Abstract: In this research paper, an innovative solution by proposing a novel mechanism for implementation of regulatory approach—based new deviation settlement scheme for frequency control is suggested. Power systems of many developing countries have to face sustained generation deficiency, large frequency fluctuations and are susceptible to even small disturbance. Operating such a system is a difficult task and innovative solutions are needed to solve this situation. To overcome this situation, India has adopted commercial mechanism known as Availability-based Tariff (ABT), which has a component linked with frequency. A commercial mechanism is a paradigm shift in the operational strategies from the conventional frequency control to new deviation control. This proposed scheme satisfies Central Electricity Regulatory Commission (CERC) criteria and inclusive future norms. The MATLAB used to enable to analyze proposed rules and the strength of the approach, is to segregate the conventional Automatic Generation Control (AGC) with new UI-based AGC. The enhancement of AGC algorithms is to meet increased demand by efficient implementation of algorithm for generators rescheduling, as per new CERC norms.

Subjects: Electrical & Electronic Engineering; Power Engineering; Engineering Economics

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PUBLIC INTEREST STATEMENT
Energy plays a vital role in the development of human activities, and sustainable social and economic development depends on adequate energy generation capacity. The objective of the paper is to provide a vision to introduce spinning reserve in the Country, which is one of the important components for ensuring grid security, quality and reliability, by adequacy of supply and maintaining Load – Generation balance. It was envisaged by the Central Electricity Regulatory Commission (CERC) that each region should maintain primary and secondary reserves. All the generating units must plan Automatic Generation Control (AGC). A bad or no forecast of load/RE Generation or poor load management may lead to heavy deviation from the schedule and grid indiscipline, thereby exhausting all reserves in the system and making the system insecure. Effectiveness of AGC is one of the steps in that direction for the stable frequency operation and security of the grid.

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1. Introduction

The developing countries have sustained power shortage problem compared to developed countries for many reasons, mostly financial in nature (Roy & Khaparde et al., 2005). Mismatch between power generation and demands, results in deviation of system frequency and tie-line power.

Automatic Generation Control (AGC) is a very indispensable control strategy in electric power system, utilized to maintain the tie-line-power flows stipulated tolerances and to hold the system frequency at or very close to a specified nominal value. Each unit generates most economic values and also maintains the correct value of share of power generations between generators, for mitigating growing power demands. (Berger & Schweppe, 1989).

The Availability-based Tariff (ABT) based commercial mechanism has brought a paradigm shift in operating strategies for conventional frequency control and dispatch techniques linked with frequency. This mechanism can be compared with real-time balancing market operation (Kumar et al., 1997a) with similar principle of operation for restructuring power plant (Kumar et al., 1997b). Any generator or utility is allowed to inject power into the pool or draw from the pool at Unscheduled Interchange (UI) prices as long as the frequency is maintained within the stipulated band (Zhong & Bhattacharya, 2003).

Such a loose power pool with floating frequency best suits the deficient power system. The ABT helps in flattening of the load curve, as some of the utilities shift their peak load to off-peak hours. Frequency control requires the provision of primary regulation, and supplementary regulation is a basic requirement. Primary regulation is provided through speed governors which respond to frequent changes by varying turbine output. Keeping governors free to operate in the entire frequency range enables smooth control of frequency fluctuations as well as security against grid disturbances (Soonee, 2005).

Several conventional load frequency control strategies are developed by the power engineers (Tyagi & Srivastava, 2006). To promote AGC performance during crest load demand is the use of storage facilities such as redox flow batteries, which not only have benefits in load leveling and peak shaving but also assist in frequency/voltage regulation (Arya, 2018). Fuzzy gain scheduling controllers for AGC of two-area interconnected electrical power systems (Arya & Kumar, 2016b) and Optimal control strategy–based AGC of the electrical power systems (Kaur, 2019) are used to improve dynamic performance.

Some of the control methods lately in literature for AGC system are a bacterial foraging optimal algorithm (BFOA), fractional order-fuzzy PID (FOFPID), Fuzzy PID, BFO-based PID, etc. It is apparent from the literature analysis that AGC performance of the power system is highly linked with controller classifications and the tuning used to optimize to controller gains (Arya & Kumar, 2016a).

It is examined by researchers that Improved Particle Swarm Optimization (IPSO) showcased an improved system dynamic performance over conventional controllers. In a deregulated environment and restructured electric system, it is favored to harness some unique control strategy, to attain AGC goals and secure system effectively.

In India, a breakthrough occurred in 2002, with the implementation of ABT. The frequency linked real-time pricing scheme based on deviation settlement mechanism (Parida, Singh, & Srivastava, 2010). provided the secondary generation load control for Indian electricity grid (Chanana, 2011).

