Optimized Price Based Frequency Regulation for Multi Area Deregulated Electricity Market

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Abstract: This paper demonstrates the study of a price based frequency linked regulation for three area multi-unit automatic generation control (AGC) under deregulated market scenario. In this work conventional secondary feedback control signal has been replaced through unscheduled interchange (UI) based price signal linking to the frequency at the prevailing time. The three area multi-unit power system mathematical model has been developed to incorporate the various types of transactions incident in a competitive electricity market and simulation is carried out using MATLAB/SIMULINK software. Particle swarm optimization (PSO) is used in optimizing the gain of integral controller of individual generating units. Simulation results exhibit the effectiveness of PSO in the tuning of gain of integral controller along with price based frequency linked regulations for system under study.

Keywords: Automatic Generation Control, Deregulated Electricity Market, Unscheduled Interchange, Particle Swarm Optimization

I. INTRODUCTION

Automatic generation control (AGC) is a very important issue in power system operation and control for supplying sufficient and reliable electric power with good quality. In deregulated market, AGC with load following is treated as an ancillary service that is essential for maintaining the electrical system reliability at an adequate level. The main objectives of the AGC in multi-area restructured power system are maintaining zero steady state errors for frequency deviation and accurate tracking of load contracts demanded by DISCOs.

In an open energy market, generation companies (GENCOs) may or may not participate in the AGC task. On the other hand, a distribution company (DISCOs) may contract individually with a GENCO or Independent power producers (IPPs) for power in its area or other areas and all these tasks are done under the supervision of the independent system operator (ISO) [1].

As mentioned above, after the power system restructuring, frequency regulation has become challenging job to establish good coordination between a large number of GENCOs and DISCOs. Many approaches have been presented by proficient authors in the literature [2-10] to regulate frequency under the deregulated electricity market using advanced control and evolutionary techniques like robust control, fuzzy logic, multi stage fuzzy proportional integral derivative (MSF-PID), genetic algorithm (GA), robust mixed H2/H∞ hybrid particle swarm optimization (HPSO), polar fuzzy, interactive artificial bee colony (IABC) optimization based fuzzy (IABCF), robust multi input multi output proportional integral derivative (MIMO-PID) and bacterial forging (BF) etc.

Frequency linked pricing is another one such approach of AGC in deregulated market that encourages generators to respond proportionally to frequency deviations or to their corresponding price signals sent out by the independent system operator (ISO) and help to restore the system frequency back to nominal or close to nominal value. Berger and Schweppe [11] demonstrated the real-time pricing of generation using the proportional integral feedback control law of frequency deviations to assist in load frequency control. J Kumar et al. [12, 13] proposed a price based bilateral market structure and its operating mechanism using the concept of contract participation factor [12, 13]. Further more details on price based frequency regulation can be found from [14, 15].

Price based frequency regulation scheme based on unscheduled interchange signal suitable to Indian market scenario is reported in [16, 17] which are also useful to avoid or reduced unintended unscheduled interchanges (UIs) among the various participants of deregulated market. Moreover, in [18] authors have analyzed impact of UI Rate on automatic generation controller of participating generators coordination of doubly fed induction generator (DFIG) based wind energy conversion system along with unscheduled interchange based frequency control scheme has been shown in [19] while PSO based optimized price based frequency control has been reported in [20].

The aim of this article is to analyze the effectiveness of PSO, in frequency-linked pricing mechanism for frequency regulation. Rest of the article is structured as follows: Section II describes about comparison of deregulated electricity market conventional control v/s UI based control. Section III details about state space model for system under study. While section IV tells about PSO and its implementation procedure for system under study. Simulation results and analysis is covered in section V. finally; section VI carries conclusions.

To Cary out the present work, UI rate v/s frequency curve for the year 2013 issued by Central electricity regulation commission (CERC) has been used and is as shown in Fig.1 [21].

