Price based Automatic Generation Control for a two-area thermal-thermal deregulated power system considering Moth-Flame Optimized PI controller

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Abstract - **This article presents a frequency dependant price signal based new Automatic Generation Control (AGC) scheme for a two-area interconnected thermal-thermal deregulated power system. In this price based AGC, the prime plan is to limit the unscheduled interchange (UI) charge by invalidating the deviations in frequency and to keep up the generation at different units economically following an unsettling influence. Unscheduled Interchange (UI) charge is one of the segments of Availability Based Tariff (ABT), acts a system for directing the grid frequency. In the meantime, this component offers the chance for the members to trade as and when accessible surplus energy at a price dictated by prevailing frequency conditions. Despite the fact that the basic standard on which the UI instrument of ABT works is quite unique in relation to the conventional Automatic Generation Control, it can even now be seen as a price based secondary generation control mechanism. This scheme also gives the system operator flexibility to schedule the generation in a desired manner. In this investigation, execution of a Proportional-Integral (PI) controller is proposed as supplementary automatic generation control of two-area thermal-thermal deregulated power system that operates under the effects of bilateral contracts on the dynamics. The tuning of the PI controller parameters is formulated as an optimization problem and solved by employing a Moth-Flame Optimization (MFO) algorithm. The outcomes demonstrate that the UI charges are significantly limited by keeping up frequency at normal value and the load perturbations can be adjusted among the generators in a desired manner following a disturbance.**

Keywords — Availability Based Tariff, Generation Control Error, Marginal Cost, Moth-Flame Optimization (MFO) algorithm and Unscheduled Interchange prices.

I. INTRODUCTION

Even in the deregulated and restructured environments of the power system which is referred as reregulation, the Automatic Generation Control (AGC) is one of the most essential control issue in an interconnected power system. The most imperative goals of the AGC is to keep up system frequency and tie-line power deviations within permissible limit by directing the output power of every generator at concurred levels in light of persistently changing load demand [1]. In the restructured environment the power industry is divided into three different sectors such as generating companies (Gencos), distributing companies (Discos) and transmitting companies (Transcos) and the biding between Discos and Gencos is controlled by the Independent System Operator (ISO). In such a new scenario, Discos can autonomously make agreement with Gencos for delivery power to meet the demand of the consumer. An ISO is a self-governing agent that manages all the transactions alleged between Discos and Gencos. A Disco Participation Matrix (DPM) is used for hallucination of bonds between Gencos and Discos [2], [3], [4].

In order to maintain grid discipline and bring about more responsibility and accountability among the participants in the system, the availability based tariff (ABT) mechanism was introduced in Indian power sector. The Central Electricity Regulatory Commission (CERC) of India introduced ABT mechanism in July 2002 for fixing up the pricing of the bulk power trades, in the place of a decade old two part tariff. The ABT, a three part tariff structure is a commercial mechanism encourages grid discipline which leads to better frequency profile. The initial segment of ABT being capacity charge paid to generating company based on the availability of the generating unit, for example, it's an capacity to deliver power on a step by step

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premise. Consequently, this tariff structure got the name Availability Based Tariff. The second part of ABT is the energy charge which is to repay the expense of fuel required to produce the planned generation. The payment made to generating company under this heading is for the pre-planned generation and not for the real generation. The third piece of ABT is unscheduled interchange (UI) charge. For whatever length of time that the generators and beneficiaries adhere to their schedules, this component is zero. In any case, if there is a deviation from the schedule, UI charge comes into the picture. The UI instrument of ABT is an arrangement of remunerations and punishments trying to uphold day ahead pre-committed schedules by the both generators and beneficiaries [5], [6].

