Power Trading and Congestion Management through Real Power Rescheduling Using Unified Power Flow Controller

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Abstract

Congestion is termed as the operating condition in which there is not enough transmission capacity to implement all the desired transactions. This paper deals with the power trading in electricity market to ensure regular supply at competitive rates. Bidding process of 75 Indian bus systems is analyzed. It is shown that how can congestion cost can be addressed through active power rescheduling with transmission line constraints using Unified power flow controller.

Keywords*: GENCO; DISCO, Congestion Management, Disco Participation Matrix (DPM), UPFC, Pool Based Transaction, Bidding, Congestion Cost, Rescheduling*

1. Introduction

Open access environment may try to purchase the energy from the cheaper source for greater profit margins, which may lead to overloading and congestion of certain corridors of the transmission network. This may result in violation of line flow, and stability limits. Utilities therefore need to determine adequately their available transfer capability (ATC) to ensure that system reliability is maintained while serving a wide range of bilateral and multilateral transactions [1]. System Operator (SO) is to manage congestion as it cause rise in electricity price resulting in market inefficiency. In corrective action congestion management schemes, it is crucial for SO to select the most sensitive generators to re-schedule their real and reactive powers for congestion management [2], [3]. Whenever transmission network congestion occurs how it segregates the wholesale electricity market and forces the market to change its price from a common market clearing price to locational market price [4]. The voltage profile become poor during peak loading of the network and can lead to congestion during such events [5]. . In order to increase ATC, voltage improvement as well as minimum capital cost the deployment of UPFC is suggested [13]. By employing a combination of capital cost indices and search for suitable locations for UPFC a cost function is developed.

2. System under Studies

The possibility of controlling power flow in power system can improve its performance with generation re-scheduling. The congestion is relieved by changing the line flows. In this paper 400 kV and 200kV reduced network of one of the Electricity Boards in India which consists of 15 generators and 97 lines, including 24 transformers is considered [3], [8]. The single line diagram of 75-bus system is shown in Figure 1.

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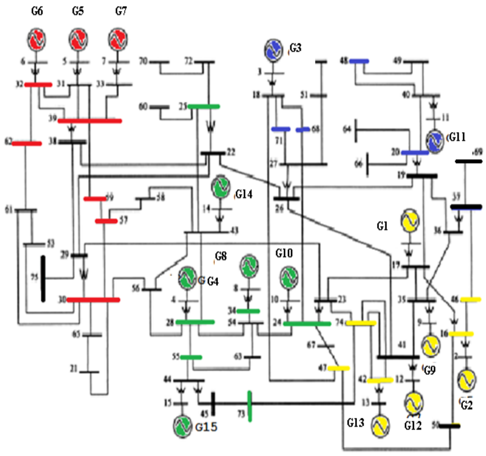

Figure 1. A 75 bus system under study

This system is divided into four areas to demonstrate the bidding process. Red, yellow, blue and green color represents Control area 1, 2, 3 & 4 respectively. Detail for Control areas is given in Table I [8].

Table I. Control Areas in 75 Bus Systems

CONTROL AREA	OWNER	DISCOS	BUSES
AREA 1	Gencos-5,6,7	1	30,57,59,61,65,75
		2	32,38,39,53,62
AREA 2	Gencos-1,2,9,12,13	3	16,46,50
		4	42,47,74
AREA 3	Gencos-3,11	5	52,71,27,26,51,68
		6	20,48,49,64,66,69,37
AREA 4	Gencos-4,8,10,14,15	7	40,56,58,60,70,72,25
		8	28,24,34,55,63,54,73,67

Distribution companies (DISCOs) make the binary contracts with GENCOs which is confirmed by the Power Exchange on the availability of ATC [7]. Such contract is represented by Distribution Participation matrix (DPM). DPM for 75 bus system for a particular schedule is shown in Table II.

