Effects of Turbines and Governing Systems on System Stability

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Abstract: Turbines and Governing Systems are ancillary controllers in power plants. In a power system, the generators are generally driven by turbines and each turbine is equipped with a governing system to control of frequency. In this paper effect of turbines and governing system on dynamic stability of power system is investigated.
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1. Introduction

Turbines and Governing Systems are important component in power system to control of frequency and also stability [1-20]. In a power system, the synchronous generators are normally driven by steam turbines, gas turbines or hydro turbines and each turbine is equipped with a governing system to provide a means by which the turbine can be started, run up to the operating speed and operate on load with the required power output. The proposed turbines work based on different theories.

In coal-burn, oil-burn and nuclear power plants the energy contained in the fuel is used to produce high-pressure, high-temperature steam in the boiler. The energy in the steam is then converted to mechanical energy in axial flow steam turbines. Each turbine consists of a number of stationary and rotating blades concentrated into groups, or stages. As the high-pressure steam enters the fixed set of stationary blades it is accelerated and acquires increased kinetic energy as it expands to a lower pressure. The stream of fluid is then guided onto the rotating blades where it experiences a change in momentum and direction thereby exerting a tangential force on the turbine blade and output torque on the turbine shaft. As the steam passes axially along the turbine shaft its pressure reduces, so its volume increases and the length of the blades must increase from the steam entrance to the exhaust to accommodate this change. Typically a complete steam turbine will be divided into three or more stages, with each turbine stage being connected in tandem on a common shaft. Dividing the turbine into stages in this way allows the steam to be reheated between stages to increase its enthalpy and consequently increase the overall efficiency of the steam cycle. Modern coal-fired steam turbines have thermal efficiency reaching 45%. Steam turbines can be classified as non-reheat, single-reheat or double-reheat systems. Non-reheat turbines have one turbine stage and are usually built for use in units of below 100 MW.

Unlike steam turbines, gas turbines do not require an intermediate working fluid and instead the fuel thermal energy is converted into mechanical energy using the hot turbine exhaust gases. Air is normally used as the working fluid with the fuel being natural gas or heavy/medium fuel oil. The most popular system for gas turbines is the open regenerative cycle and consists of a compressor, combustion chamber and turbine. The fuel is supplied through the governor valve to the combustion chamber to be burnt in the presence of air supplied by the compressor. The hot, compressed air, mixed with the combustion products, is then directed into the turbine where it expands and transfers its energy to the moving blades in much the same way as in the steam turbine. The exhaust gases are then used to heat the air delivered by the compressor. There are also other, more complicated cycles that use either compressor inter cooling and reheating, or inter cooling with regeneration and reheating. The typical efficiency of a gas turbine plant is about 35%.

A significant technological step forward in the use of gas turbines came with the introduction of the combined cycle gas turbine (CCGT). In this system the exhaust heat from the gas turbine is directed into a heat-recovery boiler (HRB) to raise steam, which is then used to generate more electricity in a steam-driven generating unit. Generally the temperature of the gas turbine exhaust gases is quite high, typically around 535 ◦C, so by adding a steam turbine cycle at the bottom end of the gas cycle the otherwise wasted heat can be utilized and the overall cycle efficiency significantly increased. Modern

CCGT plant can have an efficiency approaching, or even exceeding, 60%. Usually CCGT power stations utilize the exhaust gases from two or three gas turbines to raise steam for one steam turbine with both types of turbines driving separate generators. More recently single-shaft modes have become popular where both the gas and the steam turbines are mounted on the same shaft and drive the same generator. In some CCGT designs the HRB may be equipped with supplementary firing to increase the temperature of the HP steam. In addition, some combined cycle plants are designed to produce steam for district heating or for use in the process industry. CCGT plants, apart from higher thermal efficiency, also have other important advantages over more traditional coal-fired plants. They have a short construction time and low capital construction cost, both about half that of the equivalent coal-fired plant, they are relatively clean with almost no SO2 emission, they require little staffing, and the materials handling problem of gas versus coal and ash is much simpler.

The oldest form of power generation is by the use of water power. Hydraulic turbines derive power from the force exerted by water as it falls from an upper to a lower reservoir. The vertical distance between the upper reservoir and the level of the turbine is called the head. The size of the head is used to classify hydroelectric power plants as high-head, medium-head and low-head (run-of-river) plants, although there is no strict demarcation line [21].

