DESIGNING AUTOMATIC LOAD-FREQUENCY CONTROL SCHEME FOR SRI LANKAN POWER SYSTEM

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Degree of Master of Science

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Declaration

I declare that this is my own work and this thesis does not incorporate without acknowledgement any material previously submitted for a Degree or Diploma in any other University or institute of higher learning and to the best of my knowledge and belief it does not contain any material previously published or written by another person except where the acknowledgement is made in the text.

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(Dr. Asanka Rodrigo)

Abstract

The Sri Lankan power grid is being operated at nominal frequency which is 50 Hz and steady state regulation window is 49.50 Hz to 50.50 Hz. There will be a frequency error left behind, during either demand or generation change as per system dynamics. Such error is generally corrected by secondary control regulation which is mainly done by verbal dispatch instruction originated from system control center. Hence, the regulation quality of grid frequency is highly depended on above said manual frequency corrective action which is executed by the Control Room Operator(CRO) back in the related power plants. The amount of frequency deviations within the operational limit, have been increased significantly during the last couple of years in Sri Lankan system.

The aim of this study is to design and analyse the Automatic Load Frequency Control(ALFC) scheme for regulating secondary control spinning reserves based on persisting Area Control Error(ACE) values. Hence, MATLAB Simulink models are developed for primary and secondary regulations while addressing the unique constraints related to frequency regulation of Sri Lankan power system. Consequently, both the models are combined and the behavior of system frequency response with ALFC is studied in detail for different generation scenarios.

The outcomes direct that, how exactly ALFC could be implemented in Sri Lankan power system while exhibit the enhancement of frequency regulation quality. The designed model and obtained results during this study could be used as base-case platform for implementation or further study of ALFC methodology for Sri Lankan power system.

Key Word: Frequency Control, Automatic Load Frequency Control, Power System Model.

Acknowledgements

This note of thanks is the finishing touch of my dissertation which provides window to express my sincere thanks to the very most important people who had given tremendous support from beginning to end. The study associated with this research had enhanced my learning skills not only in the professional platform but also on a personal level.

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Besides all, this work would have been not possible if she was not there with me whole time. I would like to extend my special acknowledgement to Mrs.S.Rishanthi, my dearest wife, for her kind support.

G. Kishokumar

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

.

LIST OF ABBREVIATIONS

Abbreviation	Description
AGC	Automatic Generation Control
ALFC	Automatic Load-Frequency Control
CCP	Combined Cycle Power
CEB	Ceylon Electricity Board
CRO	Control Room Operator
DFR	Digital Fault Recorder
ED	Economic Dispatch
GE	General Electric
GIV	Gas Inlet Valve
GSS	Grid Sub Station
GT	Gas Turbine
KCCP	Kelanitissa Combined Cycle Power
KPS	Kelanitissa Power Station
LFC	Load-Frequency Control
LTI	Linear-Time Invariant
LVPS	Lakvijaya Power Station
MSIV	Main Steam Inlet Valve
MVA	Megavolt Ampere
OPF	Optimum Power Flow
PF	Participation Factor
PS	Power Station
PSS/E	Power System Simulator for Engineers
PU	Per Unit
RF	Regulation Factor
ROCOF	Rate of Change of Frequency
SCC	System Control Centre
WCP	West Cost Power

CHAPTER 01

INTRODUCTION

1.1 Introduction of Sri Lankan Power System.

The Sri Lanka national power grid is own and operated by Ceylon Electricity Board(CEB). The quality of power is primarily determined by system frequency. Nominal frequency of the Sri Lanka Power System is 50 Hz and the statutory limits for variations shall be within ±1% as given in the Grid Planning and Operating Standards. Allowable frequency window under emergency conditions shall be between a high of 52.0 Hz and a low of 47.0 Hz.

The dynamic changes in demand is tracked by single hydro unit which is configured on fast droop setting (e.g. 1.6 to 2%). All the other connected machines are set on slow droop configuration (e.g. 4 to 6%) which provides dynamic free-governor support for primary regulation control. The long-term change in system demand is monitored by System Control Center (SCC) based on system frequency and present MW generation of frequency controlling plant. Accordingly, verbal instructions are given to other relevant power plants to raise/lower their MW set point in order to bring controlling plant into desired MW level.

1.2 Frequency Control Basics

The proper frequency regulation performance is indeed important for a power system. Power system loads and losses are sensitive to frequency. Approximately close control of system frequency ensures the constant speed of induction and synchronous loads which are connected to the system.

The frequency of AC power system is depended on the power balance between the active power generation and active power consumption. As frequency is a single factor throughout the whole system, a change in active power demand at any point is affected throughout the system. Figure 1.1 shows the typical behavior of system frequency right after disturbance of tripping generator unit or addition of block of load to the system.

The initial power balance is obtained by an extraction of kinetic energy from system inertial storage which causes a declining system frequency. As the frequency decreases, the power taken by loads decreases. Equilibrium for a large system is often obtained, when the frequency sensitive reduction of loads balances out the real power mismatch occurred, and hence system achieves power balance at new frequency called quasi-steady state frequency ($f$ss) [1]. If the mismatch is significant enough to change the system frequency, beyond the governor dead-band of connected generators, their output will be increased by governor action. In this scenario, an equilibrium is obtained with the combined effect of reduction in the power taken by loads and the increased generation due to primary governor action.

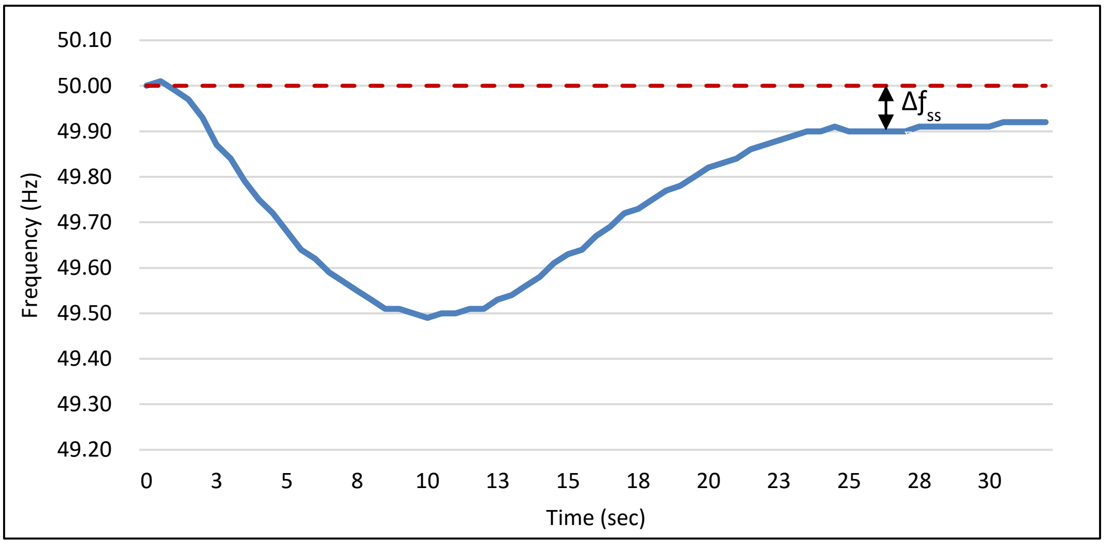


Figure 1.1: System Frequency responses during generation rejection

Though, there could be a steady state ‘frequency error’ left behind to be corrected by external measures such as activating secondary frequency control or manually changing setpoint control of particular power plant. The severity of such frequency error will be significant when system size is smaller. Figure 1.2 shows a typical frequency control reserves based on the time taken for activation.

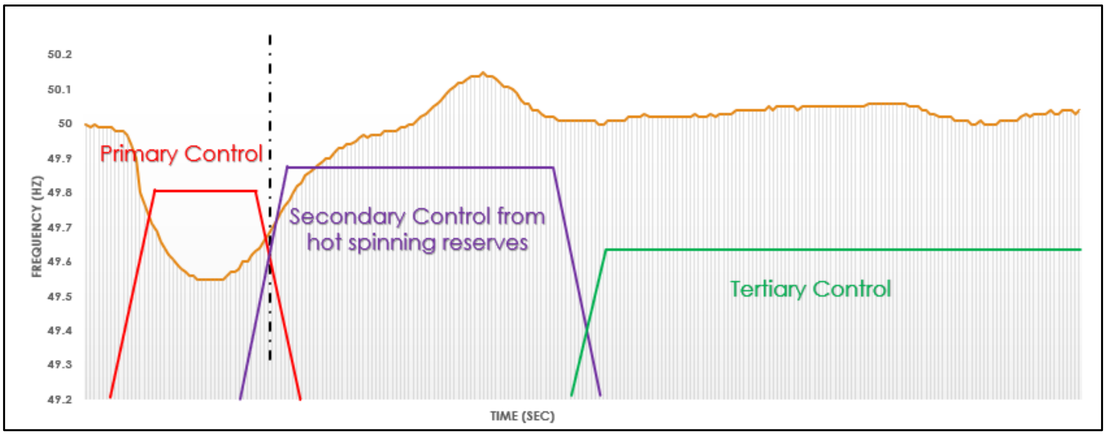


Figure 1.2: Typical Activation Time of Frequency Control Reserves

1.2.1 Primary Control

The primary governor action on each generating unit provide support for the frequency error correction during the disturbances. Amount of support is determined by speed droop setting and typical action time is from 5 to 20 secs. Utmost, Speed governing capability is decided based on available generation technology. Proper load sharing is ensured among connected generators through different droop configuration. The frequency error is always left behind while achieving generation-load equilibrium on new frequency $f$ss [2].

1.2.2 Secondary Control

Typical time window for secondary control operation will be like 20 sec to 10 min. The main objective of secondary control reserve is to reduce the steady-state frequency error while reset the primary control reserves in order to ensure proper operation on upcoming system dynamics.

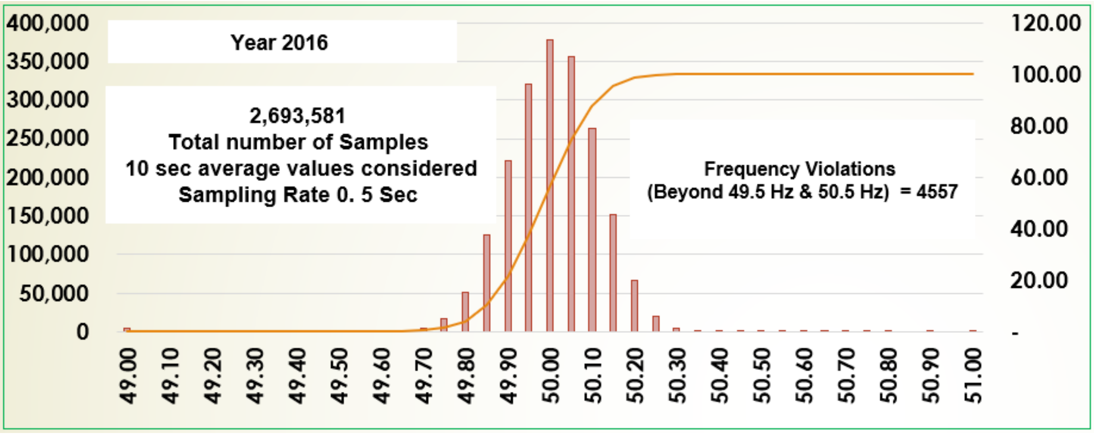
1.2.3 Tertiary Control

The tertiary control is to adjust generators towards economical operating points and to address the long-term generation deficit or surplus. The decision of dispatching this control is taken based on the severity of the disturbance. Typical activation time for tertiary control is greater then 15 to 25 min.

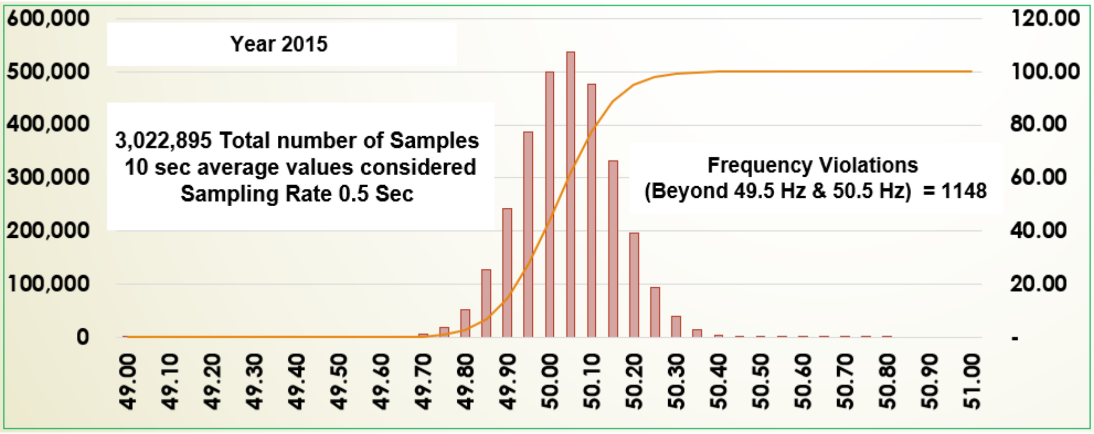
1.3 Frequency Control Drawbacks of Sri Lankan System

The secondary regulation is controlled by verbal instruction originating at system central control center in regular intervals. Based on this instruction the machines MW set point or speed reference is changed by CRO. Such manual control via human intervention is adversely reflected on the quality of the system frequency in large scale. There are number of drawbacks to be encountered due to this conventional frequency control mechanism, such as;

- Frequency varies is in large range.
- Frequency run-away is not limited during disturbances.
- Frequency recovery is very slow.
-



(a)



(b)

Figure 1.3: Recorded Frequency Statistics for Year-2015 & 2016
Source: Frequency recorder Data, System Control Center, CEB

The preliminary study is conducted and recorded frequency samples are analysed for Sri Lankan power system. Figure 1.3 (a) and (b) shows the recorded frequency which averaged over 10 sec value. The sampling rate is 0.25 sec. As per the depicted frequency sample, about 18% of recorded sample is out fallen beyond the desirable frequency regulation band which is 50Hz± 0.3%. Hence proper mechanism is indeed important to be associated with frequency control function to improve the regulation.

1.4 Solution and Motivation.

Major reason for the poor quality of regulated frequency is human intervention associated with secondary control regulation. Evidently, the automatic generation control (AGC) will be best answer for these issues. Then, there is a question remained, how islanded system like Sri Lanka could be associated with AGC.

AGC is defined by IEEE as the regulation of the power output of electric generators with in prescribed area in response to changes in system frequency tie-line loading ore the regulation of each other so as to maintain schedule system frequency and/or the established interchange with other area within predetermined limits. These all complex decision is made by centrally located AGC control mechanism, by means of Area Control Error (ACE). The existence of ACE means that there excess or deficient of spinning energy in a particular area and correction must be done on committed power plants to restore the system frequency in scheduled interval. In other terms ACE is expressing the amount of MW power needed to be changed in order to change the frequency by 0.1Hz. The three utmost controls executed by AGC, termed as Own area frequency error correction, neighbor area tile-line bias control and base point adjustment as of economic dispatch [2].

