Decentralized load frequency control in an interconnected power system using Coefficient Diagram Method

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A B S T R A C T

This paper presents a new load frequency control (LFC) design, using the Coefficient Diagram Method (CDM) in a multi-area power system. The CDM controller has been designed to reduce the effect of uncertainties owing to variations in the parameters of governors and turbines as well as load disturbance. Each local area controller is designed independently, such that, stability of the overall closed-loop system is guaranteed. The CDM structure is built on the frequency response model of multi-area power system, and physical constraints of the governors and turbines are considered. Digital simulations for both two and three-area power systems are provided to validate the effectiveness of the proposed scheme. From the simulation results it is shown that, considering the overall closed-loop system performance with the proposed CDM technique, robustness is demonstrated in the face of uncertainties due to governors and turbines parameters variation and loads disturbances. A performance comparison between the proposed controller, model predictive controllers (MPC), and a classical integral control (I) scheme is carried out, confirming the superiority of the proposed CDM technique.

Introduction

When power systems generate and distribute electrical power to factories and households, to meet varieties of power needs, both the active and reactive power balances must be maintained between generation and utilization of the electric power. Those two balances correspond to two equilibrium points, namely: frequency and voltage. When either voltage or frequency is reset at a new level due to some disturbance or instability problems, the equilibrium points will float. A quality electric power system requires the frequency and voltage to remain at standard values during operation.

Thus, a control system is important to cancel or reduce the effects of the random load changes, and to keep the frequency and voltage at the standard values. Although active power and reactive power affect the frequency and voltage respectively, the frequency is highly dependent on the active power while the voltage is highly dependent on the reactive power. Hence, the control issues in power systems can be decoupled into two independent problems. One is about the active power and frequency control while the other is about the reactive power and voltage control. The active power and frequency control is referred to as load frequency control (LFC) [1] which is the major concerned of this paper. The main goal of the load frequency control (LFC) of a power system is to maintain the frequency of each area, and tie-line power flow (in an interconnected power system) within specified tolerance. This is accomplished by adjusting the mega-watt (MW) outputs of the generators so as to accommodate fluctuating load demand.

Today, control system designers are trying to apply different control algorithms in order to find the best controller parameters to obtain optimum solutions. Fixed parameter controllers, such as an integral controller or a proportional integral (PI) controller, is also widely employed in the LFC application.

Fixed parameter controllers are designed at nominal operating points, and may no longer be suitable in all operating conditions. For this reason, adaptive gain scheduling approaches have been proposed for LFC synthesis [3]. This method overcomes the disadvantages of the conventional Proportional Integral and Derivative (PID) controllers which need adaptation of controller parameters. However, it faces some difficulties like the instability of transient response as a result of abrupt changes in the system parameters, in addition to the impossibility of obtaining accurate linear time invariant models at variable operating points [3]. In addition to dealing with changes in system parameters, fuzzy logic controllers
have been used in many reports for LFC design in a two area power system [4,5]. The applications of artificial neural network and genetic algorithms in LFC have been reported in Refs. [6,7]. In spite of these efforts, it seems that, although estimation of parameters is not required, the parameters of the controllers can be changed generally very quickly; but despite the promising results achieved, the control algorithms are complicated and unstable transient response could still be observed. Therefore, some other elegant techniques are needed to achieve a more desirable performance.

Recently, some papers have reported the application of model predictive control (MPC) technique on load frequency control issue [8,9]. In Ref. [8], the use of MPC in a multi area power system is discussed. In Ref. [9], the effect of merging wind turbines on the multi area power system controlled by MPC is discussed. From [8] and [9], fast response and robustness against parameter uncertainties and load changes can be obtained using MPC controller. On the other hand, positive effect of wind turbines (WTs) was observed, but, the problem of calculations remains an obstacle in the way of real time implementation of MPC.

In fact, due to increase in the complexity and change of the power system structure, other techniques are needed to achieve a desirable performance.

In this work, a decentralized robust load frequency control (LFC) strategy involving Coefficient Diagram Method (CDM) is developed. This strategy is an algebraic approach applied to a polynomial loop in the parameter space, where a special diagram called coefficient diagram is used as the vehicle to carry the necessary design information, and as the criteria of good design [10].

