Knowledge-based Adaptive Frequency Control of Gas Turbine Generator Model for Multi-machine Power System

H. Zainuddin and S. Jovanovic

***Abstract* — This paper investigates the performance of a knowledge-based supplementary control to enhance the quality of frequency control of gas turbine generator for multi-machine case of one area of interconnected power system. The proposed Intelligent Gas Turbine Controller (IGTC) uses acceleration feedback to counter the over and under frequency occurrences due to major disturbances in power system network. Consequently, generator tripping and load shedding operations can be reduced. In addition, this type of controller is integrated with Automatic Generation Control (AGC), a well known Load-Frequency Control (LFC) in order to ensure the system frequency is restored to the nominal value. Computer simulations of frequency response of each gas turbine governing system are used to optimize the proposed control strategy. As a result, there is substantial improvement on the system frequency represents the speed of the equivalent generator of multi-machine system that employing the proposed control strategy.**

IndexTerms — **Knowledge-based supplementary control, Acceleration feedback, Frequency control, Gas turbines, Multi-machine**

I. Introduction

Power systems from time to time experience disturbances due to faults and/or switching of major load. Such disturbances can be classified into two groups, i.e. small and large. Small disturbances are a frequent event due to the nature of power system operations. Normally, the system adapts to a steady state condition with the help of turbine governor control system. Additional control schemes such as Automatic Generation Control (AGC) are also used [1]to help restore the nominal operating system. However, large disturbances can result in very large imbalances between mechanical power and electrical power. Therefore, large disturbances are a challenging problem for the utilities because of the size and complexity of the power system [1].

During normal operation of power system, the total mechanical power input from the prime movers to the generator is equal to the sum of all the connected loads. Any significant upset of this balance causes a change in frequency. Major disturbances in power system can result in large frequency deviations. Hence, generator tripping and load shedding schemes are implemented in power systems to avoid damage of the generating units and customer load units under large disturbances. However, these schemes activated by large frequency deviations are undesirable actions, which reduce the security and profitability of the power system operation. Consequently, the highly competitive market of electrical power industry has led to research on the intelligent adaptive control in improving the conventional frequency control actions [2-9]. This offers the utilities to have high security of supply in terms of the operation of power plants and

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system control and also economically dispatch the load demand.

It has been recognized that knowledge-based acceleration feedback controller can reduce over and under frequency occurrences and improve substantially the quality of frequency control of steam-turbine generators [4-5] and gas turbine generator [2]. On the other hand, non-fixed integral gain of AGC can minimize the frequency deviations and restore the nominal frequency the soonest possible, in which fixed integral gain fails to do so over a wide range of off-nominal operating conditions [7].

The Intelligent Gas Turbine Controller (IGTC) proposed in [2] enhances substantially the quality of control of power system frequency for gas turbine generator model (single machine case). Thus, this paper is motivated by the desire to implement the knowledge-based control technique of the IGTC on multi-machine of gas turbine generator model to minimize the over and under frequency events in power systems. Computer simulations of frequency responses for a multi-machine system are used to optimize IGTC, and demonstrate its performance for major disturbances in multi-machine power system. As a result, it is shown that over and under frequency occurrences can be suppressed, and frequency deviation is minimized then system frequency is restored to the nominal value as soon as possible.

II. CONTROL STRATEGY

In this paper, gas governor-turbine system modeled in [10], i.e. GAST model is simplified and adopted to demonstrate the Load Frequency Control (LFC) analysis. The simplified GAST model illustrated in Fig. 1 has eliminated the temperature feedback which makes the generator loading in the study must not over than 76% of the machine rating. This is because the GAST model cannot give an adequate representation of the temperature control loop [10]. Description of each parameter for the simplified GAST model is noted in Table 1.

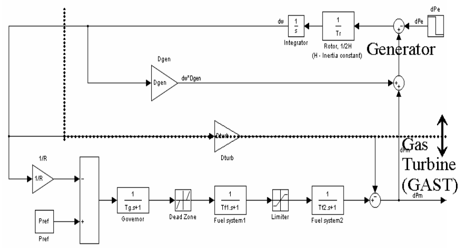

Fig. 1. Simplified GAST model without temperature feedback

TABLE 1
DESCRIPTION OF SIMPLIFIED GAST MODEL PARAMETERS

Parameter	Description
R	Governor speed droop (pu speed / pu MW)
T_g	Governor lag time constant (sec)
T_{f1}	Fuel system lag time constant 1 – valve position (sec)
T_{f2}	Fuel system lag time constant 2 – fuel injection (sec)
F_{max}	Fuel control upper limit (pu)
F_{min}	Fuel control lower limit (pu)
Z_{start}	Start of dead zone (pu)
Z_{end}	End of dead zone (pu)
D_{turb}	Turbine damping (pu)
D_{gen}	Generator damping (pu)
T_r	Turbine rotor time constant, (Inertia = 2*H)