Because of this mechanism, generating companies (Gencos) were paid at higher rates for delivering generation past their schedule and distribution companies (Discos), who are the beneficiaries, will get incentives for under drawl when the frequency is underneath the rated frequency. Likewise, when the frequency is over the rated frequency, Gencos get benefit by decreasing their generation and Discos profited by overdrawing from the grid. Gencos are punished for diminishing their generation at whatever point the frequency is low and increasing the generation when the frequency is more than the rated value. Similarly Discos are punished for overdrawing when the frequency is low and under drawing at whatever point frequency is high. In the ABT regime, the objective of the generation controllers is that they have to nullify the deviations in supply frequency and also schedule the generators according to their merit so as to economize the system operation. Hence, conventional AGC is to be modified so that the UI price signal and the marginal cost may be incorporated into the system to meet the stated objectives [7], [8]. The primary loop of this model is similar to conventional AGC, responds to changes in frequency whereas the secondary loop, called ABT control loop is different from conventional AGC. The frequency is converted to UI price signal and is compared with marginal cost of the generator to generate an error signal called Generation Control Error (GCE). Several advanced controller structures and techniques have been proposed in literature for AGC loop. But, these advanced approaches are complicated and need familiarity of users to these techniques thus reducing their applicability [9]. Alternatively, a classical Proportional Integral (PI) controller and its variant remain an engineer's preferred choice due to its structural simplicity, reliability and the favorable ratio between performances and cost. Several optimization techniques plays an important role to find the optimal controller parameters, for example, Genetic Algorithm (GA), Particle Swarm Optimization (PSO), Bacterial Foraging Optimization (BFO), Krill Herd Algorithm (KHA), and Teaching Learning Based Optimization (TLBO)) algorithm have been planned to resolve the control parameters of a several standard controllers to solve the AGC problem. In the present work, a new nature inspired algorithm named Moth-Flame Optimization (MFO) algorithm introduced by Mirhalili in 2015 [10] has been proposed for tuning of the PI controller.

II. AUTOMATIC GENERATION CONTROL IN A DEREGULATED POWER SYSTEM

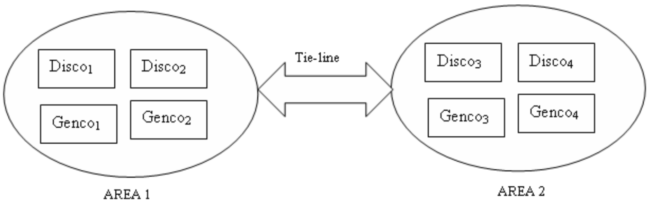

Fig.1 Schematic diagram of two-area power system in restructured environment

The deregulated power system structure changed in such a way that would allow the evolving of more specialized industries for generation (Genco), transmission (Transco) and distribution (Disco). In the deregulated power system, Discos in each area can contract with Gencos in its own or other areas. As there are several Gencos and Discos in the restructured power system, a Disco has the freedom to have a contract with any Genco for transaction of power. Such transactions are called bilateral transactions. All the transactions have to be cleared through an impartial entity called an Independent System Operator (ISO). The ISO has to control a number of so-called ancillary services, one of which is load frequency control. There is some difference between the AGC operation in conventional and deregulation environment.

After deregulation, optimization and operation are changed but their basic idea for AGC is kept same. In the new environment, Discos may contract power from any Gencos and independent system operator has to supervise these contracts. Disco Participation Matrix (DPM) concept is taken to understand the several contracts that are implemented by the Gencos and Discos. A DPM is a matrix with the number of rows equal to the number of Gencos and the number of columns equal to the number of Discos in the system. Each entry in this matrix can be thought of as fraction of a total load contracted by a Disco towards a Genco. The sum of all the entries in a column DPM is unity. In this study two-area thermal-thermal interconnected power system in which each area has two Gencos and two Discos. Let $Genco_1$, $Genco_2$, $Disco_1$, $Disco_2$ be in area 1 and $Genco_3$, $Genco_4$, $Disco_3$, $Disco_4$ be in area 2 as shown in Fig .1. The corresponding DPM is given as follow

$$DPM = \begin{bmatrix} cpf_{11} & cpf_{12} & cpf_{13} & cpf_{14} \\ cpf_{21} & cpf_{22} & cpf_{23} & cpf_{24} \\ cpf_{31} & cpf_{32} & cpf_{33} & cpf_{34} \\ cpf_{41} & cpf_{42} & cpf_{43} & cpf_{44} \end{bmatrix} \quad (1)$$

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where *cpf* represents "contract participation factor" i.e. p.u. MW load of a corresponding Disco. The scheduled steady state power flow on the tie-line is given as [3]

$$\Delta P_{Tie\ 12}^{scheduled} = \sum_{i=1}^{2}\sum_{j=3}^{4} cpf_{ij}\,\Delta P_{Lj} - \sum_{i=3}^{4}\sum_{j=1}^{2} cpf_{ij}\,\Delta P_{Lj} \quad (2)$$

The actual tie-line power is given as

$$\Delta P_{Tie\ 12}^{actual} = \frac{2\pi T_{12}}{s}(\Delta F_1 - \Delta F_2) \quad (3)$$

