AUTOMATIC GENERATION CONTROL PERFORMANCE OF THE NIGERIAN POWER SYSTEM AFTER DEREGULATION.

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Abstract
The current restructuring program which seeks to split the National Electric Power Authority (NEPA) –the sole electricity supply company in Nigeria- into one transmission company, often reffered to as a Transco, and several generation and distribution companies (Gencos & Discos), is a welcome development. This paper investigates some of the technical problems associated with Automatic Generation Control (AGC) of the Nigerian power system after deregulation. Simulation studies are presented utilizing concepts of the traditional two area power system model, but incorporating factors which represent bilateral contracts between the Gencos and the Discos, in a state space formulation. A further decomposition of the model results in a 15th order vector-matrix performance equation which is solved under some assumptions to track the relevant parameters. It is then easy to visualize the physical constraints on system operation and thus, appreciate the conclusions of the authors.

Introduction
The National Electric Power Authority (NEPA) has for many years been responsible for generation, transmission and distribution of electric power in Nigeria, except for a few Independent Power Producers (IPPs). This situation started changing recently following the Federal Government's decision to unbundle NEPA into several quasi-autonomous distribution companies often reffered to as Discos, generation companies –Gencos and a single transmission company – Transco. The final goal is full privatization cum deregulation of the Electricity Supply Industry (ESI) in Nigeria after a trial period of two years, during which a small management team excercises selected control. Therefore, the envisaged operating environment is such that the Discos can ideally buy power from Gencos of their choice while the Gencos are allowed to optimise production cost and hence, make competitive offers for sale of power. The Transco doubles as the energy carrier and an Independent Power Operator (IPO), implementing bilateral contracts between the Discos and the Gencos as well as issuing operational guidelines necessary for efficient system performance.
Given the scenario above and considering the discussions in [1,2, 3 & 4], it becomes obvious that a number of technical problems need be solved to ease the transition into full deregulation. This paper examines some of the technical issues associated with real time implementation of a deregulated electricity supply industry in Nigeria. To enhance the study, a two-area AGC model which has been previously derived for the Nigerian power system [5,6], is now modified to incorporate factors which represent bilateral contracts between the Gencos and the Discos, in a state space formulation. Working through the model results in a 15th order vector matrix performance equation which is solved under some assumptions to yield system response to varying contract conditions. In this way, the physical constraints on system operation can be better appreciated as well as some necessary conditions for efficient system performance.

2. The Deregulated Nigerian ESI

2.1 Fundamental Changes

In contrast to the former Vertically Integrated Utility (VIU), the deregulated Nigerian ESI is expected to consist initially of 11 Discos and 7 Gencos while retaining the transmission function under one Transco to be owned by the Federal Government. A detailed description of this scenario together with its implications are presented in [4]. Suffice it to repeat here that a number of technical constraints necessitate the adoption of "controlled deregulation" as opposed to "liberal deregulation" [4]. In that case, the Transco must broker and indeed approve all Disco–Genco contracts or simply buys power from the Gencos and sells to the Discos. A major disadvantage of this arrangement is how to ensure efficiency of service since the Transco is owned by government. However, it is envisaged that market forces will compel the Transco to live up to expectation, while other supply arrangements between heavy consumers and neighbouring Gencos may emerge.
Furthermore, two fundamental structural inadequacies need be addressed in order to hasten the pace towards full deregulation. The first is over-concentration of generation sources on a small percentage of the country which gives rise to heavy losses, non-optimal load flow and relatively weak grid. Full implications of this have been discussed by Somolu and Zaccheaus [7]. The next is the grid control structure which still ties the whole country strongly as a single control area. Two area operation for the Nigerian ESI has been canvassed