Table II. Disco Participation Matrix

	D1	D2	D3	D4	D5	D6	D7	D8
G6	0.1	0	0	0.05	0	0	0	0
G5	0	0.1	0	0	0	0	0	0.2
G7	0	0	0	0	0	0	0	0
G1	0	0	0.05	0	0	0.1	0	0
G2	0	0.05	0	0.1	0	0	0.15	0
G9	0.1	0	0.2	0.15	0	0	0	0
G12	0	0	0	0	0	0	0	0
G13	0	0	0	0	0	0	0	0
G3	0	0.05	0	0	0.15	0.2	0	0
G11	0	0	0	0	0	0.1	0	0
G14	0.1	0.15	0.1	0	0.25	0	0.25	0
G4	0.1	0	0.05	0.1	0	0.1	0	0.25
G8	0.1	0.15	0.1	0.1	0.1	0	0.1	0.05
G10	0	0	0	0	0	0	0	0
G15	0	0	0	0	0	0	0	0
Pool	1.1363	4.4388	2.4973	13.1255	5.4463	5.3367	5.9501	13.7502
Total	1.6363	4.9388	2.9973	13.6255	5.9463	5.8367	6.4501	14.2502

The balance demand of DISCOs is met by Pool based transaction which is shown in the second last raw of the Table II. Power demand by area 1 from pool (P_{d1}) is 5.5751 pu, by area 2 (P_{d2}) is 15.6228 pu, by area 3(P_{d3}) is 10.783 pu and by area 4 is (P_{d4}) is 19.7003 pu. Total power given by Gencos of area 1 in pool (P_{g1}) is 3.15 pu, Gencos of area 2 (P_{g2}) is 41.45, Gencos of area 3 (P_{g3}) is 2.39 pu and Gencos of area 4 (P_{g4}) is 6.49 pu.

3. Bidding Process

The bidding process is for time block of 15 minutes one day ahead. Considering the bidding from 9 am to 9.15 am on any particular day where market bidders from all areas must submit separate bids for the area in which they have generation & loads. The bidding curves for all areas area are shown in Figures 2, 3, 4 and 5.

Bidding Curve for area 1: It is assumed that in area 1 the Genco 6 bids for 1.05 pu power at Rs 2100/- , Genco 5 bids for 1.5 power at Rs 1000/- and the Genco 7 bids for 0.6 pu power at Rs 2700/-. The supply and demand curve intersects at 2700 Rs/MWh which is MCP as shown in figure 2. MVA base is taken 100.

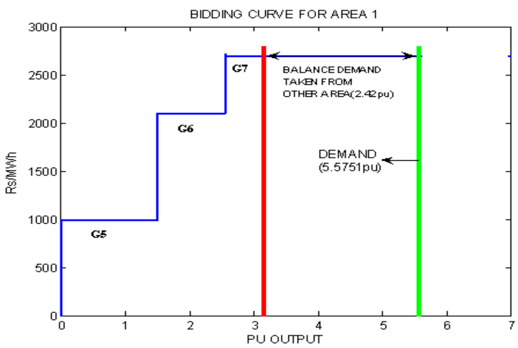

Figure 2. Bidding Curve for Area 1

Bidding Curve for area 2: In Area 2 the Genco 1 bids for 7.10 pu power at Rs 1200/- , Genco 2 bids for 2.30 pu power at Rs 2500/- , Genco 9 bids for 5.05 pu power at Rs 4600/- , Genco 12 bids for 18 pu power at Rs 3800/- and the Genco 13 bids for 9 pu power at Rs 5000/-. The supply and demand curve intersects at 3800 Rs/MWh which is MCP of this area as shown in figure 3.