The generation of each Genco must track the contracted demands of Discos in steady state. The desire total power generation of i[th] Genco in terms of DPM entries can be calculated as

$$\Delta P_{mi} = \sum_{j=1}^{4} cpf_{ij}\,\Delta P_{Lj} \quad (4)$$

Following a change in load, the primary control loop is activated initially in the AGC. The secondary loop adjusts the reference power setting ΔPref which depends Generation Control Error (GCE), for fine tuning the frequency so that it settles at a reasonable value

III. PRICE SIGNAL BASED AUTOMATIC GENERATION CONTROL (AGC) SCHEME

The basic principle of the Price based AGC loop is illustrated in Fig 2. Each generator individually monitors the UI price ρ and compares with its marginal cost γ. It derives an error signal, which is the difference of current UI price and its own marginal cost. This error signal, which can be termed as Generation Control Error (GCE), is fed to an integral controller. A positive GCE indicates that the generator will profit by increasing generation level. A negative GCE indicates that Generator will profit by decreasing the generation level. So, GCE plays a vital role in controlling the power generation [11]. In this proposed control scheme, the GCE is redefined as

$$GCE = UI\ price\ (\rho) - marginal\ cost(\gamma) \quad (5)$$

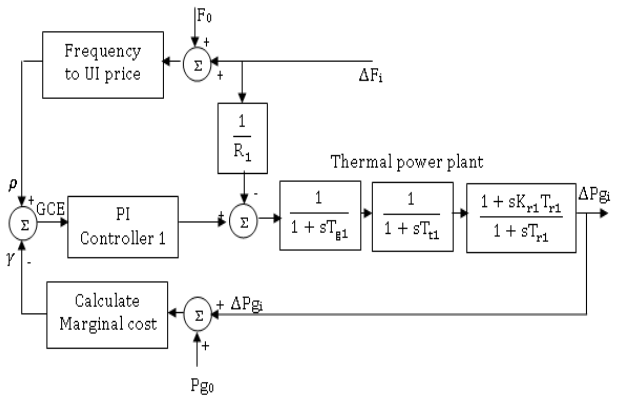

Fig.2 Block diagram of Price signal based Automatic Generation Control

3.1 Frequency to Unscheduled Interchange (UI) charge calculation

For the simulation model, CERC 2014 regulation has been considered [1]. The frequency to Unscheduled Interchange (UI) charge calculation for the year 2014 has been shown in Fig 3.

```
function p = fcn(F)
if F<=49.7
   p=8240.4;
     elseif F<=50;
            p=1780+20840*(50-F);
              elseif F<=50.05
                     p=35600*(50.05-F);
                     else
                        p=0;
end
```

Fig.3 Frequency to Unscheduled Interchange (UI) charge block

3.2 Marginal Cost Calculation

The fuel cost characteristics of generators in INR/h is given by

$$C_i(P_{gi}) = a_i + b_iP_{gi} + c_iP_{gi}^{\ 2} \quad (6)$$

where ai, bi, ci are the cost coefficients which are constant for a given generator.

The marginal cost of *i*th generator in INR/MWh is given by

$$(Marginal\ cost)_i = b_i + 2c_iP_{gi} \quad (7)$$

The actual marginal cost of each generator is calculated using (7) by taking Pgi = Pgi_0 + ΔPgi where Pgi_0 is the generation at *i*[th] generator before the disturbance and ΔPgi is the change in generation due to generation control mechanism. The reference marginal cost of individual generator is calculated using (7) by substituting the desired Pgi values. Following a change in load, the desired Pgi values may be obtained by running the economic dispatch program or by allocating the change in load to generators randomly with the experience of the system operator. In this study, a two-area interconnected deregulated power system model consisting of two thermal generating stations in each area is considered as shown in Fig 4. All generators are operating with primary/ conventional automatic generation control scheme or availability based tariff automatic based generation control scheme and each generator is owned by a separate generation company. The implementation of an availability based tariff based automatic generation control scheme is carried out for switching operations between automatic generation control and non-automatic generation control mode, which is based on the difference of the generator's marginal cost and real time frequency dependent price of unscheduled generation.