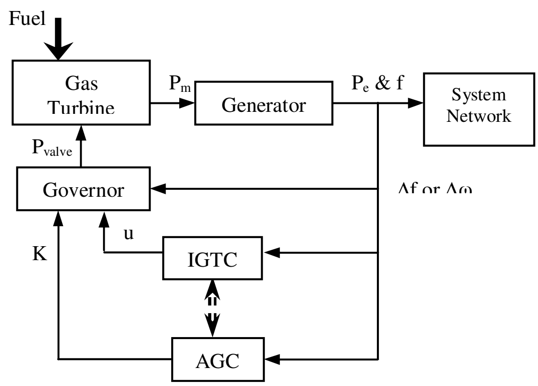

Fig. 2. Configuration of proposed intelligent gas turbine

controller (IGTC) Configuration of the proposed intelligent gas turbine controller (IGTC) for the gas governor-turbine model is shown in Fig 2.

The proposed control configuration depicted that the IGTC is interacted with the AGC to improve the control performance of the speed governor. This set up is applied to each generating unit of multi-machine system. However, the system equivalent for LFC analysis in Fig. 3 shows that the equivalent generator of multi-machine power system is driven by the combined mechanical outputs of the individual turbines [11-12]. This explains that all inertia constant, H and load damping constant, D are lumped into their equivalent value, H_{equiv} and D_{equiv} respectively. The speed of equivalent generator of multi-machine system represents the system frequency in which there is only single frequency or speed output from the multi-machine system model.

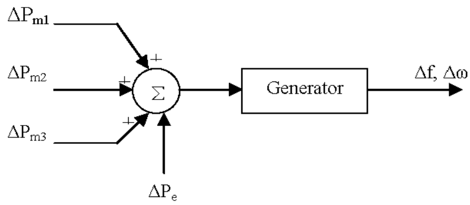

Fig. 3. Multi-turbine-generator system equivalent for LFC analysis

Both IGTC and AGC are operated discretely in which the samples of frequency deviations, Δf(nT) that fed into them are measured at every sampling time, T. Sampling time of 0.1s is used in this controller design. In addition, n is the sample time independent variable. The discrete supplementary control signal, u(nT) is determined using the trial and error basis with the help of simple control logic and computation and measurement of frequency deviation. This means that in order to change the digital signal value, i.e. increase or decrease the value of u(nT), one should consider the desired frequency performance from the computer simulations. The same concept is also applied to determine the integral gain, K(nT) representing the AGC.

The frequency variation, Δf is a result of the disproportion between the mechanical and the electrical power of the generator units. A surplus of mechanical power due to load decrease causes the generator speed to increase and the frequency to rise. A deficit of mechanical power due to load increase or generator outage causes the generator speed to decrease and the frequency to drop. Therefore, frequency limitations for over and under frequency events are introduced in utilities to avoid damage to the generator units, e.g. for 50 Hz system; 51 Hz and 49 Hz respectively. The selection of over and under frequency thresholds should also consider other issues such as the plant trip experiences and the type of loads in order to minimize the generator and load shedding operations. Otherwise, the plant will simply trip due to improper over and under frequency limitations as it is too easy for the frequency to exceed the settings value on the generator and load shedding relays.

Since acceleration/deceleration of generators is proportional to the difference between their mechanical and electrical power, large differences between mechanical and electrical power are followed by large initial acceleration/deceleration of generators. This leads to the large frequency deviations in the system. Thus, the positive or negative maximum frequency deviation, i.e. f_{max}-f_o and f_{min}-f_o is proportional to the initial acceleration, a(0) [4-5]. If the positive initial acceleration is large, the maximum frequency deviation is also large.

Subsequently, for a large negative initial acceleration, i.e. the large deceleration, the maximum frequency deviation is negative large. Conventional controllers using the speed governors are not perceptive to acceleration. Therefore, the proposed intelligent adaptive controller that is sensitive to the acceleration and uses a knowledge-based control strategy can be used as an effective measure against the large frequency deviations.

The acceleration is calculated using the following expression.

$$a(nT) = \frac{\left[\Delta f(nT) - \Delta f\left((n-1)T\right)\right]}{T} \qquad (1)$$

Hence, only one past data of frequency deviation, Δf((n-1)T is required in addition to the current measured data, $\Delta f(nT)$ to calculate the turbine acceleration and memorized control strategy is required.