In the contest of Sri Lankan power system, the major barrier for AGC implementation is unavailability of SCADA/EMS system which controls the governor set points or gives rise/lower pulses to governor on a particular power plant in real time. But, upcoming GE “e-terraGenaration” platform will enable the remote operation of the governor set point of four power plants New-Laxapana, Kothmale, Victoria and Samanalawewa. Thus, the implementation of AGC for real time system is no longer conceptual.

The control logic involved with AGC is represented by Figure 1.4. usually, AGC control is de-centralized based on area level (e.g. Sri Lankan can be considered as single area). Information of all associated parameters like real time frequency, present MW set point, tie-line flows are must be telemetered to central location where AGC computation is being done. Here AGC works as automated secondary regulation and hence speed of secondary control regulation is slower than primary control and this requirement is indeed essential for satisfactory performance of real time frequency regulations [3].

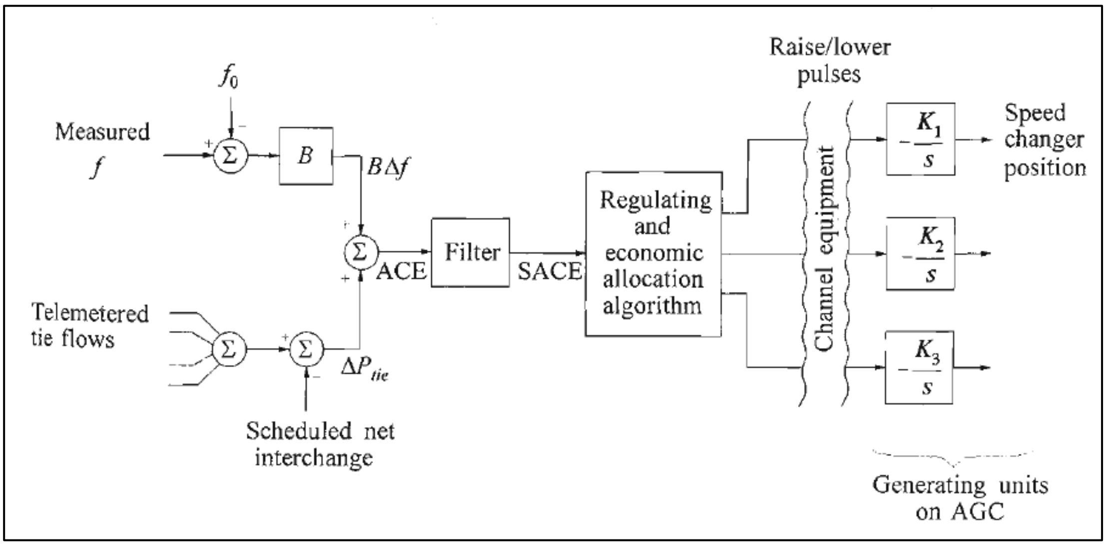


Figure 1.4: AGC logic signal flow diagram for single area
Source: P.Kundur ,"Power System Stability & Control", McGraw Hill Edu(in), 2013

Sri Lankan system can be considered as single area due to non-association of any tie line controls. Then, by triggering AGC it is expected to look after own area frequency correction only. Therefore, this point forward, the AGC control can be referred as Automatic Load-frequency Control (ALFC) of Sri Lankan system.

1.5 Objective of Research.

The primary objective of this research is to answer the question 'How ALFC can be implemented in Sri Lankan System?'. This can be done by estimating the important system parameters to develop proper ALFC model while addressing unique constraints associated with frequency controlling system in Sri Lanka. Latter, the behavior ALFC model is studied in detail with different generation scenarios.

Finally, the outcome of ALFC system with real time frequency response is studied and performance of system frequency regulation is compared with ALFC scheme.

1.6 Boundaries of Research.

The ALFC control system also could be incorporated with economic dispatch, interchange control, scheduling control, etc. This research had outlined for load-frequency control system related to primary and secondary regulation only, in order to address the ALFC requirement of Sri Lankan System. Moreover, this research does not cover into the individual plant level control parameters and its limitations.

1.7 Thesis Outline

The structure of thesis is reflected based on research progresses as explained in following topics.

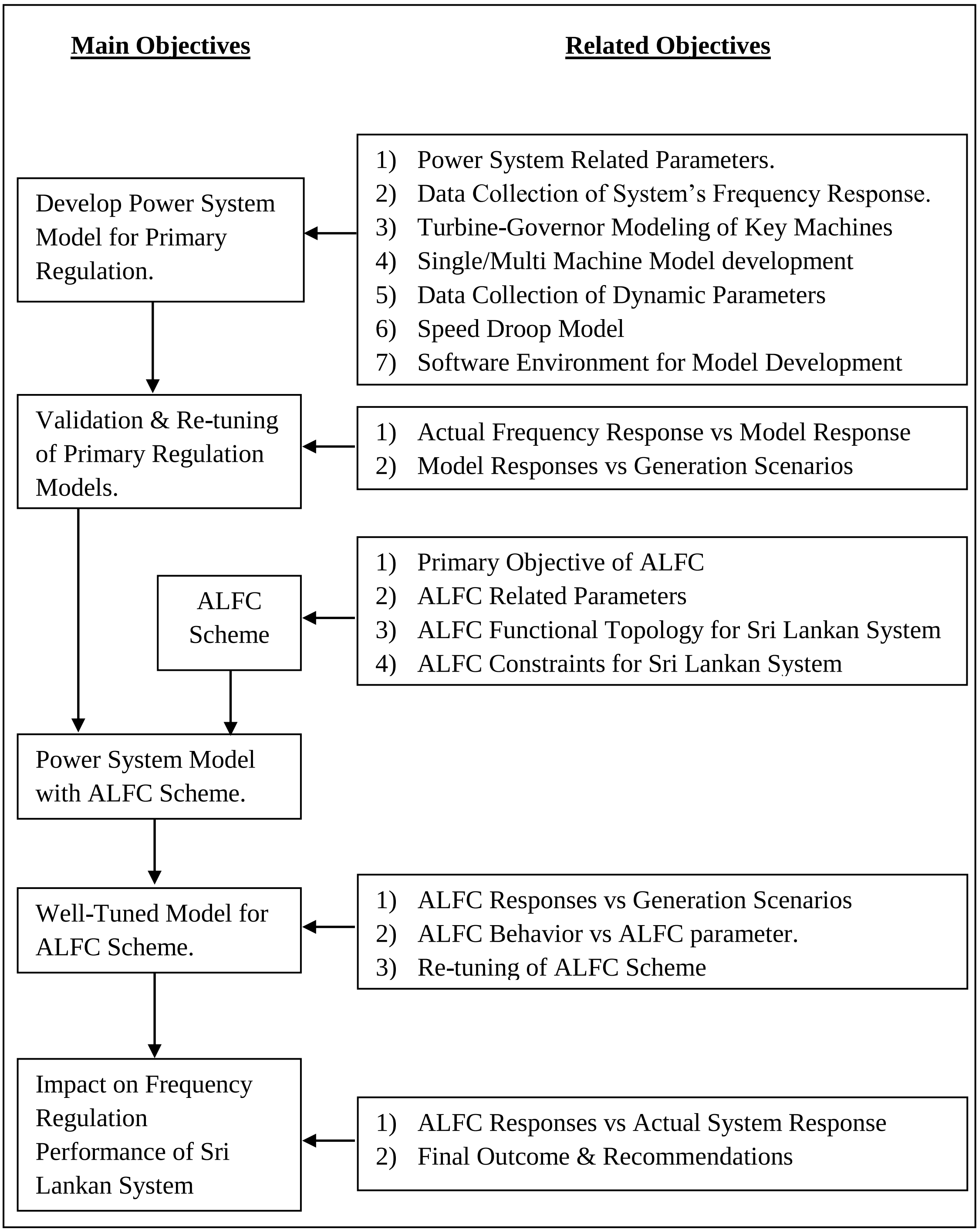
Chapter 02: Research Methodology
Chapter 03: Background of Power System Modeling for Primary Control Model
Chapter 04: Estimation of System Parameter
Chapter 05: Primary Control Model and Validation
Chapter 06: ALFC Model Development
Chapter 07: Simulation Results and Analysis
Chapter 08: Results Discussion Summary
Chapter 09: Conclusions

CHAPTER 02

RESEARCH METHODOLOGY

The study of ALFC in detail will be needed, a valid power system model for primary frequency regulation at first place. Further, the behavior of such power system model must be ensured in such a way that follows the actual system frequency responses relatively close enough. Hence, power system related parameters are founded and power system model is developed in MATLAB Simulink environment. The developed model is validated with actual transient response's data which recorded during number of generation rejections.

Subsequently, ALFC model is developed separately while addressing unique constraints associated in frequency regulations of Sri Lankan power system. Then, ALFC model is combined with validated power system model and frequency regulation performances are obtained for different generation scenarios. Then, the outcomes are studied thoroughly and models are re-tuned to meet desired ALFC responses. Finally, justification of ALFC and associated control parameters are determined based on re-tuned model outcomes. The Figure 2.1 exhibits the research methodology in macro view.



The Figure 2.1: Research Methodology and Approaches

CHAPTER 03

BACKGROUND OF POWER SYSTEM MODELING

3.1 Frequency Control Reserves.

Sri Lankan power grid is islanded system which consists 17 large hydro power plants and 11 thermal power plants in dispatchable category. The interconnection code specifies requirement of frequency capabilities of any power plant which is connected on national power grid. As per given specification plants must be able to withstand frequency variation from 47.0Hz to 52.0Hz during emergency condition while providing satisfactory stable performance during normal operational range which is 49.5Hz to 50.5Hz. All the connected generators are set on free governor mode with droop setting of 4 to 6% while one of single hydro machine is set to fast droop 1.6% or 2% to take care of real time change in demand. The fast and equivalent droop can be set on multiple machine to regulate frequency in much better level. Yet it needed to be computerized by external monitoring system to eliminate the governor hunting which deteriorates the turbine governor performance [1]. The technical requirement specified in connection code is closely followed with IPP while CEB own power plants have been given relief up to some extent due to equipment aging issues. The system frequency regulation quality is much better if governors of all connected machines kept on free governor mode in order to have full range of primary regulation support.

3.1.1 Thermal Reserves for Frequency Control

The thermal machines corresponding droop configuration and support over frequency regulation response are given in appendix-A. The power plant which covers bigger portion of demand (e.g. LVPS or WCP) has very limited support on frequency regulation. Because the LVPS having fast valving issues over frequency transients with droop configuration. Likewise, the WCP and Sojitz Kelanitissa are bound by strict PPA and hence MW ramp is slow which is not desire option for frequency regulation support though the free-governor support is enabled. Frequency controlling with KCCP was tested (with 1.8% droop setting) during most dry period of 2017. The performance of GT is very excellent on open cycle mode, but on combine cycle mode main steam inlet valves(MSIV) have severely damaged and made plant unavailable for about week. Then, KCCP halted from frequency controlling and put back on baseload operation. Hence, secondary control support from thermal generation over frequency regulation is yet to be developed in Sri Lankan system.

The thermal plants are collectively given bit of a support for primary regulation and it should be considered in model development, Hence, its required to develop thermal turbine-governor model for KCCP, Sojitz Kelanitissa CCP and WCP plants.

3.1.2 Hydro Reserves for Frequency Control

The hydro machines on droop configuration and support over frequency regulation response are given in appendix-A. As can be referred form appendix-A, all the hydro generators are supported for both primary and secondary regulation. if it secondary regulation, only large or reservoir type hydro plant could provide continuous support. Yet, there are practical limitation imposed on hydro generation such as 'reservoir level maintenance based on long term generation forecast' or 'irrigation requirement of downstream power plant' or prevailing weather conditions. All these aspects must be taken into consideration before committing hydro plant for frequency regulation.

As of present condition, relatively close frequency control is done by single hydro machines from any one of New-Laxapana, Kothmale, Upper-Kothmale, Victoria or Samanalawewa power plants. Hence, above hydro turbine-governor must be included in developed power system model.

3.2 Power system Model Development

In this research power system model development mainly focused on frequency regulation characteristics of related components in power system. On top of load frequency control mechanism, it is adequate to analyse the collective performance of all connected generators rather than considering the intermachine oscillation and transient-system performance in detail [2].

Mostly load-frequency analysis of power system is done using composite frequency response characteristics which comprises the aggregated effected of system equivalent droop and load damping characteristics. But in this research, the individual droop characteristics of particular machines have been used to address the primary regulation support given by each machine separately. Based on referred literature reviews, following main consideration are included for the model development.

1. Large hydro units which can be provide better regulation support are considered as separate turbine-governor model with droop feedback control.
2. Total primary regulation support given by thermal system is represented by single thermal turbine-governor model.
3. Rest of generators response and collective system regulation characteristics are lumped into other power system parameters like System Inertia, Load Damping and droop regulation.

Hence, considered primary regulation model is developed by associating following sub-model development approaches.

1. Synchronous machine model
2. Power system model
3. Inertia constant estimation approach
4. System damping constant estimation approach.
5. Turbine-Governor model development
6. Speed droop model
7. Selection of Simulation environment

3.3 Single Machine Model

Foremost, it is important to understand the mathematical representation of a single synchronous machine and its relative control action over frequency regulation. It is sufficed enough to have simple generator model to represent the load-frequency control mechanism on a single machine [3, 4]. The dynamic torque balancing of generator is modeled based on the moment of inertia ‘J’.

$$J\frac{d^2\theta_m(t)}{dt^2} = \tau_m - \tau_e \qquad \text{eq. 3.1}$$

Where θ_m – The position of the generator rotor.

τ_m – Mechanical torque applied by the turbine.

τ_e – Electromagnetic torque developed by the generator.