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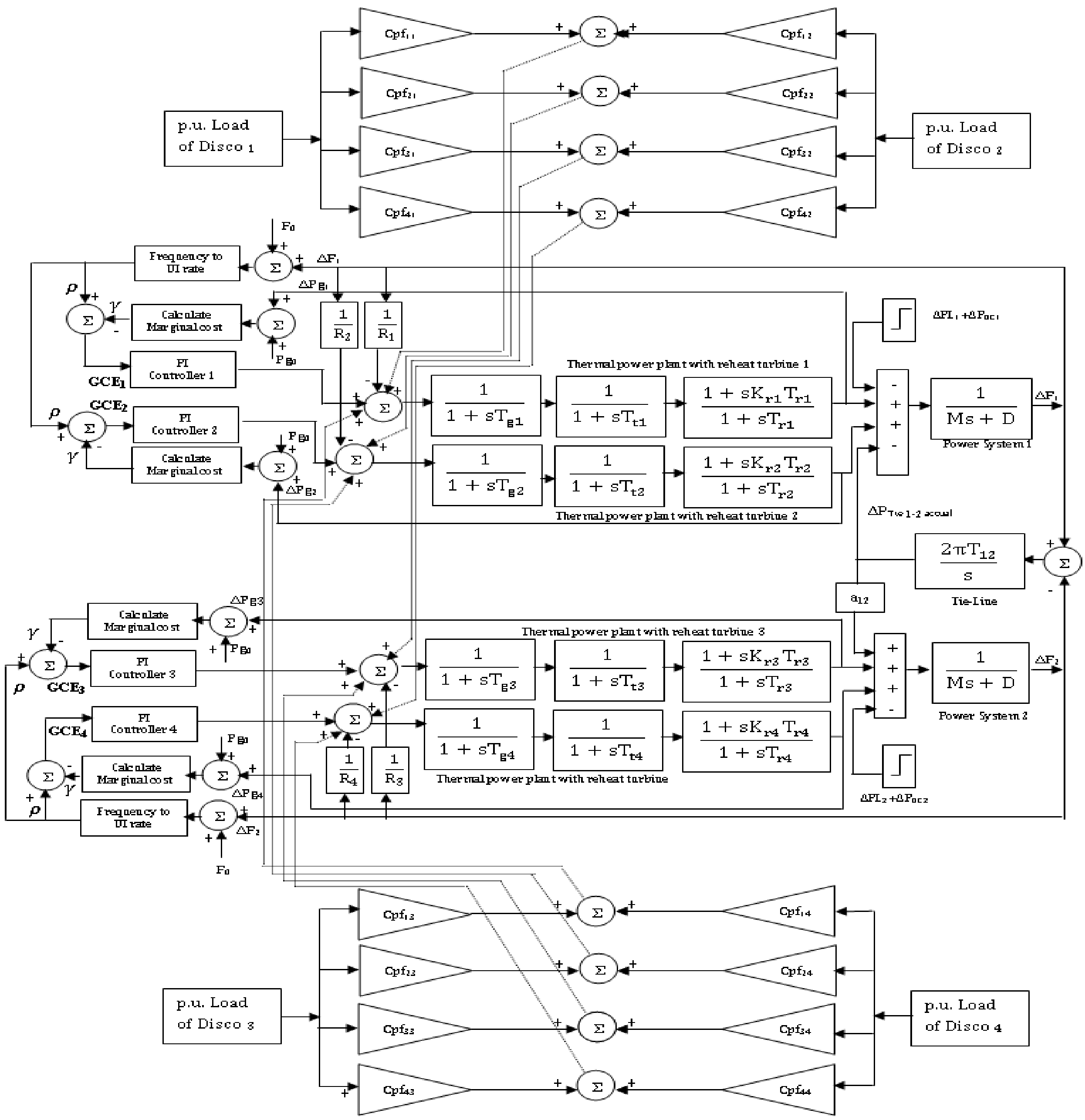

Fig. 4 Transfer function model of Price signal based Automatic Generation Control (AGC) scheme for a two area thermal-thermal deregulated power system

IV. DESIGN OF PI CONTROLLER USING MOTH-FLAME OPTIMIZATION (MFO) ALGORITHM

4.1. Controller structure of PI controller

The Proportional and integral refers to reset action which involves integration of generation control error (GCE) signal over a period of time. The rate of change of correcting signals is proportional to the GCE signals. The combination of proportional and integral terms is important to increase the speed of the response and also to eliminate the steady state error. In this study, PI controllers are used to improve the dynamic performance of price based AGC loop for a two area thermal-thermal power system is shown in Fig 5. The PI control action depends on the proportional gain (K_{Pi}) and Integral controller gain (K_{Ii}) which vary for different applications. The main function of AGC is to control load frequency and tie line power during load disturbance. So the GCE signals of frequency and tie line power are used as design criteria to tune the PI controller. The error inputs to the controllers are the respective generation control errors (GCE) given by Eqn. (5). The control inputs of the power system u1 and u2 with PI structure are given by Eqn. (8) and (3.9).