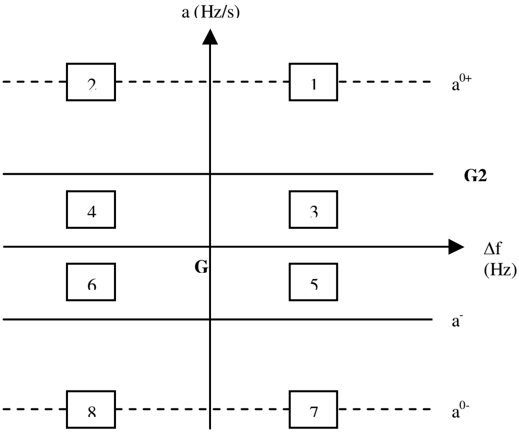

Fig. 4: Eight areas divided in a-Δf plane

In the a-Δf plane as shown in Fig. 4, the upper-half plane represents the positive acceleration while the lower-half plane represents the negative acceleration, i.e. deceleration. The area in the right-half plane represents a frequency that is greater than the nominal value or the speed faster than the desired synchronous speed. The area in the left-half plane represents a frequency that is less than the nominal value or speed slower than the desired synchronous speed. The origin 0 is the desired equilibrium point in which all dynamic performance should reach the steady state level without neglecting the synchronous speed or frequency nominal value.

The a-Δf plane is divided into eight areas. The division of the eight areas is bordered by $a=a^+$, $a=a^-$, $a=0$ and $\Delta f=0$. The required control strategies are based on the characteristics of each area and also depend on the occurrences of the disturbances. The controller has to differentiate whether it is over or under frequency event. Both events are discriminated using the initial acceleration by introducing the positive and negative initial acceleration constraint, i.e. a^{0+} and a^{0-} respectively. By establishing the event and which area the generator state belongs to, the controller should be able to decide whether the discrete supplementary digital control signal, u is positive large (U^{+max}), positive small (U^{+min}), negative large (U^{-max}), negative small (U^{-min}) or u=0. The u=0 means that the controller is not activated. The following arguments for each area are used to determine the control strategies.

Area 1: The frequency is greater than the nominal frequency and the generator speed is faster than the desired synchronous speed, i.e. $\Delta f>0$. At the same time, the acceleration of the unit is considered large, i.e. $a>a^+$. Thus, if the occurrence is over frequency, i.e. $a(0)>a^{0+}$, the negative large of supplementary control signal, U^{-max} is required. However, if the occurrence is under frequency, i.e. $a(0)<a^{0-}$, the negative small of supplementary control signal, U^{-min} is required.

Area 2: The frequency is less than the nominal frequency and the generator speed is slower than the desired synchronous speed, i.e. $\Delta f<0$. But, the unit is accelerating at large acceleration value in which the speed is increasing rapidly towards the desired speed. Therefore, u=0 is required regardless the events.

Area 3: The frequency is greater than the nominal frequency and the generator speed is faster than the desired synchronous speed. At the same time, the acceleration of the generator unit is considered small, i.e. $0<a<a^+$ in which the speed is increasing slowly leaving the desired speed. Therefore, the negative small of supplementary control signal, U^{-min} is required for both events to shift the generator speed to the desired speed. This region is used to ensure the minimum deviation and fluctuation of frequency by setting up the optimal value of a^+ and U^{-min}.

Area 4: The frequency is less than the nominal frequency and the generator speed is slower than the desired synchronous speed. However, the unit is accelerating at small acceleration value in which the speed is increasing slowly towards the desired speed. Thus, the positive small of supplementary control signal, U^{+min} is required for both events to boost up the shifting process of the generator speed to the desired speed. This region is used to ensure the minimum deviation and fluctuation of frequency by setting up the optimal value of a^+ and U^{+min}.

Area 5: This region is the inversion of the area 4. Thus, the negative small of supplementary control signal, U^{-min} is required for both events to boost up the shifting process of the generator speed to the desired speed. This area is also used to ensure the minimum deviation and fluctuation of frequency by setting up the optimal value of a^- and U^{-min}.

Area 6: This region is the inversion of the area 3. Thus, the positive small of supplementary control signal, U^{+min} is required for both events to shift the generator speed to the desired speed. This area is also used to ensure the minimum deviation and fluctuation of frequency by setting up the optimal value of a^- and U^{+min}.

