	Demand (MW)	
3	1.0000	3.5000
4	7.0000	10.5000
7	21.0000	24.0000
12	10.1667	8.0000
15	7.8333	7.5000
17	11.0000	11.0000
24	9.0000	7.0583
26	5.0000	2.4894
7	12.0000	9.9523
Total	84.0000	84.0000

verification of the proposed algorithm. In this model, there are three multilateral utility (T1, T2 and T3) and each has four participants with one generator and three consumers as shown in Fig. 2. The cost function of generator and benefit functions of consumers are listed in Table 5 [22]. In order to observe the congestion, the capacity of line 28–27 has been reduced from 65 MW to 10 MW. To meet the demand bids in this case, the generation levels of all the generators have been optimized individually. Also for market model M_2, the decentralized and centralized based approaches have been applied.

The power flow in line 28–27 before the congestion management in decentralized and centralized approach is 11.74 MW and 14.3046 MW respectively. It is observed that after the application of congestion management, the power flow in line 28–27 using both the approaches are 9.75 MW and 9.084 MW respectively as shown in Table 6. The results clearly show that the congestion has been relived using the proposed technique. The generations and demands for this case have been shown in Table 7 for decentralized market. These values for centralized market are shown in Table 8.

Market model M_3 (modified IEEE-118 bus system)

In order to formulate a multi-utility system, the modified IEEE-118 bus system is partitioned into six utilities; T1, T2, T3, T4, T5 and T6. It is assumed that each utility have three loads and two generators. In this way, there are eighteen demand and twelve

Table 6
Line flows in market model M_2 (MW).

Lines	Maximum limit	Decentralized approach								Centralized approach	
		Before congestion management				After congestion management				Before congestion management	After congestion management
		T1	T2	T3	Total	T1	T2	T3	Total		
28–27	8	5.04	2.70	6.57	14.31	2.31	2.58	2.73	7.62	11.74	7.89

Table 9
Cost and benefit function of market model M_3.

Utility	Generator bus	Generation cost function ($/h)	Consumer bus	Consumer benefit function in ($/h)
T1			2	$47.8D-0.03D^2$
	4	$40P+0.01P^2$	3	$47.8D-0.05D^2$
	6	$40P+0.01P^2$	7	$47.8D-0.02D^2$
T2			14	$49.0D-0.04D^2$
	15	$40+0.01P^2$	20	$48.5D-0.02D^2$
	24	$40P+0.01P^2$	23	$49.7D-0.02D^2$
T3			33	$49.0D-0.03D^2$
	34	$40P+0.01P^2$	35	$48.8D-0.04D^2$
	40	$40P+0.01P^2$	39	$48.8D-0.02D^2$
T4			67	$45.8D-0.03D^2$
	62	$40P+0.01P^2$	75	$45.8D-0.03D^2$
	70	$40P+0.01P^2$	78	$45.8D-0.02D^2$
T5			54	$48.0D-0.05D^2$
	85	$40P+0.01P^2$	20	$48.5D-0.03D^2$
	90	$40P+0.01P^2$	11	$47.8D-0.02D^2$
T6			106	$48.0D-0.02D^2$
	107	$40P+0.01P^2$	108	$48.0D-0.05D^2$
	112	$40P+0.01P^2$	114	$48.0D-0.02D^2$

generation bidders altogether. The marginal cost functions of generators and marginal benefit functions of consumers are listed in Table 9 [11], wherein generators of buses 4, 6 and load of buses 2, 3, 7 belong to utility T1; generators of buses 15, 24 and load of buses 14, 20, 23 belong to utility T2; generators of buses 34, 40 and load of buses 33, 35, 39 belong to utility T3; generators of buses 62, 70 and load of buses 67, 75, 78 belong to utility T4; generators of buses 85, 90 and load of buses 54, 20, 11 belong to utility T5 and generators of buses 107, 112 and load of buses 106, 108, 114 belong to utility T6. Similar to modified IEEE-30 bus system, the remaining generators and load buses of the system are not participation in the market operations. In the same way, each utility has its own resource information and all of them have the right to access the information base to obtain the biddings of all the demands to optimize their own generations. In the market model M_3, the branch 80–81 has transfer limit of 30 MW.