As per CERC norms, 2009 (49.2 Hz—50.03 Hz), 2012 (49.48 Hz—50.2 Hz), 2014 (49.69 Hz—50.05 Hz). The UI charges for all time blocks in between 50.05 Hz and 49.81 Hz follow different rates for CERC, 2017. If the grid operates at a frequency above 50 Hz, and the system has surplus power, the
unscheduled Interchange charge will be less, and the generators are automatically encouraged to reduce generation level. In the reverse situation, the UI rates are high therefore motivating generators to generate more power. The ABT thus ensures more economical and reliable operation of power plants for operation within a specified frequency limit (Bhushan, 2000).

The MATLAB used to analyze proposed rules and the strength of the approach, segregates the conventional Automatic Generation Control (AGC) with new UI-based AGC. The enhancement of AGC algorithms is to meet increased demand by efficient implementation of algorithms for generators rescheduling as per new CERC norms in the Indian Electricity market.

The objective of this paper is to evaluate the performance of participating generators, under new Central Electricity Regulatory commission norms, with merit order scheduling and rescheduling within 12% from scheduled generation (Pai & Gupta, 2016b). The purpose of research work is to provide a clear cut understanding of the implementation of new regulatory norms under specified constraint and to know the limits, where load shedding by independent system operators is a must. It also opens avenues of research for contingency.

This proposed scheme satisfies CERC criteria and inclusive future norms. The MATLAB used enables to frame a generic model to analyze rules and decide future norms. It may be included in the algorithm and is the main contribution of authors. The strength of the approach is to segregate the conventional Automatic Generation Control (AGC) with new UI-based AGC. The enhancement of AGC algorithms (Murli & Sudha, 2019) is to meet increased demand by efficient implementation of algorithm for generators, rescheduling as per new CERC norms along with Analysis and demand-side management.

The article is arranged in various sections as, Section II presents the system examined, mathematical modeling, steady state performance, supplementary AGC loop, ABT and UI mechanism, CERC norms and reforms in Indian power sectors Section III describe Block diagram and control scheme, framework for enhanced price-based AGC model for frequency regulation, complete mathematical modeling and MATLAB/SIMULINK Model. The results and analysis for step change, and sudden increase in load are dealt with in Section IV. Section V discusses conclusion and shows that this control scheme gives satisfactory results in term of frequency control.

A modified control scheme is verified by simulating it on model of isolated area system having four generators. It has been shown here that a generic model, if adopted by all generating stations, can improve the control of frequency and bring down the UI obligation of participants.

2. System examined
In this research analysis, four generators of an isolated area are considered. The parameters of the system are taken from previously published research work (Pujara & Kotwal, 2014). To implement the availability-based tariff mechanism, the understanding of marginal cost calculation of generating unit is essential. The energy cost depends on fuel usage, as per the scheduled generation. For thermal generating unit, these two costs can be combined, based on the heat rate curve of the thermal unit conversion system, to get marginal cost. The UI price is regulated as per the CERC Regulation.

As per Table 1, unscheduled interchange is priced based on the frequency of generation at that instant. As per the regulation 2017 (CERC_2017), the UI price is 2500 Rs./MWH at frequency 50.0 Hz, i.e. when the generators and the loads connected with the systems operate as per scheduled generation. The MATLAB codes are developed to calculate the UI price as per Table 1 and embedded in the MATLAB function block, drawn in Simulink block. As per the ABT mechanism (Bhushan, Roy, & Pentayya, 2004), if the plant delivers more than its scheduled generation, then the energy charge will be payable to the plant for the scheduled capacity and with the excess power at the frequency above 50.0 Hz, the UI rate will be small.
In contrast, if the plant generates more than it’s scheduled at the time of generation, with deficit at a grid frequency below 50.0 Hz, then the plant will get UI charge at higher rate. The reverse situation will occur, when the generator will deliver less power to the grid. This price control logic under ABT scheme is established through MATLAB code and generates an error signal (Pujara & Kotwal, 2004). The error signal is then sent to the PID controller, to establish the frequency control. The PID controller is tuned using internal tuning mechanism inbuilt in the MATLAB/SIMULINK.