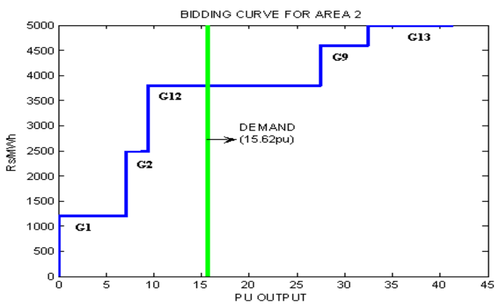

Figure 3. Bidding Curve for Area 2

Bidding Curve for area 3: In Area 3 the Genco 3 bids for 1.4 pu power at Rs 1800/-, Genco 11 bids for 0.99 pu power at Rs 3000/. The supply and demand curve intersects at 3000 Rs/MWh which is the MCP of this area as shown in figure 4.

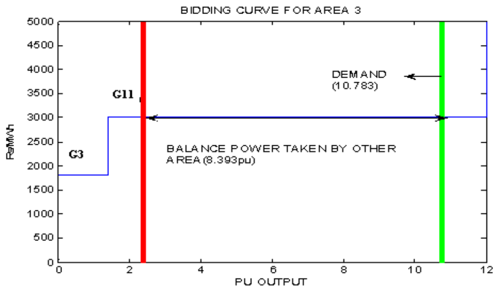

Figure 4. Bidding Curve for Area 3

Bidding Curve for area 4: In Area 2 the Genco 14 bids for 0.65 pu power at Rs 1000/- , Genco 4 bids for 0.4 pu power at Rs 2100/- , Genco 8 bids for 0.1 pu power at Rs 2800/- , Genco 10 bids for 0.8 pu power at Rs 3200/- and the Genco 15 bids for 4.54 pu power at Rs 3600/- . The supply and demand curve intersects at 2700 Rs/MWh which is MCP as shown in figure 5. The interchange of active power between the Control areas is given in Table III.

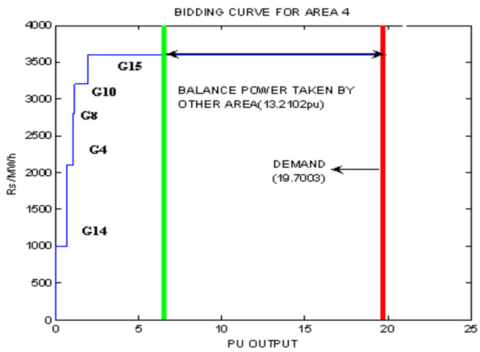

Figure 5. Bidding Curve for Area 4

Table III Interchange of power between Areas

Area	Power by Gencos	Pool demand	Power injection to system	Pool drawl from other area (s)
1	3.15pu	5.5751pu	0pu	2.4251pu
2	41.45pu	15.6228pu	25.82pu	0pu
3	2.39pu	10.783pu	0pu	8.39pu
4	6.49pu	19.7003pu	0pu	13.2103pu

The LMP for inter area transactions are obtained as shown in Figure 6. The energy and money flow is summarized in Table IV. The load flow study [9] is performed to find out the power flow in each transmission line to confirm the schedule of bidding. In this case it is obtained that the line flow of line no 71 connected b/w bus no. 26 and 41 is 4.2816 pu where as its rating is 4.15pu. Therefore this line causes congestion in the system. The congestion may be removed by rescheduling of Generation.

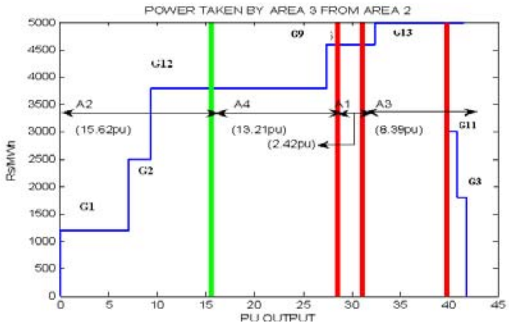

Figure 6. Power Transaction from area 2 to 1, 3 and 4

4. Rescheduling of Generation

As the line no. 71, in this problem, causes congestion schedules are not confirmed by the Power Exchange (PX) so bids are re-invited for rescheduling the generation. Gencos may come with incremental and decremental congestion bids. The selection of sensitive generators which may relieve the congestion by re-scheduling their generation is on the basis of their power transmission congestion distribution factors (PTCDF) [3] can be calculated as

$$\mathrm{PTCDF}_n^k = \frac{\Delta \mathrm{Pij}}{\Delta \mathrm{Pn}}$$

Where PTCDF represents the real power flow sensitivities of line "n" with respect to real power injection at bus 'i' and drawl at bus 'j' and termed as real power transmission congestion distribution factor.

