# The Benefits of Automatic Generation Control in Interconnected Power System Under Various System Conditions

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**Abstract** – *The increasing load demand in power system affects the grid frequency stability. When such disturbance occurs, the Generator Governing System (GOV) performs the primary control to regain the stability, but due to its droop characteristic, the frequency is brought to a new steady-state. An Automatic Generation Control (AGC) is the secondary control loop which plays a pivotal role in power system to assist the governing system to recover and maintain the system frequency stability following a disturbance while maintaining the tie-line power interchange as well. This paper explores a number of benefits provided by the Automatic Generation Control in power system through critical analysis of the implemented Proportional-Integral-Derivative (PID) based AGC control scheme. The control scheme is modelled through DIgSILENT Power Factory simulation software. A modified IEEE 14 bus network is used for validation of the control scheme through various case study implementations. The simulation results prove that the AGC consolidated with a governing system are able to maintain the power system stability under various contingencies.*

***Keywords***: *Power system stability, Automatic Generation Control (AGC), frequency control, Tie-line power interchange, Governing System (GOV)*

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## I. Introduction

The speed governing system has a significant contribution to the primary frequency control of the conventional generation system. Its function is to control the active power production based on its droop characteristic. When a disturbance occurs in the power system network, the governor will respond to such disturbance by regulating the speed of the turbine of the generator. However, its speed regulation is not accurate, and hence the system frequency cannot be returned to its nominal value following a disturbance. It has been proven that the governing system cannot maintain the frequency to its nominal value following the increment of load demand [1]. According to [2], the frequency operating range is expected to be maintained within 49.5 Hz to 50.5 Hz, and beyond these limits, an emergency control is required. The emergency control can result in load shedding as outlined in [3]; therefore, an alternative control measure needs to be considered, such as Automatic Generation Control (AGC).

The AGC is the secondary control loop that will assist the primary control (GOV response) to recover the system frequency to its nominal value. The AGC is not only contracted for frequency control, it is used to control and maintain the tie-line power interchange in a wide-area controlled power system [4].

### *A. The implementation of Automatic Generation Control (AGC)*

Power system frequency is maintained by balancing the load demand and generated power. As soon as there is an imbalance between generation and the load, resulting in a change of the net power interchange, the system frequency will subsequently change. There are three frequency control stages in the power system: primary control, secondary control and tertiary control.

Their activations are based on time-stamp as shown in Fig 2. When the disturbance is introduced, the activation of the primary control (governing system) is between 15 sec to 30 sec. The next stage is the activation of secondary control (automatic generation control) between 30 sec to 15 min. The last control stage is the tertiary control anticipated to be activated from 15 min to several hours [5].

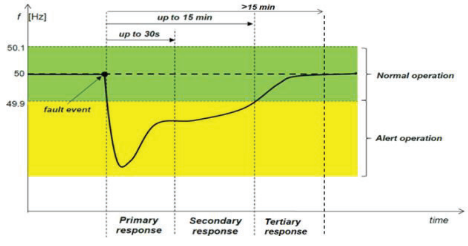


Fig. 1. Modified frequency recovery process [5]

An automatic generation or load frequency control can be modeled in two ways, firstly as a decentralized controller, and the other configuration is a centralized controller. The difference between the two controllers is that, in the decentralized controller each area has its designated controller. On the other hand, in a centralized controller, all controlled areas within the system are monitored and maintained through a single controller. For example, AGC is remotely configured at the transmission control center in most cases, and it is being monitored by the System Operator. The control inputs to the AGC, such as system frequency and tie-line power interchange, are transmitted to the control center through a telemetry system [6][7]. The modeled AGC follows the approach in [8], however, the tie-line power interchange was not considered also in [9]. There are various control strategies developed for AGC as outlined in [10], however the classical control strategy is still robust if it is adequately configured, and it is simple to apply.

## II. Modeling of decentralized Automatic Generation Control approach

Each area has its designated controller operating in isolation of other area's controllers in the decentralized frequency control model. In most systems, the power interchange between the area is not considered in decentralized control [11]. When the load changes in a particular area, all the controllers react to the load event, and this can put more strain in the transmission system when the power interchange is not being considered.