Area 7: This area is the inversion of the area 2. Hence, u=0 is required regardless the events.

Area 8: This area is the inversion of the area 1. Thus, if the event is under frequency, the positive large of supplementary control signal, U^{+max} is required. However, if the event is over frequency, the positive small of supplementary control signal, U^{+min} is required.

III. INTELLIGENT GAS TURBINE CONTROLLER

Now, the desired control rules for the IGTC from the eight proposed areas can be defined. Each proposed area represents a rule for the controller design for each type of disturbances, i.e. over and under frequency events. As a result, the following control rules are suggested in order to minimize frequency deviations and reduce generator and load shedding operations caused by major disturbances from over frequency problems, $a(0)>a^{0+}$.

State A: For $m \leq 300$;

Rule A1: if $a(0)>a^{0+}$ and $a(nT)>a^+$ and $\Delta f(nT)>0$, then
$m=0$;
$u(nT)=U^{-max}$;
$K(nT)=K^0$;

Rule A2: if $a(0)>a^{0+}$ and $a(nT)>a^+$ and $\Delta f(nT)<0$, then
$m=0$;
$u(nT)=0$;
$K(nT)=K^0$;

Rule A3: if $a(0)>a^{0+}$ and $a(nT)>0$ and $a(nT)<a^+$ and $\Delta f(nT)>0$, then
$m=m+1$; for $m=0,1,2,\ldots\ldots300$
$u(nT)=U^{-min}$;
$K(nT)=K^0$;

Rule A4: if $a(0)>a^{0+}$ and $a(nT)>0$ and $a(nT)<a^+$ and $\Delta f(nT)<0$, then
$m=m+1$; for $m=0,1,2,\ldots\ldots300$
$u(nT)=U^{+min}$;
$K(nT)=K^0$;

Rule A5: if $a(0)>a^{0+}$ and $a(nT)>a^-$ and $a(nT)<0$ and $\Delta f(nT)>0$, then
$m=m+1$; for $m=0,1,2,\ldots\ldots300$
$u(nT)=U^{-min}$;
$K(nT)=K^0$;

Rule A6: if $a(0)>a^{0+}$ and $a(nT)>a^-$ and $a(nT)<0$ and $\Delta f(nT)<0$, then
$m=m+1$; for $m=0,1,2,\ldots\ldots300$
$u(nT)=U^{+min}$;
$K(nT)=K^0$;

Rule A7: if $a(0)>a^{0+}$ and $a(nT)<a^-$ and $\Delta f(nT)>0$, then
$m=0$;
$u(nT)=0$;
$K(nT)=K^0$;

Rule A8: if $a(0)>a^{0+}$ and $a(nT)<a^-$ and $\Delta f(nT)<0$, then
$m=0$;
$u(nT)=U^{+min}$;
$K(nT)=K^0$;

State B For $m>300$;
$u(nT)=0$;
$K(nT)=K^1$;

For over frequency conditions, the maximum frequency is expected to rise above 51 Hz. The rules for this type of disturbances are divided into two states, i.e. state A and B in which state A denotes that the IGTC is triggered once the initial acceleration exceeds the threshold and it has to go through rules A1 until A8. During this state, the IGTC can either be switched on, i.e. activate (rule A1, A3-A6 and A8) or switched off, i.e. deactivate or reset (rule A2 and A7). The supplementary control signal, u, i.e. U^{+max}, U^{+min}, U^{-max} and U^{-min} for each rule (rules A1 until A8) is basically adopted from the control strategies from area 1 to area 8 (ascending). At the same time, the integral gain, $K=K^0$ which means that when state A is in operation, the integral gain remains the same as before the IGTC is being activated due to large initial acceleration.

Furthermore, state A is described by $m \leq 300$, whereby m is a counter to show that rules A3 until A6 have been continuously activated for 300 samples. On the other hand, the counting is considered sufficient and able to provide enough information that the frequency reaches the steady state or almost reaching it and its value is to be restored to the nominal value. The counter will be reset, m=0, if during the simulation, rule A1, A2, A7 or A8 is triggered and it will start to count again.

State B is described by m>300 whereby the IGTC is being reset when the frequency is considered to have reached the steady state level or almost reaching it and it is restored to the nominal value. At this point, the supplementary control is no longer necessary since the system is operated in an allowable tolerance. Simultaneously, the integral gain, K is changed from K^0 to K^1 in order to avoid large fluctuation of the frequency output once the IGTC is switched off, thus the best performance can be achieved.