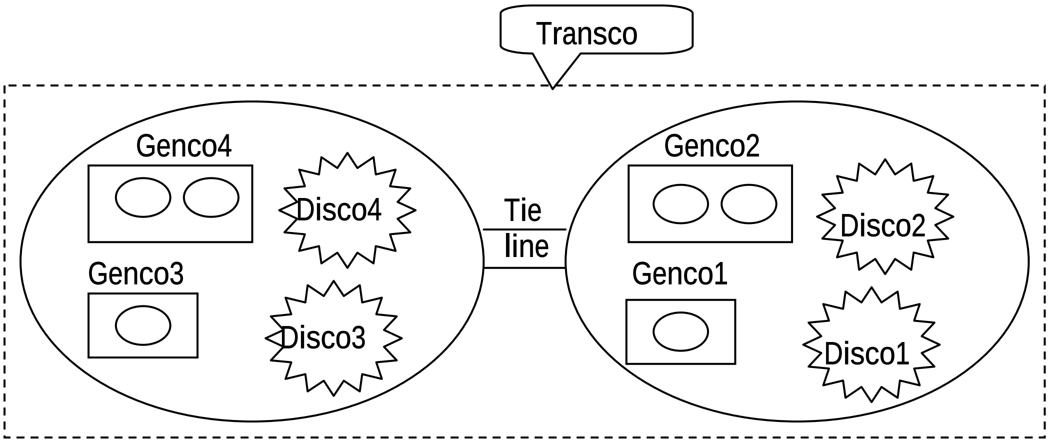

Fig.1 Two area control structure

in [5,6 & 8] with all the advantages spelt out. In this study , a two area control structure is assumed, both of them under one Transco as shown in fig.1 above. Here we assume that area 1 generation is derived from the hydro-stations in Jebba, Kainji and Shiroro while area 2 is fed from the steam/gas plants down south. Both areas can buy or sell power to each other such that the scheduled interchange power in magnitude and direction is determined by the load forecasts of the previous day.

3. The AGC Burden in a Free Market ESI

In general, the AGC burden is to match real power generation with consumption so as to maintain the frequency and scheduled tie-line power within specified limits. Practical details of AGC implementation could be found in [8,9]. However, in a free market scenario, the AGC duty is expanded to include the implementation of Disco-Genco contracts.

3.1 Block Diagram Formulation

Following some concepts developed in [3 & 10], the block diagram of fig.2 represents AGC implementation in a free market environment. In our case, two representative Kaplan units in area 1 and two gas units in area 2 are used for AGC. Like in the traditional two area model [11], all the area demand must be met by the own area generation plus the scheduled tie-line power. Thus, the load demand of the Discos in one area is treated as a local change in load represented by ΔP_{Di} (i = 1,4) and added at the input of the power system block. The unit commitment factor uc_{ij} is a measure of what part of the total generation of Genco i is allocated to Disco j by the Transco. The actual values are solely determined by the Transco after considering inputs such as available capacities of the respective Gencos, demands of the Discos (usually forecasts from the previous day), optimal power flow solutions, pacity levels of the relevant transmission lines, etc. Monitoring the uc
values will help the Transco to compute the cost of inadvertent load demands and the liability of the respective Discos.
Note that the direction of scheduled tie-line power is aimed at compensating for shortfall in area generation. In general, we can write:

$\Delta P_{tie1\text{-}2,\ scheduled}$ = (commitment of Gencos in area 1 to Discos in area 2) - (commt. of Gencos in area 2 to Discos in area 1) --------(1)

Part of the AGC burden is to maintain the scheduled tie-line power such that any deviation will be forced to zero in the steady state. Thus;

$$\Delta P_{tie,1\text{-}2,error} = \Delta P_{tie,1\text{-}2\ actual} - \Delta P_{tie,1\text{-}2,scheduled} \quad \text{----(2)}$$

must be made to vanish by AGC action. The control signal which actuates change in generation, otherwise called area control error (ACE) is defined for each area as:

$$ACE_1 = B_1\Delta f_1 + \Delta P_{tie1\text{-}2,\ error} \quad \text{-------------(3a)}$$
$$ACE_2 = B_2\Delta f_2 + \Delta P_{tie2\text{-}1,\ error} \quad \text{-------------(3b)}$$