2. Turbine Governing Systems

For many years turbine governing systems were of a mechanical–hydraulic type and used the Watt centrifugal mechanism as the speed governor. The original Watt mechanism used two fly-balls as the speed-responsive device, but on new machines the Watt governor has been replaced by an electro-hydraulic governor. The main disadvantages of the Watt centrifugal governor are the presence of dead-bands and a relatively low accuracy. The size of the dead-bands also tends to increase with time due to wear in the moving mechanical elements. Newer solutions replace the Watt centrifugal mechanism with an electronic regulator. In these systems the turbine rotor speed is measured electronically, with high accuracy, using a toothed wheel and a probe. The resulting electrical signal is amplified and acts on the pilot valve via an electro-hydraulic converter [21].

3. Turbine Characteristics

For stable operation the turbine must have a power–speed characteristic such that as the speed increases the mechanical input power reduces. Similarly, a decrease in speed should result in an increase in the mechanical power. This will restore the balance between the electrical output power and mechanical input power [21].

To examine how such a characteristic can be achieved, Figure 1 shows the idealized power–speed characteristics for an unregulated and a regulated turbine. Point A is the rated point which corresponds to the optimal steam flow through the turbine, as determined by the turbine designers. Consider first the unregulated characteristic and assume that the turbine is initially operating at point A with the turbine control valve fully open. The generator is assumed to be synchronized with the system and its speed can only change if the system frequency changes. If the system frequency rises, then the speed of the rotor is raised. As the main valve is fully open the speed increase causes additional losses in the turbine and the efficiency of the steam flow drops (with respect to the optimal point A) with a corresponding reduction in power as shown by the dashed curve 1. Similarly, a decrease in the system frequency causes the rotor speed to drop with a corresponding drop in power as shown by curve 2. The rapid reduction in turbine power with reduction in system frequency can be explained as follows. The steam flow through the turbine depends on the performance of the boiler and the boiler feed pumps. As the performance of these pumps is strongly dependent on frequency, a reduction in system frequency (and rotor speed) reduces their performance. This causes a decrease in the amount of steam flowing through the turbine and a further drop in the turbine torque. The task of the turbine governor is to set a characteristic corresponding to line 3 which has a small droop. As explained below, such a characteristic is necessary to achieve stable operation of the turbine.

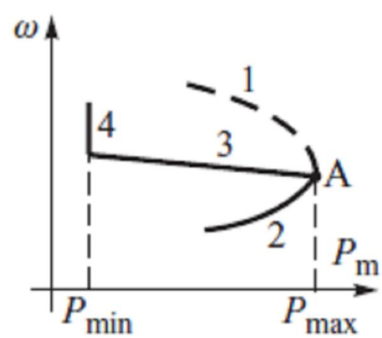

Figure 1. Turbine power–speed characteristic for the unregulated turbine (lines 1, 2) and the regulated turbine (lines 3-2-4) [21].

A simplified block diagram of elector hydraulic governors is shown in Figure 2-a. The coefficient KA corresponds to the amplification gain of the servomotor, while coefficient R corresponds to the gain of the feedback loop. Transformation of the block diagram allows R to be eliminated from the feedback loop by moving it into the main loop to obtain the block diagram shown in Figure 2-b where TG = 1/(KAR) and is the effective governor time constant. The block diagram of Figure 2-b allows an approximate analysis of the static and dynamic properties of the turbine–governor system. In the steady state $t \to \infty$, $s \to 0$ and the turbine block diagram can be simplified to that shown in Figure 2-c where P_{ref} is the load reference set point expressed as a fraction of the nominal or rated power, P_n. If the valve position c is assumed to vary between 0 (fully closed) and 1 (fully open) then a small change in turbine speed $\Delta\omega=\omega-\omega_{ref}$ will produce a corresponding change in valve position $\Delta c = -\Delta\omega/R$. normally $\Delta\omega$ is expressed as a fraction of rated speed ω_n so that:

$$\Delta c=-\frac{1}{\rho}\frac{\Delta\omega}{\omega_n} \quad \text{or} \quad \frac{\Delta\omega}{\omega_n}=-\rho\Delta c$$

4. System under Study

In order to show effect of turbine governing systems on stability, a typical power system is considered as test case. The turbine governing systems parameters are changed to show effect of them on stability. Figure 3 shows the test system and its data are given in [22].