Let $$\theta_m(t) = \omega_0 t + \delta(t)$$

$$\omega_m(t) = \frac{d\theta_m(t)}{dt} = \omega_0 + \frac{d\delta(t)}{dt} \qquad \text{eq. 3.2}$$

Where ω_0 – Nominal angular speed

$\omega_m(t)$ – Actual angular speed of rotor

If eq. 3.2 is substituted in eq. 3.1, Then;

$$J\frac{d\omega_m(t)}{dt} = \tau_m - \tau_e \qquad \text{eq. 3.3}$$

The Inertia Constant 'H' of a generating unit is defined as [1];

$$H = \frac{Kinetic\ Energy\ styored\ in\ a\ machine}{Rtated\ MVA\ power} \qquad \text{eq. 3.4 (a)}$$

$$H = \frac{\frac{1}{2}.J.{\omega_0}^2}{S} \qquad \text{eq. 3.4 (b)}$$

J – Moment of inertia (kg·m^2) H- inertia constant (MW-s/MVA)

S – Rated power of generator in MVA

Hence combining eq. 3.3 & eq. 3.4 and rearranging;

$$\frac{2HS}{\omega_0}\frac{d\omega_m(t)}{dt} = \omega_0\tau_m - \omega_0\tau_e \qquad \text{eq. 3.5}$$

The mechanical power and electrical power are given as;

$$P_m = \omega_0 \tau_m \text{ and } P_e = \omega_0 \tau_e$$

Thus eq. 3.5 yields with conversion in to per unit (dividing equation entirely by base power ‘S’);

$$\frac{2H}{\omega_0} \frac{d\omega_m(t)}{dt} = P_{m(pu)} - P_{e(pu)} \qquad \text{eq. 3.6}$$

Moreover, if $\omega_m = 2\pi f$ and $\omega_o = 2\pi f_o$, then eq. 3.6 yields in normal notation;

$$\frac{2H}{f_0} \frac{df_m}{dt} = P_m - P_e \qquad \text{eq. 3.7}$$

If eq. 3.7 consider on vicinity of the operating point of generator during system dynamic condition perturbated by an electrical power change ΔP_e in per unit quantities could be represented by linearizing eq. 3.7 [1,6], which gives;

$$2H \frac{d\Delta f}{dt} = \Delta P_m - \Delta P_e \qquad \text{eq. 3.8}$$

The Δf_{pu} is in per unit quantity as derived $\Delta f_{pu} = {}^{\Delta f_m}/_{f_o}$. Further, throughout the research all the parameters are considered to be per unit (pu) value, hence system frequency and speed can be used interchangeably.

The Laplace domain transferring of eq. 3.8 yields;

$$2H\, S\, \Delta f\ (s) = \Delta P_m(s) - \Delta P_e\ (s) \qquad \text{eq. 3.9}$$

The eq 3.09 could be represented in signal flow diagram as shown in Figure 3.1

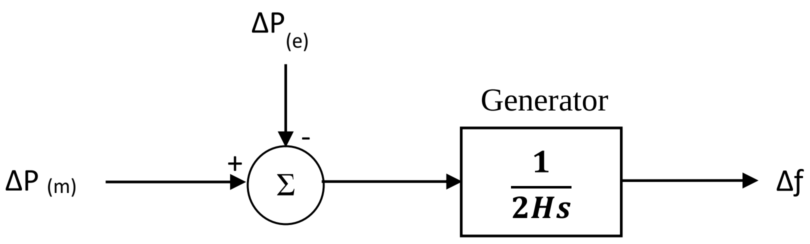


Figure 3.1 Single Generator Representation.

3.4 Multimachine Model.

Any power system has number of machines connected in parallel. The system frequency is a common factor throughout the tightly connected network. Hence, as per the composite regulation characteristic theory of power system, it is relatively close that collective support from all connected generator with respect to change in frequency could be represented by an equivalent single generator. Then, the equivalent machine has an inertia constant which represents the entire system response against frequency change.

In general, power system loads are frequency depended and such frequency dependency is expressed single lumped value called load-damping constant 'D'. This can be further drilled down by analyzing individual components of ΔP_e. The load change ΔP_e is comprised of the effects of both frequency depend electrical loads (given by $D\Delta f$) and frequency independent electrical loads (given by ΔP_L). In general, such sensitivity of electrical loads is represented by equation 3.10.

$$\Delta P_e = \Delta P_L + D\Delta f_{pu} \qquad \text{eq. 3.10}$$

Hence eq 3.8 can be rearranged as;

$$2H\frac{d\Delta f_{pu}}{dt} + D\Delta f_{pu} = \Delta P_m - \Delta P_L \qquad \text{eq. 3.11}$$

Converting eq. 3.11 into S-Domain by taking Laplace transformation, which yields in usual notation;

$$2H.S.\Delta f(s) + D.\Delta f(s) = \Delta P_m(s) - \Delta P_L(s) \qquad \text{eq. 3.12}$$

Thus, the multi machine collective effects of the turbine outputs can be incorporated into eq. 3.12 which in turns changes as (in usual notation);

$$(2H.S + D)\,\Delta f(s) = \sum_{1}^{n} \Delta P_{m_i} - \Delta P_L \qquad \text{eq. 3.13}$$

Here H is equivalent system inertia constant and D is equivalent load damping constant. Figure 3.2 depicts the collective representation of power system model for load-frequency study.

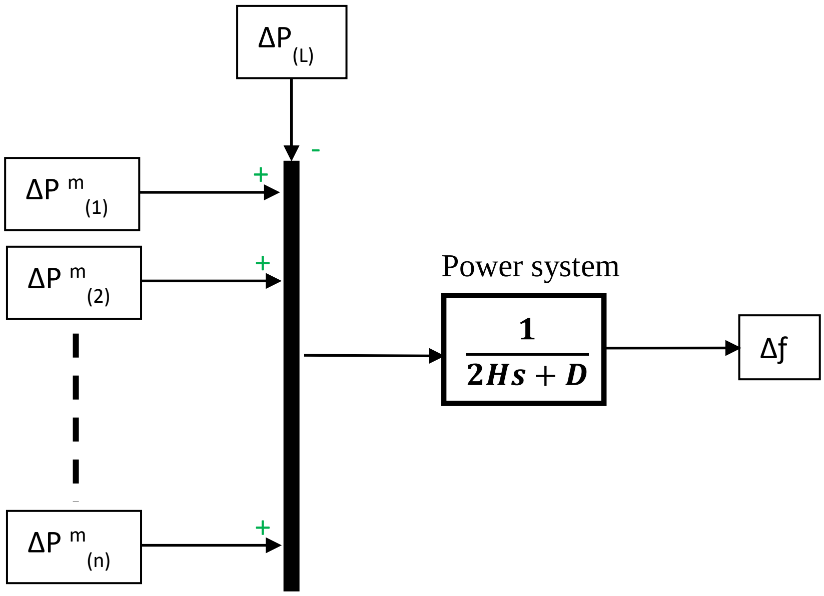


Figure 3.2 Power System Representation.

Where, $\Delta P^{m}_{(n)}$ - Change in mechanical output power on n^{th} generator (in per unit).

3.5 Power system Inertia Constant Estimation

As a part of this research the inertia constant for Sri Lankan power system is estimated based on measured transient responses analysis. The system inertia is utmost important parameter which determines rate of change of system frequency (ROCOF) during disturbances. Based on swing equation for system dynamics theory, the system inertia is defined by basic system attributes as shown in equation 3.4 (a) [5].

Till the date the system inertia constant is calculated based on equation 3.4 (b) which associated only with generator's capability and same had been applied for load flow and other system related dynamic studies in Sri Lanka. But it would be more accurate if power system inertia is estimated from the real time transient's characteristics. The conventional and transient analysis approaches are being detailed in here.

3.5.1 Inertia Constant Estimation – Conventional method

The H is determined by the committed generating units without considering any other inertia supports element in the power system. The equation 3.14 shows the simple equation for this calculation [5];

$$H = \frac{\sum_1^n H_i . MVA_i}{\sum_1^n MVA_i} \qquad \text{eq. 3.14}$$

As can be seen from equation 3.14, it is very straight forward and easy to obtain H value. But, other system related parameters like frequency depended load support up on system inertia is not considered. The accuracy could be differed from actual system response during the dynamic situation analysis. There are two publications particularly referred to understand the work done up on inertia estimation of Sri Lankan system based on this conventional approach given reference No [6] and [7]. On these references, different generation scenarios were considered and the average inertia value obtain based on equation 3.3 was “4 s” and “4.2 s” respectively.

3.5.2 Inertia Constant Estimation – Measured Transient Analysis

In detail analysis, the ROCOF which occurs soon after sudden change of either generation or load is largely determined by the system inertia. Such, behavior is represented through equation 3.15 [5].

$$Inertia\ Constant\ (H) = \frac{\Delta P_{(e)_{pu}}}{2 * \left[\frac{d\left(\Delta f / f_0\right)}{dt}\right]_{at\ t=0}} \qquad \text{eq. 3.15}$$

$\Delta P_{(e)_{pu}}$ - Amount of change in generation or load in pu.

$\frac{d\left(\Delta f / f_0\right)}{dt}$ - Initial rate of change of frequency in pu

In this research, H value estimation was done base on above approach since the frequency records during system disturbance are easily collected and available in high numbers at CEB’s system control center. Further, same approach even eliminates the influence of error data regarding the machine characteristics which interns eases the model validation faster.

3.6 Load-damping constant calculation

the load-damping constant of frequency sensitive loads which are being connected to the system is to be addressed in next. Damping constant is nothing but the percentage of load change for 1% frequency change. If it considered system with n generators with load-damping constant D, the steady state frequency deviation (Δf_{ss}) following to the change in load ΔP_L is given by equation 3.16 as per composite frequency response characteristics of the power system [1].

$$\Delta f_{ss} = \frac{\Delta P_L}{\left(\frac{1}{R_{eq}} + D\right)} \qquad \text{eq. 3.16}$$

Where

$$\frac{1}{R_{eq}} = \frac{1}{R_1} + \frac{1}{R_2} + \cdots \frac{1}{R_n} \qquad \text{eq. 3.17}$$

Evidently, the equivalent droop R_{eq} needed to be calculated from individual droop setting (R_i) of all connected machines. Then, the intentional change in ΔP_L during unchanged demand condition would provide observable change in system frequency so that corresponding Δf_{ss} obtained. As per equation 3.16, parameter D is calculated. Such approach had to be done in multiple time based on different load scenarios in order reveal proper frequency dependency of loads. Though, D value is obtained in above approach, the finding is subjected to fast variation with load scenarios. Hence rather than calculating values, it is decided to assume 'D = 1 %' as per IEEE taskforce committee recommendation for Load-Frequency analysis [3]. Yet, D value is intensively tuned during model validation process. The finding related to damping characteristics which was mentioned on reference No [6] also ensuring the assumption on its close proximity value.

3.7 Turbine - Governors Model.

As discussed paragraph 3.2 and 3.3 it is required develop model of turbine which changes the mechanical output ΔP_m based on the changes on gate movement ΔX_c. Similarly, model of governor which changes the gate or valve position based on the change in frequency Δf or change in speed reference setting ΔP_c needed to developed. There are intensive and numerous researches have been done on molding of turbine-governors system. Because of the wide variety of designs found, the turbine-governor models are not designed to provide a high degree of accuracy with regard to any particular plant. Rather, they represent the principal dynamic effects of the energy source and prime mover, with its associated controls, in power plants [1].

In practice governor or turbine control is much complex architecture then then the mathematical representation used in this study. For example, rate liming control, multi-stage hydroelectric amplification stages, lead-leg compensator and non-linearity in servo mechanisms, dead band association are neglected during this study. Because, interested model is adequate enough to represent the primary effects of frequency regulation which this whole study requires. The 'IEEE task force committee reports for suitable methodology for selection and simplification of turbine-governor models' is closely followed for the selection of hydro, steam and gas turbine governing system in model development. The turbine and governor model are recommended to be studied separately for better understanding.

3.7.1 Hydro Governor model.

For the selection of hydro governor, electro- hydraulic governor model with transient compensation loop represented by IEEE "HYGOV" is considered. The transient effect produced by water inertia is indeed important to be addressed in governor model. A sudden change in gate position would cause water pressure to be dropped up to some extent until water flow and power output to be catchup. This, changes turbine power in an opposite from desired direction. A large transient droop with long resetting time is used on control loop on order to address above phenomenal. This ensures the stable performance as well. The rate feedback control limits the gate movement until the water pressure balances. Figure 3.3 illustrate the effect of transient compensation of governors. The interested governor model is further simplified by removing effect of dead band and gate rate limiting functions.

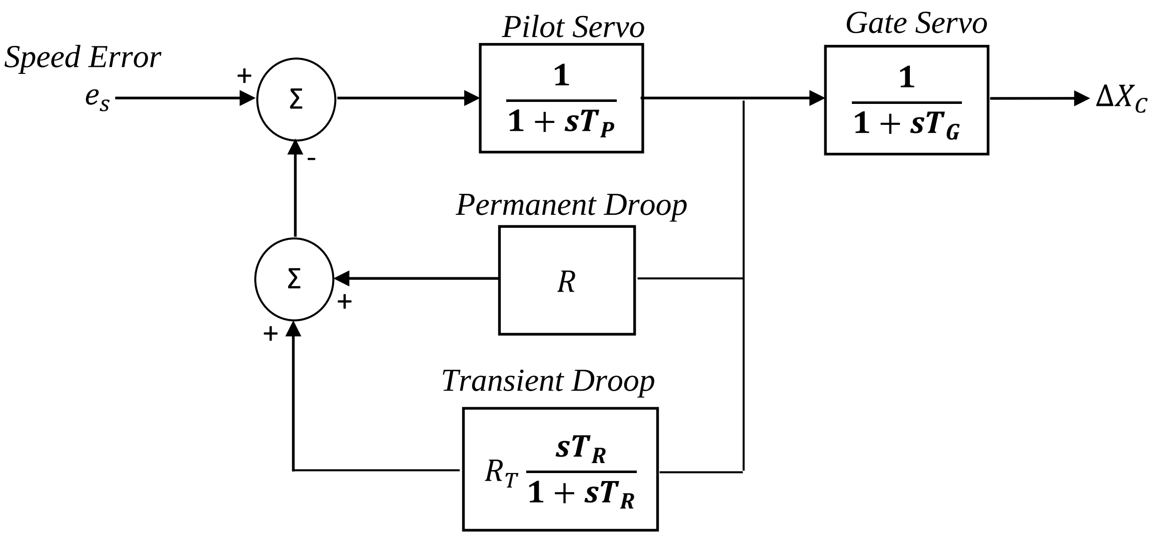


Figure 3.3 Governor Model with Transient Compensators.

T_P – Pilot Valve servo time constant

T_G – Main gate servo time constant

R- Permanent Droop

R_T – Temporary Droop

T_R – Resetting Time

ΔX_C – Gate movement in pu

The error signal e_s for the governor input is obtain by speed reference setting of individual machines and frequency error feedback via droop control as illustrated in figure 3.4.