2.1. Automatic generation control

The automatic generation control models are used to control the frequency deviation in the system (Reddy, Kumar, & Chanana, 2006). The speed governor controls the amount of steam through the valve by controlling the position of the valve according to the shaft speed of the generator and thus controls the turbine output power. This is called primary frequency control. The mathematical model is described as follows:

Under steady state, the frequency remains at rated value, but electrical load varies with time, therefore the matching of mechanical input and electrical output is essential to maintain constant frequency (Donde, Pai, & Hiskens, 2001). The deviation in the frequency is,

$$\Delta f(s) = \frac{1}{2Ms + D} [\Delta Pm(s) - \Delta Pe(s)]$$  \hspace{1cm} (1)

$$\Delta Pe = \Delta PL + D\Delta \omega$$  \hspace{1cm} (2)

where M is the frequency independent component and D is the frequency dependent component. D is called as the frequency characteristics of the load also known as the damping constant. Where \(\Delta P_{ref}\) is the reference set power. The hydraulic amplifier then converts this output into the valve position given by the following equation:

$$\Delta Pg(s) = \frac{1}{R} \Delta f(s)$$  \hspace{1cm} (3)

$$\Delta Pv(s) = \frac{Kg}{1 + sTg} \Delta Pg(s)$$  \hspace{1cm} (4)

$$\Delta Pm(s) = \frac{Kt}{1 + sTt} \Delta Pv(s)$$  \hspace{1cm} (5)

Tg is the time constant of hydraulic servomotor and steam valve position dynamics. R is called as the droop characteristics of the generator which gives the mechanical output-generator speed relationship. The word droop means with only primary control when system load increases, the primary control will make an increase in mechanical power to regain the balance with lower frequency. The block diagram for automatic generation control is given in Figure 1(a).

2.2. Steady-state performance of the AGC

In the steady state, the AGC loop is open and the output is obtained by substituting \(s \rightarrow 0\) in the transfer function. With these, the turbine and governor transfer functions become unity. Thus, turbine output = generator output = load demand.
\[ \Delta P_m(s) = \Delta P_{ref}(s) - \frac{1}{\Delta f} \Delta f \]  

When the generator is connected to an infinite bus, then, \( \Delta f = 0 \). Hence

\[ \Delta P_m = \Delta P_{ref} \]  

If the network is finite, for a fixed speed changer setting \( \Delta P_{ref} = 0 \). Then,

\[ \Delta P_m = -\frac{1}{\Delta f} \Delta f(s) \quad \text{OR} \quad \Delta f = -\frac{1}{\Delta f} \Delta P_m \]  

If the frequency dependent load is present, then

\[ \Delta P_m = \Delta P_{ref} - \left( \frac{1}{\Delta f} + D \right) \Delta f(s) \]  

\[ \text{OR} \quad \Delta f = -\frac{\Delta P_m}{D + \frac{1}{\Delta f}} \]  

### 2.3. Supplementary AGC loop

The AGC loop discussed above is the primary loop. It achieves the primary goal of controlling the frequency deviations by adjusting the turbine output power to match the load demand. The change in load causes a change in steady-state frequency \( \Delta f \).

For the restoration of the frequency of the nominal value, an additional control loop is required known as the supplementary control. This is achieved by using an integral controller which brings back the frequency deviation to zero. Figure 1(b) shows a block diagram representation of AGC with supplementary control loop (Pai & Gupta, 2016b).
2.4. ABT & UI mechanism
The several reforms were initiated by the Government of India (GOI), to boost generation capacity. In 2003, Availability-based Tariff was introduced to deal with grid operation problems. It is a three-part tariff scheme which consists of fixed cost or the capacity charge, variable cost or the energy charge and a frequency dependent component called as the deviation charge.

In the scenario of generation shortage, the third component of ABT, i.e. the deviation charge acts as a mechanism for regulating the grid frequency (Bhattacharya, Chattopadhyay, & Parikh, 1998). In UI-based generation control mechanism, all generating stations can self-dispatch power based on frequency actuated UI rate signal (Hasan & Ahmad, 2016). The marginal cost of each generator unit is compared with the UI signal, to decide whether the generation should be increased or decreased, to achieve new equilibrium state.

2.5. CERC regulations
The shape of UI price versus frequency curve for CERC_2017 is shown in Figure 2. The UI rates are depending on system frequency and in regulating by Central Electricity Regulatory Committee norms. The UI rates are to be readjusted whenever the energy costs of generation in the Country get revised. At regular interval of time, UI curve has been modified under regulation, issued by CERC since introduced in 2009. Price vectors are indicated in Table 1.

2.6. Reforms in indian power sectors
The Electricity Act 2003 has given a major boost to trading activities, and encouraged competition in the electricity markets Due to the poor financial state of SEBs (State Electricity Boards), GOI decided to amend the IE Act, 1910 and ES Act, 1948, in order to attract private players in power generation. Further, efforts were initiated for functional unbundling and privatization of SEBs into distinct generation, transmission & distribution companies and formation of State Electricity Regulatory Commissions (SERCs). Electricity Regulatory commission (ERC) Act was enacted in 1998, which provided for setting up CERC and State Regulatory Commissions.