The modeling of the decentralized controller can be divided into two parts, one without considering the inter-areal power interchange, and the second is when the scheduled power interchange between the areas is considered.

The decentralized control model to be performed is when the power interchange between the areas is being considered. This model ensures not only the maintenance of the frequency but also the inter-areal scheduled power interchange.

In decentralized control, the change in system frequency and change in schedule power interchange are the inputs to the controller. In this case, the PID-controller is used to process the input signals to restore the system frequency. The block diagram of the decentralized control loop is shown in Fig 2 below. The highlighted part in a dashed red box is the decentralized controller.

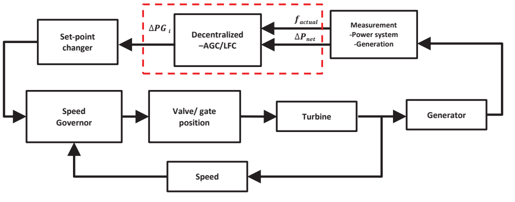


Fig. 2. Coordination of a decentralized frequency controller in the power system block diagram [6]

The mathematical modeling of the block diagram shown in Fig. 2 is indicated from equation (1) to (5). The input signals to the controller, which is the frequency and tie-line power interchange, are measured at the local busbar and receiving end of the transmission of the area of concern respectively. In steady-state, the frequency measured will be 50 Hz, and the reference setpoint frequency is also 50 Hz; there will be no control signal sent to the controller. The change in tie-line schedule power between the areas and the change in frequency can be determined using equations (1) and (2) as shown below. In equation (1), $f_{ref}$ is the nominal frequency setpoint (50 Hz), and $f$ is the measured frequency at the busbar terminals.

$$\Delta f = f_{ref} - f \tag{1}$$

$$\Delta P_{net} = \frac{P_{net} - P_{net.ref}}{P_{base}} \tag{2}$$

In equation (2), $P_{net}$ is the measured total scheduled power flow at the receiving of each area, $P_{net.ref}$ is the schedule power interchange setpoint between the areas, $P_{base}$ is the base power to convert the change in tie-line power interchange to per unit value.

The Area-Control Error ($ACE$) is determined by multiplying the change in frequency with the frequency bias factor and subtracting the change in tie-line power interchange as shown in equation (3) below. $\beta_i$ is the bias factor.

$$ACE = \beta_i \times \Delta f - \Delta P_{net} \tag{3}$$

The Area Control Error ($ACE$) is fed to the PID-controller, the control output ($\Delta P_{set}$) from the PID-controller is then multiplied by the control participation factor ($pf_i$), and the final output signal ($\Delta PG_i$) is sent to the respective speed governing system.

$$\Delta P_{set} = K_p\left(ACE\right) + \int_0^t ACE\,dt + K_d \times \frac{d(ACE)}{dt} \tag{4}$$

$$\Delta PG_i = \Delta P_{set} \times pf_i \tag{5}$$

The mathematical modeling of the decentralized automatic generation control is presented through block diagrams, as demonstrated in Fig. 3 and 4. The difference between the two diagrams is that Fig. 3 is not considering the tie-line power interchange while Fig. 4 considers the tie-line power interchange. The block diagram in Fig. 3 is suitable to be applied in area 1 as there is no scheduled power being received in that area.

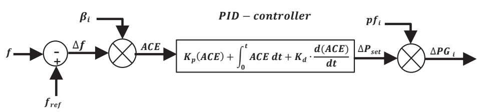


Fig. 3. Decentralized AGC block diagram without considering tie-line power interchange [4]

The block diagram illustrated in Fig. 4 below is suitable for application in areas where there is a scheduled power interchange that needs to be maintained.

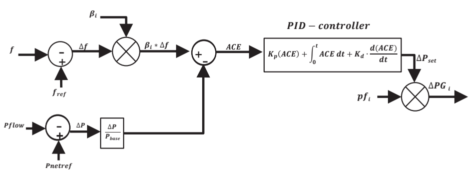


Fig. 4. Decentralized AGC block diagram considering tie-line power interchange [4]

# III. Modeling of a decentralized Automatic Generation Control (AGC) in DIgSILENT Power Factory Software

The modeling of the AGC on DIgSILENT is achieved by first creating the frame-block. The purpose of the frame-block is to define inputs and output assignments. The inputs to the controller to be defined include frequency measurements and the active power flow on the transmission lines at the receiving end of the area. These analog signals are sent to the controller and processed for obtaining a desired control output signal.