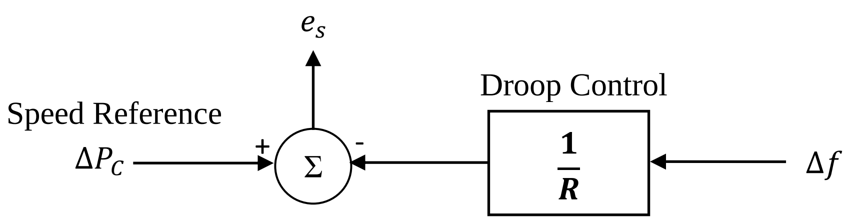


Figure 3.4 Governor input signal flow diagram

Hence, error signal could be given as

$$e_s = \Delta P_C - \frac{1}{R}\Delta f \qquad \text{eq. 3.17}$$

Therefore, the total transfer function of hydro governor is given as;

$$\Delta X_C = \left(\Delta P_C - \frac{1}{R}\Delta f\right)\left(\frac{1}{1+s.T_P}\right)\left(\frac{1+s.T_R}{1+s.\left({R_T}/{R} \right).T_R}\right)\left(\frac{1}{1+s.T_G}\right) \qquad \text{eq. 3.18}$$

3.7.2 Hydro-Turbine Model.

The simplified hydro turbine model represented by water inertia constant or water starting time constant (T_w) is considered. This model provides standards turbine representation by neglecting the complexity of surge chamber and non-linear penstock effects. The dynamic performance of a hydro system depends on the penstock characteristics which are primarily determined by the water starting time constant. Classical transfer function of a hydro turbine is expressed in equation 3.19 which gives the turbine's mechanical power output changes with respect to the changes in gate opening. The T_w express the time requirement for water to accelerate and achieve its maximum speed before hitting turbine blades from standstill water from forebay [1].

$$\Delta P_m = \left(\frac{1-s.T_w}{1+s.(0.5T_w)}\right).\Delta X_C \qquad \text{eq. 3.19}$$

3.7.3 Gas Turbine Model.

In Sri Lanka, the combine cycle plants, consist of gas turbine/s along with single stage heat recovery steam generator turbine. As per the present operation practices gas turbine is set on free governor mode with slow droop setting around 5%. But the steam turbine governor is fixed and only allowed to change the steam valves during sliding pressure conditions on HRSG. However, the steam turbine response is significantly slower than the gas turbine response during system frequency runaway and hence could be even negated from the primary response characteristics analysis.

The selected model for representation of gas turbine for this research is IEEE "GAST" model.

The gas turbine comprises of three stages of responses knows as fuel control in valves, speed control in turbines and output temperature/load control. The typical GAST model is addressed by above three major time constants of individual control loop. Such simplified model completely neglects the complexity involved in heavy duty gas turbines. the equation 3.20 provides the transfer function of the simplified GAST model with respect to change in the fuel control valves ΔX_V.

$$\Delta P_m = \left(\frac{1}{1+s.T_1}\right)\left(\frac{1}{1+sT_2}\right)\left(\frac{1}{1+sT_3}\right).\Delta X_V \qquad \text{eq. } 3.20$$

Where T_1 – Time constant of Fuel Control Valve Response

T_2 – Time constant of turbine control response

T_3 – Time constant of Load Limit response

Though the collective supports from gas turbine could be represented by equation 3.20, the actual scenario is much different. Usually gas turbine output at its turbine maximum level is reluctant to have responses for under frequency stages due to high exhaust temperature issues. Since all large gas turbines are being operated at maximum limits typically as base load or mid banders, the frequency regulation support provided is very minimal during system disturbance. This aspect is given weightage on developed model by giving low participation factor value as feed forward gain for gas turbines [3],[6].

3.7.4 Steam/Gas Governor Model.

The speed-governor mechanism in most steam/gas turbine is an electro-hydraulic system which controls the main gas inlet valve (GIV) or main steam inlet valve (MSIV) position and thereby mechanical power output of the turbines. The target is to change the steam/gas turbine output based on error signal input represented by equation 3.17. The steam/gas turbine governors can be represented in simple terms unlike hydro governors since energy related parameters of steam/gas dynamics is controllable with ancillary systems. The simplified equation governor response is given in equation 3.21 [1],[3].

$$\frac{d\Delta X_C}{dt} = -\frac{\mathbf{1}}{\boldsymbol{T_G}}\Delta X_c + \frac{\boldsymbol{G_G}}{\boldsymbol{T_G}} e_t \qquad \text{eq. 3.21}$$

Typical value for governor gain $\boldsymbol{G_G}$ **=** 1 and taking Laplace transform on both sides yields,

$$\Delta X_C(s) = \left(\frac{\mathbf{1}}{\mathbf{1} + \boldsymbol{s}.\boldsymbol{T_G}}\right) e_s \qquad \text{eq. 3.22}$$

3.7.5 Steam Turbine Model.

The required steam turbine is classified as singe stage re-heater type tandem compound turbine [1]. As per the discussion in paragraph 3.2 the steam turbines which are to be addressed in primary regulation model falls in above category only. The IEEE recommended model for steam turbine model “TGOV1” is shown in equation 3.23. For the sake of simplified analysis its assumed that the control valve characteristic is linear.

$$\Delta P_m = \left[\frac{1 + s.F_{HP}T_{RH}}{(1 + s.T_{CH})(1 + s.T_{RH})}\right].\Delta X_C \qquad \text{eq. 3.23}$$

If plant is not associated with reheating mechanism then T_{RH} must set to $T_{RH} = 0$. Thereby, equation 3.24 shrinks as;

$$\Delta P_m = \left(\frac{1}{(1 + s.T_{CH})}\right).\Delta X_C \qquad \text{eq. 3.24}$$

Where T_G - Valve/Governor time constant

F_{HP} – Fraction of HP turbine contribution over total power.

T_{RH} - Re-Heater Time Constant

T_{CH} - Steam-Chest and MSIV Time Constant

The steam turbine connected to Sri Lankan network are mostly set on fixed governor control (e.g. LVPS units). Therefor the primary system model development is mostly not being considered with the relative support given by steam turbines alone.

3.8 Equivalent Speed-Droop Model.

The droop must be represented in pu value as entire power system model is expressed in pu quantities. When power system is characterized as standalone single model the regulation support via droop control also could be represented in pu quantities by using total generation as base value.

$$\mathrm{R}_{ef} = R_i \frac{\mathrm{P}_G}{P_t} \qquad \text{eq. } 3.25$$

R_{ef} - Droop setting in per unit in ith machine in system MW rating

R_i - Droop setting in per unit in ith machine in turbine rating

P_G - Total system generation in MW

P_t - MW rating for the turbine

The ΔP_m change over primary regulation due to Δf error is given in pu quantities by equation 3.26.

$$\sum_{1}^{n} \Delta P_m = \frac{1}{\mathrm{P}_G} \left(\sum_{1}^{n} \frac{P_{t_i}}{R_i} \right) \qquad \text{eq. } 3.26$$

The mechanical power changes are regulated by the machines operated on free governor mode. As of equation 3.26, there is no any real benefit of associating machine models where machine governors are fixed. Best example would be LVPS steam turbines. Eventually, power system architecture for primary regulation as described in chapter 1 is entirely described by equation 3.26.

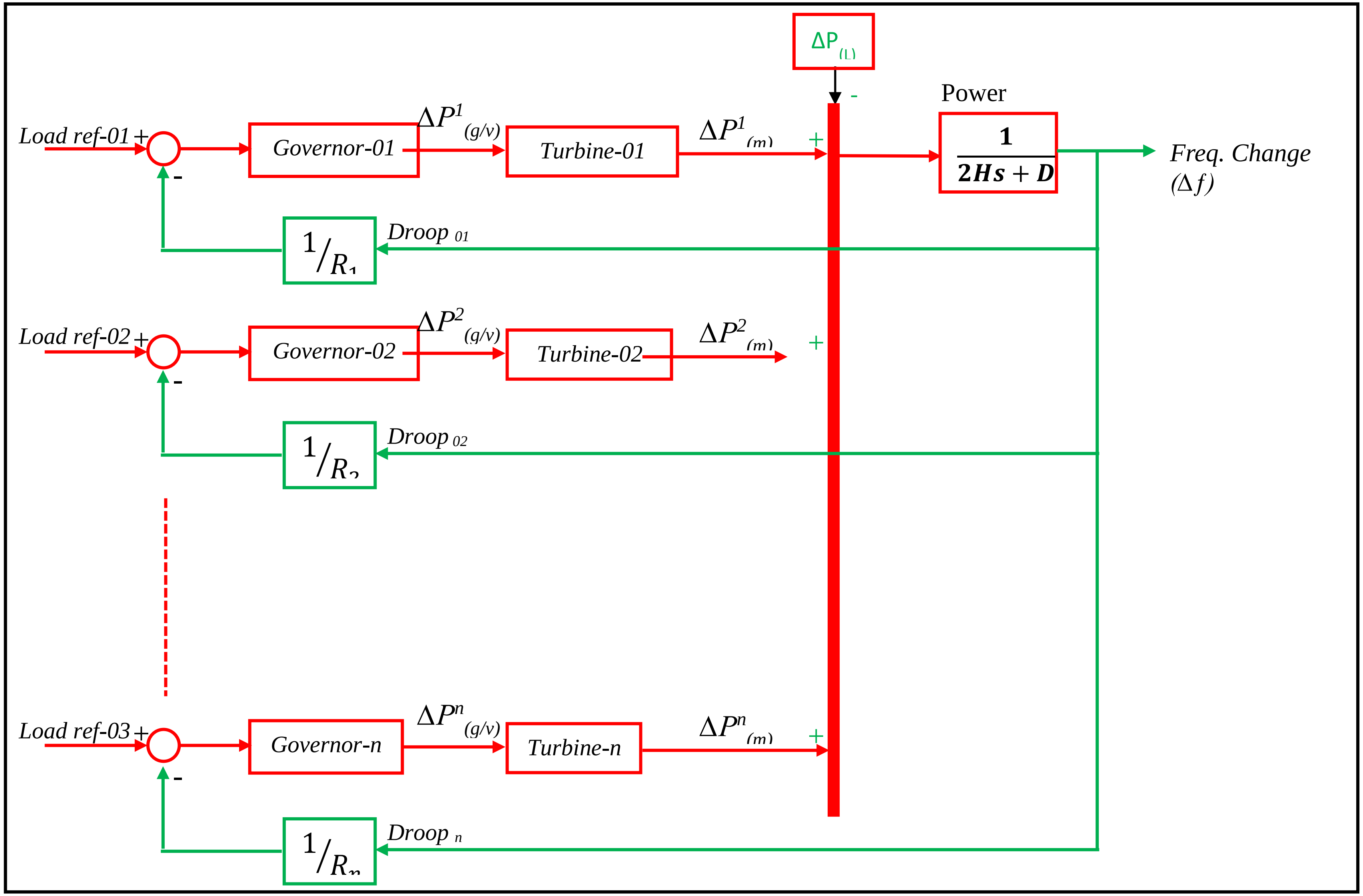


Figure 3.5: Power System Model for Primary Regulation

3.9 Power System Model for Primary Regulation Model.

As per literature discussion above, all put together and complete power system is represented by Figure 3.5.

3.10 Simulation Environment Selection.

The MATLAB Simulink is selected for development of above driven model. The system related dynamic studies are done PSS/E which in turns double confirms the develop hydro turbine models and associated dynamic parameters. Major reasons for selection of MATLAB Simulink are, easy integration of external disturbance signals while simulation can be done much faster for even hours of input variation.

CHAPTER 04

ESTIMATION OF SYSTEM PARAMETER

4.1 Concerned Parameters

The composite power system model represented in Figure 3.5 is developed in MATLAB Simulink environment. As per the Figure 3.5 the H, D, R and turbine-governor dynamic parameters are to be known to develop valid model for Sri Lankan power system.

4.2 Estimation of inertia constant.

In this research, H value estimation work is confined with the data from generation rejection only. Because, data availability for generation rejection are high and the load rejection data could not be classified as purely as load rejection due to mix of embedded generation. Frequency record during disturbances are collected from the frequency recorder which is being installed at system control center. In addition to that, some more records are collected from digital fault recorder (DFR) 'BEN 6000' mainly from Kelanitissa GSS.

Figure 4.1 shows the collected frequency response of the system during disturbance of 80MW generation rejection. The most linear variation of frequency soon after the disturbance is identified based on the excel based data analysis model. Figure 4.2 depicts the excel based analysis model which has been used to drive the estimation values of system inertia. Whole idea of this model is to identify proper and maximum ROCOF just after system disturbance so as estimating system inertia by using equation 3.15. From the recording maximum and linear part of ROCOOF is selected and initial rate of change of frequency in pu value is calculated using 50 Hz as nominal frequency. Likewise, $\Delta P_{(e)_{pu}}$ is calculated using rejected generation by applying base value which is total active power demand of power system at time of disturbance. Please refer the outlined area in red on Figure 4.2 to grab more idea of selecting linear region of ROCOF. Finally, about 3 seconds average of estimated inertia is used as system inertia during particular disturbance. This method is referred as inertia estimation using measured transient analysis which is detailed in section 3.5.2.

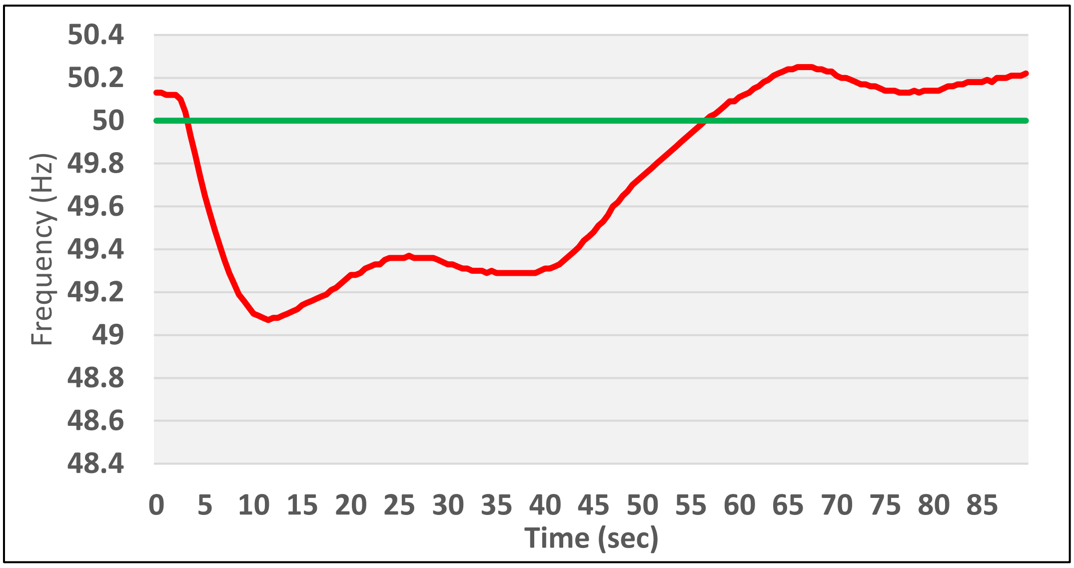


Figure 4.1: System Frequency Variation during 80 MW rejection caused by tripping of GT07 (Date :11/12/2016 Time:13:17)

Date	Time (hh:mm)	Time (sec)	Frequency	Δt (sec)	Δf (hz)	$\Delta f/f_o$	$(\Delta f/f_0)$ / Δt	Equation 2.4	Δp = 80 Demand =	1375
20161211	13:17	29.003	50.13							
20161211	13:17	29.502	50.13	0.5	0	0	0	#DIV/0!		
20161211	13:17	30.001	50.12	0.499	-0.01	-0.0002	-0.000401	-72.58181818		
20161211	13:17	30.501	50.12	0.5	0	0	0	#DIV/0!		
20161211	13:17	30.984	50.12	0.483	0	0	0	#DIV/0!		
20161211	13:17	31.483	50.1	0.499	-0.02	-0.0004	-0.000802	-36.29090909		
20161211	13:17	31.998	50.04	0.515	-0.06	-0.0012	-0.00233	-12.48484848		
20161211	13:17	32.497	49.93	0.499	-0.11	-0.0022	-0.004409	-6.598347107		
20161211	13:17	32.997	49.84	0.5	-0.09	-0.0018	-0.0036	-8.080808081		
20161211	13:17	33.496	49.74	0.499	-0.1	-0.002	-0.004008	-7.258181818		
20161211	13:17	33.995	49.65	0.499	-0.09	-0.0018	-0.003607	-8.064646465		
20161211	13:17	34.510	49.57	0.515	-0.08	-0.0016	-0.003107	-9.363636364	Average Inertia =	-9.415
20161211	13:17	35.010	49.49	0.5	-0.08	-0.0016	-0.0032	-9.090909091		
20161211	13:17	35.509	49.42	0.499	-0.07	-0.0014	-0.002806	-10.36883117		
20161211	13:17	36.026	49.35	0.517	-0.07	-0.0014	-0.002708	-10.74285714		
20161211	13:17	36.525	49.29	0.499	-0.06	-0.0012	-0.002405	-12.0969697		
20161211	13:17	37.040	49.24	0.515	-0.05	-0.001	-0.001942	-14.98181818		
20161211	13:17	37.539	49.19	0.499	-0.05	-0.001	-0.002004	-14.51636364		
20161211	13:17	38.055	49.16	0.516	-0.03	-0.0006	-0.001163	-25.01818182		
20161211	13:17	38.554	49.13	0.499	-0.03	-0.0006	-0.001202	-24.19393939		
20161211	13:17	39.069	49.1	0.515	-0.03	-0.0006	-0.001165	-24.96969697		
20161211	13:17	39.584	49.09	0.515	-0.01	-0.0002	-0.000388	-74.90909091		
20161211	13:17	40.083	49.08	0.499	-0.01	-0.0002	-0.000401	-72.58181818		

Figure 4.2: Measured Transient Analysis Model to Determine System Inertia

There are 25 number of such system disturbances as shown in figure 4.2 collected and analysed. Also, it is ensured that to collect the data on different generation-load scenario in order to diversify the inertia variation with system demand characteristics. Table 4.1 briefs the summary of detailed analysis and estimated inertia values based on above given approach.