$$u_1 = K_{P1}\, GCE_1 + K_{I1} \int GCE_1\, dt \quad (8)$$

$$u_2 = K_{P2}\, GCE_2 + K_{I2} \int GCE_2\, dt \quad (9)$$

In this study, Moth-Flame Optimization (MFO) algorithm is used to tune the PI controller for a two area thermal-thermal interconnected power system. Proportional gain constant

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(K_{Pi}) and Integral gain constant (K_{Ii}), are considered as variables describing a population defined in an MFO. The performance of these responses is measured using performance functions such as Integral of Squared Error (ISE) given by Eqn (10).

$$J = \int_0^{t_{sim}} [(GCE)^2]\, dt \quad (10)$$

The problem constraints are the proposed controller parameter bounds. Therefore, the design problem can be formulated as,

$$Minimize\ J \quad (11)$$

Subject to

$$K_P^{min} \leq K_P \leq K_P^{max}, K_I^{min} \leq K_I \leq K_I^{max} \quad (12)$$

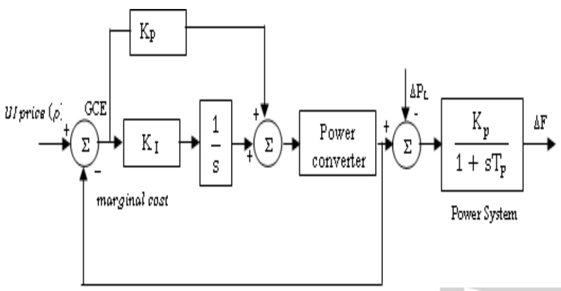

Fig. 5 Block diagram for PI controller with price based AGC loop

4.2. Moth-flame optimization (MFO) Algorithm

Mirjalili proposed moth-flame optimization (MFO) in 2015 [10] that is motivated by the moths navigation approach. Moths depend on transverse orientation for navigation where a moth flies by keeping up a settled point concerning the moon. At the point when moths see the human-made artificial light, they endeavor to have a similar angle of the light to fly in the straight line. Moths and flames are the primary components of the artificial MFO algorithm. MFO is population-based algorithms with the set of n moths are used as search operators. Flames are the best N positions of moths that are acquired so far. In this manner, every moth seeks around a flame and updates it if there should be an occurrence of finding a better solution. Given logarithmic spiral, a moth updates its position concerning a given flame as in the Eqn (13) [10].

$$S(M_i, F_j) = D_i e^{bt} \cos(2\pi t) + F_j \quad (13)$$

where Di shows the Euclidian distance of the i^{th} moth for the j^{th} flame, b is a constant to define the shape of the logarithmic spiral, Mi demonstrate the i^{th} moth, Fj shows the j^{th} flame, and t is a random number in [−1, 1].

As might be found in the above equation, the next position of a moth is characterized with respect to a flame. The t parameter in the spiral equation describes how much the next position of the moth ought to be near the flame. The spiral equation permits a moth to fly around a flame and not necessarily in the space between flames taking into account both exploration and exploitation of solutions. With a specific end goal to further emphasize exploitation, we suppose that t is a random number in [r, 1] where r is linearly decreased from −1 to −2 through the span of emphasis and is called convergence constant. With this technique, moths tend to exploit their corresponding flames more precisely corresponding to the number of iterations. In order to upgrade the likelihood of converging to a global solution, a given moth is obliged to update its position utilizing one of the flames (the corresponding flame). In every iteration and in the wake of updating the flame-list, the flames are sorted based on their fitness values. After that, the moths update their positions as for their corresponding flames. To permit much exploitation of the best encouraging solutions, the number of flames to be taken after is diminished as for the iteration number as given in the Eqn (14).

$$N_{flames} = round\left(N - l * \left(\frac{N-1}{T}\right)\right) \quad (14)$$

where *l* is the present iteration number, N is the maximum number of flames, and T demonstrates the maximum number of iterations