Where B is the frequency bias setting (in MW/0.1 Hz, a negative value) and f is frequency. As shown on the block diagram of fig.2, $\Delta P_{tie1\text{-}2,error}$ is related to $\Delta P_{tie2\text{-}1,error}$ by the equation:

$$\Delta P_{tie1-2,error} = -\frac{P_{1rated}}{P_{2rated}} \Delta P_{tie1-2,error} \quad \text{---(4a)}$$

$$= \alpha_{12}\Delta P_{tie1-2,error} \quad \text{----------------- (4b)}$$

where P_{rated} is the area power rating and α_{12} is as defined in (4a). Following the procedure in [10], the ACE signal is shared among all the Gencos participating in AGC through the apf factors shown on the block diagram. The CC blocks compute the cross-commitments needed for solving equ.(1). Other blocks and variables are as used in the traditional AGC scheme [6,11].

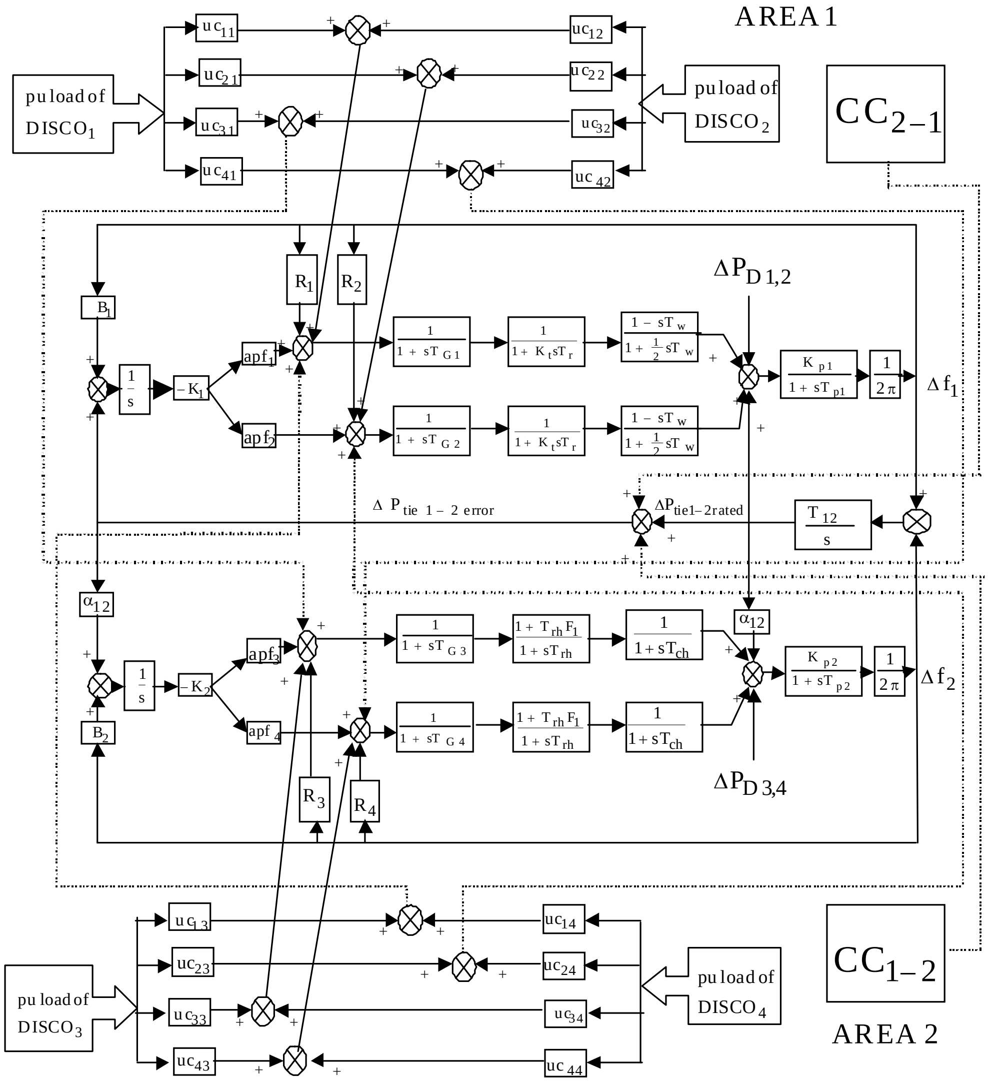

Fig. 2 Free market LFC block diagram

3.2 State Space Representation

The AGC scheme depicted in fig.2 can be analytically expressed in the usual state variable formulation in closed loop as:

$$\dot{X} = AX + BU \text{ -------------(5)}$$

where the state vector $X \varepsilon \Re^n$; the input vector $U \varepsilon \Re^m$; while $A \varepsilon \Re^{nxn}$ and $B \varepsilon \Re^{nxm}$ are the system and input matrices respectively, which can be extracted from fig.2 using the standard technique. Elements of the X and U vectors as well as the A and B matrices are shown below.

4. Simulation Procedure