Fig. 1: UI rate v/s frequency curve (CERC, 2013) [21]

The detailed schematic of three area, ten generators and nine discos scheme has been prepared on the basis of frame work done in [16, 17] and shown in Fig.2.
II. DEREGULATED ELECTRICITY MARKET CONVENTIONAL CONTROL VS UI BASED CONTROL

In traditional multi area deregulated scenario, Area control error (ACE) signal has to be distributed among no. of generators in the area as in proportion to their participation in the AGC. Coefficient that distributes ACE to several GENCOs is termed as “ACE participation factor” (APF). Note that,

\[ \sum_{i=1}^{n} apf_i = 1 \text{ where } n = \text{total no. of GENCOs}. \]  

Also, the scheduled steady state power flow on the tie line is given as

\[ P_{\text{tie } k-m, \text{ scheduled}} = \left( \text{Demand of DISCOs in area } m \text{ from } \text{GENCOs in area } k \right) - \left( \text{Demand of DISCOs in area } k \text{ from } \text{GENCOs in area } m \right) \]  

At any given time, the tie line power error \( \Delta P_{\text{tie } k-m, \text{ error}} \) is:

\[ \Delta P_{\text{tie } k-m, \text{ error}} = P_{\text{tie } k-m, \text{ actual}} - P_{\text{tie } k-m, \text{ scheduled}} \]  

\( \Delta P_{\text{tie } k-m, \text{ error}} \) vanishes in the steady state as the actual tie line power flow reaches the scheduled power flow. This error signal is used to generate the respective ACE signals.

i.e. \( \text{ACE}_k = B_k \alpha_k \gamma_k - \Delta P_{\text{tie } k-m, \text{ error}} \)  

Where, \( k,m = \text{no. of Area} \)

Also, \( \Delta P_{\text{tie } k-m, \text{ error}} = \frac{P_k}{P_{\text{rated } k}} + \Delta P_{\text{tie } m-k, \text{ error}} \)

Where, \( P_k \) and \( P_{\text{rated } k} \) = area rated power

Also \( \alpha_{k,m} = \frac{P_k}{P_{\text{rated } k}} \)

Unlike in traditional deregulated system, in UI based secondary control no. of generators of each area receives an individual error signal named as generation control error (GCE) [17] which is the output signal of each GCE block in Fig. 2. Each generator of three areas participates in AGC and their participation depends upon GCE signal.

\( \text{GCE}_i = \text{output of GCE block} \) i= no. of generators

Detailed logic of GCE block is as follows:

Input of GCE block is the difference of UI rate signal (\( \rho \)) and marginal cost signal (\( \gamma \)) of each unit. In GCE block these two signals have been compared with following logic:

\[ \text{if } \gamma > \rho; \text{ Where } \rho = 1780 \text{ Rs. /MWh at 50Hz.} \]

\[ \text{if } \rho > \gamma; \text{ GCE} = \rho - \gamma; \text{ \text{else if } } \rho < \rho; \text{ GCE} = 0; \text{ \text{else GCE} = 0; \text{ \text{end} \text{ \text{else}}} \}

\[ \text{if } \rho < \gamma; \text{ GCE} = \rho - \gamma; \text{ \text{else if } GCE > \rho; \text{ GCE} = 0; \text{ \text{else GCE} = 0; \text{ \text{end}}} \]

Also, the logic of F to UI block of Fig.1 is as follows:

\[ \text{if } f <= 49.94; \rho = 11104 \text{ \text{else if } } f <= 50; \rho = 1780 + 155400*(50-f) \text{ \text{else if } } f <= 50.05 \rho = 35600*(50.05-f) \text{ \text{else } } \rho = 0 \text{ \text{end}}} \]

\[ \begin{align*}
\text{Few important findings of UI based control:} \\
\text{• There would be no frequency bias or tie line bias in net interchange schedule [22].} \\
\text{• The required collective action for correction of frequency (only improvement of frequency in this case) would be induced through the pricing of UI, rather than through frequency bias as in ACE [22].} \\
\text{• Control areas would be only notional, in the sense that it would not be mandatory for them to absorb their own load changes fully. Hence there would be no requirement for the control areas to maintain their actual interchanges close to their net interchange schedules and also, no need to reduce generation control error (GCE) to zero every ten minutes as the case in ACE [20].} \\
\text{• The actual interchange can remain deviated from the net interchange schedule; because here we are pricing the deviations and hence GCE signal does not drive steady state frequency error to zero but depends on slope of UI curve, if curve is steeper (slope at nominal frequency very large) frequency error goes nearer to zero [22].} \\
\text{• The concept of contract participation factor matrix (CPF) remains unchanged.} \\
\end{align*} \]

III. STATE SPACE EQUATIONS FOR THREE AREA SYSTEM

The proposed system is a three area system with ten Generators and nine Discos. A state space model is prepared by taking Fig.2 as a reference and written in the form as:

\[ x = Ax + Bu + Fw + Py \]  

(10)

For the proposed model the system is of 46th Order.