V. SIMULATION RESULTS AND OBSERVATIONS

In this test system consists of two Gencos and two Discos in each area. All the Gencos in every area consider as thermal reheat units. In this study, Moth-flame optimization (MFO) Algorithmis utilized for ideal tuning PI controller for price based AGC loop of a two-area thermal-thermal deregulated power system. The ideal arrangement of control inputs is taken for improvement issue and the target work in Eqn (10) is determined to utilize the Generation Control Error (5). The optimum control parameters of PI controller such as proportional gain (Kp) and Integral gain value (Ki) is 0.378 and 0.247 respectively. Under current regulations (CERC, 2009), UI price is pegged at 1800 INR/MWh at 50 Hz frequency. This means that if everyone (Generators and Loads) adhere to the schedule, the frequency should be 50 Hz and UI price 1800 INR/MWh. However, at 1800 INR/MWh UI price some generators get an error signal causing them to deviate from their schedule. This may even cause the frequency to deviate from nominal value. This outcome is undesirable, as it results in UI among generators even when load is as per schedule. To illustrate our point, we simulated an isolated area system having a capacity of 5000 MW supplied by four generating stations. The relevant data is shown in appendix. The system data is given in Table 1. The generator capacities and their cost coefficients are given in Table 2. The power generations are given in Table 3 for various schedules and their corresponding marginal costs are given in Table4. Here every one of the Discos has the contract with the Gencos and the accompanying Disco Participation Matrix (DPM) alluding to Eq (1) is considered as

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$$DPM = \begin{bmatrix} 0.5 & 0.5 & 0.0 & 0.0 \\ 0.5 & 0.5 & 0.0 & 0.0 \\ 0.0 & 0.0 & 0.5 & 0.5 \\ 0.0 & 0.0 & 0.5 & 0.5 \end{bmatrix} \quad (15)$$

Case 1: The generators are scheduled in merit order and load level results in system marginal cost of 1800 INR/MWh. This scenario represents the only case in which price based generation control works successfully. The scheduled generation of this scenario is given in first row of Table 3. For this scenario, the generation is scheduled so that the overall system marginal cost is 1800 INR/MWh. The load level does not change during the simulation. This means that none of the generators will get any error signal. The outcome of simulation is shown in Fig 6. It is observed that there is no impact on either frequency/UI price or scheduled generation.

Case 2: The generators are scheduled in merit order and the system marginal cost is equal to the reference UI price of CERC 2009 regulations. A load increase of 400 MW in area 1 is considered. The power generations of schedule 1 from Table 3 is considered. As the load is increased by 400 MW, the total load on the system becomes 3483.33 MW. Allocating this total load on equal marginal cost basis $Genco_1$ and $Genco_2$ in area 1 will get additional 200 MW each. With this new generation schedule,. the system frequency response and UI price and change in generation power is shown in Fig 7. As the system frequency in area 1 deviated its nominal value with the sudden increase in load, it has to pay the UI charge is 2000 INR/MWh.

Case 3: The generators are scheduled in merit order and the system marginal cost is equal to the reference UI price. A load is decrease of 400 MW in area 1 is considered. The power generations of schedule 1 from Table 3 is considered. As the load is decrease by 400 MW, the total load on the system becomes 2683.33 MW. Allocating this total load on equal marginal cost basis $Genco_1$ and $Genco_2$ in area 1 will get reduced power generation of 200 MW each. With this new generation schedule,. the system frequency response and UI price and change in generation power is shown in Fig 8. As the system frequency in area 1 more than the nominal value with the sudden decrease in load, it has to pay the UI charge is reduced 1600 INR/MWh from the nominal price 1800 INR/MWh at 50 Hz. A rise in frequency is observed and consequently the UI price falls to around 1600 INR/MWh. Only Generators 1 and 2 are capable of reducing their outputs.