It is required here to show that in the steady state, the AGC action returns the system to the nominal frequency and scheduled tie-line loading by zeroing the deviations occasioned by a change in load demand. It is also expected that the generation of the Gencos will settle at the level requested of them by the Transco. Due to space constraints, only one example scenario is presented. It is assumed that any sudden change in load demand within an area is treated as a local problem, such that tie-line power transients settle at the scheduled value. This is both practicable and realistic. Parameter values for the traditional model is taken from [6 & 8].

For the sake of simplicity, assuming the Discos make the following hypothetical demands from the Gencos in puMW:

Disco1 = 0.1; Disco2 = 0.1; Disco3 = 0.125; Disco4 = 0.2. In consequence therefore, the Transco could share to the Gencos as follows: from Disco1; Genco1 gets 0.05 puMW, Genco2 = 0.05, Genco3 = Genco4 =0. From Disco2; Genco1 = Genco2 = 0.05 while Genco3 = Genco4 = 0. From Diaco3; Genco1 = Genco2 = Genco4 = 0.025, Genco3 = 0.05. From Disco4; Genco1 = Genco2 = 0.02, Genco3 = 0.06 while Genco4 = 0.1. Hence, the commitment factors for Disco4 for instance (see fig.2) can be computed as follows:

uc_{14} = 0.02/0.2 = 0.1. Similarly, uc_{24} = 0.1, uc_{34} = 0.3 and uc_{44} = 0.5. Same procedure for others.

The Genco participation in AGC is apportioned by the apfs as determined by the Transco based on available spinning reserve plus other factors: (note