The order of matrix A = 46X46, B = 46X10, \( u = 10 \times 1, F = 46X10, w = 9X1, P = 46X3, \gamma = 3 \times 1 \).

State variables:

\[ x = [X1=\Delta f1, X2=\Delta f2, X3=\Delta f3, X4=\Delta Pri12, X5=\Delta Pri13, X6=\Delta Pri1, X7=\Delta Pri1, X8=\Delta Pgov1, X9=\Delta Pri2, X10=\Delta Pri2, X11=\Delta Pgov2, X12=\Delta Pri3, X13=\Delta Pri3, X14=\Delta Pgov3, X15=\Delta Pri4, X16=\Delta Pri4, X17=\Delta Pgov4, X18=\Delta gce1dt, X19=\Delta gce2dt, X20=\Delta gce3dt, X21=\Delta gce4dt, X22=\Delta Pri5, X23=\Delta Pri5, X24=\Delta Pgov5, X25=\Delta Pri6, X26=\Delta Pgov6, X27=\Delta Pgov7, X28=\Delta Pri7, X29=\Delta Pri7, X30=\Delta Pgov7, X31=\Delta Pri8, X32=\Delta Pgov8, X33=\Delta Pri9, X34=\Delta Pri9, X35=\Delta Pgov9, X36=\Delta Pri10, X37=\Delta Pri10, X38=\Delta Pgov10, X39=\Delta Pri23] \]
Control Inputs:
\[ u_1 = k_1 \int \Delta gce_1 \, dt \], \[ u_2 = k_2 \int \Delta gce_2 \, dt \], \[ u_3 = k_3 \int \Delta gce_3 \, dt \], \[ u_4 = k_4 \int \Delta gce_4 \, dt \], \[ u_5 = k_5 \int \Delta gce_5 \, dt \], \[ u_6 = k_6 \int \Delta gce_6 \, dt \], \[ u_7 = k_7 \int \Delta gce_7 \, dt \], \[ u_8 = k_8 \int \Delta gce_8 \, dt \], \[ u_9 = k_9 \int \Delta gce_9 \, dt \], \[ u_{10} = k_{10} \int \Delta gce_{10} \, dt \].

Disturbance Inputs (contracted demand of various Discos from Various Gencos of three area system):
\[ d_1 = \Delta P_{Disco_1} \], \[ d_2 = \Delta P_{Disco_2} \], \[ d_3 = \Delta P_{Disco_3} \], \[ d_4 = \Delta P_{Disco_4} \], \[ d_5 = \Delta P_{Disco_5} \], \[ d_6 = \Delta P_{Disco_6} \], \[ d_7 = \Delta P_{Disco_7} \], \[ d_8 = \Delta P_{Disco_8} \], \[ d_9 = \Delta P_{Disco_9} \].

Disturbance Inputs (Uncontracted demand of various Discos from Gencos of their area):
\[ d_{uc1} = \Delta P_{uc_1} \], \[ d_{uc2} = \Delta P_{uc_2} \], \[ d_{uc3} = \Delta P_{uc_3} \].

State equations:
From the transfer function blocks labeled for area 1 are:

**Block 1:**
\[ x_1 = -\frac{1}{\tau_{p1}} x_1 - \frac{K_{p2}}{\tau_{p2}} x_4 - \frac{K_{p3}}{\tau_{p3}} x_5 + \frac{K_{p4}}{\tau_{p4}} x_6 + \frac{K_{p5}}{\tau_{p5}} x_9 + \frac{K_{p6}}{\tau_{p6}} x_{12} + \frac{K_{p7}}{\tau_{p7}} x_{15} + \frac{K_{p8}}{\tau_{p8}} x_{18} + (d_1 + d_2 + d_3 + d_4 + d_{uc1}) \]

**Block 4:**
\[ x_4 = 2\pi T_1 x_2 - 2\pi T_1 x_2 \]

**Block 5:**
\[ x_5 = 2\pi T_1 x_4 - 2\pi T_1 x_3 \]

**Block 6:**
\[ x_6 = -\frac{1}{\tau_{t1}} x_6 + \frac{(1 - \frac{K_{t1}}{2\pi T_1}) x_7 + \frac{K_{t1}}{2\pi T_1} x_6}{\tau_{t1}} \]