On the other hand, for under frequency conditions, $a(0)<a^{0-}$, the minimum frequency is expected to drop below 49 Hz. Again the rules for this type of disturbances are also divided into two states, i.e. state C and D in which state C denotes that the IGTC is triggered once the initial deceleration exceeds the threshold. Therefore, state C is the inversion of state A and the integral gain, K is changed from K^0 to K^2 as state C and D are designed to deal with under frequency disturbances.

State E

Rule E: if $a(0)<a^{0+}$ or $a(0)>a^{0-}$, then

$m=0;$
$u(nT)=0;$
$K(nT)=K^0;$

State E as described above shows that the rule is applicable for minor frequency fluctuations, i.e. $a(0)<a^{0+}$ or $a(0)>a^{0-}$. The initial acceleration or deceleration does not exceed the allowable limits. Consequently, the IGTC is not activated at all, u=0 and the integral gain remains constant, $K= K^0$. In addition, the counter is also not operated. Rule for state E is necessary to avoid wear and tear of the IGTC on the generating units.

IV. PARAMETER SETTING

For one area of multi-machine power system, parameters are individually set from computer simulation of frequency response of each generating unit. Performance of each unit is firstly considered before the overall frequency response of the multi-machine system. This approach is much easier and more systematic to optimize the parameter value of the proposed controller rather than simulating the overall frequency response of the multi-machine system. Moreover, this is to ensure the optimum performance of each generating unit.

As mentioned in [2], there are 4 important parameters need to be considered to ensure the proposed controller to function effectively in preventing major disturbances. Those are:

i. Initial acceleration limit, a(0).
ii. Updating acceleration sample limit, a(nT).
iii. Supplementary digital control signal, u(nT).
iv. Variable integral gain, K.

Details of the parameters are noted in Table II and III.

TABLE II
PARAMETER FOR INTELLIGENT GAS TURBINE CONTROLLER

Parameter	Value	
	Positive Limit	Negative Limit
a(0)	a^{0+}	a^{0-}
a(nT)	a^{+}	a^{-}
u(nT)	U^{+max} and U^{+min}	U^{-max} and U^{-min}

TABLE III
DIFFERENT VALUES OF INTEGRAL GAIN

Integral Gain, K	Description
K^0	Existing integral gain
K^1	After over frequency event
K^2	After under frequency event

The initial acceleration positive and negative limits are defined as constraint parameters. They are determined from the knowledge that maximum and minimum frequency deviations are proportional to the initial acceleration. It is shown in reference [4], that $a^{0-}\approx$-0.5 Hz/s corresponds to f_{min}=59.5 Hz. Hence, for 50 Hz system, f_{max}=51 Hz will suggest a^{0+}=1 Hz/s and f_{min}=49 Hz will give a^{0-}=-1 Hz/s. However, in order to make the controller reacts faster to the acceleration feedback, it is designed to activate using half of the suggested initial acceleration, a(0). As a result, a^{0+}=0.5 Hz/s and a^{0-}=-0.5 Hz/s are used as default settings to avoid the frequency from exceeding 51 Hz and 49 Hz respectively.

The optimal value of positive and negative limits for updating acceleration sample are determined by the computer simulations and also categorized as constraint parameters. The value of a^{+} and a^{-} secure the minimal frequency deviations. For example, if we use a+=0.05 Hz/s and a-=-0.05 Hz/s for the controller which corresponds to f_o=50.05 Hz and 49.95 Hz respectively, we want the frequency response to be in that range and close to the nominal value with the help of supplementary control signal, u. Next, the frequency is being restored to its nominal value via integral gain, K control scheme.

The limits of supplementary digital control signal are defined as control parameters. Their optimal values are determined from the computer simulations. Setting up these parameters is the most challenging task compared to other parameters for the controller. Positive values of supplementary digital control signals are used to counter negative frequency deviations and vice-versa. The optimal values for U^{-max} and U^{+max} are obtained by minimizing the positive and negative maximum frequency deviations correspondingly, i.e. f_{max}-f_o and f_{min}-f_o. Optimal values for U^{-min} and U^{+min} are gained by minimizing and smoothing the positive and negative frequency deviations correspondingly so that the frequency response close to the nominal value and is restored to that nominal frequency via the integral gain, K control action.

Determination of variable integral gain, K value is also done from the computer simulations. Optimal value of K^0 is obtained before applying the IGTC on the dynamic model. Thus, it is defined as the existing integral gain value. In order to permanently reset the IGTC when the frequency has reached the steady state and returned to its nominal value after over and under frequency circumstances, the K value has to be changed from K^0 to K^1 or K^2 as shown in Table 3. Therefore, optimal K^1 and K^2 are determined by minimizing the frequency deviations caused by permanently switching off the IGTC, i.e. u=0. The change of K from K^0 to K^1 or K^2 should be synchronized with the change of u from U^{-min} or U^{+min} to zero in order to minimize the frequency fluctuation and deviation.