3. Block diagram and control scheme of price-based AGC
The block diagram representation of ABT-based control loops of two controlling loops have been shown. Primary control loop is shown in Figure 3(a) (Chanana & Kumar, 2008) which has been operated manually and responds to change in frequency instantaneously, by using free governor mode of operation. Secondary control loop (Parida et al., 2008) has been operated manually, whenever there is requirement of more generation that cannot be met through primary loop.

A control scheme of price-based Automatic generation control (Chonana & Kumar, 2010) is dealt with. According to this scheme, primary control remains same as that of the conventional control
system, while secondary control system uses UI price signals. A Signal S1 block represents the change in frequency and is added with the nominal frequency. After that, signal S2 block converts frequency signal into price signal. In Block S3, the marginal cost of generators is calculated, and it is subsequently fed to Block S4 for the generation of generator control error (gce). This error is now applied to governor, to control frequency. The change in generation is checked for 12% deviation condition against change in load demand.

The frequency linked price-based automatic generation control mechanism shown in figure 3(b), (Pujra & Kotwal, 2006) ensures that the generating units respond to UI price signal automatically in real time (Tan, Zang & YU, 2012). As per this control, each generator individually monitors the UI price (ρ) and compares with its marginal cost (γ), then generated control error signal. This error signal is fed to the gce logic block signal and further, it is fed to the integral controller block. A positive gce signal indicates that the generator will be in profit, by increasing the generation level, while negative gce signal, indicates that the generator will be in profit, by decreasing the generation level.
3.1. Mathematical modeling

It is assumed that the generators of single area are generating power at their scheduled value and frequency of the grid is at its scheduled frequency 50 Hz. Now, when a step change of P MW occurs in the system, it results in deviation $\Delta f$ in the supply frequency

$$S_1(f) = \Delta f + f^0\text{Hz}$$ (11)

At this frequency, signal $S_1(f)$ corresponding UI Price signal $S_2(\rho)$ can be calculated as per UI rate with respect to the frequency regulation issued by given year, equation (12) to (16) shows the calculation of UI price signal for UI rate issued by CERC (Tyagi & Srivastava, 2004).

If $S_1(f) > 50.05\text{Hz}$, $S_2(\rho) = 0$ Rs/MWH (12)

If $50.0 \text{Hz} < S_1(f) \leq 50.05 \text{Hz}$, $S_2(\rho) = 2500 + 27500 \{50 - S_1(f)\}$ Rs/MWH (13)

If $49.81 \text{Hz} < S_1(f) \leq 50 \text{Hz}$, $S_2(\rho) = 50000 + \{50.05 - S_1(f)\}$ (14)

If $S_1(f) \leq 49.81 \text{Hz}$, $S_2(\rho) = 8000$ Rs/MWH (15)

Now, the obtained UI price signal $S_2(\rho)$ is compared with the incremental cost signal $S_4(\gamma)$ of generator, which generates a signal $S_5(\text{gce})$. This incremental cost signal $S_4(\gamma)$ of each generator is given by following equation.

$$S_4(\gamma) = 2 \times c_i \times S_3(P_g) + b\text{Rs/MWH}$$ (16)

$S_3(P_g)$ is given by equation

$$S_3(P_g) = P^0_g + \Delta P_g\text{MW}$$ (17)

Further, $S_2(\rho)$ is compared with the following logic to generate Generation Control Error (GCE), $S_5(\text{gce})$ Rs/MWH.

If $S_4(\gamma) > \rho^0$ (18)

No, then go to (24) otherwise

If $S_2(\rho) > S_4(\gamma)$ (19)

No, then go to (21) otherwise

$S_5(\text{gce}) = S_2(\rho) - S_4(\gamma)$ (20)

If $S_2(\rho) < \rho^0$ (21)

No, then go to (23) otherwise

$S_5(\text{gce}) = S_2(\rho) - \rho^0$ (22)

$S_5(\text{gce}) = 0$ (23)

If $S_2(\rho) < S_4(\gamma)$ (24)

No, then go to (26) otherwise

$S_5(\text{gce}) = S_2(\rho) - S_4(\gamma)$ (25)

If $S_2(\rho) < \rho^0$ (26)

No, then go to (24) otherwise

$S_5(\text{gce}) = S_2(\rho) - \rho^0$ (27)
\[ S5(gce) = 0 \]  

For \( S5(gce) \) signal from equation (11) and equation (17), the steady state error is given by the relation, where \( K_U = \text{Slope of UI curve} \), the value corresponds to UI price \( p_0 \) in Hz. \( K_{II} = \text{Integral controller gain of } i^{th} \text{ generating unit} \), \( R_i = \text{Speed regulation in Hz./MW} \), \( c_i = \text{Incremental cost coefficient of } i^{th} \text{ generator unit} \) (Wood & Wallenberg, 1984).