**Block 7:**
\[ x_7 = -\frac{1}{T_{x1}} x_7 + \frac{1}{T_{x1}} x_8 \]

**Block 8:**
\[ x_8 = -\frac{1}{R_1 T_{gov1}} x_1 - \frac{1}{T_{gov1}} x_6 + \frac{1}{T_{gov1}} u_1 + (D_1 + D_2 + D_3) \frac{1}{T_{gov1}} \]

**Block 9:**
\[ x_9 = -\frac{1}{T_{t2}} x_9 + \frac{(1 - \frac{K_{t2}}{T_{t2}}) x_{10} + \frac{K_{t2}}{T_{t2}} x_{11}}{T_{t2}} \]

**Block 10:**
\[ x_{10} = -\frac{1}{T_{t2}} x_{10} + \frac{1}{T_{t2}} x_{11} \]

**Block 11:**
\[ x_{11} = -\frac{1}{R_2 T_{gov2}} x_1 - \frac{1}{T_{gov2}} x_{11} + \frac{1}{T_{gov2}} u_2 + (D_4 + D_5 + D_6) \frac{1}{T_{gov2}} \]

**Block 12:**
\[ x_{12} = -\frac{1}{T_{t3}} x_{12} + \frac{(1 - \frac{K_{t3}}{T_{t3}}) x_{13} + \frac{K_{t3}}{T_{t3}} x_{14}}{T_{t3}} \]

**Block 13:**
\[ x_{13} = -\frac{1}{T_{t3}} x_{13} + \frac{1}{T_{t3}} x_{14} \]

**Block 14:**
\[ x_{14} = -\frac{1}{R_3 T_{gov3}} x_1 - \frac{1}{T_{gov3}} x_{14} + \frac{1}{T_{gov3}} u_3 + (D_4 + D_6 + D_8) \frac{1}{T_{gov3}} \]

**Block 15:**
\[ x_{15} = -\frac{1}{T_{t4}} x_{15} + \frac{1}{T_{t4}} K_{r4} x_{16} + \frac{K_{r4}}{T_{t4}} x_{17} \]

**Block 16:**
\[ x_{16} = \frac{1}{T_{t4}} x_{16} + \frac{1}{T_{t4}} x_{17} \]

**Block 17:**
\[ x_{17} = -\frac{1}{R_4 T_{gov4}} x_{17} - \frac{1}{T_{gov4}} x_{17} + \frac{1}{T_{gov4}} u_4 + (D_1 + D_2 + D_4) \frac{1}{T_{gov4}} \]

**IV. Particle Swarm Optimization**

Particle swarm optimization (PSO) is a fast, simple and efficient population based optimization method which was proposed by Eberhart and Kennedy (1995) [23, 24]. It has been motivated by the behavior of organisms such as fish schooling and bird flocking. In PSO, a swarm consists of number of particles which represent the possible solutions. The coordinates of each particle are associated with two vectors, namely the position (S) and velocity (V) vectors. The size of both vectors is same as that of the problem space dimension. All particles in a swarm fly in the search space to explore optimal solutions. Each particle updates its position based upon its own best position, global best position among particles and its previous velocity vector according to the following equations:

\[ V_{j}^{k+1} = W \cdot V_{j}^{k} + C_1 \cdot \text{Rand}() \cdot \text{random} \cdot (S_{j}^{k} - S_j) + C_2 \cdot \text{Rand}() \cdot \text{random} \cdot (G_{max} - S_j) \]

\[ S_{j}^{k+1} = S_j^k + k \cdot V_{j}^{k+1} \]

\[ k = \frac{2}{|2 - \varphi - \sqrt{4 - 4 \varphi}|}, \quad \varphi \geq 4 \]

\[ W = W_{\max} - \frac{W_{\max} - W_{\min}}{\text{Iter}_{\max}} \cdot \text{Iter} \]

Where, k is constriction factor to insure convergence of the PSO.