Table 4.1: Collected Disturbance Record and Inertia Estimation Summary

	Date	**Time**	**ΔP (MW)**	**Demand (MW)**	**Session**	**Inertia (s)**
1	20.06.2016	06:23	90	1840	D	8.05
2	28.05.2016	13:11	40	1480	D	6.56
3	26.05.2016	15:19	38	1650	D	8.43
4	26.05.2016	02:06	38	1010	O/P	5.43
5	25.05.2016	21:24	38	1790	N	6.76
6	01.10.2016	18:22	46	2110	N	7.41
7	16.07.2016	19:10	70	2150	N	6.67
8	17.10.2016	17:33	58	1930	D	7.55
9	18.10.2016	08:02	37	1520	D	8.30
10	19.10.2016	06:39	55	1630	D	8.46
11	25.11.2016	16:33	58	1809	D	8.32
12	14.11.2016	15:36	50	1263	D	6.99
13	28.11.2016	18:20	55	2320	N/P	7.57
14	11.12.2016	13:17	80	1425	D	9.08
15	27.12.2016	19:32	100	2201	N/P	6.02
16	18.01.2017	21:45	40	1640	D	7.18
17	24.01.2017	16:47	52	1770	D	7.67
18	18.05.2017	14:34	110	1410	D	9.59
20	27.06.2017	03:20	54	1050	O/P	4.98
21	26.07.2017	05:30	115	1920	D	7.47
22	31.08.2017	08:35	62	1840	D	7.05
23	27.09.2017	01:15	40	974	O/P	4.38
24	15.11.2017	03:16	25	1080	O/P	4.61
25	19.11.2017	03:21	37	920	O/P	4.91

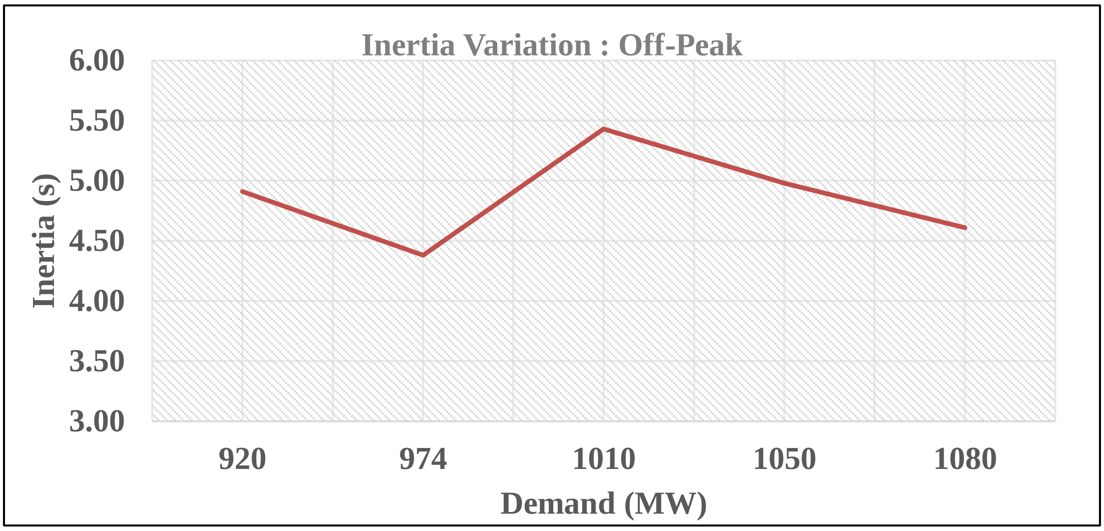
D: Day Time (07:00 hrs to 17:00 hrs),

N/P: Night Peak (17:00 hrs to 21:00 hrs)

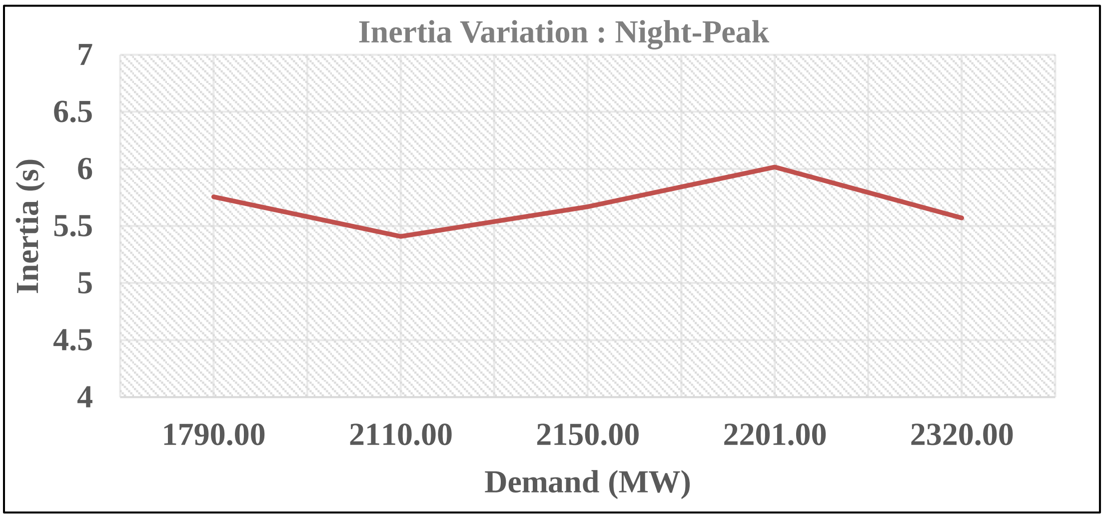
O/P: Off Peak (21:00 hrs to next day 07:00 hrs)

As can be seen from table 4.1, inertia variation with respect to different demand condition is significant characteristic to be analysed. Yet, it must be decided between, whether to use single average value and develop single system model or to use different values to address different demand scenario of power system. The second option would much desirable, since optimum power flow (OPF) analysis of Sri Lankan network is being done for three different demand scenarios known as off-peak, day-time & night-peak.

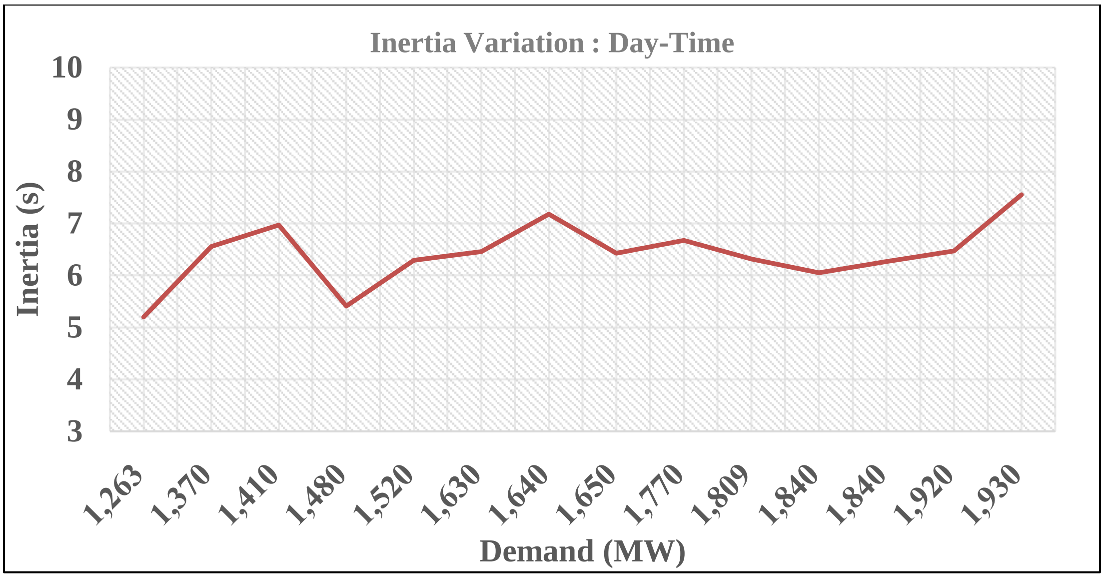
The variation of estimated inertia constant on different demand scenario is represented with Figure 4.3 (a),(b),(c).



(a)



(b)



(c)

Figure 4.3: Variation of estimated inertia constant with off-peak, Night-peak and day-time demand scenario.

The average value of system inertia is taken from above trend analysis. Table 4.2 shows the average values of estimated inertia constant which is calculated by using actual transient responses for different demand scenario.

Table 4.2: Summary of Estimated System Inertia

Scenario	**Inertia Average (s)**
Day Time	6.38
Night Peak	5.68
Off Peak	4.86

These finding are used as starting values for developed power system model and tuned further during the validation of model.

4.3 Load-damping constant calculation

The effect of damping constant over system frequency during dynamic condition is depicted in Figure 4.4. If load damping is higher then, the frequency run-away will be limited and the frequency recovery will be also faster. Behavior of such performance of the system with different damping constant is studied through the validated system as well in this research. Table 4.3 summarizes the final finding which developed through the validation process of model with respect to damping constant variation associated with different demand scenarios. Please refer the section 3.6 for the initial estimation methodology of damping constant.

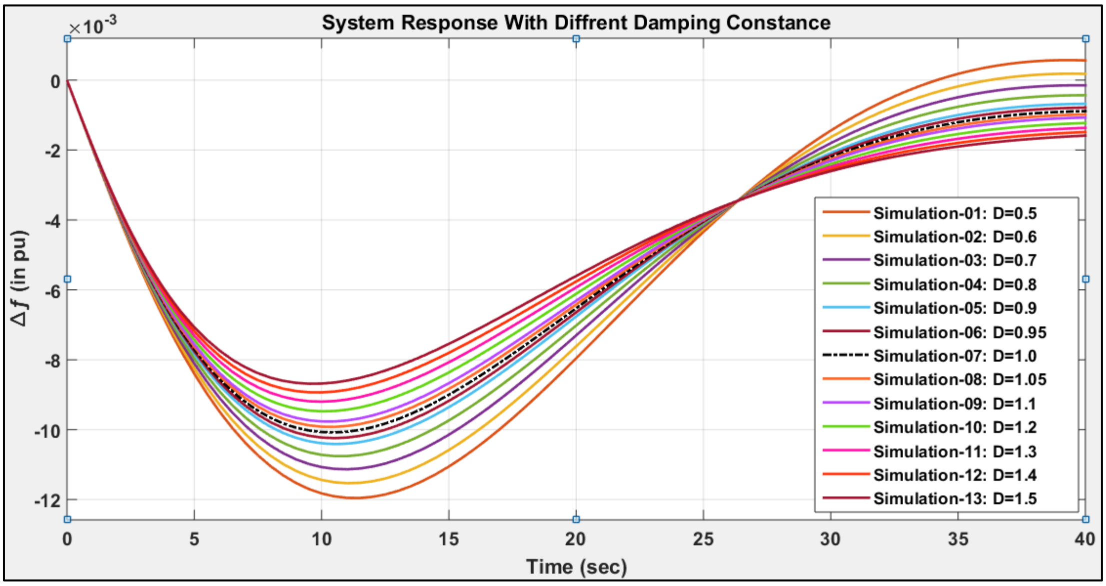


Figure 4.4: Impact of different damping constant over system frequency response.

Table 4.3: Final best match damping constant value for different load-scenarios.

Damping Constant (best matched values)	
Day Time	0.98
Night-Peak	0.72
Off-Peak	0.59

4.4 Turbine-Governor Model : Hydro System

The dynamic parameters those are being used for system power flow study in PSS/E environment is initially taken. Later on, Victoria, N'Laxapana and Samanalawewa hydro machine's parameters were updated as per the recommendations given by the Manitoba HVDC Research Centre. Table 4.4 summarizes the hydro machine parameters for molding.

Table 4.4: Hydro Machine Dynamic Parameters

Notation	Kothmale-01	Kothmale-02	Kothmale-03	Victoria-01	Victoria-02	Victoria-03	Laxapana-01	Laxapana-02	S'Wewa-01	S'Wewa-02
R	0.018	0.018	0.018	0.02	0.02	0.02	0.043	0.043	0.05	0.05
r	0.3	0.3	0.3	0.3	0.3	0.3	0.28	0.28	0.35	0.35
T_r	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
T_f	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
T_g	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
VELM	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
GMAX	0.95	0.95	0.95	0.85	0.85	0.85	0.95	0.95	1	1
GMIN	0	0	0	0	0	0	0	0	0	0
T_W	1.3	1.3	1.3	1.05	1.05	1.05	2	2	1.8	1.8
A_t	1.1	1.1	1.1	1	1	1	1.1	1.1	1.1	1.1
D_{turb}	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Q_{NL}	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08

Where;

Notation	**Description**
R	Permanent droop (p.u. on generator (megavolt ampere [MVA] rating)
r	Transient droop (p.u. on generator MVA rating)
Tr	Governor time constant (s)
Tf	Filter time constant (s)
Tg	Gate Servo time constant (s)
VELM	Gate velocity limit (p.u./s)
GMAX	Maximum gate limit (p.u.)
GMIN	Minimum gate limit (p.u.)
T_W	Water time constant (s)
A_t	Turbine gain (p.u.)
Dturb	Turbine mechanical damping (p.u. on generator MVA rating)
QNL	No-load water flow rate that accounts for the fixed losses in the turbine (p.u. of base water flow)

Developed hydro turbine models are represented in Figure 4.5 as developed in Simulink.

