THE EFFECTS OF HYDRO POWER PLANTS' GOVERNOR SETTINGS ON THE STABILITY OF TURKISH POWER SYSTEM FREQUENCY

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ABSTRACT

This paper discusses the effects of hydro power plants' (HPP) governor settings on the stability of Turkish power system frequency. A representative network model is utilized to investigate the contribution of HPPs in frequency oscillation damping performance. A case study performed for a large HPP in Turkish network shows that modification of transient droop setting on the speed-governor in order to improve response time conflicts with the stable operation of the units. This modification, which is common in most HPPs, has essentially a negative effect on the Turkish frequency stability.

I. INTRODUCTION

The interconnection of Turkish electrical network with Union for the Coordination of Transmission of Electricity (UCTE) network is an ongoing project since the end of 90's. The synchronization of Turkish grid to UCTE through 380 kV network will enlarge the capacity of UCTE system by 40.000 MW roughly when the project is realized [1]. Although, frequency response of the Turkish Power System to the incidences is satisfactory, it has been observed that there are periodic oscillations with frequency deviation of ≤ 50 mHz, 20-30 seconds time period. There is a strong linkage between amount of HPPs in service and amount of periodic oscillations in the system frequency, due to the observation that when most of the major HPPs are taken out of operation, these periodic oscillations disappear [2].

Hydraulic turbines have a peculiar response due to water inertia: a change in gate position produces an initial turbine power change which is opposite to that sought. For stable control performance, a large transient droop with a long resetting time is therefore required. This is accomplished by the provision of a rate feedback or transient gain reduction compensation [3]. However, this transient droop is often deactivated during grid operation in order to speed up the primary control time response.

The units in all large HPPs have recently been subjected to step function tests (increasing and decreasing the speed set point 200 mHz with the speed feed back disconnected) in accordance with recommendation published by UCTE [4]. The response of the units to these step function tests in all HPPs except Karakaya appears to be within the expected limits. (The complete primary reserve was activated within 30 seconds.) Although, these inadequate settings provide the satisfactory primary reserve activation speed, this situation cause unstable island operation and negative contribution to the stability of the frequency control.

The rest of the paper is organized as follows. Section 2 presents the investigation study of the stability of the units at Birecik HPP (one of the major HPPs in Turkey with 750 MW installed capacity) under system-islanding condition for the purpose of understanding the reason of unit trips during system-islanding on October 31, 2006. Section 3 investigates the negative contribution of the inadequate settings to the stability of the Turkish power system frequency. The conclusion drawn from the study is provided in Section 4.

II. ISLAND OPERATION OF BIRECIK HPP

Birecik HPP is one of the major HPPs in Turkey consisting of 125 MW rated 6 coherent Francis type units connected to 380 kV network. Each unit has PID governors and their parameters had changed in order to speed up the primary control time response. The mathematical model of the governor head and its parameters are given in Fig. 1. and Table 1, respectively.

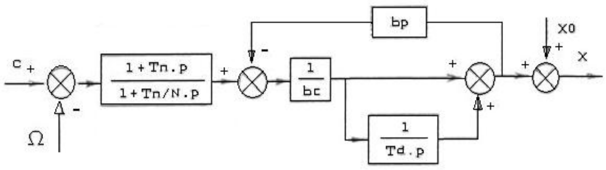

Fig. 1. Governor mathematical model

where;

c : Speed Set point
Ω : Speed Measurement
xo : Opening Set point
p : Laplace variable
x : Position Set point

Table. 1. Governor Settings

Parameters		Proposed Settings by Manufacturer (Old Settings)	Existing Setting (New Settings)
Tn	Derivative Constant	0.65 Sec	0.65 Sec
N	Differentiator Gain	10	10
bt	Transient Speed Droop	0.8	0.45
Td	Integral Constant	6 Sec	1 Sec
bp	Permanent Speed Droop	0.04	0.04

The step response simulations of Unit-1 in Birecik HPP with the old and new governor settings are given in Fig. 2.

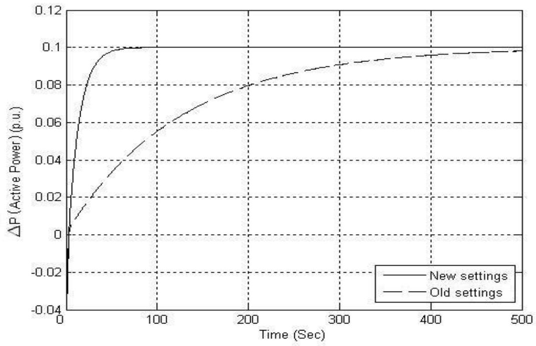

Fig. 2. -200mHz step response of the unit for the new and old governor settings.