**PSO implementation for optimization of gain Ki**

Optimization of gain of integral controller of each unit in multi area is done using Integral Square Error (ISE) criterion. Required objective function of UI based AGC scheme is the minimization of sum of total Generation Control Error (GCE) plus sum of total tie line power error. Generalized objective function used for multi area scheme is,

\[ J = \min \left[ \sum_{i=1}^{n} gce_i^2 + k_1 \cdot \sum \Delta P_{tie \cdot k \cdot m \cdot ee \cdot rerd} \right] \]
$k_i = \text{weighing factor in the range } 10^5 \text{ multiply with } \sum \Delta P_i \text{ (tie } k_i = m, \text{error) to make mutual competitive}
\text{ during optimization with } \sum \Delta \gamma_i = g\text{e}^2.$

Steps of PSO algorithm implemented for optimization of
gain $K_i$ ($i=1$ to $n$) are as follow:

- Initialize real coded particles ($K_i$ gains) of $n$ population for each $K_i$. For case under consideration $i=1$ to $10$.
- Evaluate objective function for all particles as per equation (15).
- Search for global minimum of objective function ‘1’ and its corresponding global best particle $P_{\text{best}}$ and individual best particle $P_{\text{loc}}$ for all particles.
- Generate new population using eq. (11), (12), (13) and (14).
- Make comparison with previous iteration data and update global best position.
- Update iteration counter and go to step 2 until iteration counter reaches to its maximum value.

V. SIMULATION AND RESULT ANALYSIS

Simulations are carried out for different test cases of the
possible contracts under large load demands and disturbances.
The scheduled load of discs in different areas,
\[ \Delta P_{\text{Disco}1} = 0.1 \text{p.u.} \quad \Delta P_{\text{Disco2}} = 0.1 \text{p.u.} \quad \Delta P_{\text{Disco3}} = 0.05 \text{p.u.} \quad \Delta P_{\text{Disco4}} = 0.05 \text{p.u.} \quad \Delta P_{\text{Disco5}} = 0.1 \text{p.u.} \quad \Delta P_{\text{Disco6}} = 0.1 \text{p.u.} \quad \Delta P_{\text{Disco7}} = 0.1 \text{p.u.} \quad \Delta P_{\text{Disco8}} = 0.05 \text{p.u.} \quad \Delta P_{\text{Disco9}} = 0.05 \text{p.u.} \quad \Delta P_{\text{Disco10}} = 0.05 \text{p.u.} \]
the un-contracted load in area one is $\Delta \text{pu} = 0.06 \text{p.u.}$

The total generation required of individual GENCOs can
be calculated as:
\[ \Delta P_{g_i} = \sum_{j=1}^{n-g} \Delta P_{\text{Disco}_j} \cdot b_j + \Delta g_{\text{opt}} \cdot b_{\text{tie}} \] (16)

The mutual scheduled tie-line power flows among the areas
can be represented by the following formulae:
\[ \sum_{i=1}^{m} \Delta P_{\text{tie}_i} = \sum_{j=1}^{n-g} \Delta P_{\text{Disco}_j} \cdot b_j - \sum_{j=1}^{n-g} \Delta P_{\text{Disco}_j} \cdot b_j \] (17)

\[ \sum_{i=1}^{m} \Delta P_{\text{tie}_i} = \sum_{j=1}^{n-g} \Delta P_{\text{Disco}_j} \cdot b_j - \sum_{j=1}^{n-g} \Delta P_{\text{Disco}_j} \cdot b_j \] (18)

\[ \sum_{i=1}^{m} \Delta P_{\text{tie}_i} = \sum_{j=1}^{n-g} \Delta P_{\text{Disco}_j} \cdot b_j - \sum_{j=1}^{n-g} \Delta P_{\text{Disco}_j} \cdot b_j \] (19)

The necessary system data is given in Annexure.

Test Case A. Poolco based transactions:

In this scenario GENCOs participate in automatic generation
control of their own areas only. It is assumed that large step
contracted loads are simultaneously demanded by DISCOs of
areas one, two and three. A case of Poolco based contracts
between DISCOs and available GENCOs is simulated based
on the following contract participation factor matrix (CPF).

The magnitude of the elements of CPF matrix ($\text{cpfs}$) are

\[ \text{CPF}_{11} \quad \text{CPF}_{12} \quad \text{CPF}_{13} \]

\[ \text{CPF}_{21} \quad \text{CPF}_{22} \quad \text{CPF}_{23} \]

\[ \text{CPF}_{31} \quad \text{CPF}_{32} \quad \text{CPF}_{33} \]

In the steady state, tie-line power flow errors, frequency
deviations and hence the generation control errors of all the
generators of each area driven back nearly to zero. The
generated powers properly converge to the specified calculated
values.