\[
\Delta f(s) = -\frac{P}{(Hs + D)} \left( \sum_{i=1}^{n} \frac{K_i R_i}{s + 2C_i} \right) \text{Hz} 
\]  

\[
\Delta f ss \rightarrow \text{lim}_{s \to 0} s \Delta f(s) = -\frac{P}{1 + \frac{1}{D} \left( \sum_{i=1}^{n} \frac{K_i R_i}{2C_i} \right)} \text{Hz} 
\]  

\[
\Delta f ss = \frac{P \times S}{(M_{s^2} + Ds) + \left( \sum_{i=1}^{n} \frac{K_i R_i}{N_i} \right)} \text{Hz} 
\]  

\[
\Delta f ss = 0 \text{Hz} 
\]  

3.2. MATLAB/SIMULINK model

The price-based deviation settlement mechanism for AGC system is illustrated by Figure 4. The simulation starts with the application of a load change. The change in frequency is measured and is added to the nominal frequency. (Gupta & Verma, 1998). This frequency is then converted to the deviation price. The marginal cost of the generators is then calculated. The marginal cost is then compared to the deviation charge, to generate the generation, control error (gce). This gce is next applied to the governor and the turbine blocks to change their output (Shital & Chetan, 2014) corresponding to the change in load demand to generate \( \Delta P_g \). This change in generation, then checks for the 12% deviation condition. If the deviation is more than 12% of the scheduled generation, then the generator will change its output up to the 12% limit and the rest of the load will be taken up by the rest of the generators. It is tested in the isolated area system consisting of four generating units with a total capacity of 5000 MW. The data for isolated area and generating stations are given in Table 2 to Table 4.

4. Results and analysis

The UI price-based block diagram contains a model of the isolated area with four generating systems. The coefficients of different blocks represent the speed governor of the thermal generating system. The cost coefficients of the cost function of different generators are indicated in Table 2. Table 3 shows the generator capacity. Different cases are studied for load variations in isolated areas. The corresponding tie-line power changes are observed. Since a UI price based secondary control is used here, the UI price dynamics are also observed.

4.1. A. Case I: Application of step load change of +50 MW, When Marginal Cost is 2570 MW

In this case, when the system marginal cost is more than nominal UI rate. When the step load change of +50 MW, the generator 1 is loaded to its full capacity and hence cannot absorb changes in load demand. The generators 2, 3 and 4 are capable to absorb the increase in load demand. Since the marginal cost of generators 2 and 3 is less than generator 4, therefore generators 2 and 3 will participate in rescheduling process and receive the profit of deviation price [Table 5]. The results of the simulation are shown in Figure 4(a-d).
Figure 4. MATLAB/SIMULINK based Price based automatic generation control system. $\Delta P_g 1, \Delta P_g 2, \Delta P_g 3, \Delta P_g 4$ v/s time response with step load change of +50 MW. $P_g 1, P_g 2, P_g 3, P_g 4$ v/s time response with step load change of +50 MW. U I Rates v/s time response with step load change of +50 MW. Frequency v/s time response with step load change of +50 MW.

(a) $\Delta P_g 1, \Delta P_g 2, \Delta P_g 3, \Delta P_g 4$ v/s time response with step load change of +50 MW

(b) $P_g 1, P_g 2, P_g 3, P_g 4$ v/s time response with step load change of +50 MW

(c) U I Rates v/s time response with step load change of +50 MW

(d) Frequency v/s time response with step load change of +50 MW

Table 2. AREA DATA

| Area Parameters | Area Parameter Values |
|-----------------|-----------------------|
| Capacity        | 5000 MW               |
| $M$             | 1000 MW-s/Hz          |
| $D$             | 100 MW/Hz             |
| $f^o$           | 50 Hz                 |
4.1.1. Case II: Application of step load change of +100 MW, when Marginal Cost is 2570 MW
When +100 MW load is applied suddenly, Generator 1 is loaded to their maximum capacity and hence cannot absorb any increase in load demand. Generators 2 and 3 can absorb the increase in load demand, and Generator 4 will not participate in rescheduling due to the application of the 12% deviation schedule. Generator 3 will be loaded to the maximum of 338 MW due to the implementation of the 12% deviation regulation. Hence, the rest of the load will be taken up by the Generator 2 [Table 6].

The results of the simulation are shown in Figure 5(a-d):

4.1.2. Case III: Application of Step load change during loss of generation or emergency of +250 MW, when Marginal Cost is 2570 MW
In this, all the generators will receive steady state error signal. Generator 1 is loaded to its maximum capacity and hence cannot absorb any increase in load demand. Generators 2 and 3 can absorb the increase in load demand, and Generator 4 will not participate in rescheduling due to the application of the 12% deviation schedule. Generator 3 will share additional load of 38 MW and Generator 2 will take additional load of 82 MW after implementation of the 12% deviation regulation [Table 7]. Hence, the rest of the load must be shed by the Regional Load Dispatch Centre (RLDC). The results of simulation are shown in Figure 6(a-d).