The CDM is fairly new for load frequency control application. However, its basic principle has been known in industries and control community for more than 40 years with successful application in servo control, steel mill drive control, gas turbine control, and spacecraft attitude control [11].

In this paper, decentralized load frequency control for a multi-area power system has been developed based on the CDM technique. The parameters of the polynomials of CDM technique have been designed based on the dynamic model of the multi-area power system. The effects of the physical constraints such as generation rate constraint (GRC) and speed governor dead band [2] are considered. The power system with the proposed CDM technique has been tested through the effect of uncertainties due to governor and turbine parameters variation, and load disturbance using computer simulation. A comparison has been made between the CDM and the traditional integral controller confirming the superiority of the proposed CDM technique. The simulation results proved that the proposed controller can be applied successfully to the application of power system load frequency control. With the aim of robustness evaluation of the proposed CDM, another comparison between the proposed method and MPC technique has been made in a three area power system in case of both load changes and parameters uncertainties. The simulation results supported that CDM acts as robust control and more suitable for real time implementation.

The rest of the paper is organized as follows: the description of the dynamics of the interconnected power system is given in Section ‘System dynamics’. A general consideration about CDM and its design are presented in Section ‘Coefficient Diagram Method’. The implementation scheme of a two area power system together with the CDM technique is described in Section ‘Case study’. Simulation results and general remarks are presented in Section ‘Results and discussions’. Finally, the conclusion is given in Section ‘Conclusion’.

System dynamics

A multi-area power system comprises areas that are interconnected by tie-lines. The trend of frequency measured in each control area is an indicator of the trend of the mismatch power in the interconnection, and not in the control area alone. The LFC system in each control area of an interconnected (multi-area) power system should control the interchange power with the other control areas as well as its local frequency. Therefore, the dynamic LFC system model must take into account the tie-line power signal. For this purpose, consider Fig. 1 which shows a power system with N-control areas [2].

In this section, a frequency response model for any area-i of N power system control areas with an aggregated generator unit in each area is described [2].

The overall generator-load dynamic relationship between the incremental mismatch power \( (\Delta P_{mi} - \Delta P_{li}) \) and the frequency deviation \( (\Delta f_i) \) can be express as:

![Fig. 1. Dynamic model of a control area in an interconnected environment.](image-url)
\[ \Delta f_i = \left( \frac{1}{2H_i} \right) \Delta P_m - \left( \frac{1}{2H_i} \right) \Delta P_L - \left( \frac{D_i}{2H_i} \right) \Delta f_i - \left( \frac{1}{2H_i} \right) \Delta P_{\text{tie},i} \] (1)

while the dynamic of the governor can be expressed as:

\[ \Delta P_m = \left( \frac{1}{T_g} \right) \Delta P_g - \left( \frac{1}{T_g} \right) \Delta P_{\text{mi}} \] (2)

and the dynamic of the turbine can be expressed as:

\[ \Delta P_g = \left( \frac{1}{T_g} \right) \Delta P_g - \left( \frac{1}{R_s T_g} \right) \Delta f_i - \left( \frac{1}{T_g} \right) \Delta P_g \] (3)

The total tie-line power change between area-i and the other areas can be calculated as:

\[ \Delta P_{\text{tie},i} = 2\pi \cdot \left[ \sum_{j=1}^{N} T_{ij} \Delta f_i - \sum_{j \neq i}^{N} T_{ij} \Delta f_j \right] \] (4)

where \((\cdot)\) is a differential operator.

In a multi-area power system, in addition to regulating area frequency, the supplementary control should maintain the net interchange power with neighboring areas at scheduled values. This is generally accomplished by adding a tie-line flow deviation to the frequency deviation in the supplementary feedback loop. A suitable linear combination of frequency and tie-line power changes for area \(i\), is known as the area control error (ACE),

\[ \text{ACE}_i = \Delta P_{\text{tie},i} + B_i \Delta f_i \] (5)