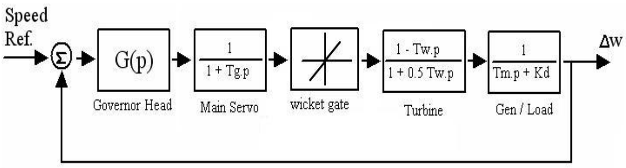

Fig. 3. Mathematical representation of a single unit to simulate island operation

The parameters of above model are given as;

Tm : 7 sec (Mechanical Starting Time)
Tw : 2.17 sec (Water Starting Time)
Tg : 0.2 sec (Wicket Gate Opening Time)
Kd : Not provided, assumed as zero
p : Laplace variable
Opening rate of wicket gate : 0.05 p.u./sec
Closing rate of wicket gate : 0.2 p.u./sec

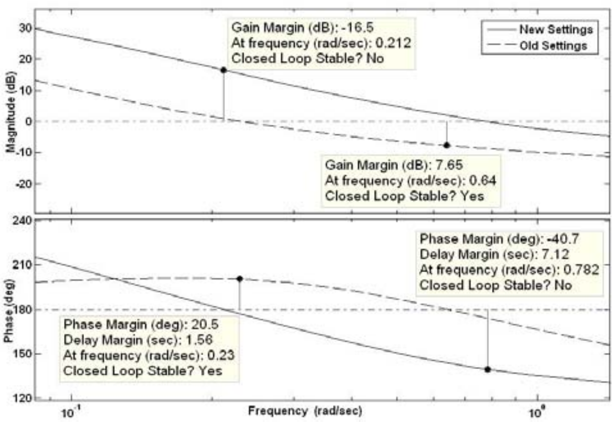

Fig.4. Bode Plots of the system with the new and old governor settings

Fig. 2 shows that the new settings increase the speed of the primary control time response. However, when the stability of a single unit for island operation is checked with the mathematical model given in Fig. 3, it is seen that these settings do not provide stable island operation. The Bode Plots of the system with the old and new settings obtained by utilizing MATLAB-Simulink is illustrated in Fig. 4.

Opening of the busbar coupler at Birecik 380 kV substation leaded two units in Birecik HPP to an islanding operation on October 31, 2006. The isolated network supplied by the units in Birecik HPP is illustrated in Fig. 5. During maneuver, the power demand of the load was 197 MW and the power generation was 194 MW.

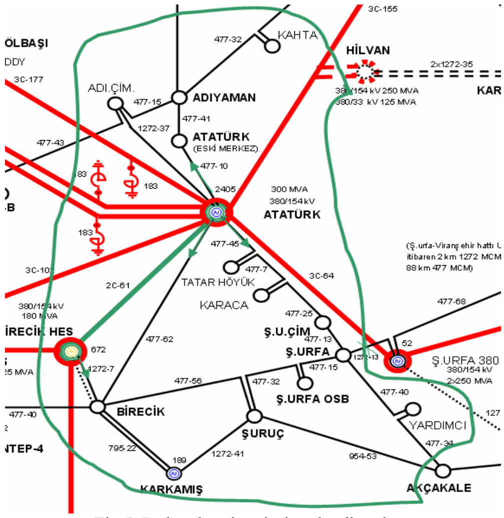

Fig.5. Isolated region during the disturbance.

After the islanding the unit trip is triggered by over speed protection. The islanding of the unit is simulated with the mathematical model given in Fig. 3. The measured and simulated frequency is given in Fig. 6.

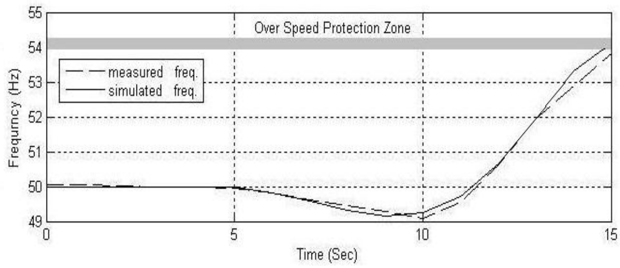

Fig.6. Simulated & measured frequency of islanding instant

Essentially Birecik HPP will be unable to supply its load with this setting in case of a fault resulting in island operation of the plant. After this observation, the Transmission System Operator (TEİAŞ) ordered to the power plant to restore the old governor settings and repeat the same scenario in order to confirm the stable island operation of the power plant. The island operation test is performed by National Load Dispatch Center (NLDC). During switching for islanding, the power demand of the island was about 200 MW and the power generation was about 194 MW. The measured and simulated frequency regarding the island operation test is given in Fig. 7.