$$
A=\begin{bmatrix}
-\frac{1}{T_{p1}} & 0 & \frac{K_{p1}}{T_{p1}} & \frac{K_{p1}}{T_{p1}} & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & -\frac{K_{p1}}{T_{p1}} \\
0 & -\frac{1}{T_{p2}} & 0 & 0 & \frac{K_{p2}}{T_{p2}} & \frac{K_{p2}}{T_{p2}} & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \frac{a_{12}K_{p2}}{T_{p2}} \\
0 & 0 & -\frac{2}{T_w} & 0 & 0 & 0 & \frac{2Y}{T_w} & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & -\frac{2}{T_w} & 0 & 0 & 0 & \frac{2Y}{T_w} & 0 & -\frac{2}{T_wT_RK_t} & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & -\frac{1}{T_{ch}} & 0 & 0 & 0 & 0 & \frac{1+T_{rh}F_1}{T_{ch}} & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & -\frac{1}{T_{ch}} & 0 & 0 & 0 & 0 & \frac{1+T_{rh}F_1}{T_{ch}} & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & -\frac{1}{K_tT_R} & 0 & \frac{1}{K_tT_R} & 0 & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & -\frac{1}{K_tT_R} & 0 & \frac{1}{K_tT_R} & 0 & 0 & 0 & 0 & 0 \\
-\frac{1}{2\pi R_1T_{G1}} & 0 & 0 & 0 & 0 & 0 & 0 & 0 & -\frac{1}{T_{G1}} & 0 & 0 & 0 & -\frac{K_1apf_1}{T_{G1}} & 0 & 0 \\
-\frac{1}{2\pi R_2T_{G2}} & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & -\frac{1}{T_{G2}} & 0 & 0 & -\frac{K_1apf_2}{T_{G2}} & 0 & 0 \\
0 & -\frac{1}{2\pi R_3T_{G3}} & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & -\frac{1}{T_{G3}} & 0 & 0 & -\frac{K_2apf_3}{T_{G3}} \\
0 & -\frac{1}{2\pi R_4T_{G4}} & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & -\frac{1}{T_{G4}} & 0 & -\frac{K_2apf_4}{T_{G4}} \\
\frac{B_2}{2\pi} & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 1 \\
0 & \frac{B_2}{2\pi} & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \alpha_{12} \\
\frac{T_{12}}{2\pi} & -\frac{T_{12}}{2\pi} & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0
\end{bmatrix} \quad \text{--(6)}
$$

$$
X=\left[\Delta w_1 \quad \Delta w_2 \quad \Delta P_{G1} \quad \Delta P_{G2} \quad \Delta P_{G3} \quad \Delta P_{G4} \quad \Delta P_{w1} \quad \Delta P_{w2} \quad \Delta P_{m1} \quad \Delta P_{m2} \quad \Delta P_{m3} \quad \Delta P_{m4} \quad \int ACE_1dt \quad \int ACE_2dt \quad \Delta P_{tie1-2}\right]^T
$$

that ACE exists in the transient state and vanishes in the steady state. It follows that the steady state output of a Genco is determined by the total Disco demands committed to it. In other words;

$$\Delta P_{Gi} = \sum_j uc_{ij}\Delta P_{Dj} \qquad \text{------(7)}$$

where ΔP_{Gi} is the generation of Genco i, ΔP_{Dj} is the total demand of Disco j while uc_{ij} is as defined above. Expanding eqn.(7) for Genco4 gives;

$\Delta P_{G4} = uc_{41}\Delta P_{D1} + uc_{42}\Delta P_{D2} + uc_{43}\Delta P_{D3} + uc_{44}\Delta P_{D4}$

= 0.125puMW. Similarly,

$\Delta P_{G1} = 0.145$; $\Delta P_{G2} = 0.145$; and $\Delta P_{G3} = 0.11$

The scheduled tie-line power is computed from (1), which can be written as:

$$\Delta P_{tie1-2,scheduled} = \sum_{i=1}^{2}\sum_{j=3}^{4} uc_{ij}\Delta P_{Dj} - \sum_{i=3}^{4}\sum_{j=1}^{2} uc_{ij}\Delta P_{Dj} \qquad \text{------(8) or,}$$

$(uc_{13}\Delta P_{D3} + uc_{14}\Delta P_{D4} + uc_{23}\Delta P_{D3} + uc_{24}\Delta P_{D4}) - (uc_{31}\Delta P_{D1} + uc_{31}\Delta P_{D2} + uc_{41}\Delta P_{D1} + uc_{42}\Delta P_{D2})$

= 0.09 puMW.

In the particular case of Nigeria with a large land mass, the scheduled inter-change power will be determined by striking an economic balance between optimum loss regime and minimum incremental generation cost. This is because, during the high flood season, the reservoirs of the major hydro-stations tend to over-fill, which suggest operation at full capacity. However, Lagos, the load center, lies down south, and hence requires long distance power transmission with the associated losses. Other influencing factors may include existing contracts with IPPs and enhanced system security.