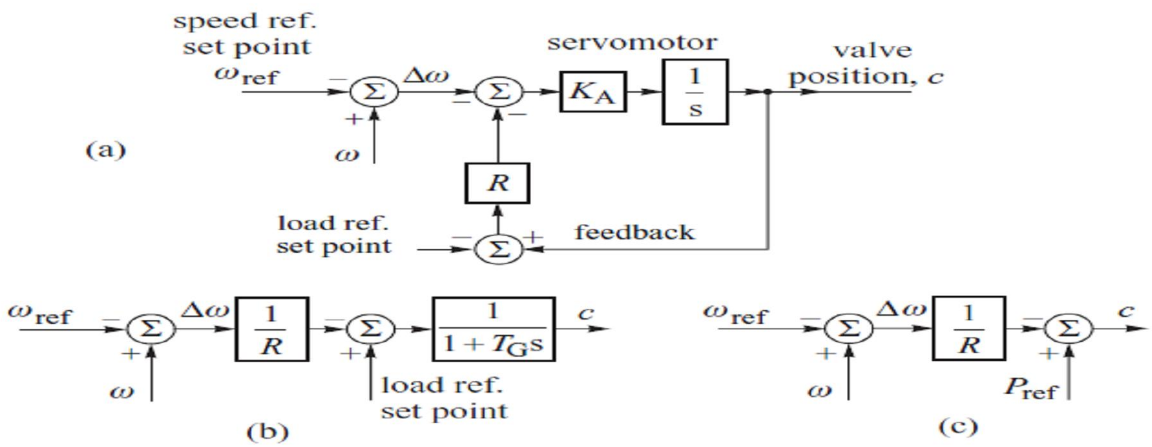

Figure 2. Simplified model of the steam turbine governing system: (a) block diagram with negative feedback; (b) equivalent block diagram; (c) equivalent block diagram for the steady state [21].

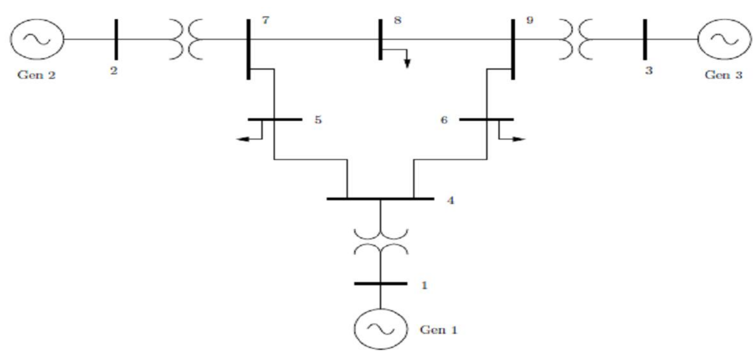

Figure 3. WSCC 3-generator 9-bus test system [22]

Table 1. Turbine governing systems parameters

	Droop R	Pole time constant	Zero time constant
Case 1	0.02	10	1
Case 2	0.04	10	1
Case 3	0.02	20	1
Case 4	0.02	10	0.1

5. Simulation results

Four cases are considered for simulation in the Table 1, where the case 1 is the nominal condition.

The simulation results for the proposed system are depicted in Figures 4-12.The simulation results show the effect of turbine governing systems parameters on stability of power system. It is clearly seen that the system stability is a function of turbine governing systems parameters. The system oscillation depends to turbine governing systems tuning and with changing turbine governing systems parameters the oscillations are changed. The effect of turbine governing systems parameters on stability denotes the importance of turbine governing systems sitting in power systems. An optimal and good tuned turbine governing systems can improve power system stability, while a non-tuned turbine governing systems can greatly affect on stability and would lead to instability.