4.2. B. Case I: Application of step increase of load of +50 MW, When Marginal Cost is 3290 MW under peak load condition
This is the case of peak load demand and system marginal cost more than nominal UI rate. Here all generators are scheduled on generating maximum output. Now, with the application of a step load change of +50 MW is witnessed. Since Generators 1, 2, and 3 are already loaded to their maximum capacity, and hence cannot absorb any load demand, Generator 4 can absorb the increase in the load demand [Table 8]. The results of the simulation are shown in Figure 7(a-d).

4.2.1. Case II: Application of Step increase of load of +100 MW, when Marginal Cost is 3290 MW
With the application of a step load change of +100 MW Generators 1, 2 and 3 are loaded to their maximum capacity and hence cannot absorb any increase in load demand. Generator 4 can absorb the increase in load demand. Generator 4 will be loaded to the maximum of 784 MW due to the implementation of the 12% deviation regulation.

Hence, due to the gap between the generation and the load demand, there will be a dip in the frequency and as such load shedding action needs to be taken. to maintain the system
| Time in Seconds | Deviation Price (Rs./MWH) | Avg. Freq. in Hz | Change in Avg. change in gen. (MW) | Profit in (Rs.) | PG1 | PG2 | PG3 | PG4
|----------------|--------------------------|-----------------|-----------------------------------|----------------|-----|-----|-----|-----|
| 0-900          | 38000.47                 | 49.95           | 0                                 | 26,647.50      | 0   | 28.05| 21.95| 0   |
| 901-1800       | 25700.20                 | 49.95           | 0                                 | 26,647.50      | 0   | 28.05| 21.95| 0   |
| 1801-2700      | 25700.95                 | 49.95           | 0                                 | 26,647.50      | 0   | 28.05| 21.95| 0   |
| 2701-3600      | 25709.5                 | 49.95           | 0                                 | 26,647.50      | 0   | 28.05| 21.95| 0   |
| Total          |                          | 38000.47        | 49.95                             | 26,647.50      | 0   | 28.05| 21.95| 0   |

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Table 6. Normal load demand with step load change of +100 MW (under 12% Regulation)

| Time in Seconds | Avg. Freq. in Hz | Change in Deviation Price (Rs./MWH) | Avg. change in gen. (MW) | Profit in (Rs.) |
|-----------------|------------------|-------------------------------------|--------------------------|----------------|
|                 |                  |                                     | ΔPg1 | ΔPg2 | ΔPg3 | ΔPg4 | Gen 1  | Gen 2  | Gen 3  | Gen 4  |
| 0-900           | 49.86            | 5000.00                             | 0    | 62.25 | 37.75 | 0    | 77,812.50 | 47,187.50 | 0     |
| 901-1800        | 49.99            | 2550.57                             | 0    | 62.25 | 37.75 | 0    | 39,723.28 | 24,089.22 | 0     |
| 1801-2700       | 49.98            | 2550.54                             | 0    | 62.25 | 37.75 | 0    | 39,723.28 | 24,089.22 | 0     |
| 2701-3600       | 49.98            | 2550.55                             | 0    | 62.25 | 37.75 | 0    | 39,723.28 | 24,089.22 | 0     |
| Total           |                  |                                     | 0    | 249.00| 151.00| 0    | 196,982.3 | 119,455.2 | 0     |
frequency or the Regional Load Dispatch Centre (RLDC). The scheduled generation of Generator 4 must be revised to utilize its full capacity [Table 9]. The results of the simulation are given below. Figure 8(a-d).
Table 7. Normal load demand with step load change of +250 MW at Emergency Condition (under 12% Regulation)

Deviation price as per CERC regulation 2017 and system marginal cost 2570 Rs./MWH