Equations (1)–(4) represent the frequency response model for \(N\) power system control areas with one generator unit in each area, and can be combined in the following state space model:

\[
\begin{bmatrix}
\Delta P_{\text{mi}} \\
\Delta P_m \\
\Delta f_i \\
\Delta P_{\text{tie},i}
\end{bmatrix}
= 
\begin{bmatrix}
-\frac{1}{T_g} & 0 & -\frac{1}{R_s T_g} & 0 \\
\frac{1}{T_g} & -\frac{1}{T_g} & 0 & 0 \\
0 & 0 & -\frac{1}{\pi T_g} & -\frac{1}{\pi T_g} \\
0 & 0 & 2\pi & -\sum_{j=1}^{N} T_{ij} \\
\end{bmatrix}
\begin{bmatrix}
\Delta P_{\text{mi}} \\
\Delta P_m \\
\Delta f_i \\
\Delta P_{\text{tie},i}
\end{bmatrix}
+ 
\begin{bmatrix}
0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 \\
-\frac{1}{2\pi} & 0 & 0 & 0 \\
0 & 0 & 0 & 0 \\
\end{bmatrix}
\begin{bmatrix}
\Delta f_i \\
\Delta f_i \\
\Delta P_{\text{tie},i} \\
\Delta P_{\text{tie},i}
\end{bmatrix}
+ 
\begin{bmatrix}
\frac{1}{T_g} \\
0 \\
0 \\
0 \\
\end{bmatrix}
\begin{bmatrix}
\Delta f_i \\
\Delta f_i \\
\Delta P_{\text{tie},i} \\
\Delta P_{\text{tie},i}
\end{bmatrix}
\] (6)

where \(\Delta P_{\text{mi}}\), the governor output change of area \(i\); \(\Delta P_m\), the mechanical power change of area \(i\); \(\Delta f_i\), the frequency deviation of area \(i\); \(\Delta P_{\text{tie}}\), the load change of area \(i\); \(P_{\text{ci}}\), supplementary control action of area \(i\); \(y_i\), the system output of area \(i\); \(H_i\), equivalent inertia constant of area \(i\); \(D_i\), equivalent damping coefficient of area \(i\); \(R_s\), speed droop characteristic of area \(i\); \(T_{gi}, T_{ri}\), governor and turbine time constants of area \(i\); \(\text{ACE}_i\), the control error of area \(i\); \(B_i\), a frequency bias factor of area \(i\); \(T_{gi}\), tie-line synchronizing coefficient with area \(j\); \(\Delta P_{\text{tie},i}\), the total tie-line power change between area \(i\) and the other areas; \(\Delta t_i\), control area interface,

\[ t_i = \left[ \sum_{j \neq i}^{N} T_{ij} \Delta f_i \right] . \]

\[ y = \frac{N(s) F(s) - A(s) N(s)}{P(s)} d \] (7)

where \(P(s)\) is considered as the characteristic polynomial of the closed-loop system and is defined by

\[ P(s) = A(s) D(s) + B(s) N(s) \] (8)

\(A(s)\) and \(B(s)\) are considered as the control polynomial and is defined as:

\[ A(s) = \sum_{i=0}^{p} a_i s^i \quad \text{and} \quad B(s) = \sum_{i=0}^{q} b_i s^i \] (9)

\(u\) as the controller signal; \(d\) as the external disturbance signal; and \(y\) is denoted as the output of the control system.
For practical realization, the condition \( p \geq q \) must be satisfied. To get the characteristic polynomial \( P(s) \), the controller polynomials from (3) are substituted in (2) and is given as:

\[
P(s) = \sum_{i=0}^{p} l_i s^i D(s) + \sum_{i=0}^{q} k_i s^i N(s) = \sum_{i=0}^{n} a_i s^i, \quad a_i > 0
\]  

(10)

CDM needs some design parameters with respect to the characteristic polynomial coefficients which are the equivalent time constant \( \tau \) (which gives the speed of closed loop response), the stability indices \( \gamma_i \) (which give the stability and the shape of the time response), and the stability limits \( \gamma_n \). The relations between these parameters and the coefficients of the characteristic polynomial \( a_i \) can be described as follows:

\[
\gamma_i = \frac{a_i^2}{a_{i-1} a_{i-1}}, \quad i \in [1, n - 1], \quad \gamma_0 = \gamma_n = \infty
\]  

(11)

According to Manabe’s standard form, \( \gamma_i \) values are selected as \( \{2.5, 2, 2 \ldots 2\} \). The above \( \gamma_i \) values can be changed by the designer as per the requirement. Using the key parameters \( \tau \) and \( \gamma_i \), target characteristic polynomial \( P_{\text{target}}(s) \) can be framed as:

\[
P_{\text{target}}(s) = a \left[ \sum_{j=2}^{n} \left( \prod_{i=j}^{1} \frac{1}{\tau_i} \right) \left( \frac{\tau}{\tau_s} \right)^i \right] + \tau s + 1
\]  

(14)

where \( P(s) = P_{\text{target}}(s) \).