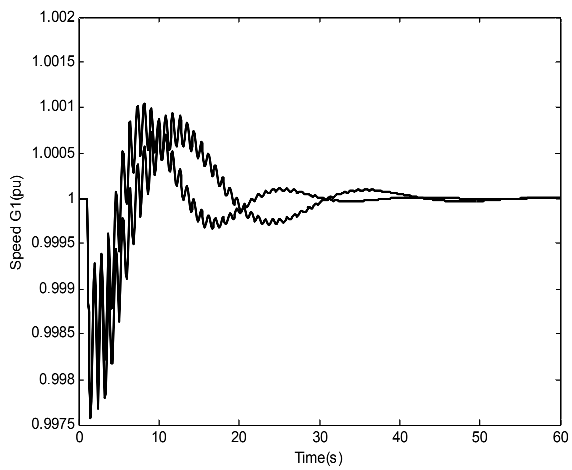

Figure 4 Speed G_1 (solid: case 1; dashed: case 2)

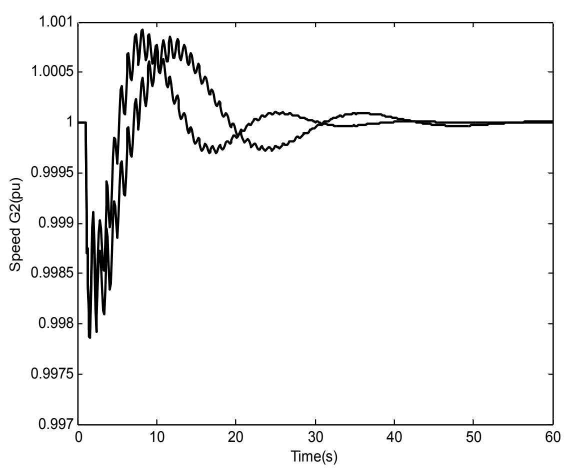

Figure 5. Speed G_2 (solid: case 1; dashed: case 2)

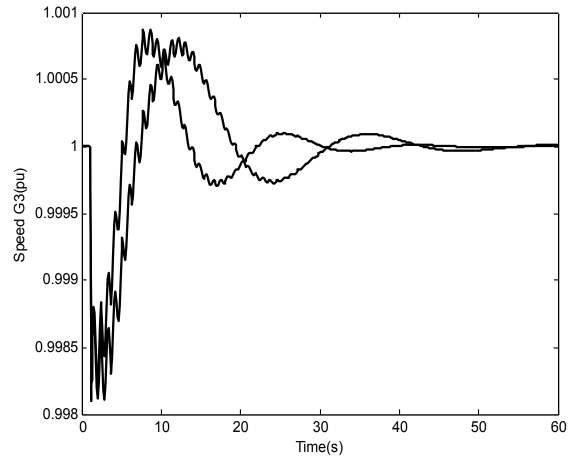

Figure 6. Speed G_3 (solid: case 1; dashed: case 2)

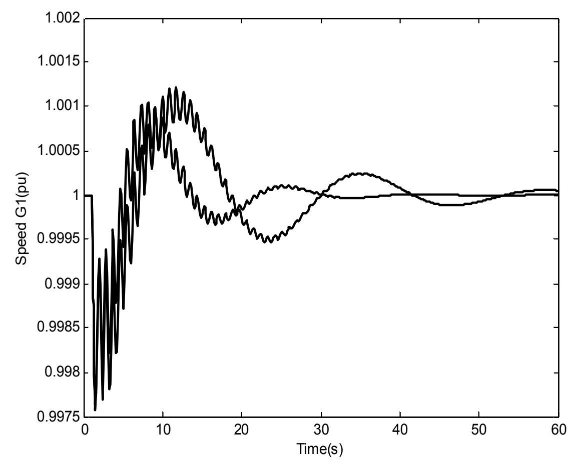

Figure 7. Speed G1 (solid: case 1; dashed: case 3)

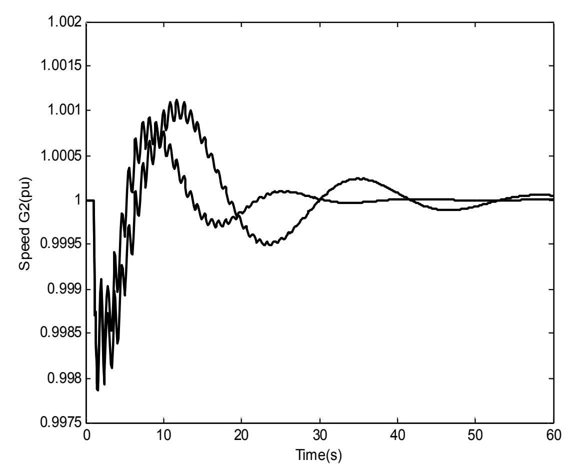

Figure 8. Speed G_2 (solid: case 1; dashed: case 3)