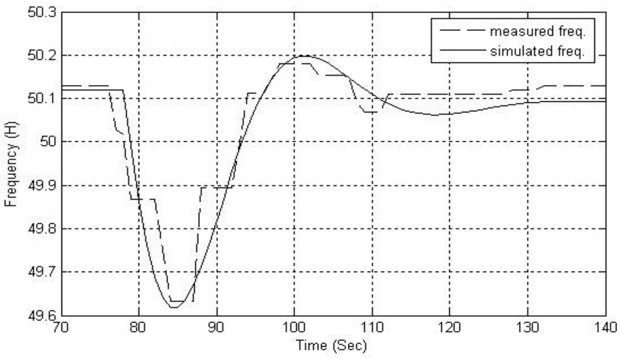

Fig. 7. Simulated & measured frequency in island operation test

III. SYSTEM WIDE EFFECT OF HPPS ON FREQUENCY STABILITY

It is well known that the governor settings that result in a fast response usually cause frequency instability under system-islanding conditions [3]. Usually fast settings for HPPs have no negative effect on system frequency in large systems like UCTE where HPP contribution to generation is 5%. However, it is described in the following subsections that as the contribution of HPPs with fast settings is increased, the frequency oscillation damping reduces. In order to observe the effect of HPPs on the Turkish system frequency, major HPPs are modeled individually. They have PID controllers with differentiator gain is set to zero forming a PI controller, except Birecik HPP which is modeled as stated above. The rest of Turkish network is modeled by assigning a single controller model for each plant type. Thermal Power Plant (TPP) and Natural Gas Combined Cycle Power Plants (NGCCPP) controllers are represented by models that resemble the characteristics of the plant type. Common frequency approach and perfect coherency approximation is utilized.

REPRESENTATIVE POWER SYSTEM MODEL

Utilizing the approach presented in [5], transient response of a power system in case of a disturbance can be represented by the following equations. Starting from the well known swing equation in Laplace domain;

$$M_i \;\; s w_i = P_i^m - P_i \quad \text{(pu)} \qquad (1)$$

where

i : Generator index

P^m : Mechanical power

P : Active power production

M : Inertia constant of rotating mass

w : Frequency (or angular frequency)

s : Laplace variable

One can easily derive the equation with delta (Δ) variables;

$$M_i \;\; s\Delta w_i = \Delta P_i^m - \Delta P_i \quad \text{(pu)} \qquad (2)$$

Note that basis is chosen as machine ratings for above equations. Changing P_{base} from machine rated value to total system generation and then summing over all generators;

$$\frac{\sum_{i=1}^{g} Pe_i M_i}{\sum_{i=1}^{g} P_i} s\Delta w_i = \frac{\sum_{i=1}^{g} Pe_i \Delta P_i^m}{\sum_{i=1}^{g} P_i} - \frac{\sum_{i=1}^{g} Pe_i \Delta P_i}{\sum_{i=1}^{g} P_i} \qquad (3)$$

where;

g : Total number of generators

Pe_i : Rated active power of i[th] generator ($P_{base} = Pe_i$ in (1))

Arranging above equation;

$$\widetilde{M} s \Delta w_i = \sum_{i=1}^{g} k_i \Delta P_i^m - \overline{\Delta P_e} \qquad (4)$$

where;

$$\widetilde{M} = \frac{\sum_{i=1}^{g} Pe_i M_i}{\sum_{i=1}^{g} P_i} \qquad (5)$$

$\widetilde{M}$ is the weighted average inertia constant of all generators based on total system generation.

$$k_i = \frac{Pe_i}{\sum_{i=1}^{g} P_i} \qquad (6)$$

k_i is the ratio of rated power of i[th] unit to total system generation. Note that for generators that do not contribute to primary frequency regulation mechanical power does not change. Thus for such generators this value has no effect on frequency deviation.

$$\overline{\Delta P_e} = \frac{\sum_{i=1}^{g} Pe_i \Delta P_i}{\sum_{i=1}^{g} P_i} \qquad (7)$$

$\overline{\Delta P_e}$ is the total electrical load change in p.u. where P_{base} is equal to total system generation.