In the system topology, the congested branch is given in Table 10 for both decentralized and centralized approaches. The line flows in these branches are obtained after applying the proposed congestion management as shown in Table 10. It can be observed that the proposed method has succeeded in managing the congestion in the lines using DOPF and COPF approaches. For optimizing the generators' power individually to meet the demand bids, the suggested IP optimization approach is applied to centralized and decentralized markets, before and after the congestion in lines as shown in Tables 11 and 12. In order to authenticate the obtained results of the decentralized approach, the results of these cases have been obtained by centralized formulation of the market structure whose solution has been obtained by the proposed method.

It has been observed from Tables 11 and 12 that the generators' outputs are different in the two approaches. In the proposed method, losses are also incorporated with the output of slack bus. In the decentralized approach, the first generator of utility T1 has been considered as a slack bus. The losses due to other utilities have been incorporated with the slack bus generator.

Table 11
Generation and demand in decentralized market model M_3 (MW).

Utility	Generator bus	PG	Load bus	PD
T1	4	50.4496	2	33.0311
	6	68.4232	3	32.3741
			7	53.4687
	Loss	5.90		
T2	15	70.3606	14	21.4945
	24	42.1120	20	30.4890
			23	60.4891
	Loss	3.43		
T3	34	60.1272	33	36.9917
	40	61.4836	35	32.3540
			39	52.2651
	Loss	5.31		
T4	62	41.8231	67	32.0465
	70	66.1817	75	30.6142
			78	45.3422
	Loss	7.37		
T5	85	8.8101	54	0.000
	90	2.1635	30	2.3894
			11	8.5842
	Loss	1.21		
T6	107	1.6043	106	3.7273
	112	7.3412	108	1.4908
			114	3.7273
	Loss	3.42		

Table 12
Generation and demand in centralized market model M_3 (MW).

Generator bus	PG	Load bus	PD
4	59.4863	2	22.8834
6	59.3865	3	13.7012
		7	34.1794
15	59.2816	14	29.9290
24	53.1910	20	51.1052
		23	80.6721
34	60.5005	33	40.6766
40	61.1103	35	24.1163
		39	21.3053
62	64.1525	67	15.2802
70	43.8523	75	15.7599
		78	23.0614
85	5.8940	54	13.7811
90	5.0796	30	12.4574
		11	47.1095
107	4.0655	106	20.3546
112	4.8800	108	5.0000
		114	9.5072
Loss	22.30	Total	480.88
Total	503.18		

Therefore, the additional cost of loss is included with this generator and the total generation cost becomes more as given in Table 11. The generator rescheduling has been adopted by OPF solution for congestion management. Also, the voltages on buses are within their security limits of 0.9 p.u. and 1.6 p.u. The V_{min} and V_{max} are 0.952 p.u. and 1.137 p.u. at bus 107 and bus 10 respectively for

Table 10
Line flow in market model M_3 (MW).

Line 80–81	Maximum limit	T1	T2	T3	T4	T5	T6	Total
Decentralized approach	30	3.89	3.58	3.49	3.42	0.35	0.33	15.56
Centralized approach	30	18.76						

Table 13
Comparison of profits in decentralized market model M_1 ($/h).

Utilities	Without loss consideration		With loss consideration	
	Before congestion management	After congestion management	Before congestion management	After congestion management
T1	46.0024	38.1908	44.6122	34.4862
T2	32.6967	30.5182	30.1797	27.7648
T3	19.6054	16.6975	17.5125	13.0406
Total	98.3045	85.4065	92.3044	75.2916

the centralized market model. Similarly, in the decentralized market model, V_{min} and V_{max} are 0.932 p.u. and 1.121 p.u. at buses 107 and 10 respectively.