The block diagrams for each area are shown from Fig. 5 to 8 below. In these block diagrams, the time delay has been included to delay the action of the secondary controller so that the primary control can have enough time to adjust and regulate the frequency until it reaches its steady state. The secondary control action only takes place once the primary control reaches its new steady-state.

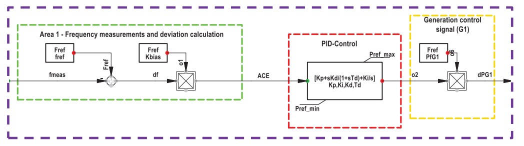


Fig. 5. Area 1 decentralized AGC block diagram

Area 1 controller, shown in Fig. 5 above, is used as an additional control loop to the governing system of generator 1, which supplies both areas 2 and 4; hence there is no power interchange control loop included on the controller. Instead, the input signal to the controller is the system frequency. The output control signal is sent to the generator 1 governing system.

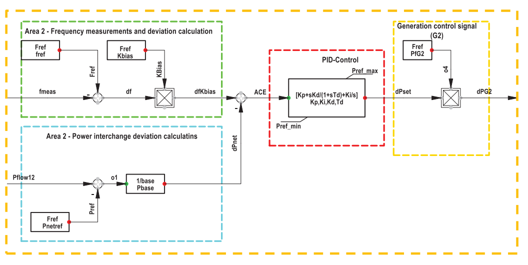


Fig. 6. Area 2 decentralized AGC block diagram

Area 2 decentralized controller consists of two different input signals. The first signal is the system frequency, and the second signal is the tie-line flow from area 1 to area 2. The area control error is processed through the PID-controller, and the output is multiplied by the generation participation factor. The output signal of the controller is sent to generator 2, as shown in Fig. 6 above.

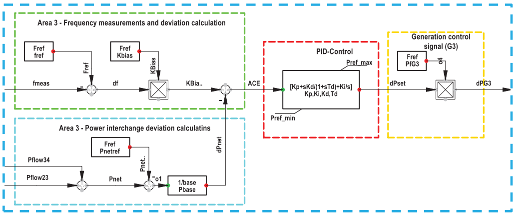


Fig. 7. Area 3 decentralized AGC block diagram

The operation of areas 2, 3, and 4 controllers are the same. Their control loops facilitate two functions: ensuring the frequency stability while maintaining the scheduled tie-line power interchange. The output signal for the control loop in area 3 is sent to generator 3, as shown in Fig. 7 above. For area 4 control loop, the output signal is sent to generators 6 and 8 governing systems as indicated in Fig. 8 below.

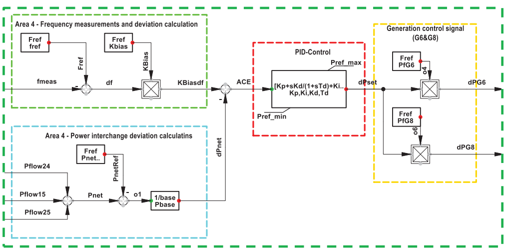


Fig. 8. Area 4 decentralized AGC block diagram

The parameters of the developed decentralized AGC scheme for area 1, area 2, area 3, and area 4 are shown in Table I below:

TABLE I
AUTOMATIC GENERATION CONTROL SCHEME PARAMETERS

| Name | Area 1 | Area 2 | Area 3 | Area 4 |
|---|---|---|---|---|
| Net-power interchange setpoint [MW] | - | -101.28 | -63.21 | -119.64 |
| Base power [MW] | - | 323 | 323 | 323 |
| F Reference frequency [p.u] | 1.00 | 1.00 | 1.00 | 1.00 |
| Frequency bias (KBias) [p.u] | 1.00 | 1.00 | 1.00 | 1.00 |
| Kp Proportional gain of PID controller [p.u] | 1.00 | 1.00 | 1.00 | 1.00 |
| Ki Integral gain of PID controller [s-1] | 0.60 | 0.60 | 0.60 | 0.60 |
| Kd Derivative gain of PID controller [p.u] | 0.50 | 0.50 | 0.50 | 0.50 |
| Td Derivative time constant of PID controller [s] | 0.001 | 0.001 | 0.001 | 0.001 |
| Generator participation factor [p.u] | 1.00 | 1.00 | 1.00 | 1.00 |
| df_min Minimum limitation of signal scaling [p.u] | -0.107 | -0.107 | -0.107 | -0.107 |
| df_max Maximum limitation of signal scaling [p.u] | 0.107 | 0.107 | 0.107 | 0.107 |