The model that represents the transient response of the power system based on the above equations is illustrated in Fig. 8.

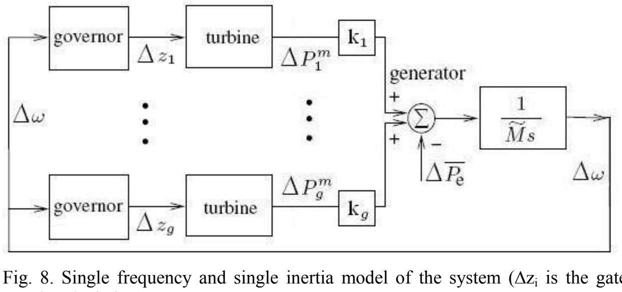

Fig. 8. Single frequency and single inertia model of the system (Δz_i is the gate opening deviation)

SIMULATION RESULTS

The simulation results are compared with the measurements of the incident on 25 April 2006. Approximately 430 MW of generation is lost while system has a total generation of 20.000 MW. System frequency measurements and simulation results are shown in Fig. 9.

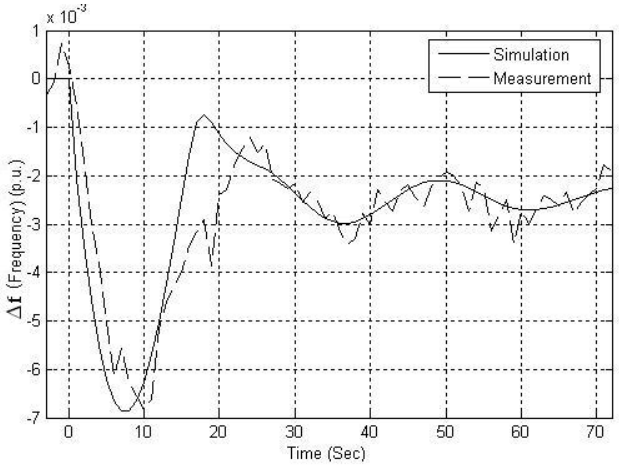

Fig. 9. Simulation results comparison with measurements

By this model, similar oscillation characteristics are observed. The same approach is used to model possible variations in frequency response of the system regarding changes in generation contribution to primary frequency control. Considering generation profile of Turkish power system, four possible cases are simulated to investigate the effect of HPPs on frequency stability.

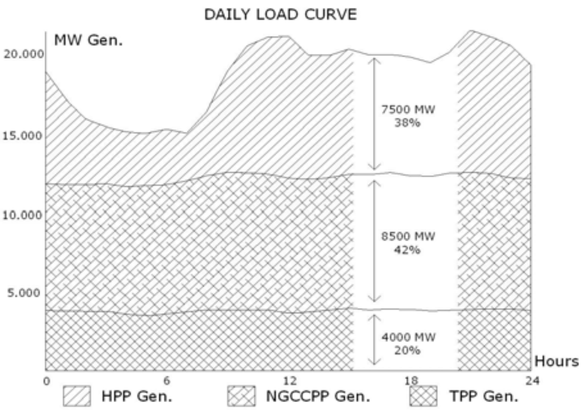

Fig. 10. Load curve & fault instant generations (from TEİAŞ NLDC)

As seen in daily load curve of 25 April 2006 in Fig. 10, peak load is supplied by HPPs. The NGCCPPs operate as base-load power plants due to the long-term sale agreements with the private companies, and essentially the HPPs operate as peaker-plants. Hence, the contribution of HPPs to generation will change with respect to the demand increase in summer or winter seasons or decrease in early morning hours.

The total generation is assumed 25.000 MW for simulation of day hours in winter or summer seasons and 15.000 MW for early morning hours. Representations of these cases are defined below and simulation results are compared in Fig. 11-12.

- The simulation for the incident on 25 April 2006 is considered as Case 0.
- Total generation is increased and decreased by changing HPP contribution and the same generation loss is applied in p.u. as Cases 1&2, respectively.
- Cases 0, 1 and 2 are repeated for optimum choice of HPP PI governor parameters described in [3] (see Appendix) and results are denoted as Case 3, 4 and 5, respectively.