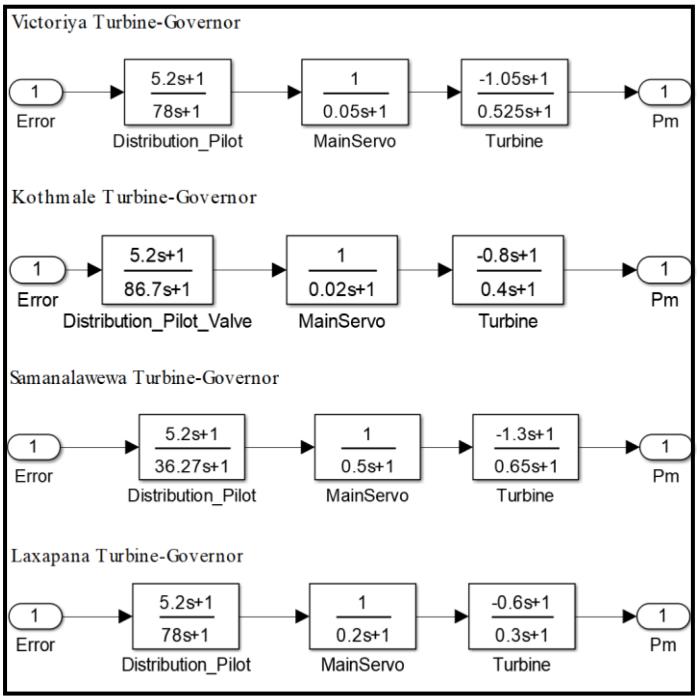


Figure 4.5: Hydro Turbine-Governor Model Representation in Simulink

4.5 Turbine-Governor Model: Steam System

Same as section 4.2, the dynamic parameters those are being used for steam turbines on system power flow study in PSS/E environment is taken. Table 4.5 summarizes the steam turbine parameters for molding.

Table 4.5: Steam Turbine Model Parameters.

Parameter	Description	WCP ST	KCCP ST	SOJITZ ST
R	Turbine-governor droop (R),	0.05	0.05	0.05
T_1 (>0)	Main steam control valve Time Constant (sec)	0.5	0.1	0.1
VMAX	Main steam control valve moment max limit	0.95	0.95	0.95
VMIN	Main steam control valve moment min limit	0.05	0	0
T_2	T2/T3 = high-pressure fraction of the turbine power that is developed by the HP turbine stage (sec)	2.666	1.8	1.8
T3 (>0)	Reheater time constant (sec)	8	6	6
D_t	Turbine mechanical damping (pu)	0	0	0

4.6 Turbine-Governor Model: Gas Turbine System

Same as section 4.2, the dynamic parameters those are being used for gas turbines also taken from existing tool PSS/E. Table 4.6 summarizes the gas turbine parameters for molding.

Table 4.6: Gas Turbine Model Parameters.

Parameter	Description	KCCP GT	Sojitz GT	WCP GT-01	WCP GT-02	GT 07
R	Speed Droop	0.05	0.05	0.05	0.05	1
T_1 (>0)	Time constant of Fuel Control Valve Response	0.4	0.4	0.4	0.4	0.05
T2 (> 0)	Time constant of turbine control response	0.1	0.1	0.1	0.1	0.4
T3 (>0)	Time constant of Load Limit response	3	3	3	3	0.1

CHAPTER 05

PRIMARY REGULATION MODEL AND VALIDATION

5.1 Power system Model for Primary Regulation

The variation range of estimated inertia is significantly spans from 4.30 to 9.10 as per data given Table 3.1. Therefore, using an average single value to represent whole generation scenario is not justifiable. The inertia constant variation is studied with three different generation scenarios known as off-peak, day-time and night-peak as depicted in Figure 3.3. The load damping constant was assumed as 1% at an initial stage and later properly tuned with validated models.

Once H and D value is calculated and R values are extracted and individual power system models for three generation scenarios are developed based on the primary regulation model represented in Figure 3.5. The Figure 5.1 exhibits the architecture of untuned power system model which is developed in MATLAB Simulink for primary regulation of power system. Here it's important to note that, each power plant speed reference change is set to zero (ΔP_C = 0). Which in turn yields that, there are no any external input is given to governor to change mechanical power (ΔP_m). The change in consumed electrical power (ΔP_L) is represented as the disturbance which exhibits the MW power change in per unit quantities. The frequency error (Δf) is negatively fed back to the governor input through speed-droop logic. Hence the presented model will be corrected the frequency error only by droop control actions which is referred as primary regulation control. In actual scenario, during a disturbance system does not response such way that, what had been explained in ideal free-governor control theory because of many unaddressed non-linear characteristics associated with system components [4]. Thus, the regulation factor (RF) is to be introduced to control and closely follow the machine responses as of actual conditions. Proper RF value is tuned during validation process of interested model. The gate limitation and noise filtering effects of the individual machines are omitted for a moment to analyze only the primary regulation characteristics over load-frequency control behavior.

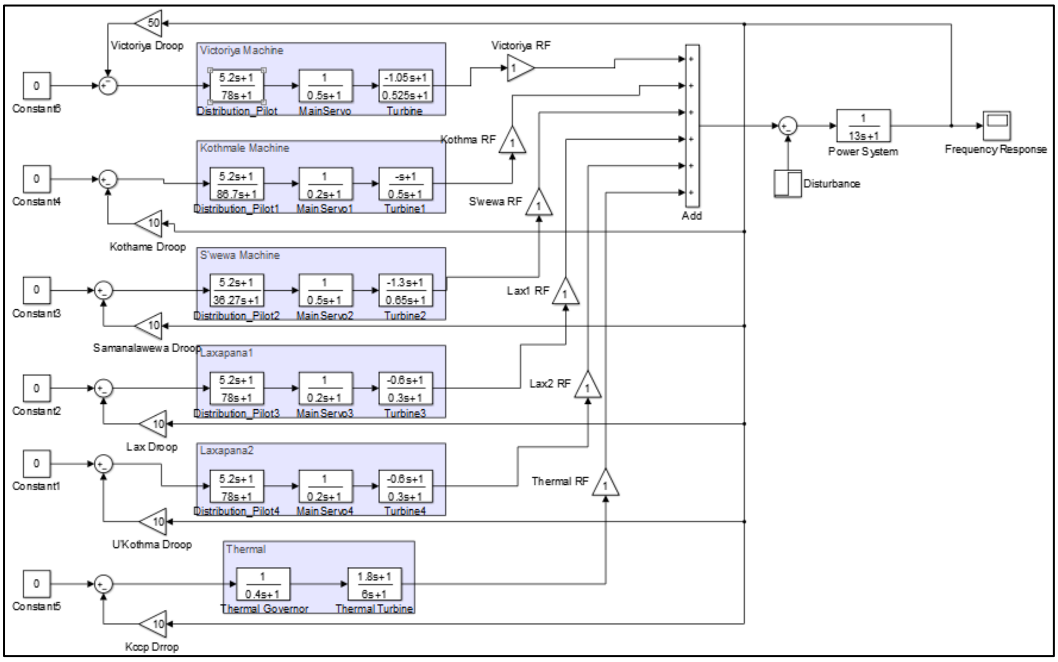


Figure 5.1: Power Model for Primary Regulation

Moreover, actual generation scenarios are taken into model development so as to make model validation precise and accurate.

5.2 Model Tuning Approach.

Once separate models were identified for three different generation scenarios, model must be tuned for proper validation. The tuning approaches used are shown below.

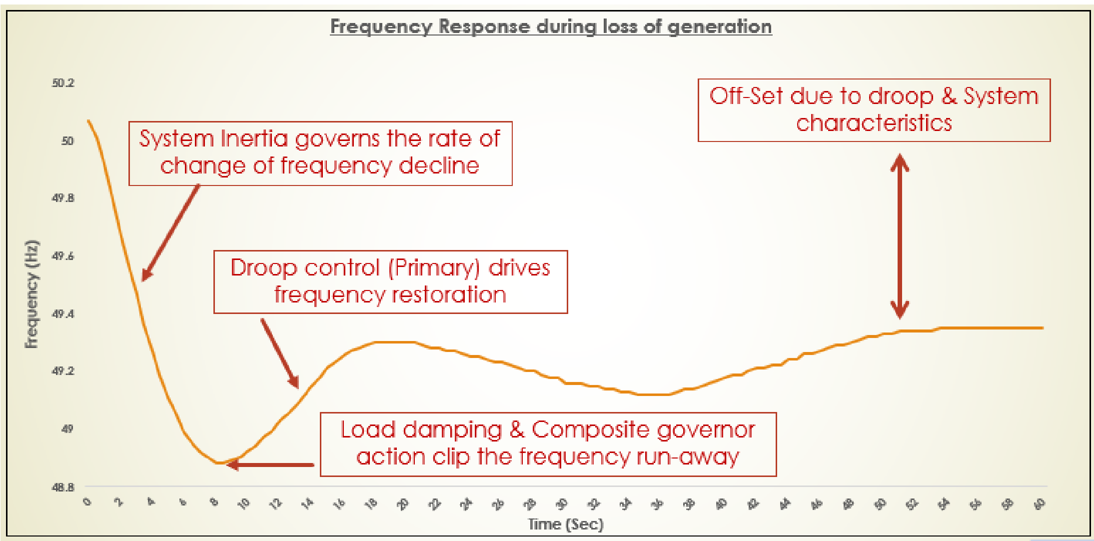


Figure 5.2: Model Tuning Approach

Then, developed model is tuned as per the approaches given if in Figure 5.2. Tuning had to done up until the model follows the actual system response which was completely control by system primary regulation characteristics. In general, the time taken for primary regulation support during a disturbance is lying on somewhere 15sec to 25sec for Sri Lankan system. Hence, it's sufficient enough if model response follows the actual system response for about 20 to 25 sec of frequency variation from beginning of disturbance. Beyond this period, system condition is very likely to be controlled by manual interaction by plant operators based on the dispatch instruction given by system operator. Tuning the model in such a way as explained above would enable proper model which closely following actual primary regulation response of Sri Lankan power system.

5.3 Primary Regulation Model : Off-Peak

To be in line with the off-peak characteristics of system, actual scenario for rejection of 54 MW at 03:20 hrs is selected. This disturbance is caused by tripping of dedicated wind transformer connected to Lakvijaya Power station's GSS. Figure 5.3 is the recorded frequency response of the system following to the disturbance.

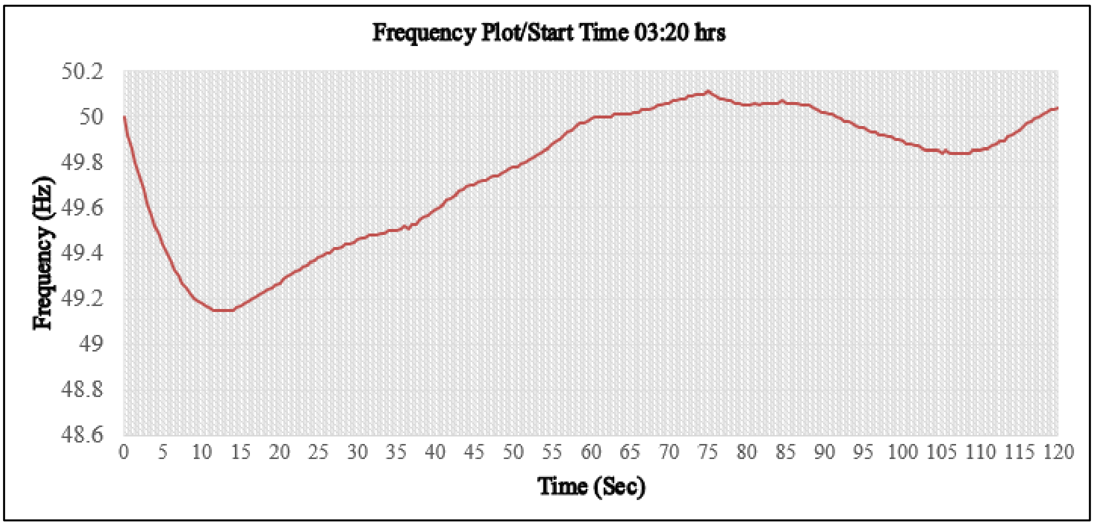


Figure 5.3: Frequency response of system at Off-Peak (54 MW/03:20 hrs)

The frequency control was taken care by single Victoria machine and both New Laxapana machines were kept at 10MW, just before the disturbance. Hence primary regulation model developed accordingly with other calculated parameters. Figure 5.4 shows developed primary regulation model for off-peak scenario. Reader must note that the regulation support provided by other connected hydro thermal system is not separately modeled in here. But the regulation support given by entire system is influenced by means of other related system parameters such as RF, H and D during model tuning process during validation.

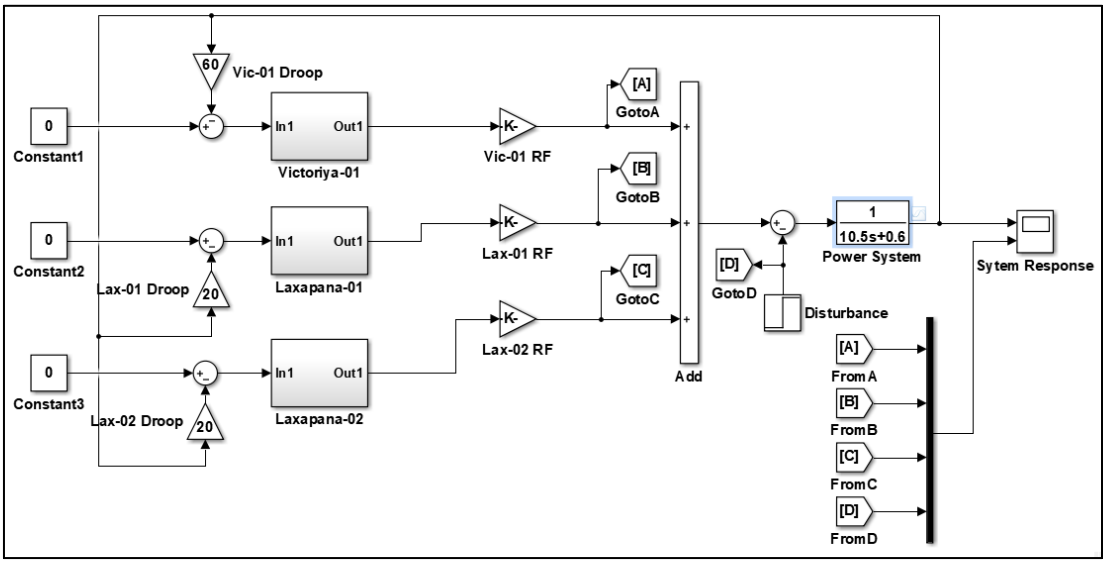


Figure 5.4: Simulink Model for Off-Peak scenario.