V. SIMULATION RESUTLS

The multi-machine system chosen for computer simulation is the 3-gas-turbine-generator system illustrated in Fig. 5. It is a one area of an interconnected 50Hz power system, where all the three generators are equipped with the primary frequency control and the AGC. All ratings and parameters for the generating units are suggested in Table 4. The regulation constant or governor speed droop of each generating unit is R = 0.06 per unit based on their own rating. Therefore, the values of R shown in the table are based on 100 MVA.

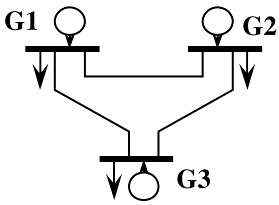

Fig.5. Three generating units in one area of interconnected power system

TABLE IV
PARAMETERS FOR EACH GAS TURBINE GENERATOR

Parameter	G1	G2	G3
Rating	150 MVA	120 MVA	80 MVA
R	0.04	0.05	0.075
T_g	0.1	0.1	0.1
T_{f1}	1.5	1.5	1.5
T_{f2}	0.1	0.1	0.1
F_{max}	1.5	1.2	1
F_{min}	-0.05	-0.05	-0.05
Z_{start}	-0.002	-0.002	-0.002
Z_{end}	0.002	0.002	0.002
D_{turb}	0	0	0
D_{gen}	1	1	1
T_r	13	12	10

Performance of the proposed controller is investigated using load increase and decrease tests. Load increase test signifies the large under frequency event, whilst load decrease test represents the large over frequency event. As mention earlier, the optimal controller parameters are determined from computer simulation of frequency response of each generating unit. Hence, step inputs applied to perform the tests are noted in Table V, in which each generator loading is less than 76% of the machine rating.

TABLE V
STEP INPUT FOR EACH GENERATING UNIT BASED ON 100 MVA

Generator	Over Frequency Event (Load Decrease Test)	Under Frequency Event (Load Increase Test)
G1	From 0.8pu to 0.3pu	From 0.3pu to 0.8pu
G2	From 0.7pu to 0.3pu	From 0.3pu to 0.7pu
G3	From 0.5pu to 0.2pu	From 0.2pu to 0.5pu

Optimal parameters for the AGC and IGTC to function effectively based on the given event of over and under frequency are shown in Table VI. Initially, the system is simulated without IGTC. Thus, the integral gain of AGC remains constant as K^0. However, as the AGC is integrated with IGTC, fixed integral gain is no longer suitable. Hence, K^1 and K^2 are introduced to support the integration so that the desired system response can be obtained.

TABLE VI
OPTIMAL PARAMETERS FOR THE PROPOSED CONTROLLER
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Parameter	G1	G2	G3
a^{0+}	0.01	0.01	0.01
a^{0-}	-0.01	-0.01	-0.01
a^{+}	0.005	0.002	0.002
a^{-}	-0.005	-0.002	-0.002
U^{+max}	2.0	1.4	0.9
U^{-max}	-2.0	-1.4	-0.9
U^{+min}	0.37	0.3	0.18
U^{-min}	-0.37	-0.3	-0.18
K^0	-2.0	-1.8	-1.3
K^1	-0.9	-0.9	-0.7
K^2	-3.75	-3.15	-2.04

Once the optimal parameters in Table 6 have been determined, the performance of the proposed controller on multi-machine system is ready to be tested. Total load change previously tested on generator G1, G2 and G3 is used to perform large over and under frequency events. It can be easily calculated that total load change or step input size used in this study to introduce major disturbance to the system is $\Delta P_e=\pm 1.2$ pu. Keep in mind that the system equivalent of multi-machine generator for LFC analysis previously depicted in Fig. 3 is applied in the study. Therefore, only one step input block available in Simulink/Matlab is used to commence the load increase and decrease tests.

For over frequency event, step input from 2.0pu to 0.8pu (total combination of step input for G1, G2 and G3) is applied on the system. Simulation results of frequency response due to over frequency event are illustrated in Fig. 6, while Fig. 7 and Fig. 8 present IGTC and AGC outputs correspondingly. From the simulation results, substantial differences can be observed in power system responses, with and without IGTC, demonstrating that IGTC of gas turbines can be very effective in suppressing large frequency deviations.