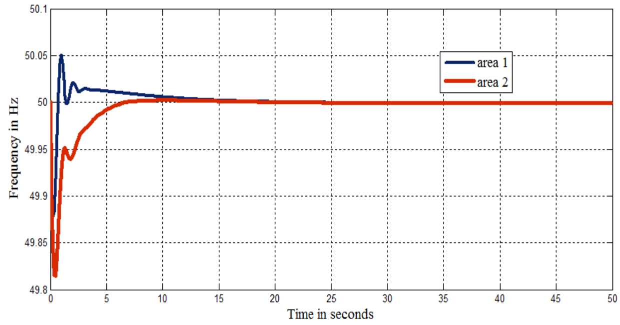

Fig. 6(a) Frequency in Hz

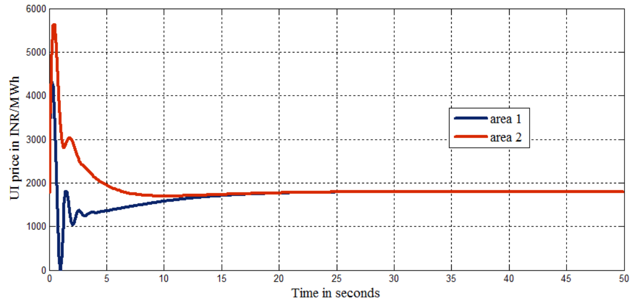

Fig. 6(b) UI price in INR/MWh

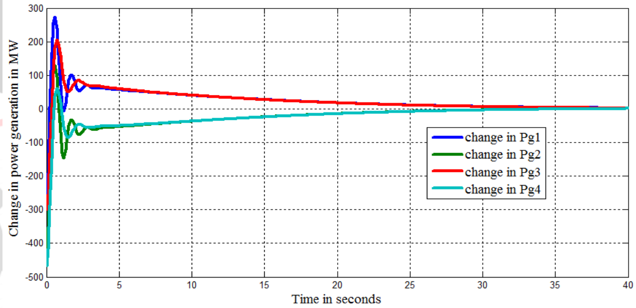

Fig. 6(c) change in power generation in MW

Fig.6 Dynamic responses of the frequency deviations, unscheduled interchange (UI) price and change in power generation for a two area thermal-thermal system in case 1

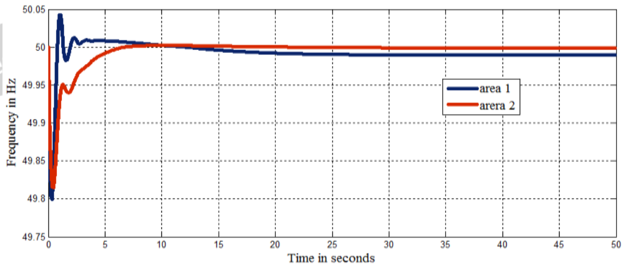

Fig. 7(a) Frequency in Hz

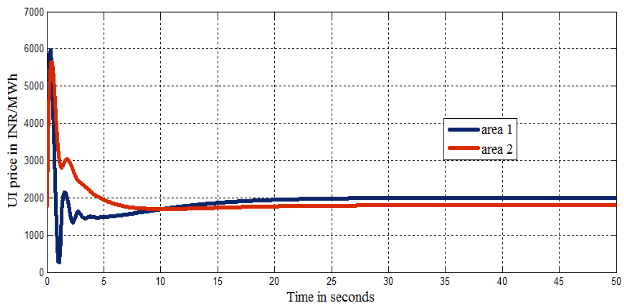

Fig. 7(b) UI price in INR/MWh

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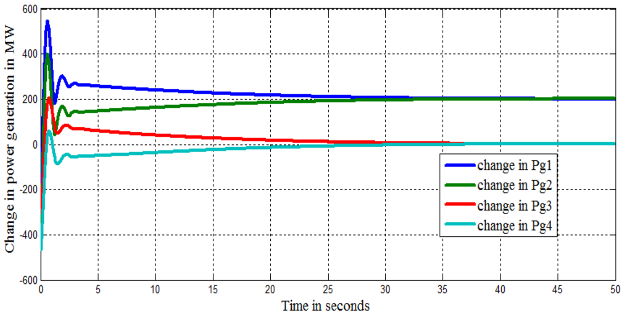

Fig. 7(c) change in power generation in MW

Fig.6 Dynamic responses of the frequency deviations, unscheduled interchange (UI) price and change in power generation for a two area thermal-thermal system in case 2