4.1 Results.

Figs.6(a&b), 7 and 8(a,b,c&d), depict the excursions of area frequencies, tie-line loading and Genco outputs respectively. It is seen that the frequency transients vanish in the steady state while outputs of the Gencos and the tie-line power settle at the preset values. For instance, the output of the Genco1 was computed to be 0.1puMw and also for Genco2. Genco3 was supposed to generate 0.11puMω while Genco 4 gives 0.125pu Mω. The generated power transients settle at the respective set points.

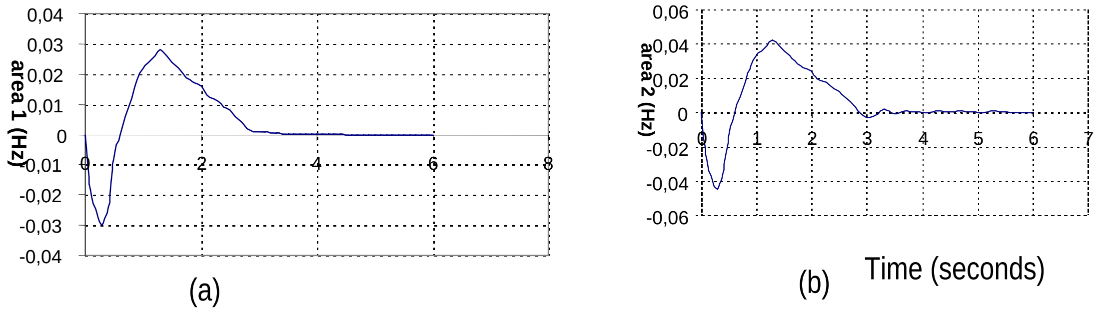

Fig. 3 Frequency transient against time in seconds

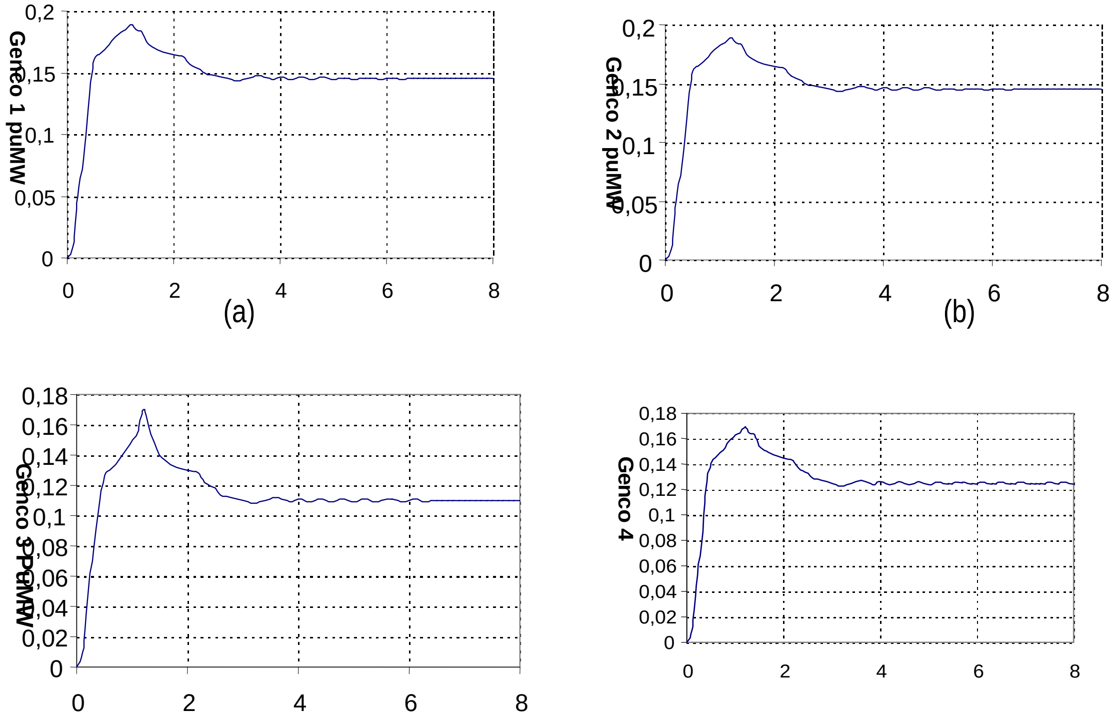

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Fig.4 Transients of Genco outputs against time in seconds

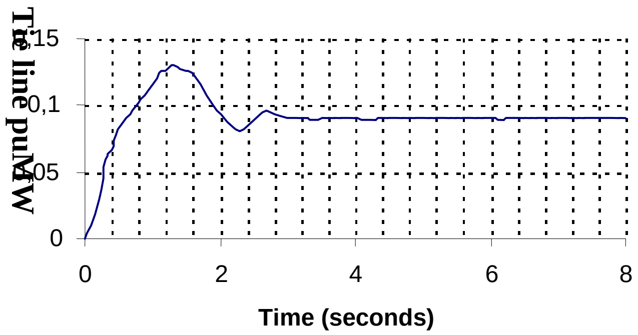

Fig. 5 Tie-line power transient.

$$B=\begin{bmatrix} -\frac{K_{p1}}{T_{P1}} & -\frac{K_{p2}}{T_{P1}} & 0 & 0 \\ 0 & 0 & -\frac{K_{p2}}{T_{P2}} & -\frac{K_{p2}}{T_{P2}} \\ 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 \\ \frac{uc_{11}}{T_{G1}} & \frac{uc_{12}}{T_{G1}} & \frac{uc_{13}}{T_{G1}} & \frac{uc_{14}}{T_{G1}} \\ \frac{uc_{21}}{T_{G2}} & \frac{uc_{22}}{T_{G2}} & \frac{uc_{23}}{T_{G2}} & \frac{uc_{24}}{T_{G2}} \\ \frac{uc_{31}}{T_{G3}} & \frac{uc_{32}}{T_{G3}} & \frac{uc_{33}}{T_{G3}} & \frac{uc_{34}}{T_{G3}} \\ \frac{uc_{41}}{T_{G4}} & \frac{uc_{42}}{T_{G4}} & \frac{uc_{43}}{T_{G4}} & \frac{uc_{44}}{T_{G4}} \\ (uc_{31}+uc_{41}) & (uc_{32}+uc_{42}) & -(uc_{13}+uc_{23}) & -(uc_{14}+uc_{24}) \\ -(uc_{31}+uc_{41}) & -(uc_{32}+uc_{23}) & (uc_{13}+uc_{23}) & (uc_{14}+uc_{24}) \\ 0 & 0 & 0 & 0 \end{bmatrix} \tag{a}$$

$$U=\begin{bmatrix} \Delta P_{D1} \\ \Delta P_{D2} \\ \Delta P_{D3} \\ \Delta P_{D4} \end{bmatrix}$$

5. Conclusion

This paper has described a viable technique of managing the load frequency control of the Nigerian power system after deregulation. The method incorporates the implementation of Disco – Genco contracts into the traditional LFC scheme. Thus, the Transco doubles as the transporter of power and system operator which appears both efficient and cost effective. The latter function has been canvassed for an Independent System Operator (ISO) in developed economies. However, for the Transco to achieve the goals set in the paper, efficient procedures must be developed for solving the optimal power flow problem as well as accurate determination of line ampacities, both of which will reduce technical losses and by extrapolation, cost of system operation. Further work is recommended to integrate the actual state of the existing transmission lines and the generating stations.

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