| Time in Seconds | Avg. Freq. in Hz | Change in Deviation Price (Rs./MWH) | Avg. change in gen. (MW) | ΔPg1 | ΔPg2 | ΔPg3 | ΔPg4 | Gen 1 | Gen 2 | Gen 3 | Gen 4 | Profit in (Rs.) |
|-----------------|-----------------|-----------------------------------|--------------------------|------|------|------|------|------|------|------|------|------|-----------------|
| 0–900           | 48.70           | 8000                              |                          | 0    | 81.6 | 37.4 | 0    | 0    | 163,200 | 74,800 | 0    | 0    | 316,200          |
| 901–1800        | 50.0            | 2500                              |                          | 0    | 81.6 | 37.4 | 0    | 0    | 51,000  | 23,375 | 0    | 0    | 144,925          |
| 1801–2700       | 50.0            | 2500                              |                          | 0    | 81.6 | 37.4 | 0    | 0    | 51,000  | 23,375 | 0    | 0    | 144,925          |
| 2701–3600       | 50.0            | 2500                              |                          | 0    | 81.6 | 37.4 | 0    | 0    | 51,000  | 23,375 | 0    | 0    | 144,925          |
| Total           |                 |                                   |                          | 0    | 326.4| 149.6| 0    | 0    | 316,200 | 144,925 | 0    | 0    | 661,125          |
4.2.2. Case III: Sudden increase of load of +250 MW, when marginal cost is 3290 MW
With the application of a step load change of +250 MW. This situation occurs due to an emergency or loss of generation. In this situation, Generators 1, 2 and 3 are loaded to their maximum capacity and hence cannot absorb any increase in load demand. Generator 4 can absorb the increase in load demand. Generator 4 will be loaded to the maximum of 784 MW due to the implementation...
Table 8. Peak load demand with step load change of +50 MW (under 12% Regulation)

Deviation price as per CERC regulation 2017 and system marginal cost 3290 Rs./MWH

| Time in Seconds | Avg. Freq. in Hz | Change in Deviation Price (Rs./MWH) | Avg. change in gen. (MW) | Profit in (Rs.) |
|-----------------|-----------------|-------------------------------------|--------------------------|----------------|
|                 | Avg. Pg1 | Avg. Pg2 | Avg. Pg3 | Avg. Pg4 | Gen 1 | Gen 2 | Gen 3 | Gen 4 |
| 0-900           | 4.995     | 5400     | 0        | 0        | 50.00  | 0     | 0     | 0     | 67,500 |
| 901-1800        | 4.999     | 2800     | 0        | 0        | 0      | 49.95 | 0     | 0     | 34,965 |
| 1801-2700       | 4.999     | 2800     | 0        | 0        | 0      | 49.95 | 0     | 0     | 34,965 |
| 2701-3600       | 4.999     | 2800     | 0        | 0        | 0      | 49.95 | 0     | 0     | 34,965 |
| Total           | 0        | 0        | 0        | 200.63   | 0      | 0     | 0     | 0     | 172,395 |
of the 12% deviation regulation. This situation can be handled by rescheduling of generators or load shedding from RLDC [Table 10]. The results of the simulation are given below. Figure 9(a-d).

It is observed that under normal load as well as in peak load condition, the frequency remains constant irrespective of the system marginal cost and merit order scheduling, until the load is kept
Table 9. Peak load demand with step load change of +100 MW (under 12% Regulation)

Deviation price as per CERC regulation 2017 and system marginal cost 3290 Rs./MWH

| Time in Seconds | Avg. Freq. in Hz | Change in Deviation Price (Rs./MWH) | Avg. change in gen. (MW) | Profit in (Rs.) |
|----------------|-----------------|-------------------------------------|--------------------------|-----------------|
|                |                 |                                     | ΔPg1 | ΔPg2 | ΔPg3 | ΔPg4 | Gen 1 | Gen 2 | Gen 3 | Gen 4 |
| 0-900          | 49.84           | 7990.75                             | 0    | 0    | 0    | 84.00 | 0     | 0     | 0     | 99,564.12 |
| 901-1800       | 49.95           | 6990.65                             | 0    | 0    | 0    | 83.95 | 0     | 0     | 0     | 82,295.74 |
| 1801-2700      | 49.95           | 6990.65                             | 0    | 0    | 0    | 83.98 | 0     | 0     | 0     | 82,295.74 |
| 2701-3600      | 49.95           | 6999.65                             | 0    | 0    | 0    | 83.98 | 0     | 0     | 0     | 82,295.74 |
| Total          |                 |                                     | 0    | 0    | 0    | 335.91 | 0     | 0     | 0     | 346,451.3 |
under normal load condition, with the application of +50 MW step change in load is witnessed when the 12% deviation regulation is considered, the Generator 4 does not take part in the rescheduling process, and the entire load is shared between Generator 2 and 3.

Under normal load condition, with the application of +100 MW load change, generator 3 will be loaded to the maximum of 350 MW, i.e. to the maximum change in generation of 37.5 MW, i.e. (12% of 312.5 MW). Hence, the rest of the load will be taken up by the Generator 2. During normal load condition, the dip in frequency is up to 49.94 Hz and returns near to the nominal value in approx. 20 secs. Whereas in case of peak load condition, with the application of +50 MW load change the dip in frequency is up to 49.88 Hz and returns near to the nominal value in approx. 30 secs.