Objective function is chosen as minimization of the total congestion cost, CC, subjected to various operating constraints. Mathematically, the objective function can be

$$\text{Min CC} = \sum_{r=1}^{\mathrm{Ng,up}} c_{\mathrm{Pg,r}}^{+} \Delta P_{g,r}^{+} + \sum_{s=1}^{\mathrm{Ng,dn}} c_{\mathrm{Pg,s}}^{-} \Delta P_{g,s}^{-}$$

The constraints are as follows:

$$(\Delta \mathrm{Pij} + P_{ij}^{0})2 + (Q_{ij}^{o})2 \leq (S_{ij}^{\max})2$$

The above equation can be written as:

$$(\sum_{n=2}^{75} \mathrm{PTCDF}_n^k \Delta P_n + P_{ij}^{0})2 + (Q_{ij}^{o})2 \leq (S_{ij}^{\max})2$$

k=1,2,. Nl

$$\Delta P_i^{\min} \leq \Delta P_i \leq \Delta P_i^{\max} \qquad i=1, 2, \ldots\ldots. \quad \mathrm{Nb}$$

$$\sum_{i=1}^{N_b} \Delta P_i - \Delta P_L = 0$$

Where ΔP_L is change in the total real power transmission loss in the system. Depending upon PTCDF some of the Gencos participates in rescheduling. Let the G-1 bids to increase its power by a maximum of 3 pu at a bid price 4000 Rs/MWh while it offers to reduce it by -7.1 pu at a price of 1000 Rs/MWh. The bidding prices for Gencos G-12, G-13 and G-14 are given in Table IV.

Table IV. Re-scheduled Bids

Gencos	c_{Pg}^{+} (Rs/MWh)	c_{Pg}^{-} (Rs/MWh)	ΔP_{gmin} (pu)	ΔP_{gmax} (pu)
G-1	4000	1000	-7.1	3
G-12	4000	2000	-10	4
G-13	5200	2000	-9	3
G-14	4000	900	- 0.65	0.5

Table V. Summary of Energy and Money Flow for active Power Bidding

Area	S. No.	Gencos Power with their MCPs (Rs.)	Balance Power from other Areas	Total Amount paid to Gencos of (Rs.)	Power (pu) received by Discos	Fund to Be collected from Discos (Rs.)
Area 1	G6	1.05pu@ 2700/-	2.4251pu@5000/-	2063050	D1-1.1363@3700.47/-	420431
	G5	1.5pu@2700/-	(from area 2)		D2-4.4388@3700.47/-	1642060
	G7	0.6pu@2700/-				
Area 2	G1	7.1pu@3800/-	2.4251pu@5000/- - to area 1	5936664	D3-2.4973@3800/-	948974
	G2	2.30pu@3800/-	8.393pu@5000/- to area 3			
	G12	18pu@3800/-	13.2102pu@5000/- to area 4			
Area 3	G3	1.4pu@3000/-	8.393pu@5000/-	4913500	D5-5.4463@4556.24/-	2481468
	G11	0.99pu@3000/-	(from area 2)		D6-5.3367@4556.24/-	2431532
Area 4	G14	0.65pu@3600/-	13.2102pu@5000/	8941550	D7-5.9501@4538.79/-	2700625
	G4	0.4pu@3600/-				
	G8	0.1pu@3600/-	(from area 2)			
	G10	0.8pu@3600/-			D8-13.750@4538.79/-	6240925
	G15	4.54pu@3600/-				
Total cost				2,18,54,764		2,18,54,764