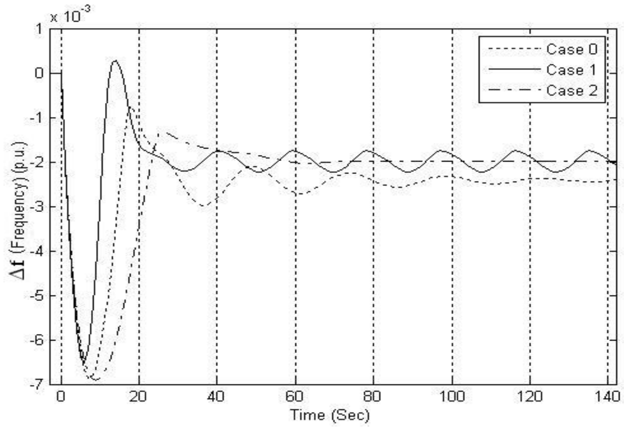

Fig. 11. Cases 1&2 simulations compared to Case 0.

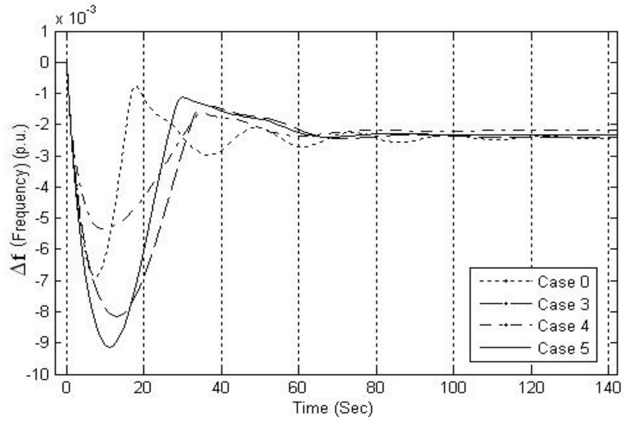

Fig.12. Cases 3, 4&5 simulations compared to Case 0

As seen in Fig. 11&12 sustained frequency oscillations are observed as the contribution of HPPs with unstable settings increase (Case 1). This result consists with the statement in [2], that is, when most HPPs in Turkish network are in service, oscillations in system frequency increases. Further, controllers of HPPs are re-tuned (Cases 3&5), using the optimum choice of parameters described in [3]. The observed system response is slower, however, the oscillations are well damped and steady state is reached in 60 sec, which appears to be a better response than Case 0. When the total generation is reduced (Case 2), decreasing the contribution of HPPs, the oscillations are damped faster than Case 0, which indicates the negative effect of unstable settings of HPPs on system frequency.

IV. CONCLUSION

The followings are among the main conclusions of the study:

- The increase of HPPs participation with fast controller settings (unstable in island operation) to primary frequency control will significantly reduce the damping of frequency oscillations in Turkey.
- On the other hand, the increase of HPPs participation with sluggish controller settings (stable in island operation), although the damping increases, the system overall response slows down essentially.
- In order to improve the oscillatory characteristic of Turkish frequency, it should be assured that all of the controllers of HPPs should be adjusted carefully considering this conflict.
- Given the sluggish response due to stable operation of HPPs, the speed of overall primary activation of the power system could be improved by increasing the TPPs/HPPs ratio in providing primary frequency control.

This paper is a preliminary study of a more detailed research regarding the improvement of frequency stability of Turkish power system. Complete network will be considered in the future study which will include a more detailed representation of generators and their controllers that are contributing during the primary response.

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APPENDIX

It is well-known that PID (with D = 0) controller is equivalent to mechanical-hydraulic governor [3]. Equivalent models are represented in Fig. 13. Converting PI parameters to temporary droop (r) and reset time (T_r) parameters requires the following calculations.

$K_p + K_i / s = (1 + s.T_r) / s.r.T_r$

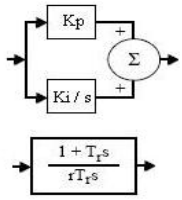

Fig. 13. Equivalent models

where :

K_p : Proportional gain

K_i : Integral gain

s : Laplace variable

$K_i = 1 / r.Tr$

$K_p = 1 / r$

For stable operation under islanding conditions, the optimum choice of parameters r and T_r is related to water starting time (T_w) and mechanical starting time (T_m) as follows:

$$r = [\, 2.3 - (\, T_w - 1.0 \,)\, 0.15 \,]\, T_w / T_m \qquad (8)$$

$$T_r = [\, 5.0 - (\, T_w - 1.0 \,)\, 0.50 \,]\, T_w \qquad (9)$$