Profit analysis of both the market models M_1 and M_2

The profits offered by both the market structures (M_1 and M_2) have been given in Tables 13–16 without and with loss consideration in the power network in the case of decentralized and centralized based approaches. The results obtained using decentralized and centralized based approaches have also been compared using bar graphs. These graphs have been shown in Figs. 3–5 for market M_1 and Figs. 6–8 for market M_2 without and with loss consideration. Figs. 3 and 4 show the profit offered by market model M_1 with decentralized without and with losses respectively. The total profit in decentralized market after applying congestion management is more as compared to centralized approach as shown in Fig. 5. Similarly, Figs. 6–8 show the profits offered by market M_2 model using both the approaches. The profit offered by proposed method is more as compared to [22] as shown in Table 17 without loss consideration after congestion management.

Profit analysis of market model M_3 (modified IEEE-118 bus system)

The profit offered by this market structure has been shown in Table 18 for decentralized based approach in the power network.

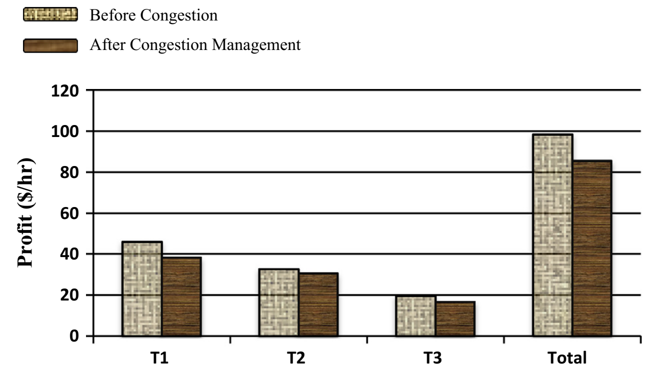

Fig. 3. Profit ($/h) in decentralized market M_1 without loss consideration.

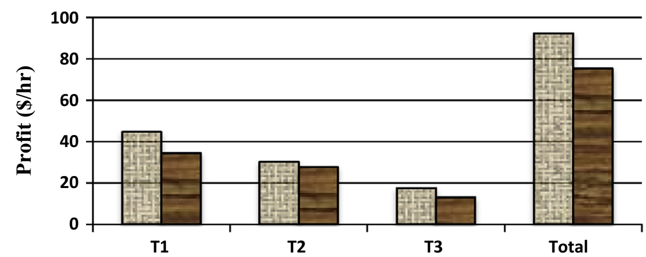

Fig. 4. Profit ($/h) in decentralized market M_1 with loss consideration.

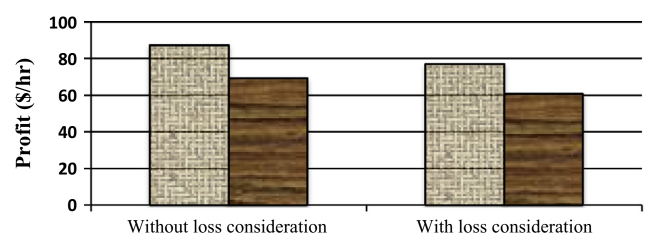

Fig. 5. Profit ($/h) in centralized market model M_1.

Table 14
Comparison of profits in centralized market model M_1 ($/h).

Without loss consideration		With loss consideration	
Before congestion management	After congestion management	Before congestion management	After congestion management
87.3641	69.1582	77.0017	60.6616

Table 15
Comparison of profits in decentralized market model M_2 ($/h).

Utilities	Without loss consideration		With loss consideration	
	Before congestion management	After congestion management	Before congestion management	After congestion management
T1	76.7	76.6738	52.8472	30.00795
T2	14.56	14.9413	5.556	14.9413
T3	286.8	286.561	246.7421	286.561
Total	378.06	378.1761	305.1453	331.5103

Table 16
Comparison of profits in centralized market model M_2 ($/h).