Then for this case the optimization problem is formulated as follows:

$$\text{Min CC} = 4000*\Delta P_{g,1}^{+} + 4000*\Delta P_{g,12}^{+} + 5200*\Delta P_{g,13}^{+} + 4000*\Delta P_{g,14}^{+} - 1000*\Delta P_{g,1}^{-} - 2000*\Delta P_{g,12}^{-} - 2000*\Delta P_{g,13}^{-} - 900*\Delta P_{g,14}^{+}$$

This optimization problem can be formulated using the GAMS solver [10] and congestion cost comes out to be Rs.298560/. The Energy and Money Flow for active power bidding is shown in table V

5. Optimal Location of UPFC

The UPFC consists of a shunt (exciting) and a series (boosting) transformers [11]. Converter-1 is primarily used to provide the real power demand of converter- 2 at the common DC link terminal from the AC power system and can also generate or absorb reactive power, similar to the Static Compensator (STATCOM), at its AC terminal.

Converter-2 is used to generate a voltage source at the fundamental frequency with variable amplitude and phase angle, which is added to the AC transmission line by the series connected boosting transformer. The equivalent circuit of UPFC placed in line- k connected between bus- i and bus- j is shown in figure 7.

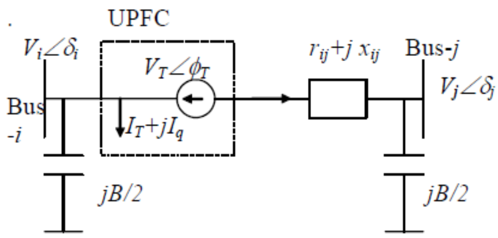

Figure 7. Equivalent circuit of UPFC

Based on the basic principle of UPFC and network theory, the active and reactive power flows in the line, from bus- i to bus- j, having UPFC can be written as

$$P_{ij} = \ (V_i^2 + V_T^2) g_{ij} + 2V_i V_T b_{ij} \cos(\theta_T - \delta_i) - V_j V_T [g_{ij} \cos(\theta_T - \delta_j) + b_{ij} \sin(\theta_T - \delta_j)] - V_i V_j [g_{ij} \cos(\delta_{ij}) + b_{ij} \sin(\delta_{ij})] \tag{1}$$

$$Q_{ij} = -V_i I_q - V_i^2 \left(b_{ij} + \frac{B}{2}\right) - V_i V_T [g_{ij} \sin(\theta_T - \delta_i) + b_{ij} \cos\left(\sin(\theta_T - \delta_i\right) - V_i V_j [g_{ij} \cos(\delta_{ij}) + b_{ij} \sin(\delta_{ij})] \tag{2}$$

Where $g_{ij} + jb_{ij}$ = 1/ $(r_{ij} + jx_{ij})$ and Iq is the reactive current flowing in the shunt transformer to improve the voltage of the shunt connected bus of UPFC.The real power and reactive power injections at bus- i with the system loading can be written as

$$\lambda = -\sum_{j \in N_b} P_{ij} \Big/ P_{Di}^0 \tag{3}$$

$$\lambda = -\sum_{j \in N_b} Q_{ij} \Big/ Q_{Di}^0 \tag{4}$$

The sensitivity of system loading factor (λ), corresponding to the real power balance equation, with respect to the control parameters of UPFC is defined

$$c_1^k = \partial\lambda \Big/ \partial V_T \, |V_{T=0} \tag{5}$$

$$c_2^k = \partial\lambda \Big/ V_T \partial\phi_T \, |\phi_{T=0} \tag{6}$$

where c_1^k and c_2^k are the system real power loading sensitivity with respect to the series injected voltage magnitude and the series injected phase angle of the UPFC, placed in line- k, respectively. Using equation 1, the sensitivity factor calculated at i th bus of line- k where UPFC is placed will be

$$c_1^k = [-2V_i g_{ij} (\cos(\delta_i)) + V_j \left(g_{ij} \cos(\delta_j) - b_{ij} \sin(\delta_j)\right)] / (P_{Di}^0) \tag{7}$$

$$c_2^k = [-2V_i g_{ij} (\sin(\delta_i)) + V_j \left(-g_{ij} \sin(\delta_j) - b_{ij} \cos(\delta_j)\right)] / (P_{Di}^0) \tag{8}$$

Sensitivity factors for each line are calculated. From where line 26 (i=16 & j=50) found most sensitive with value $c_1^k = -20.124$ and $c_2^k = -26.19$.