Also, the reference numerator polynomials \( F(s) \) can be calculated from:

For practical realization, the condition \( p \geq q \) must be satisfied.
Table 1
Parameters and data of a practical two area power system.

<table>
<thead>
<tr>
<th>Area</th>
<th>K (s)</th>
<th>D (pu/Hz)</th>
<th>2H (pu s)</th>
<th>R (Hz/pu)</th>
<th>T2 (s)</th>
<th>T1 (s)</th>
<th>T12</th>
</tr>
</thead>
<tbody>
<tr>
<td>Area 1</td>
<td>-0.3/s</td>
<td>0.015</td>
<td>0.1667</td>
<td>3.00</td>
<td>0.08</td>
<td>0.40</td>
<td>0.20</td>
</tr>
<tr>
<td>Area 2</td>
<td>-0.2/s</td>
<td>0.016</td>
<td>0.2017</td>
<td>2.73</td>
<td>0.06</td>
<td>0.44</td>
<td></td>
</tr>
</tbody>
</table>

The time constant can be taken as $= 2$ s, and choosing $k_0 = 40$, then

\[
D_1 = 0.3485 + 0.1739s^2 + 0.0805s^3 + 0.005334s^4
\]
\[
N_1 = 1.256 + 0.3483s
\]
The stability indices ($\gamma_{\text{i1}}$) have been chosen as:

\[
\gamma_{\text{i1}} = [1.65, 1.5, 2.7, 72], \quad i \in [1, 5], \quad \gamma_0 = \gamma_6 = \infty
\]

And the stability limits ($\gamma_{\text{i2}}$) are:

\[
\gamma_{\text{i2}} = [0.153, 1.66, 0.523, 0.68, 0.0138], \quad i \in [1, 5]
\]

\[
P_{\text{target,1}} = 50 + 100s + 202.18s^2 + 61.1615s^3 + 12.425s^4 + 0.96s^5 + 0.001s^6
\]

\[
B_1 = 40 + 69s + 100s^2
\]

\[
A_1 = 150s + 2s^2
\]

\[
D_2 = 0.3825 + 0.2097s^2 + 0.10127s^3 + 0.00532s^4
\]
\[
N_2 = 1.256 + 0.3827s
\]
The stability indices ($\gamma_{\text{i2}}$) have been chosen as:

\[
\gamma_{\text{i2}} = [1.64, 2.3, 1.53, 3.5], \quad i \in [1, 5], \quad \gamma_0 = \gamma_6 = \infty
\]

And the stability limits ($\gamma_{\text{i2}}$) are:

\[
\gamma_{\text{i2}} = [0.1562, 1.434, 0.809, 0.7179, 0.653], \quad i \in [1, 5]
\]

\[
P_{\text{target,2}} = 40 + 80s + 160.7s^2 + 51s^3 + 6.6s^4 + 0.6s^5 + 0.015s^6
\]

And choosing $k_0 = 32$, then

\[
B_2 = 32 + 54s + 100s^2
\]

\[
A_2 = 60s + 3s^2
\]

The simulation studies are carried out for the proposed controllers with generation rate constraint (GRC) of 10% per minute and the maximum value of dead band for governor is specified as 0.05 pu for each area [2].