Without loss consideration		With loss consideration	
Before congestion management	After congestion management	Before congestion management	After congestion management
387.8	300.9729	303.615	303.501

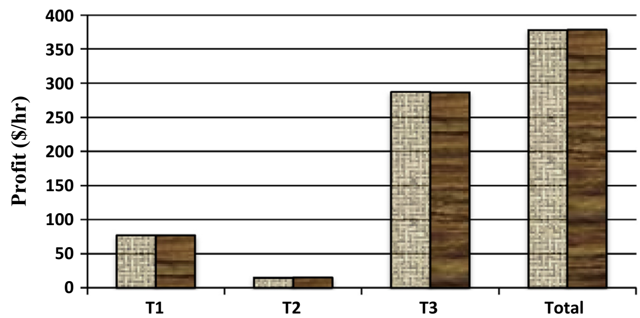

Fig. 6. Profit ($/h) in decentralized market model M_2 without loss consideration.

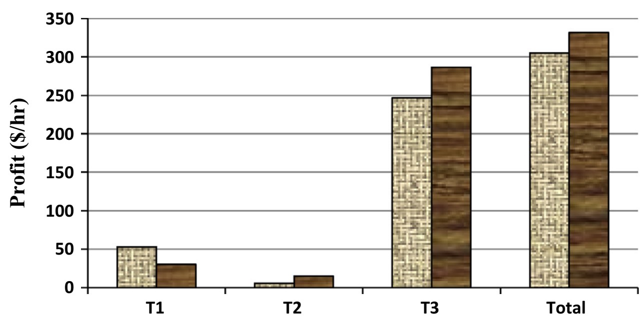

Fig. 7. Profit ($/h) in decentralized market model M_2 with loss consideration.

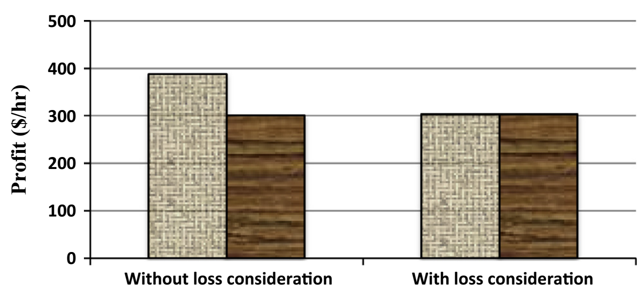

Fig. 8. Profit ($/h) in centralized market model M_2.

Table 17
Comparison of profits ($/h) of decentralized market model M_2 with Ref. [21] without loss consideration after congestion management.

Utilities	Proposed method	Ref. [21]
T1	76.6738	87.7500
T2	14.9413	30.8600
T3	286.5610	183.3300
Total	378.1761	301.9400

Table 18
Profit ($/h) of decentralized market M_3 with loss consideration.

Utilities	Generation cost ($/h)	Consumer benefits ($/h)	Market profits ($/h)
T1	4827.181	5539.80	712.68
T2	4566.10	5428.00	861.90
T3	4938.40	5804.40	866.00
T4	4381.50	5167.60	786.10
T5	439.77	532.29	92.520
T6	358.38	428.72	70.34
Total	20,391.05	22,900.81	3389.54

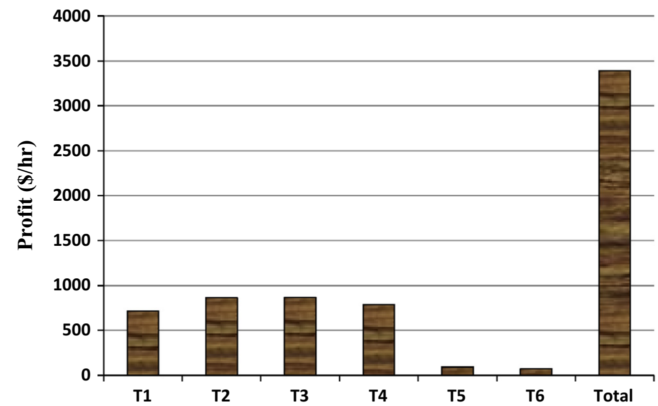

Fig. 9. Profit ($/h) in market model M_3 (modified IEEE-118 bus system) with loss consideration.