6. UPFC Model for Load Flow Studies

After selecting the location for UPFC the modeling of UPFC is important. The UPFC circuit used to derive the steady-state model is shown [13] in Figure 8.

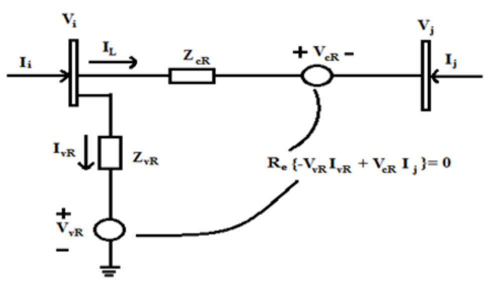

Figure 8. Circuit for modeling of UPFC

The UPFC linearised power equations are combined with the linearised system of equations corresponding to the rest of the network,

i.e. $[f(X)] = [J_{\mathrm{upfc}}][\Delta X]$

[ΔX] is the solution vector and $[J_{upfc}]$ is the Jacobian matrix. If both nodes, i and j, are PQ-type and the UPFC is controlling the active power, flowing from i to j, and reactive power injected at node j, the solution vector and Jacobian matrix[12]-[13] are defined as shown in equation (11).

$$[\mathrm{f(X)}] = [\Delta \mathrm{P}^{\mathrm{i}}\ \Delta \mathrm{P}^{\mathrm{j}}\ \Delta \mathrm{Q}^{\mathrm{i}} \Delta \mathrm{Q}^{\mathrm{j}}\ \Delta \mathrm{P}^{\mathrm{ji}}\ \Delta \mathrm{Q}^{\mathrm{ji}}\ \Delta \mathrm{P}^{\mathrm{cR}} +\ \Delta \mathrm{P}^{\mathrm{vR}}]^{\mathrm{T}} \tag{9}$$

$$[\Delta \mathrm{X}] = [\Delta\theta_{\mathrm{i}} \Delta\theta_{\mathrm{j}} \frac{\Delta \mathrm{V_i}}{\mathrm{V_i}} \frac{\Delta \mathrm{V_j}}{\mathrm{V_j}}\ \Delta\theta_{\mathrm{cR}} \frac{\Delta \mathrm{V_{cR}}}{\mathrm{V_{cR}}}\ \Delta\theta_{\mathrm{vR}}]^{\mathrm{T}} \tag{10}$$

$$[\,\mathrm{J_{upfc}}\,] = \begin{bmatrix} \mathrm{H_{ii}} & \mathrm{H_{ij}} & \mathrm{N_{ii}} & \mathrm{N_{ij}} & \mathrm{H_{icR}} & \mathrm{N_{icR}} & \mathrm{H_{ivR}} \\ \mathrm{H_{ji}} & \mathrm{H_{jj}} & \mathrm{N_{ji}} & \mathrm{N_{jj}} & \mathrm{H_{jcR}} & \mathrm{N_{jcR}} & 0 \\ \mathrm{J_{ii}} & \mathrm{J_{ij}} & \mathrm{L_{ii}} & \mathrm{L_{ij}} & \mathrm{J_{icR}} & \mathrm{L_{icR}} & \mathrm{J_{ivR}} \\ \mathrm{J_{ji}} & \mathrm{J_{jj}} & \mathrm{L_{ji}} & \mathrm{L_{jj}} & \mathrm{J_{jcR}} & \mathrm{L_{jcR}} & 0 \\ \mathrm{H_{ji}} & \mathrm{H_{jj}} & \mathrm{N_{ji}} & \mathrm{N_{jj}} & \mathrm{H_{jcR}} & \mathrm{N_{jcR}} & 0 \\ \mathrm{J_{ji}} & \mathrm{J_{jj}} & \mathrm{L_{ji}} & \mathrm{L_{jj}} & \mathrm{J_{jcR}} & \mathrm{L_{jcR}} & 0 \\ (\mathrm{H_{cRi}} + \mathrm{H_{vRi}}) & \mathrm{H_{cRj}} & (\mathrm{H_{cRi}} + \mathrm{N_{vRi}}) & \mathrm{N_{cRj}} & \mathrm{H_{cRcR}} & \mathrm{N_{cRcR}} & \mathrm{H_{vRvr}} \end{bmatrix} \tag{11}$$