Under peak load condition, with the application of +100 MW load change Generator 4 will be loaded to the maximum of 784 MW, i.e. to the max. change in generation of 84 MW (12% of 700 MW); Hence, for the rest of the load, the load shedding action needs to be taken, to maintain the system frequency or the Regional Load Dispatch Centre (RLDC).

5. Conclusion
This paper discusses UI mechanism of ABT as a price based secondary control for automatic generation control that can be implemented in Indian system. A modified controller is proposed and which is able to deal with the fixed nature of UI curve, The results are verified through simulation on various scenarios for step change in load. The simulation results show that the control is successful to bring down the frequency deviation. Implementation of proposed control on all central and state generating stations will not only better control of frequency but merit order dispatch of generation can also be ensured at the same time.

In this paper, the impact, modified price-based AGC is applied for isolated area system, In future, the impact of such mechanism on frequency, UIs, and tie line exchanges can be observed by taking multi-area systems.

7. Nomenclature

- $\Delta f$: Change in supply frequency
- $c$: Incremental cost co-efficient of generating unit in Rs./MW2H
- $b$: Incremental cost co-efficient of generating unit in Rs./MWH
- $P_g^0$: Scheduled generation of generator in MW
- $\Delta P_g$: Change in generation
- $\rho_0$: UI rate at nominal frequency 50 Hz in Rs./MWH
Table 10. Peak load demand with step load change of +250 MW (under 12% Regulation)

Deviation price as per CERC regulation 2017 and system marginal cost 3290 Rs./MWH

| Time in Seconds | Avg. Freq. in Hz | Change in Deviation Price (Rs./MWH) | Avg. change in gen. (MW) | Profit in (Rs.) |
|-----------------|-----------------|-------------------------------------|--------------------------|----------------|
|                 |                 |                                     | ΔPg1 | ΔPg2 | ΔPg3 | ΔPg4 | Gen 1 | Gen 2 | Gen 3 | Gen 4 |
| 0-900           | 48.35           | 8000                                | 0    | 0    | 0    | 84.00 | 0     | 0     | 0     | 168,000 |
| 901-1800        | 48.35           | 8000                                | 0    | 0    | 0    | 83.95 | 0     | 0     | 0     | 167,900 |
| 1801-2700       | 48.35           | 8000                                | 0    | 0    | 0    | 83.98 | 0     | 0     | 0     | 167,960 |
| 2701-3600       | 48.35           | 8000                                | 0    | 0    | 0    | 83.98 | 0     | 0     | 0     | 167,960 |
| Total           |                 |                                     | 0    | 0    | 0    | 355.91| 0     | 0     | 0     | 671,820 |
Figure 9. Δ Pg 1, Δ Pg 2, Δ Pg 3, Δ Pg 4 v/s time response with step load change of +250 MW.
Pg 1, Pg 2, Pg 3, Pg 4 v/s time response with step load change of +250 MW. U I Rates v/s time response with step load change of +250 MW. Frequency v/s time response with step load change of +250 MW.

\[ P \quad \text{Step load in MW} \]

\[ K_U \quad \text{Slope of UI curve, value corresponds to UI price } p_0 \text{ in Hz. Rs./MWH} \]

\[ D \quad \text{Damping coefficient in MW/Hz} \]

\[ M \quad \text{System inertia in MW. Sec./Hz} \]

\[ R_i \quad \text{Speed regulation in Hz./MW} \]

\[ k_i \quad \text{Integral controller gain of ith generating unit } \gamma_i \text{ Marginal cost of } i^{th} \text{ generating unit Rs./MWH} \]

8. Future scope

8.1. Contingencies management

In India, the regional grids are planned based on Central Electricity Authority. The transmission system must be capable of withstanding and be secured against outage without necessitating load shedding or rescheduling of generators. All generating units operate within the reactive capability curve and the network voltage profile within prescribed limits. In case of multiple contingencies, load shedding or generators rescheduling is required. The complete operational planning for years, seasonal is required to prepare contingency plans. A further number of constraints such as line overloads and voltage profile are to be addressed during real-time operation. The existing frequency-based UI price helps in power deficit scenario and ABT mechanism takes care of scheduling open access transaction.

8.2. Demand-side management

The scheduled load shedding is expected to take care of the long-term capacity shortage (seasonal and yearly). To account for the forced outage of generating units, forecasting errors, and generation constraints, additional load shedding is planned on daily or day ahead basis, which is termed as unscheduled load shedding. The under-frequency load shedding is provided to take care of sudden contingencies when frequency dips below 48.5 Hz. Now the focus of Government of India is on smart metering and demand response so that at the time of peak load, the load can be handled at the demand side so that minimum load shedding shall be required, and it encourages the consumer participation for the peak load management.

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