The total profit using the proposed method for the centralized market considering losses is 2413.1 $/h.

It has been observed that the total profit in the decentralized market by applying congestion management is marginally more than the centralized approach as shown in Table 18. The comparison of profits between decentralized and centralized power markets have been shown in Fig. 9 which is also valid for both the approaches without considering the losses. The total profits offered by centralized and decentralized approaches without considering losses are 3283.07 $/h and 3582.45 $/h respectively and these values are higher as compared to the ones reported in [21].

Conclusion

The paper presents multi-utility IP based OPF algorithm for independent dispatch of each utility for congestion management while achieving a multi-utility optimum. It deals with IP based OPF in decentralized multi-utility power markets which provides an independent dispatch to achieve optimal solutions of the system. The centralized approach has also been carried out in this work to authentication and compare the results of decentralized approach. The algorithm is of particular interest in a multi-utility setting where the coordination among the market players achieve maximum social welfare in the market using decentralized approach. However, the dispatching independence and its own profit have to be maintained in such cases independently with the help of system information announced by the operator which are security constraints information and public issues. The results of modified IEEE-30 bus system for two cases and modified IEEE-118 bus system have demonstrated the effectiveness of the suggested method. The results show that the congestion management using decentralized approach gives more social welfare and effective solution as compared to centralized approach without sharing confidential economic information in terms of costs and benefits of market participants. For the suggested method, the system information is only required which is announced by market players. The comparison of the proposed algorithm with the existing method reveals that the proposed technique can achieve higher benefit.

References

[1] Nayak AS, Pai MA. Congestion management in restructured power systems using an optimal power flow framework. PSERC Publication; 2002.
[2] Christil RD. Transmission management in deregulated Environment. Proc IEEE 2000;88(2):170–95.