Test Case B. Combination of Poolco and Bilateral based
transactions:

In this case, any DISCO has the freedom to have a contract
with any GENCO in its own and other areas. It is assumed that
all the DISCOs contract with the available GENCOs for power
as per the following CPFs:

\[ \text{CPF}_{11} \quad \text{CPF}_{12} \quad \text{CPF}_{13} \]

\[ \text{CPF}_{21} \quad \text{CPF}_{22} \quad \text{CPF}_{23} \]

\[ \text{CPF}_{31} \quad \text{CPF}_{32} \quad \text{CPF}_{33} \]

Table I. Steady state values for test case B

<table>
<thead>
<tr>
<th>Case B</th>
<th>Computed value</th>
<th>Simulation value</th>
<th>Error</th>
<th>Optimal value of $K_0$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Area 1 frequency (Hz)</td>
<td>50.0000</td>
<td>50.0023</td>
<td>-0.0023</td>
<td>-</td>
</tr>
<tr>
<td>Area 2 frequency (Hz)</td>
<td>50.0000</td>
<td>50.0023</td>
<td>-0.0023</td>
<td>-</td>
</tr>
<tr>
<td>Area 3 frequency (Hz)</td>
<td>50.0000</td>
<td>50.0023</td>
<td>-0.0023</td>
<td>-</td>
</tr>
<tr>
<td>$\Delta P_{\text{Disco}_1}$ (MW)</td>
<td>254.00</td>
<td>254.26</td>
<td>-0.26</td>
<td>0.0003</td>
</tr>
<tr>
<td>$\Delta P_{\text{Disco}_2}$ (MW)</td>
<td>234.75</td>
<td>234.55</td>
<td>-0.1</td>
<td>0.0002</td>
</tr>
<tr>
<td>$\Delta P_{\text{Disco}_3}$ (MW)</td>
<td>303.75</td>
<td>303.18</td>
<td>-0.57</td>
<td>0.0002304</td>
</tr>
<tr>
<td>$\Delta P_{\text{Disco}_4}$ (MW)</td>
<td>157.50</td>
<td>157.39</td>
<td>0.11</td>
<td>0.0003</td>
</tr>
<tr>
<td>$\Delta P_{\text{Disco}_5}$ (MW)</td>
<td>69.00</td>
<td>69.16</td>
<td>-0.16</td>
<td>0.00009</td>
</tr>
<tr>
<td>$\Delta P_{\text{Disco}_6}$ (MW)</td>
<td>263.00</td>
<td>263.11</td>
<td>-0.11</td>
<td>0.0001947</td>
</tr>
<tr>
<td>$\Delta P_{\text{Disco}_7}$ (MW)</td>
<td>138.00</td>
<td>138.14</td>
<td>-0.14</td>
<td>0.0001334</td>
</tr>
<tr>
<td>$\Delta P_{\text{Disco}_8}$ (MW)</td>
<td>332.00</td>
<td>331.9</td>
<td>-0.1</td>
<td>0.0003178</td>
</tr>
<tr>
<td>$\Delta P_{\text{Disco}_9}$ (MW)</td>
<td>185.50</td>
<td>185.39</td>
<td>0.11</td>
<td>0.0001</td>
</tr>
<tr>
<td>$\Delta P_{\text{Disco}_{10}}$ (MW)</td>
<td>122.50</td>
<td>123.24</td>
<td>-0.74</td>
<td>0.0002583</td>
</tr>
<tr>
<td>$\text{Ptie-1}$ (MW)</td>
<td>11</td>
<td>12.25</td>
<td>-2.25</td>
<td>-</td>
</tr>
<tr>
<td>$\text{Ptie-2}$ (MW)</td>
<td>81</td>
<td>83.5</td>
<td>2.5</td>
<td>-</td>
</tr>
<tr>
<td>$\text{Ptie-3}$ (MW)</td>
<td>-39</td>
<td>-37</td>
<td>-2</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 1 indicate all the parameter values in numerical with
comparison of calculated and simulated data and optimal value
of gain of integral controllers for test case B. Fig. 3[a-c] shows
the all three area frequency response which settles close to
50Hz value in steady state on account of large slope of selected UI curve. Also, with optimized gain controllers’ transient response of each area frequency curve have been improved. Fig. 3(d-f) shows the response of actual power on the tie line. It is observed that with PSO actual tie line power settles reasonably close to its corresponding desired value which also confirms the satisfactory operation of UI based control in multi area deregulated market system. Though small deviation has been observed this is due to absence of tie line bias control. Fig.3(g) shows response of actual generated powers of the GENCOs for with and without PSO optimized gain. The final generation values of GENCOs with PSO optimized gain case are quite nearer to the desired generation in the steady state following optimum response. While Fig.3 (h) indicates the response of GCE error for with and without PSO optimized gain of integral controller of each unit. All units’ GCE error response is improved with optimized gain values which show evidence of reduction of unnecessary UI exchange of power.