The model simulation is tuned and compared with actual frequency response on same time scale. If model response and actual response having significant mismatch then model is re-tuned till both the response relatively follow each other. Figure 5.4 shows the well-tuned model for off-peak scenario and Figure 5.5 shows the comparison of model response with actual frequency variation. Therefore, develop off-peak model can be used to address the behavior of primary regulation support adequately during ALFC model development.

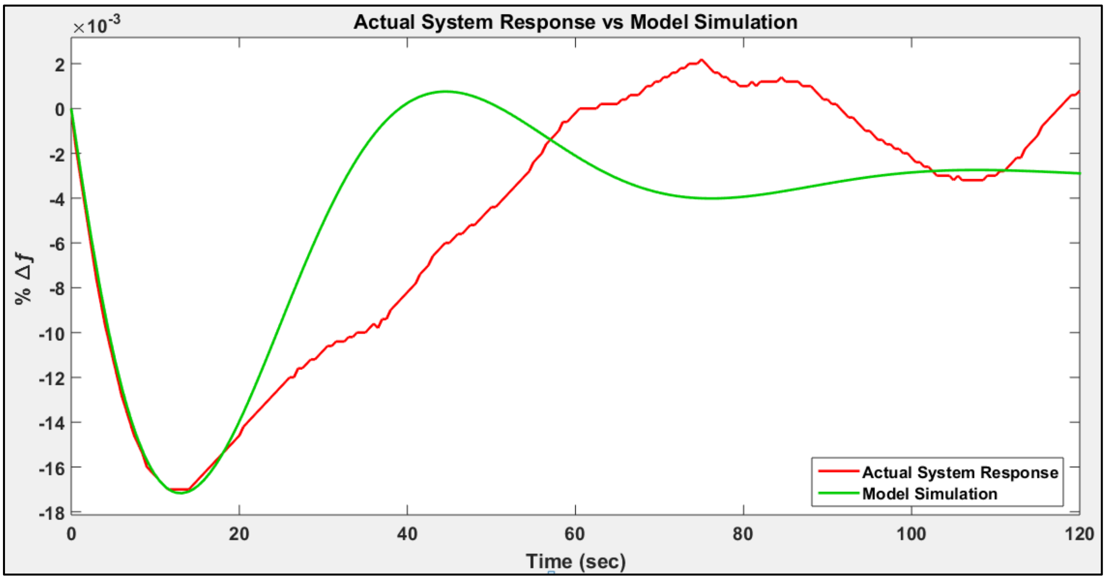


Figure 5.5: Off-Peak Model Response vs Actual system Response

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5.4 Primary Regulation Model : Day-Time

Similarly, for day-time scenario of system, actual case is selected as rejection of 80 MW done due to tripping of KPS GT7 at 11:31 hrs. The approaches associated with tuning and validations are similar as explained in above section 5.4. Likewise, Figure 5.6 shows tuned model while Figure 5.7 shows model simulation results with actual system response. Therefore, develop day-time model can be used to address the behavior of primary regulation support adequately during ALFC model development.

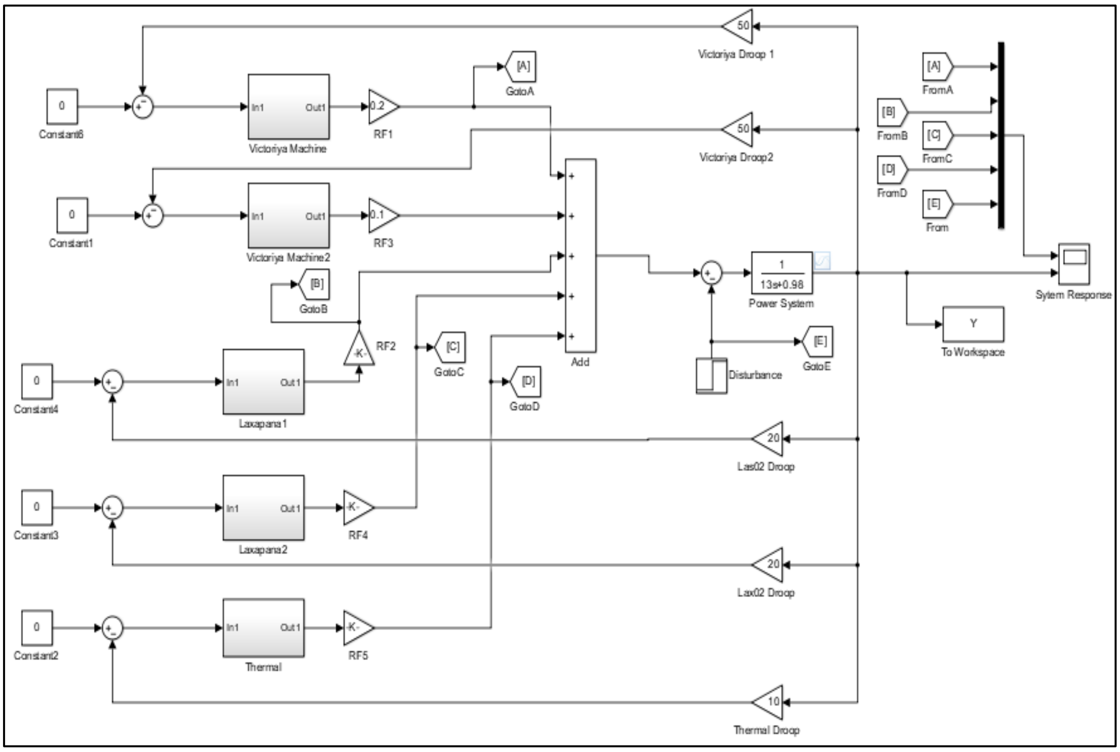


Figure 5.6: Simulink Model for Day-Time scenario.

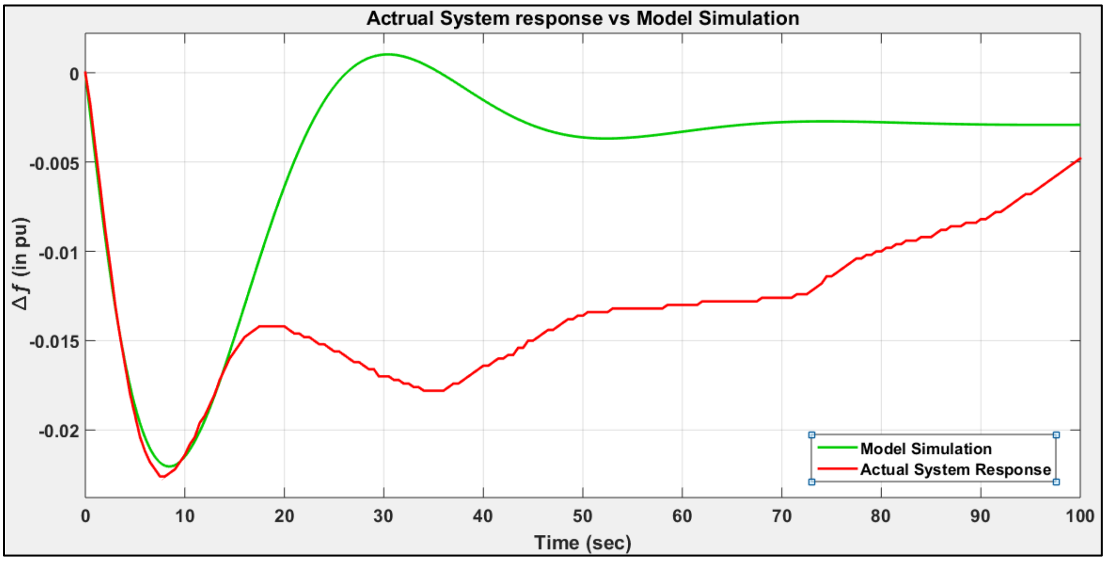


Figure 5.7: Day-Time Model Response vs Actual system Response

5.5 Primary Regulation Model : Night-Peak

Likewise, for Night-peak scenario of system, actual case is selected as rejection of 55 MW done due to tripping of KCCP ST at 18:20 hrs. The approaches associated with tuning and validations are similar as explained in above section 5.4. The Figure 5.8 shows tuned model while Figure 5.9 shows model simulation results with actual system response. Therefore, develop night-peak model can be used to address the behavior of primary regulation support adequately during ALFC model development.

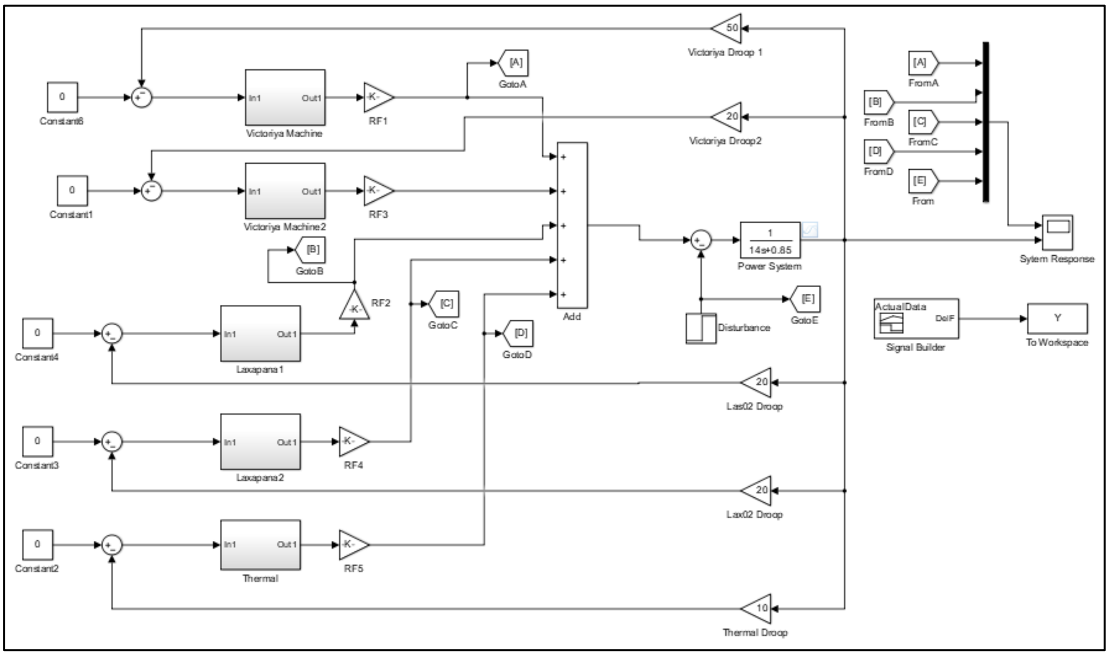


Figure 5.8: Simulink Model for Night-Peak scenario.

As per figure 5.9, night-peak model provides slow recovery on primary frequency regulation. This is due to system condition as at 18:20 hrs as system is already on its increasing generation curve towards night-peak.

With all above results, three different validated models are driven and used for ALFC model development.

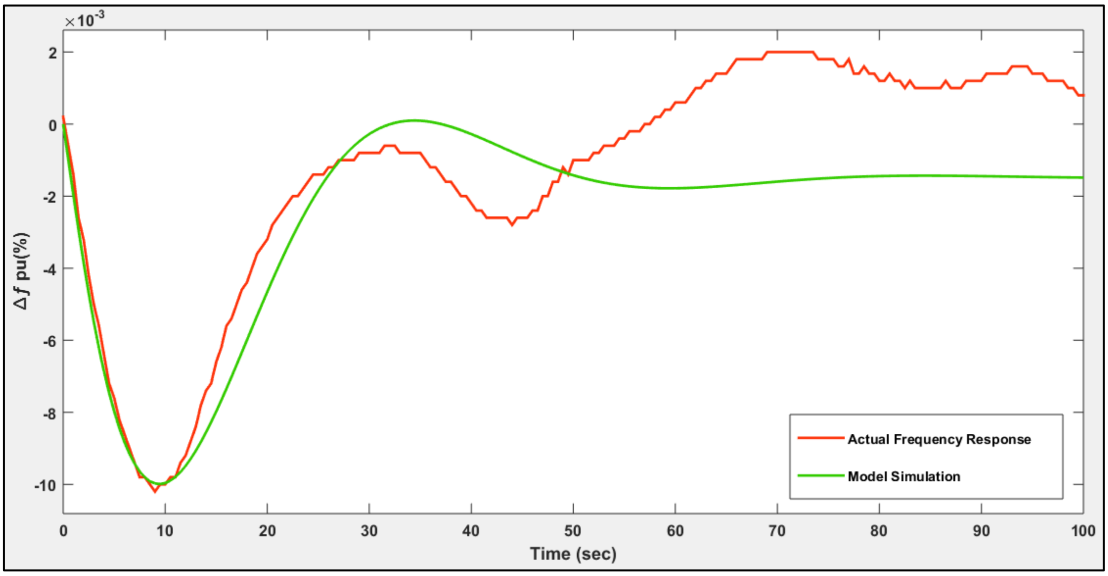


Figure 5.9: Night-Peak Model Response vs Actual system Response

CHAPTER 06

ALFC MODEL DEVELOPMENT

6.1 Automatic Load-Frequency Control (ALFC)

In desired output of individual power plant which committed for ALFC is achieved through supplementary control loop as shown in Figure 6.1. The ultimate target of ALFC scheme is to reduce the steady state frequency error while make frequency recovery faster.