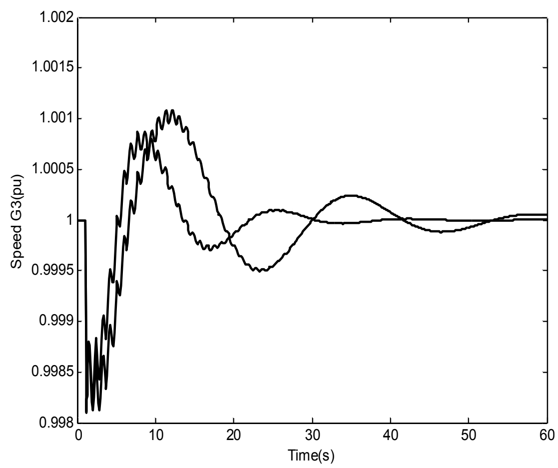

Figure 9. Speed G_3 (solid: case 1; dashed: case 3)

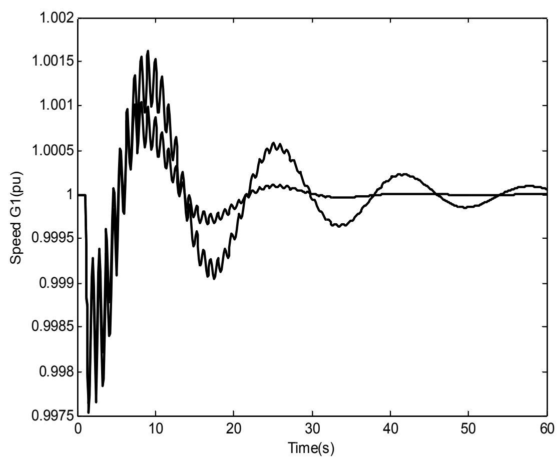

Figure 10. Speed G_1 (solid: case 1; dashed: case 4)

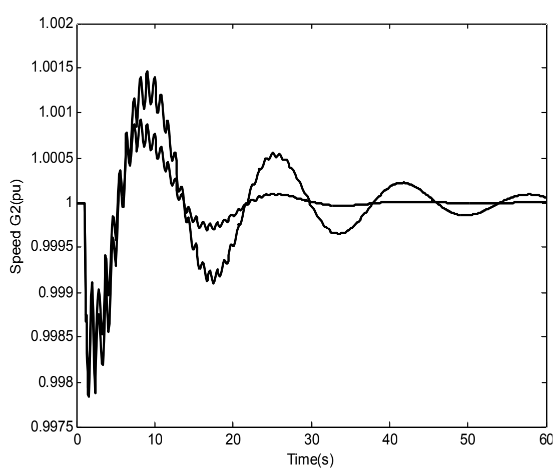

Figure 11. Speed G_2 (solid: case 1; dashed: case 4)

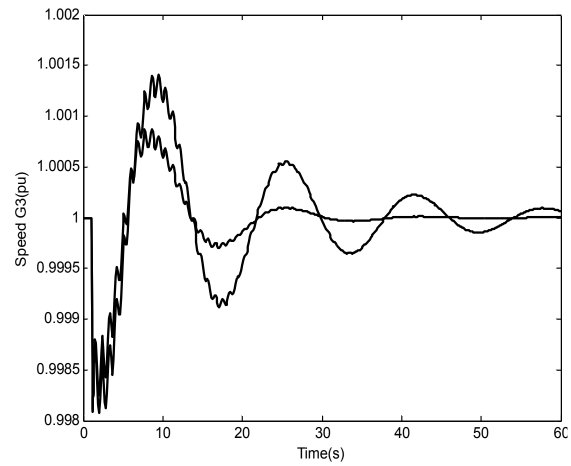

Figure 12. Speed G_3 (solid: case 1; dashed: case 4)

6. Conclusion

Effect of turbine governing systems on stability and oscillations was investigated in this paper. A typical power system equipped with turbine governing systems on all generators was chosen as case study and effect of turbine governing systems parameters was investigated on test system. The simulation results showed the great effect of turbine governing systems parameters on power system stability. The power system stability is associated with turbine governing systems good sitting and non-tuned turbine governing systems may lead to instability.

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