![Graphs showing Area 1, Area 2, Area 3, and tie-line frequency responses with and without PSO.]({})

**Table II Steady state values for Test Case C:**

<table>
<thead>
<tr>
<th>Case C:</th>
<th>Computed value</th>
<th>Simulation value</th>
<th>Error</th>
<th>Optimal value of Kd</th>
</tr>
</thead>
<tbody>
<tr>
<td>Area 1 frequency in (Hz)</td>
<td>50.000</td>
<td>50.000</td>
<td>0.00</td>
<td>-</td>
</tr>
<tr>
<td>Area 2 frequency in (Hz)</td>
<td>50.000</td>
<td>50.000</td>
<td>0.00</td>
<td>-</td>
</tr>
<tr>
<td>Area 3 frequency in (Hz)</td>
<td>50.000</td>
<td>50.000</td>
<td>0.00</td>
<td>-</td>
</tr>
<tr>
<td>∆Op1 in (MW)</td>
<td>332.12 (254.75 + 78.12)</td>
<td>331.62 (254.75 + 77.62)</td>
<td>0.50</td>
<td>0.009</td>
</tr>
<tr>
<td>∆Op2 in (MW)</td>
<td>311.85 (234.75 + 78.12)</td>
<td>311.65 (234.75 + 6.90)</td>
<td>1.17</td>
<td>0.0005</td>
</tr>
<tr>
<td>∆Op3 in (MW)</td>
<td>324.04 (303.75 + 20.30)</td>
<td>324.04 (303.75 + 20.30)</td>
<td>1.59</td>
<td>0.004</td>
</tr>
<tr>
<td>∆Op4 in (MW)</td>
<td>331.62 (157.50 + 21.88)</td>
<td>331.62 (157.50 + 20.56)</td>
<td>1.32</td>
<td>0.0034</td>
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<tr>
<td>∆Op5 in (MW)</td>
<td>69.97</td>
<td>69.97</td>
<td>-0.97</td>
<td>0.000070</td>
</tr>
<tr>
<td>∆Op6 in (MW)</td>
<td>263.75</td>
<td>263.75</td>
<td>-0.57</td>
<td>0.000558</td>
</tr>
<tr>
<td>∆Op7 in (MW)</td>
<td>138.79</td>
<td>138.79</td>
<td>-0.79</td>
<td>0.000600</td>
</tr>
<tr>
<td>∆Op8 in (MW)</td>
<td>332.57</td>
<td>332.57</td>
<td>-0.57</td>
<td>0.000060</td>
</tr>
<tr>
<td>∆Op9 in (MW)</td>
<td>186.13</td>
<td>186.13</td>
<td>-0.13</td>
<td>0.000060</td>
</tr>
<tr>
<td>∆Op10 in (MW)</td>
<td>123.00</td>
<td>123.00</td>
<td>-0.5</td>
<td>0.000017</td>
</tr>
<tr>
<td>Pne1-1 in MW</td>
<td>11</td>
<td>11.00</td>
<td>0.0</td>
<td>-</td>
</tr>
<tr>
<td>Pne1-3 in MW</td>
<td>-81</td>
<td>-83.63</td>
<td>4.63</td>
<td>-</td>
</tr>
<tr>
<td>Pne2-1 in MW</td>
<td>-39</td>
<td>-36.48</td>
<td>2.52</td>
<td>-</td>
</tr>
</tbody>
</table>

**Test Case C. Contract Violation**

In this case, DISCOs may violate a contract by demanding more power than that specified in the contract. This excess power is reflected as a local load of the area (un-contracted demand). So to simulate this case again test case B has been considered with a modification that DISCOs of area one demands 0.06 pu of excess power. “CPFk” matrix is the same as in test case B. The scheduled incremental tie-line powers remain the same as in test case B in the steady state. Un-contracted load of the area one DISCOs is taken up by the GENCOs of its own area according to error signal received from their individual GCE block in steady state by following the merit order dispatch.
Table II indicates the all parameter values in numerical with comparison of calculated and simulated data and optimal value of gain of integral controllers for test case c. 