[3] Nishimura F, Tabors RD, Llic MD, Lacalle-Melero JR. Benefit optimization of centralized and decentralized power systems in a multi area environment. IEEE Trans Power Syst 1993;8(3):1180–6.
[4] Singh H, Hao S, Papalexopoulos A. Transmission congestion management in competitive electricity markets. IEEE Trans Power Syst 1998;13(2):672–9.
[5] Dutta S, Singh SP. Optimal rescheduling of generators for congestion management based on particle swarm optimization. IEEE Trans Power Syst 2008;23(4):1560–9.
[6] Bakirtzis AG, Biskas PN. A decentralized solution to the DC-OPF of interconnected power systems. IEEE Trans Power Syst 2003;18(3):1007–13.
[7] Bakirtzis AG, Biskas PN. A decentralized implementation of DC optimal power flow on a network of computers. IEEE Trans Power Syst 2005;20(3):25–33.
[8] Conejo AJ, Aguado JA. Multi area coordinated decentralized DC optimal power flow. IEEE Trans Power Syst 1998;13(4):1272–8.
[9] Hao S. Decentralized approach to inter congestion management. IEEE Trans Power Syst 2005;20(2):675–83.
[10] Hao S, Shirmohammadi D. Congestion management with Ex Ante pricing for decentralized electricity markets. IEEE Trans Power Syst 2002;17(4):1030–6.
[11] Liu K, Ni Y, Wu FF, Bi TS. Decentralized congestion management for multilateral transactions based on optimal recourse allocation. IEEE Trans Power Syst 2007;22(4):1835–42.
[12] Gribik PR, Angelidis GA, Kovacs RR. Transmission access and pricing. IEEE Trans Power Syst 1999;14(3):865–76.
[13] Biskas PN, Bakirtzis AG. Decentralized congestion management of interconnected power systems. Proc Inst Electr Eng Gener Transm Distrib 2002;149(4):432–8.
[14] Wang X, Song YH. Advanced real-time congestion management through both pool balancing market and bilateral market. IEEE Power Eng Rev 2000;20(2):47–9.
[15] Wang X, Song YH, Lu Q. Lagrangian decomposition approach to active power congestion management across interconnected regions. Proc Inst Electr Eng Gener Transm Distrib 2001;148(5):497–503.
[16] Huang A, Sung-Kwan J, Bin Song K, Kim JH, Lee K. Asynchronous decentralized method for interconnected electricity markets. Electr Power Syst Res 2008;30:283–90.
[17] Wei P, Ni Y, Wu FF. Decentralized approach for congestion management and congestion price discovering. IEE Proc Gener Transm Distrib 2002;149(6):645–52.
[18] Botterud A, Ilic MD, Wangesteen I. Optimal investments in power generation under centralized and decentralized decision making. IEEE Trans Power Syst 2005;20(1):254–63.
[19] Shayesteh E, Moghadderm MP, Yousefi A, Haghifam MR, Sheik-El-Eslami MK. A demand side approach for congestion management in competitive environment. Eur Trans Electr Power 2010;20:470–90.
[20] Morais H, Faria P, Vale Z. Demand response design and use based on network locational marginal prices. Electr Power Energy Syst 2014;61:180–91.
[21] Song YH, Wang X. Operation of market-oriented power system. Springer-Verlag London limited; 2003.
[22] Visalakshi S, Baskar S. Covariance matrix adapted evolution strategy-based decentralized congestion management for multilateral transactions. IET Gener Transm Distrib 2010;4(3):400–17.
[23] Aguado JA, Quintana VH. Inter-utilities power-exchange coordination: a market-oriented approach. IEEE Trans Power Syst 2001;16(2):513–9.
[24] Soroudi A, Ehsan M, Caire R, Hadjsaid N. Hybrid immune-genetic algorithm method for benefit maximisation of distribution network operators and distributed generation owners in a deregulated environment. IET Gener Transm Distrib 2011;5(9):961–72.
[25] Chen M, Hsu Y, Wu Y. Modified penalty function method for optimal social welfare of electric power supply chain with transmission constraints. Electr Power Energy Syst 2014;57:90–6.
[26] Chand S, De A. A multi-objective solution algorithm for optimum utilization of smart grid infrastructure towards social welfare. Electr Power Energy Syst 2014;58:307–18.
[27] Karmarkar N. A new polynomial-time algorithm for linear programming. Combinatorica 1984;4(4):373–95.
[28] Wu YC, Debs AS, Marsten RE. A direct nonlinear predictor-corrector primal-dual interior point algorithm for optimal power flows. IEEE Trans Power Syst 1994;9(2):876–83.
[29] Wei H, Sasaki H, Kubakawa J, Yokoyama R. An interior point nonlinear programming for optimal power flow problems with a novel data structure. IEEE Trans Power Syst 1998;13(3):870–7.
[30] Yan XH, Quintana VH. Improving an interior-point-based OPF by dynamic adjustments of step sizes and tolerances. IEEE Trans Power Syst 1999;14(2):709–17.
[31] Torres GL, Quintana VH. On a nonlinear multiple-centrality corrections interior-point method for optimal power flow. IEEE Trans Power Syst 2001;16(2):222–8.
[32] Taha HA. Operation research: an introduction. Pearson Education (Singapore) Inc.; 2002.
[33] Yan W, Yu J, Yu DC, Bhattarai K. A new optimal reactive power flow model in rectangular form and its solution by predictor corrector primal dual interior point method. IEEE Trans Power Syst 2006;21(1):61–7.
[34] Patra S, Goswami SK. Optimal power flow solution using a non-interior point method. Electr Power Energy Syst 2007;29:138–46.
[35] Venkatesh P, Ganadass R, Padhy NP. Available transfer capability determination using power transfer distribution factors. Int J Emerg Electr Power Syst 2004;1:1–14.