The modeled Automatic Generation Control scheme needs to be tested in order to verify its effectiveness and efficacy in the power system.

## IV. Power System network model under study

In order to investigate the effectiveness of the modeled control scheme, the IEEE-14 network configured in [1] is utilized. The data and parameters for this network can be obtained in [12]. The parameters for the governing system used are found in [13] and the parameter for the exciter are found in [14] Fig. 9 illustrates the modified IEEE-14 bus network model utilized. The network is customized into four areas. Each area has its dedicated control scheme. Area 1 consists of one generator which is also the reference generator. In area 2 and 3 consist of a load and a generator respectively. Area 4 consists of 2 generators and a bulk load as indicated in Fig. 9 below.

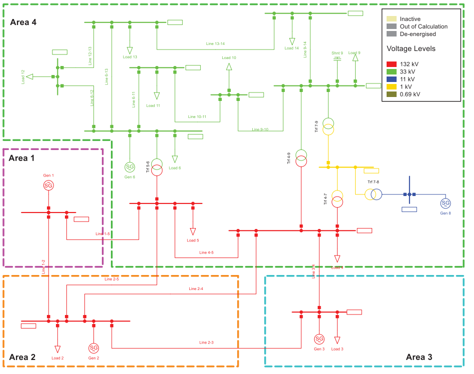


Fig. 9. Customized four-area 14 bus power system network

## V. Simulations and results discussion

The case studies to be investigated are performed on DIgSILENT power factory software using Root Mean-Square simulation tool. The choice of the selected simulation tool within DIgSILENT is motivated by the instability phenomena classification as per [15]. This tool allows an analysis of events or disturbances for a longer duration.

The case studies to be performed include 10% load demand increase as well as the generator trip. The aim of performing these contingencies is to analyze the power system response on these disturbances in order to evaluate the contribution of the modeled Automatic Generation Control scheme.

### *A. Case study 1 – 10% load demand increase*

The simulation case duration is set to 260 sec for the full duration of the event. However, the first load demand increase disturbance is initiated at 20 sec post case simulation. The load demand increment is set 1 % per one step increase to a full 10 % load demand increases. The simulation events a distinguished by colour coding. The red colour indicates the governing system response when a load disturbance is introduced while the blue colour is for the integrated control loop of the governing system and the automatic generation control. Area 4 is composed with high load density; hence more generation power is needed.

Fig. 10 (a) below illustrates the response of the system frequency following a load demand increase contingency. The response of the governing system represented by red graph is noted and the frequency decline from the initial state to a new steady state of 49.60 Hz post disturbance. However when the AGC was activated the system frequency was maintained at its nominal state of 50 Hz post disturbance. This is a significant contribution by the AGC to the system stability. Fig. 10(b), (c), and (d) demonstrates the response of the governing system as well as the AGC on the tie-line power interchange. It can be noted that the governing system could not maintain the tie -line power interchange. It is only when the AGC was put into service that the power interchange was maintained for area 2 and 3. However, the AGC could not maintain the scheduled power interchange for area 4, but it was improved from the governing system response alone. Area 4 is heavily loaded, therefore an additional generation supply is required in order to maintain the power interchange.

The utilization of AGC has improved the grid losses in the network as indicated in Fig. 11(a) below. In order for the AGC to perform its function, there should be enough generation reserves on those generators that are participating or contracted to secondary control response. Fig. 11(b) below shows available reserve before and post disturbance.

In order to prove the efficacy of the AGC, another contingency is applied to verify its response to the condition.