Case I

The system performance with the proposed CDM controllers at nominal parameters is tested and compared to the system

\[
D_1 = 0.3485 + 0.1739s^2 + 0.0805s^3 + 0.005334s^4
\]
\[
N_1 = 1.256 + 0.3483s
\]
The stability indices ($\gamma_{\text{i1}}$) have been chosen as:

\[
\gamma_{\text{i1}} = [1.65, 1.5, 2.7, 72], \quad i \in [1, 5], \quad \gamma_0 = \gamma_6 = \infty
\]

And the stability limits ($\gamma_{\text{i2}}$) are:

\[
\gamma_{\text{i2}} = [0.153, 1.66, 0.523, 0.68, 0.0138], \quad i \in [1, 5]
\]

\[
P_{\text{target,1}} = 50 + 100s + 202.18s^2 + 61.1615s^3 + 12.425s^4 + 0.96s^5 + 0.001s^6
\]

\[
B_1 = 40 + 69s + 100s^2
\]

\[
A_1 = 150s + 2s^2
\]

The simulation studies are carried out for the proposed controllers with generation rate constraint (GRC) of 10% per minute and the maximum value of dead band for governor is specified as 0.05 pu for each area [2].

Case I

The system performance with the proposed CDM controllers at nominal parameters is tested and compared to the system
Fig. 5. Power system responses to case 2 (a) frequency deviation in area-1, (b) frequency deviation in area 2 and (c) tie-line power change. (Solid) for CDM and (dotted) for conventional controller.

Fig. 6. Three-control area power system.

Table 2
Parameters and data of a practical three control area power system.

<table>
<thead>
<tr>
<th>Area</th>
<th>K [s]</th>
<th>D (pu/Hz)</th>
<th>2H (pu s)</th>
<th>R (Hz/pu)</th>
<th>T_e [s]</th>
<th>T_i [s]</th>
<th>T_{ij}</th>
</tr>
</thead>
<tbody>
<tr>
<td>Area-1</td>
<td>-0.3/s</td>
<td>0.015</td>
<td>0.1667</td>
<td>3.00</td>
<td>0.08</td>
<td>0.40</td>
<td>T_{ij} = 0.20</td>
</tr>
<tr>
<td>Area-2</td>
<td>-0.2/s</td>
<td>0.016</td>
<td>0.2017</td>
<td>2.73</td>
<td>0.06</td>
<td>0.44</td>
<td>T_{ij} = 0.20</td>
</tr>
<tr>
<td>Area-3</td>
<td>-0.4/s</td>
<td>0.015</td>
<td>0.1247</td>
<td>2.82</td>
<td>0.07</td>
<td>0.3</td>
<td>T_{ij} = 0.25</td>
</tr>
</tbody>
</table>

(Pe_{base} = 800 MVA)
performance with a conventional integrator and at only-load-change in area-2. Fig. 4 shows the simulation results in this case. The results from the top to the bottom are: the frequency deviations of area-1 $\Delta f_1$, the frequency deviations of area-2 $\Delta f_2$, and the tie-line power change between area-1 and area-2 $\Delta P_{tie}$. As mention above the proposed CDM and classical integrator controllers are utilized and compared following a step load change in area-2 ($\Delta P_{l2}$ assumed to be 0.02 pu at $t = 30$ s). It is noteworthy that with the proposed CDM controller the system is more stable and fast as compared to the system with traditional integrator.

Case 2

The robustness of the proposed CDM controller against a wide range of parameters uncertainty is validated. In this case, the governor and turbine time constants of the two areas are increased to $T_{g1} = 0.105$ s ($\approx 31\%$ change), $T_{t1} = 0.785$ s ($\approx 95\%$ change), $T_{g2} = 0.105$ s ($\approx 66\%$ change) and $T_{t2} = 0.6$ s ($\approx 38\%$ change), respectively. Fig. 5 depicts the response of the CDM and conventional integral controllers in the presence of above uncertainty, at same load change described in the first case. It has been indicated that a desirable performance response has been achieved using the proposed CDM controller while with conventional integrator, the performance and stability is seriously degraded.

Case 3

In order to evaluate the robustness of the proposed CDM, a comparison has been made between CDM and the model predictive control presented in [8], but for three area power system. Consider three identical interconnected control areas as shown in Fig. 6 where the simulation parameters [2] are given in Table 2. The system is tested at a simultaneous 0.02-pu load step disturbances in control area-2 at $t = 3$ s. It is also tested and validated against wide range of parameter uncertainties. In the tested scenarios, the governor and turbine time constants of each area is increased to $T_{g1} = 0.105$ s ($\approx 31\%$ change), $T_{t1} = 0.785$ s ($\approx 95\%$ change), $T_{g2} = 0.105$ s ($\approx 66\%$ change) and $T_{t2} = 0.6$ s ($\approx 38\%$ change), respectively.