The series and shunt voltage parameters are adjusted by trial and error in order to achieve a power flow solution. The rating of UPFC parameters are $\mathrm{V_{cR}}$=0.4882(p.u.), θ_{cR}=52.76(deg), $\mathrm{V_{vR}}$=0.9403 (p.u.), θ_{vR}= -19.54(deg) [12].

7. Results and Discussion

The above optimization problem has been formulated using the GAMS solver [10]. The money flow before rescheduling is shown in table V. The money flow after rescheduling through active power bidding without UPFC is shown in figure 10

Table VI. Energy and Money flow with Active Power Rescheduling using UPFC

Area	S. No.	Gencos Power with their MCPs (Rs.)	Balance Power from other Areas	Total Amount paid to Gencos of (Rs.)	Power (pu) received by Discos	Fund to Be collected from Discos (Rs.)
Area 1	G6	1.05pu@ 2700/-	2.4251pu@5000/- (from area 2)	2063050	D1-1.1363@3700/-	420431
	G5	1.5pu@2700/-			D2-4.4388@3700/-	1642060
	G7	0.6pu@2700/-				
Area 2	G1	7.1pu@3800/- +0.8336@4000/-	2.4251pu@5000/- to area 1	6033875	D3-2.4973@3862/-	964513
	G2	2.30pu@3800/-	8.393pu@5000/- to area 3			
	G9	5.05pu@3800/-			D4-13.1255@3862/-	50869362
	G12	18pu@3800/- -1.4336@2000/-	12.7102pu@5000/- to area 4			
	G13	9pu@3800/-				
Area 3	G3	1.4pu@3000/-	8.393pu@5000/-	4913500	D5-5.4463@4556/-	2481331
	G11	0.99pu@3000/-	(from area 2)		D6-5.3367@4556/-	2431400
Area 4	G14	0.65pu@3600/- +0.5@4000/-	12.7102pu@5000/ (from area 2)	8891500	D7-5.9501@4513/-	2685280
	G4	0.4pu@3600/-				
	G8	0.1pu@3600/-				
	G10	0.8pu@3600/-			D8-13.750@4513/-	6205375
	G15	4.54pu@3600/-				
Total cost				2,19,01,925		2,19,01,925

The change in real power output of generators G-1, G-12, G-14 with and without UPFC is given in Table VII. The CC after implementation of UPFC reduces to Rs. 246680/-. The total amount paid to Gencos & funds collected from Discos (revised) after rescheduling with UPFC is shown in Table VI.

Table VII. Change in P- Generation (pu) for the 75-bus system for Active Power Bidding with/without UPFC

	P_g -1	P_g -12	P_g -14
Without UPFC	1.0919	-1.6911	0.5
With UPFC	0.8336	-1.4336	0.5

Thus UPFC is highly effective in reducing the congestion cost. After placing UPFC the line flows at the base and also obtained after the congestion management along with their ratings are given in figure 9.