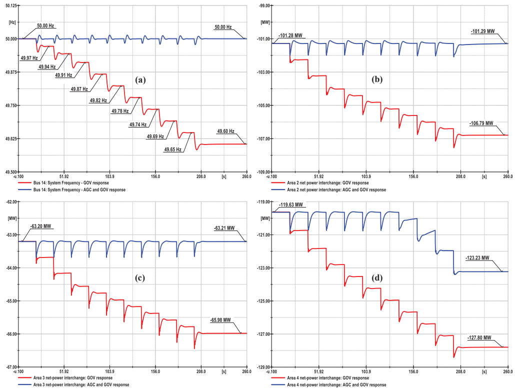


Fig. 10. (a) System frequency, (b) Area 2 power interchange, (c) Area 3 power interchange, (d) Area 4 power interchange

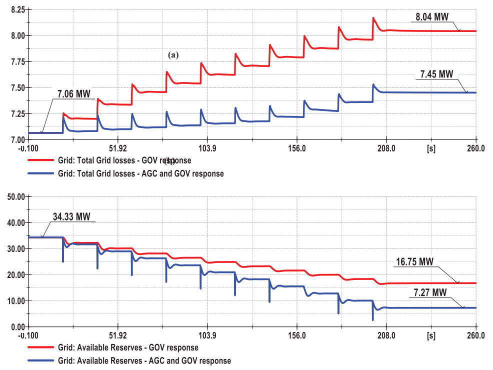


Fig. 11. (a) Total grid losses, (b) Available reserves

### *B. Case study 2 – Tripping of generator 8*

Case study 2 evaluates the response of the governing system and the AGC under the condition of a generator trip. This case study is performed to prove the robustness of the AGC. In Fig. 12(a) below is the system frequency response following generator 8 tripping condition. It can be noted that when generator 8 tripped, the system frequency fell to 49.6 7Hz under the governing system response. However, the when the AGC was activated, the system frequency was recovered to its nominal value of 50Hz.

However, the AGC slightly improve the tie-line interchange for area 2, as well as the point of nadir as shown in Fig. 12(b) below. For area 3, the power interchange was successfully maintained post-disturbance. In area 4, the AGC only improved the point of nadir only.

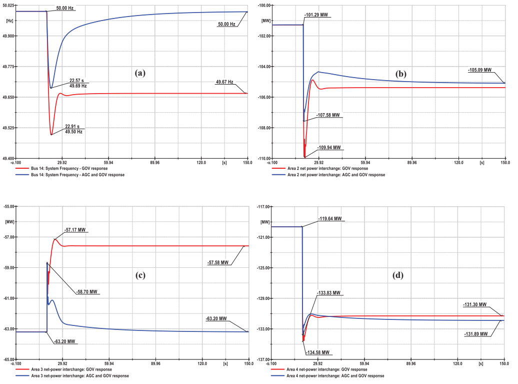


Fig. 12. (a) System frequency, (b) Area 2 power interchange, (c) Area 3 power interchange, (d) Area 4 power interchange

## VI. Conclusion

Power system stability is part of the day-to-day activity to all the utility custodians and those responsible for the smooth operation of the power system, such as system operators. Therefore, various control and monitoring strategies are explored every day. Therefore, it is essential to understand what each component within the sphere of control and operation can provide to enable and ensure the stability of the network grid.

Automatic generation control has been interrogated; its contribution to the power system is noticeable. However, a significant contribution of this control strategy could be realized more in a power system where there are enough generation reserves.

Therefore, a new control approach is required to deal with the drawback of the AGC. The AGC is mainly configured as an additional control loop to the governing system of the synchronous generator. The limitations of the AGC in power system needs to be explored in order to improve its robustness for future applications

Considering the restriction and prohibitory measures to mitigate the use of fossil fuel generators, which negatively impact the environment, has drawn more attention in an exploration of using distributed energy resources as an alternative supply. Therefore, utilization of wind turbine generators as an alternative source of supply to stabilize the power system grid needs considered as future research. The wind power plants need to be adequately integrated into the power system grid to avoid any impact that could lead to power system instability. Therefore, a control system that will allow its smooth integration to the grid is proposed for future research. The wind power plant is proposed as an active power compensator to control the power system frequency following system disturbances.

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