Fig. 6 shows that by employing the IGTC, the frequency remains below the desired threshold, i.e. the frequency rises to just below than 51 Hz. Subsequently, the frequency inclines to the nominal value and finally settles down at 50 Hz without any large oscillation. The frequency response is shifted and forced down by the IGTC output to avoid over frequency and smooth out long transient period. In contrast, without the IGTC, is just to see the frequency response is restored to its nominal value regardless the upper bound of frequency tolerance, thus, the frequency exceeds the allowable tolerance and experience large fluctuations. The improvement of frequency response explains the enhancement of power generation stability.

As shown in Fig. 7 and 8, at approximate operating time of 42s, the IGTC is permanently switched off as the supplementary control signal from IGTC is no longer necessary, and the AGC changes its integral gain from K^0 to K^1. The vital point where both IGTC and AGC change synchronously is called *synchronous point* and it is required to avoid high imbalance of the system which could lead to undesired high frequency deviation and fluctuation; whereby this has been discussed earlier to explain the rules of IGTC. For that reason, there is no disturbance on the frequency deviation response when the controller is permanently switched off.

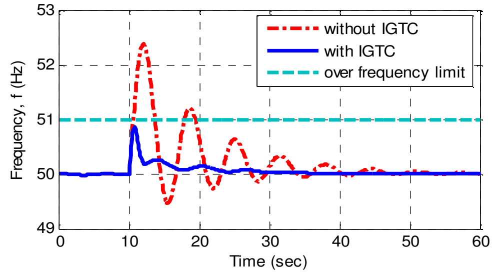

Fig. 6. Frequency response due to over frequency event

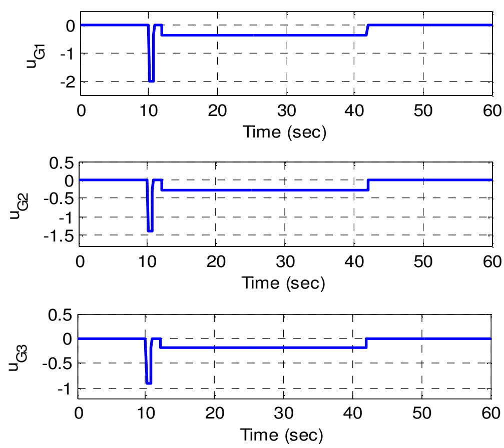

Fig. 7. IGTC output for each generator due to over frequency event

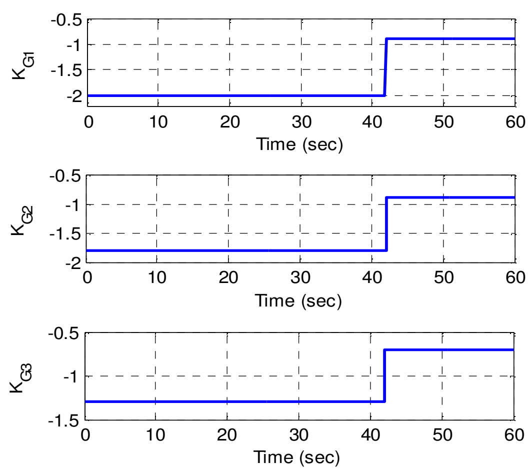

Fig. 8. AGC output for each generator due to over frequency event

On the other hand, for under frequency event, step input from 0.8pu to 2.0pu (total combination of step input for G1, G2 and G3) is applied on the system. The desired frequency response due to under frequency occurrence has also been achieved as shown in Fig. 9, whilst the IGTC and AGC outputs are illustrated in Fig. 10 and Fig. 11 correspondingly.