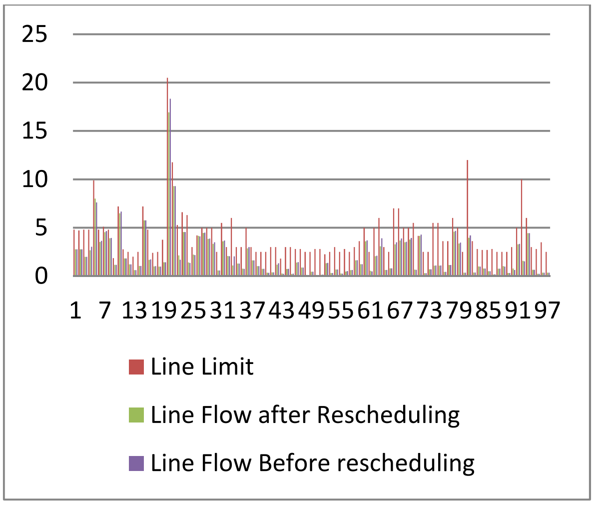

Figure 9. Line Flows for active power bidding with UPFC

The comparison of amount paid to Gencos & funds collected from Discos without rescheduling and with active power rescheduling with & without UPFC is shown in figure 10.

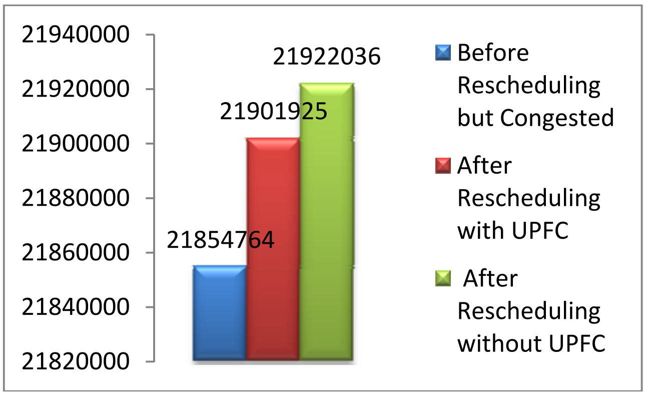

Figure 10. Total money flow before rescheduling and With & without UPFC after rescheduling through Active Power Bidding

8. Conclusion

In this paper MCP and LMP are calculated for Pool based transaction. The Congestion so obtained is addressed by the real power rescheduling bids of generators. A suitable objective function is chosen for the congestion cost. Using GAMS solver the change in generations of Gencos is calculated. The revised rates for MCP and LMP are calculated. It is obtained that the congestion is relieved in problem under study. The UPFC is placed at an optimal location using real power sensitivity indices. and the effect of placing UPFC at an appropriate location reduces Congestion Cost.

NOMENCLATURE:

Nl Number of Lines in the system,
Nb Number of Buses in the system,
Pg Power generation in each area,
Pd Power demand in each area,
P_{ij}^{0} Base case real power flow,
Q_{ij}^{0} Reactive power flow at normal operation,
CC Congestion Cost,
Ng,up Number of participants for incremental-bid congestion,
Ng,dn Number of participants for decremental-bid congestion,
$c_{Pg,r}^{+}$ Incremental congestion bid of r^{th} generator, $\Delta P_{g,r}^{+}$ Increase in the real power output of r^{th} generator,
$c_{Pg,s}^{-}$ Decremental congestion bid of s^{th} generator, $\Delta P_{g,s}^{-}$ Reduction in real power output of s^{th} generator,
$\Delta P_{D,t}$ Reduction in power consumption by a t^{th} customer,
$\Delta Q_{g,v}$ Adjustment in reactive power output of v^{th} generator,
$C_{Qg,v}(\Delta Q_{g,v})$ Reactive Bid Function
$C_{Pd,t}$ Load Curtailment Bid
ΔP_{L} Changes in the total real power transmission loss,
S_{ij}^{max} Line flow limit,
TCDFs Transmission Congestion Distribution Factors,
UPFC Unified Power flow Controller

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