Set of Fig. 4 (a-h) shows the waveforms of various parameters for test case C. All parameters follow its desired values in steady state. Fig. 4 (g) shows the generation response of GENCOs of area one following a load change in area one. They respond to the load perturbation (contracted & uncontracted) and increase their generations. Also the uncontracted demand of DISCOs of area one is taken up by the same area GENCOs by following the merit order dispatch as they receive the error signal which is the difference of UI rate and their marginal cost signal [16, 17, 20]. The purpose of this work is to test the effectiveness of the proposed control against un-contracted load disturbances.

![Area one frequency](image1)
![Area two frequency](image2)
![Area three frequency](image3)
![Area one tie-line Actual power](image4)
![Area two tie-line Actual power](image5)
![Area three tie-line actual power](image6)

![Area one tie-line actual power](image7)
![Area three tie-line actual power](image8)

![Generation control error of various GENCOs of Area one](image9)

Fig. 4 Simulation results of bilateral with contract violation based transaction (Case C)

VI. CONCLUSIONS

Price based frequency control gives the similar performance as the conventional control in deregulated market. The state space model for proposed scheme has been investigated. GCE signal of each GENCOs does not drive steady state frequency error to zero but it depends on slope of UI curve. In present work UI rate v/s frequency curve is fairly large so frequency error goes very close to zero. It has been also observed that tie lines actual power remains slight deviated in both the case due to absence of tie line bias control. Classical particle swarm optimization technique is used to get optimal value of gain of integral controller of individual GENCOs. It has been revealed from the simulation results that optimized gain of integral controller saves the unnecessary UI exchange and gives optimal performance in all the cases. Last but not least this proposed control is suitable for the generation deficient country like India, as real time frequency signal can be easily available on any wall socket.

REFERENCES


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<table>
<thead>
<tr>
<th>PSO Input Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. of population: $n_p$ (i=1to10)</td>
<td>100</td>
</tr>
<tr>
<td>$W_{max}$</td>
<td>200</td>
</tr>
<tr>
<td>$C_1=C_2$</td>
<td>1.05</td>
</tr>
<tr>
<td>$W_{min}$</td>
<td>0.7</td>
</tr>
<tr>
<td>$A$ (constriction factor)</td>
<td>0.3</td>
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</table>

### ANNEXURE


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<table>
<thead>
<tr>
<th>Area</th>
<th>1</th>
<th>2</th>
<th>3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator unit</td>
<td>G1</td>
<td>G2</td>
<td>G3</td>
</tr>
<tr>
<td>Rating (MW)</td>
<td>1200</td>
<td>600</td>
<td>800</td>
</tr>
<tr>
<td>Hi (s)</td>
<td>6</td>
<td>4</td>
<td>5</td>
</tr>
<tr>
<td>Di (pu/Hz)</td>
<td>0.05</td>
<td>0.08</td>
<td>0.05</td>
</tr>
<tr>
<td>Ri (%)</td>
<td>3</td>
<td>3</td>
<td>3.2</td>
</tr>
<tr>
<td>Ti (sec)</td>
<td>0.40</td>
<td>0.36</td>
<td>0.42</td>
</tr>
<tr>
<td>Ti (sec)</td>
<td>0.3</td>
<td>0.2</td>
<td>0.07</td>
</tr>
<tr>
<td>Ti (sec)</td>
<td>4.2</td>
<td>4.2</td>
<td>4.2</td>
</tr>
<tr>
<td>Reheat Gain Kr</td>
<td>0.34</td>
<td>0.34</td>
<td>0.34</td>
</tr>
<tr>
<td>T_Bj (pu/Hz)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Base power (MW)</td>
<td>3400</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost coefficient</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>b (Rs./MWh)</td>
<td>671</td>
<td>1450</td>
<td>732</td>
</tr>
<tr>
<td>c (Rs./MW²h)</td>
<td>1.0675</td>
<td>1.0675</td>
<td>3.8125</td>
</tr>
<tr>
<td>Initial Generation Scheduling Data</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>PG_i₀ in (MW)</td>
<td>528.8</td>
<td>163.93</td>
<td>140.07</td>
</tr>
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</table>
Fig. 2: State space schematic of three area deregulated system with UI based control