Fig. 7. System response to case 3: (a) frequency deviations and (b) tie-line powers CDM (solid line), MPC (dashed line) and conventional integrator (dotted line).
The parameters of the CDM controller of each area are set as follows:

The time constant can be taken as $1$ s for all three controllers and choosing $k_{0.1} = 23$, $k_{0.2} = 31$ and $k_{0.3} = 30$, then

$$D_1 = 0.348S + 0.1739S^2 + 0.0805S^3 + 0.005334S^4$$
$$N_1 = 2.009 + 0.38275$$
The stability indices ($\gamma_{1,i}$) have been chosen as:

$$\gamma_{1,i} = [0.24, 18.28, 0.76, 3.96, 8.66], \ i \in [1, 5], \ \gamma_0 = \gamma_0 = \infty$$

And the stability limits ($\gamma'_{1,i}$) are:

$$\gamma'_{1,i} = [0.054, 5.475, 0.306, 1.42, 0.2525], \ i \in [1, 5]$$

$P_{\text{target}} = 65 + 65S + 263.325S^2 + 61.71S^3 + 18.5S^4 + 1.4S^5 + 0.001S^6$

$$B_1 = 23 + 20.165 + 63S^2$$
$$A_1 = 225S + 2S^2$$

$$D_2 = 0.382S + 0.2097S^2 + 0.10127S^3 + 0.00532S^4$$
$$N_2 = 2.009 + 0.38275$$
The stability indices ($\gamma_{1,i}$) have been chosen as:

$$\gamma_{1,i} = [0.179, 16.97, 1.66, 3.3, 5.26], \ i \in [1, 5], \ \gamma_0 = \gamma_0 = \infty$$

And the stability limits ($\gamma'_{1,i}$) are:

$$\gamma'_{1,i} = [0.0589, 6.188, 0.3619, 0.7925, 0.303], \ i \in [1, 5]$$

$P_{\text{target}} = 64 + 64S + 357.5S^2 + 117.68S^3 + 23.28S^4 + 1.4S^5 + 0.016S^6$

$$B_2 = 31 + 245 + 131S^2$$
$$A_2 = 225S + 2S^2$$

$$D_3 = 0.3696S + 0.1302S^2 + 0.0464S^3 + 0.00262S^4$$
$$N_3 = 2.3236 + 0.36925$$
The stability indices ($\gamma_{1,i}$) have been chosen as:

$$\gamma_{1,i} = [0.156, 33.17, 1.56, 2.28, 6.31], \ i \in [1, 5], \ \gamma_0 = \gamma_0 = \infty$$

And the stability limits ($\gamma'_{1,i}$) are:

$$\gamma'_{1,i} = [0.0301, 7.051, 0.4681, 0.799, 0.438], \ i \in [1, 5]$$

$P_{\text{target}} = 69.7 + 69.7S + 446.739S^2 + 86.328S^3 + 10.07S^4 + 0.585S^5 + 0.005S^6$

$$B_3 = 30 + 25S + 152.5S^2$$
$$A_3 = 225S + 2S^2$$

Fig. 7 depicts the response of the proposed CDM and both of MPC and conventional integral controllers in the presence of the above uncertainties. It is shown in the figure that when the system with the conventional controller became unstable, the system with both CDM and MPC controllers could give robust response versus load change and parameters uncertainties. In addition, the tie-line powers and the frequency responses of the system with the proposed CDM is much better than the one with MPC.

**Conclusion**

In this paper, a robust decentralized LFC design using CDM has been proposed for an interconnected power system. The proposed method was applied to both two and three-control area power system and was tested, considering different load change and parameters change cases. The results were compared with the results of conventional integrator and model predictive controllers. Simulation results demonstrated the effectiveness of the proposed CDM methodology. It was shown that the power system with the proposed CDM controller is robust against the load change and parameter perturbation; and the system and has a more desirable performance as compared to classical integral control design, in all of the performed tested cases. Also, the simulation results indicated that both CDM and MPC controllers can give robust response versus load change and parameters uncertainties, but the proposed CDM is more practical in term of the calculation burdens which is available in the case of MPC.

**References**