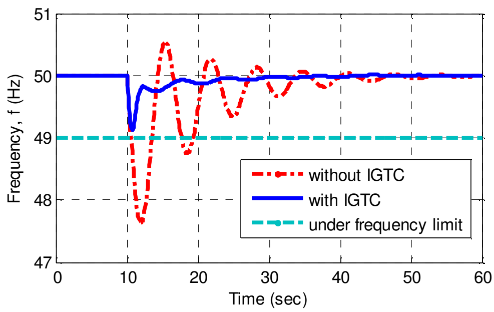

Fig. 9. Frequency response due to under frequency event

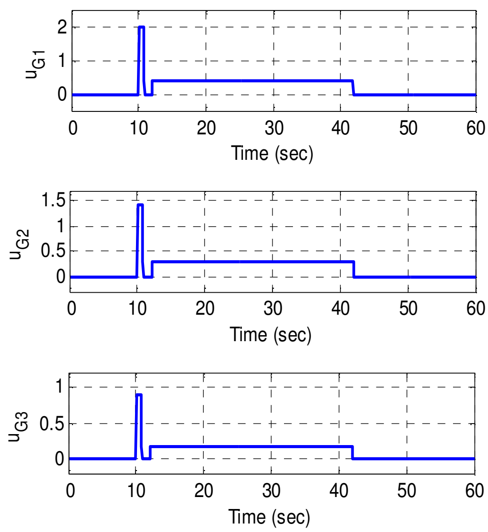

Fig. 10. IGTC output for each generator due to under frequency event

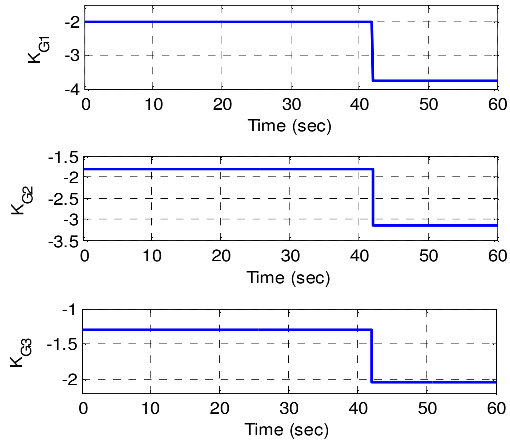

Fig. 11. AGC output for each generator due to under frequency event

The multi-machine power system is also tested with other combination of step input for load increase and decrease tests. However, the step input size, ΔP_e remains 1.2pu. Therefore, Fig. 12 shows the frequency response due to load decrease test with step input from 2.4pu to 1.2pu. On the other hand, Fig. 13 denotes the frequency response due to load increase test with step input from 1.2pu to 2.4pu. The results show that by employing the IGTC, the frequency not exceeded the desired threshold. Subsequently, the frequency inclines to the nominal value of 50 Hz without any large oscillation. This demonstrates that any combination of step input with step size of 1.2pu, the system is significantly enhanced.

However, as the *synchronous point* is reached, the response is started to fluctuated and then tends to restore to the nominal value again. This is due to the fact that the new integral gain, K^1 and K^2 are not the optimal value for these conditions of step input. Therefore, new optimal value of K is required for each situation.

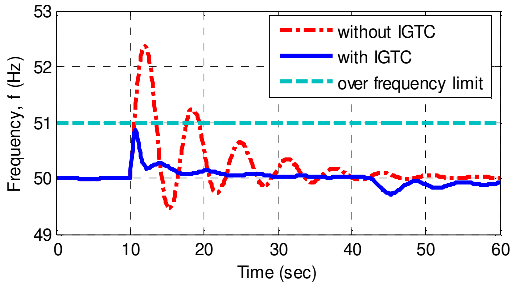

Fig. 12. Frequency response due to over frequency event (step input from 2.4pu to 1.2pu)

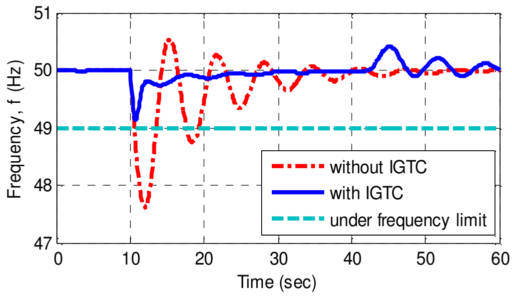

Fig. 13. Frequency response due to under frequency event (step input from 1.2pu to 2.4pu)

VI. Conclusion

This paper proposes a knowledge-based acceleration feedback controller for frequency control of gas turbine generator (IGTC) for multi-machine case. The multi-machine system is represented by 3 units of gas turbine generator in one area of interconnected power system. Computer simulations of frequency response for each generating unit are used to optimize the control parameters. Then, these optimal parameters of IGTC are used to demonstrate the performance of the proposed controller for major system disturbances on suggested multi-machine power system.

The control strategy has obviously succeeded, in which the quality of frequency control substantially improved, and the major disturbances are suppressed, subsequently, generator tripping and load shedding operations can be prevented. The intelligent control signal makes the frequency response to remain within the allowable tolerance. All these indicate the main purposes and advantages of applying the proposed control strategy.

In addition, the use of variable integral gain of AGC gives an opportunity for the frequency response to be restored to the nominal value smoothly without large ripple during the transient period. This condition can be achieved by determining the optimal value of integral gain once the *synchronous point* is reached.

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