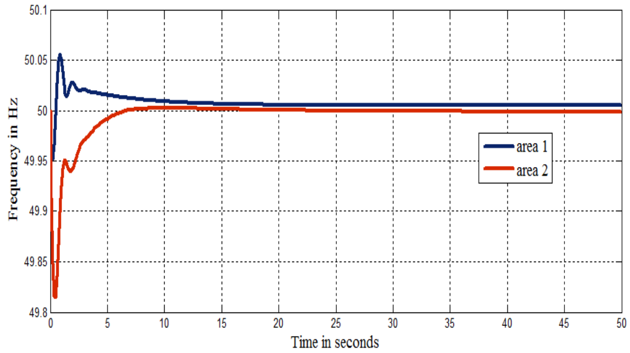

Fig. 8(a) Frequency in Hz

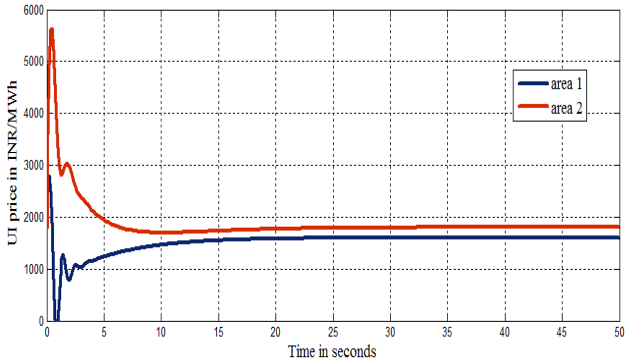

Fig. 8(b) UI price in INR/MWh

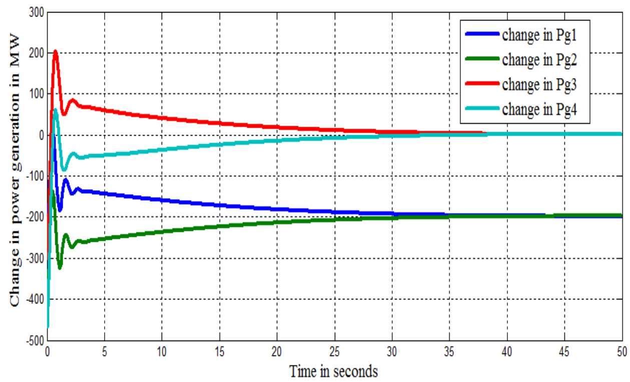

Fig. 8(c) change in power generation in MW

Fig.6 Dynamic responses of the frequency deviations, unscheduled interchange (UI) price and change in power generation for a two area thermal-thermal system in case 3

VI. CONCLUSION

In this paper, a new scheme is presented to generate GCE using the UI prices and the marginal costs to minimize the UI charge by mitigating the frequency deviations and to maintain the desired generation schedule. Frequency stability and economic operation are simultaneously achieved through this scheme and no tertiary control loop is required for this purpose as in the case of conventional AGC. The benefit of this scheme is that the generators can earn profit by increasing the generation during the peak hours and decreasing the generation during the off peak hours. Implementation of proposed control on all central and state generating stations will not only result in better control of frequency, but merit order dispatch of generation can also be ensured at the same time. The UI obligations of participants can be drastically reduced through this mechanism.

APPENDIX

Table 1 System data [6, 7]

Capacity = 5000 MW
M= 1000 MW-s/Hz
D= 100 MW/Hz
F^o=50 Hz
$R_1 = R_2 = R_3 = R_4$ = 2.4 Hz / p.u.MW
$T_{g1} = T_{g2} = T_{g3} = T_{g4}$ = 0.08 s,
$T_{r1} = T_{r2} = T_{r1} = T_{r2}$ = 10 s
$T_{t1} = T_{t2} = T_{t3} = T_{t4}$ = 0.3 s
$K_{r1} = K_{r2} = K_{r3} = K_{r4}$ = 0.5
$2\pi T_{12}$ = 0.545 p.u.MW / Hz, a_{12}= -1

Table 2 Generator Data [6, 7]

		$Genco_1$	$Genco_2$	$Genco_3$	$Genco_4$
Capacity (MW)		1500	1500	1500	1500
Cost	*bi* (INR/MWh)	800	1000	800	1000
Coefficients	*ci* (INR/MW^2h)	0.3	0.3	0.3	0.3

Table 3 Generation Schedule (in MW) [6, 7]

	$Genco_1$	$Genco_2$	$Genco_3$	$Genco_4$
Schedule 1	1500	1333.33	250	0
Schedule 1I	1500	1500	83.33	0
Schedule 1II	1500	1500	250	0

Table 4 Marginal Costs in INR/MWh [6, 7]

	$Genco_1$	$Genco_2$	$Genco_3$	$Genco_4$
Schedule 1	1700	1800	1800	2000
Schedule 1I	1700	1700	1700	2000
Schedule 1II	1700	1900	1900	2000

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