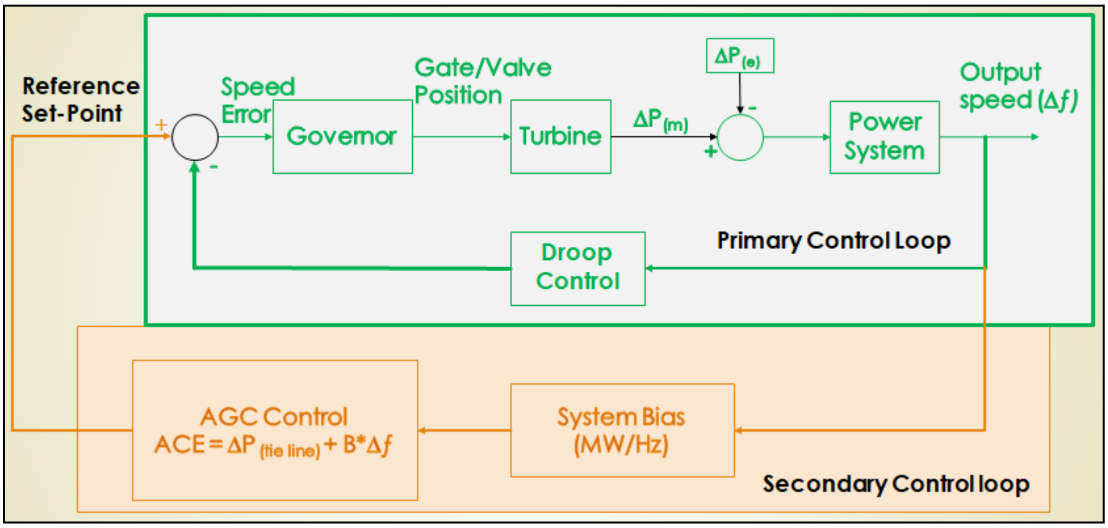


Figure 6.1: Primary and Secondary Regulation Control Architecture

As per Figure 1.4 and Figure 6.1, ALFC decision is based on area control value(ACE) which in turns represented by tie line power control and own area frequency error.

$$ACE = \Delta P_{\text{tie line}} + B * \Delta f \qquad \text{eq. 6.1}$$

Where system frequency bias (B) is given as;

$$B = \frac{\Delta P_{e_{\text{in pu}}}}{\Delta f_{ss_{pu}}} \qquad \text{eq. 6.2}$$

ACE = Area Control error value for particular area in pu MW

B - Frequency bias value for an area which expressed in MW/0.1Hz

$\Delta P_{\text{tie line}}$ - Net power interchange change with neighbor area in pu MW

ΔP_L - Electrical Power change in per unit

Δf_{ss} - Frequency change up to quasi-steady state in per unit

Sri Lankan system is islanded network and hence the tie line representation on ACE equation could set to zero. Then, equation 6.1 shrinks to;

$$\text{ACE} = \text{B} * \Delta f \qquad \text{eq. } 6.3$$

6.2 Benefit of Secondary control

To understand the benefit of automated secondary control, consider a simple turbine-governor models with typical parameters as shown in Figure 6.2 [8].

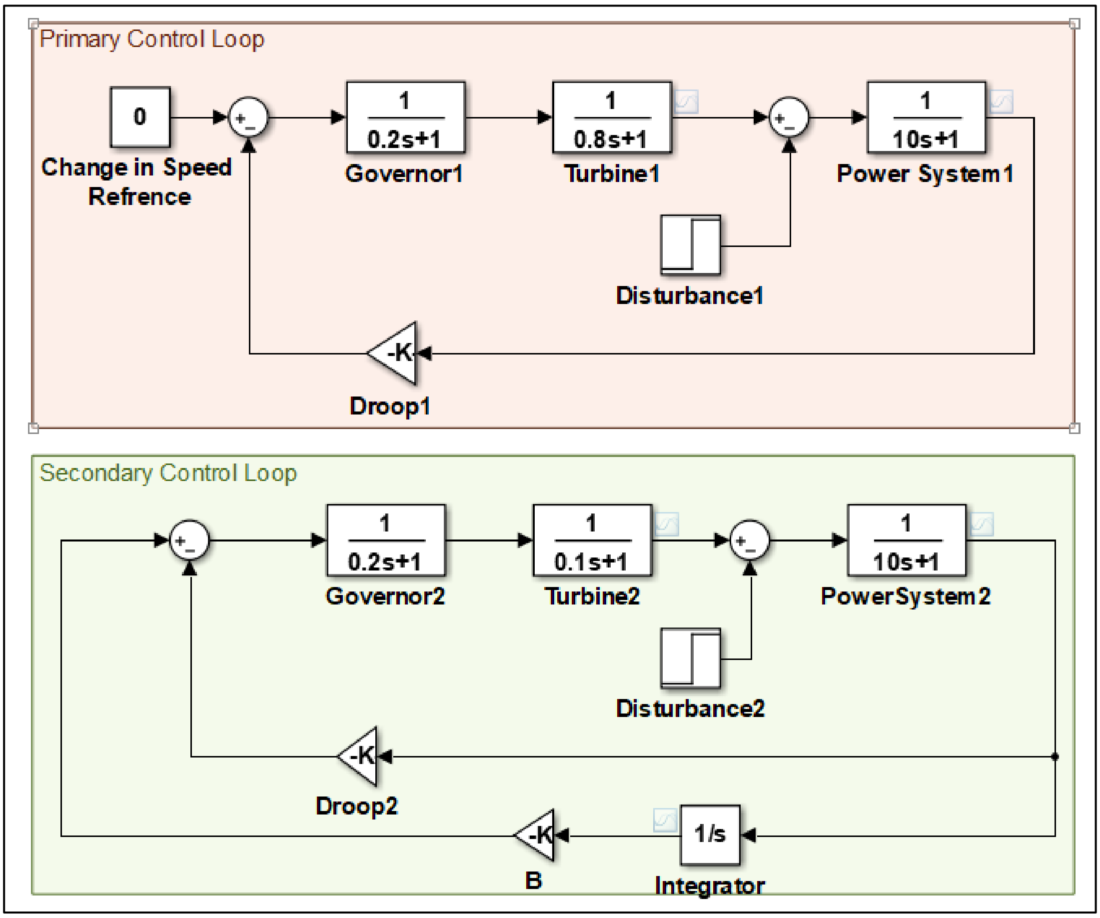


Figure 6.2: Single machine model with primary and secondary regulation controls

The primary loop achieves the primary goal of real power balance by adjusting the turbine output ΔP_m to match the change in load demand ΔP_L. But a change in load results in a steady state frequency deviation represented by Δf. The recovery of the deviated frequency back to the nominal value is done by additional control loop shown in Figure 6.2. This objective is met by using an integral controller which makes the frequency deviation zero. The system with the supplementary loop is generally called the ALFC. The main purpose of ALFC is to make $\Delta f = 0$ or bring Δf back to regulation interval. Thus, the speed changer setting (or ΔP_c) is changed corresponding to $\Delta f(s)$ value through an integrator which accumulates the frequency error with time. The purpose of integral action on this feedback loop is to identify the time-error of the Δf value. So, the integral action results in automatic adjustment of ΔP_c so as to make Δf =0 or bring Δf back to regulation interval. Above explanation is ensured and elaborated through Simulink model. Typical values for individual components are assumed and 1% generation change is triggered at t=0 as disturbance, as shown in Figure 6.2.

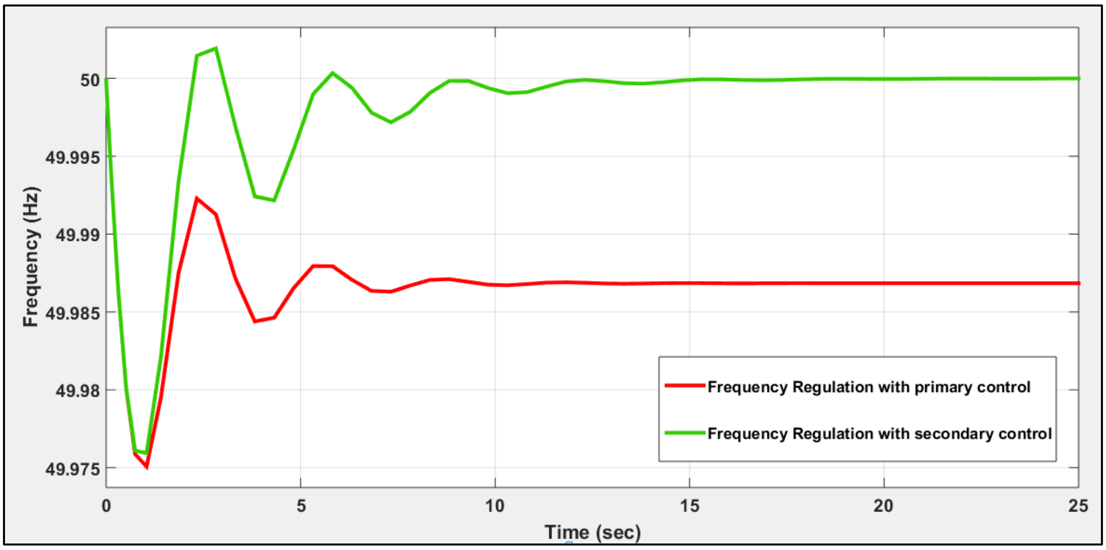
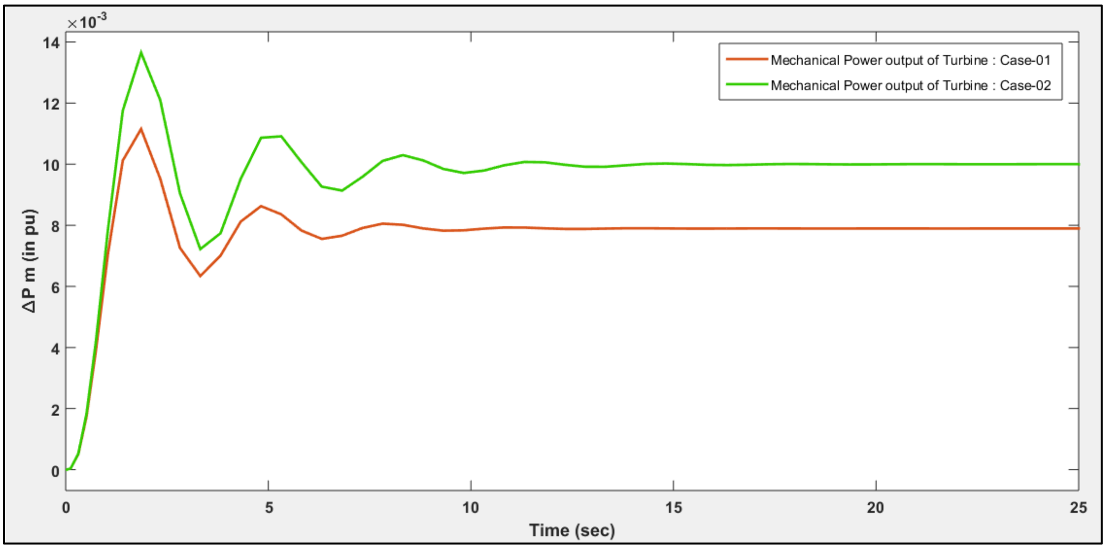
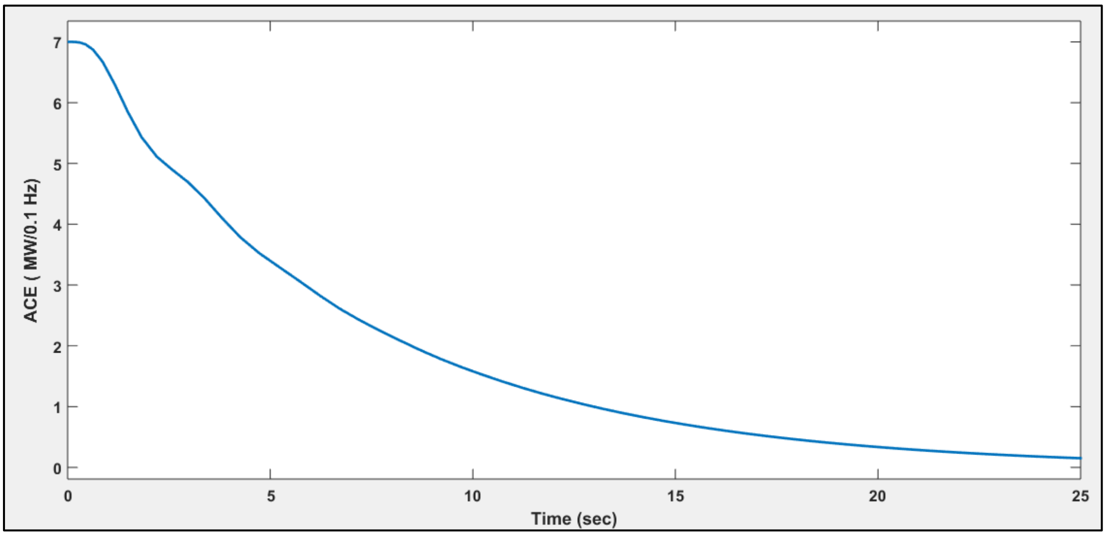


Figure 6.2: Model Simulation of frequency variation for 1% load change

Moreover, Figure 6.3 (a),(b) compares turbine output change ΔP_m and ACE value which is indicated as integral output on Figure 6.2.



(a) Mechanical power output variation with and without secondary control



(b) Integrator output with secondary control

Figure 6.3: Turbine output and ACE value variation with ALFC

The simulation results show that, the model with ALFC as secondary control which is done via integral control loop corrects frequency error or brings the ACE value to schedule interval. Hence, the benefit of implementation of AGC is evidently improving the quality of frequency regulation.

6.3 Detailed secondary control architecture for ALFC

The ALFC architecture implementation can be explained with help of Figure 6.4 as it shows the major controlling and associated signal flowing direction in a nutshell.

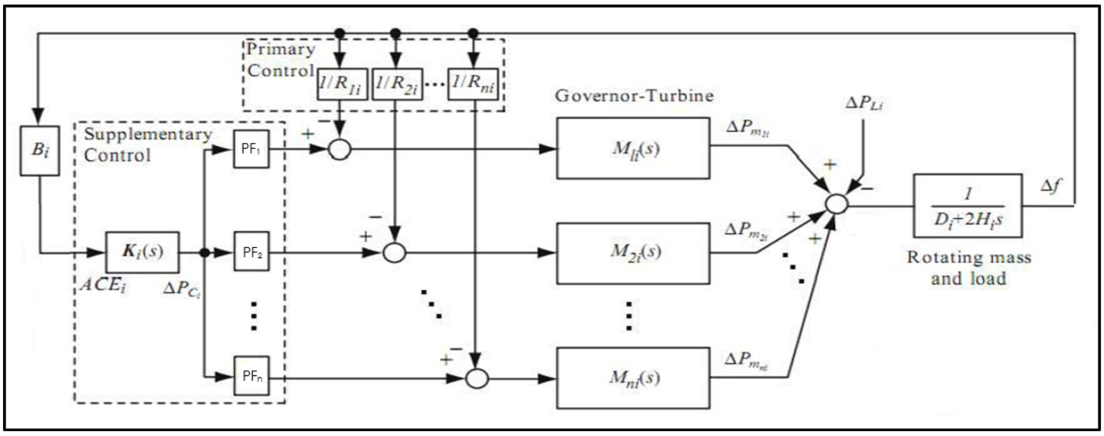


Figure 6.4: ALFC architecture and signal flow diagram

Source: P.Kundur ,"Power System Stability & Control", McGraw Hill Edu(in), 2013

Power system model primary regulation is developed and valided. Please refer chapter 04 and 05 for further details. The validated primary regulation model comprises the System Inertia (H), load damping (D), turbine-governor details along with speed-droop (R) characteristics. Therefore, to complete the ALFC model the System Bias (B), Participation factor (PF) are to be calculated along with ALFC decision making algorithm. In addition, ALFC model aslo must be developed in such a way that to address unique constraints subjected on frequency controlling strategies of Sri Lankan system.

The ALFC scheme shown Figure 6.4 is drilled down further with respect to the target of this research work as suitable as for Sri Lankan System. The detailed signals associated on such ALFC is exhibited on Figure 6.5. Shown signal flow chart is developed based on the literature given in IEEE Committee Report (1970 &1991), of Automatic Generation Control of Electric Power System and AGC guide of General Electric (GE) Grid e-terrageneration package.

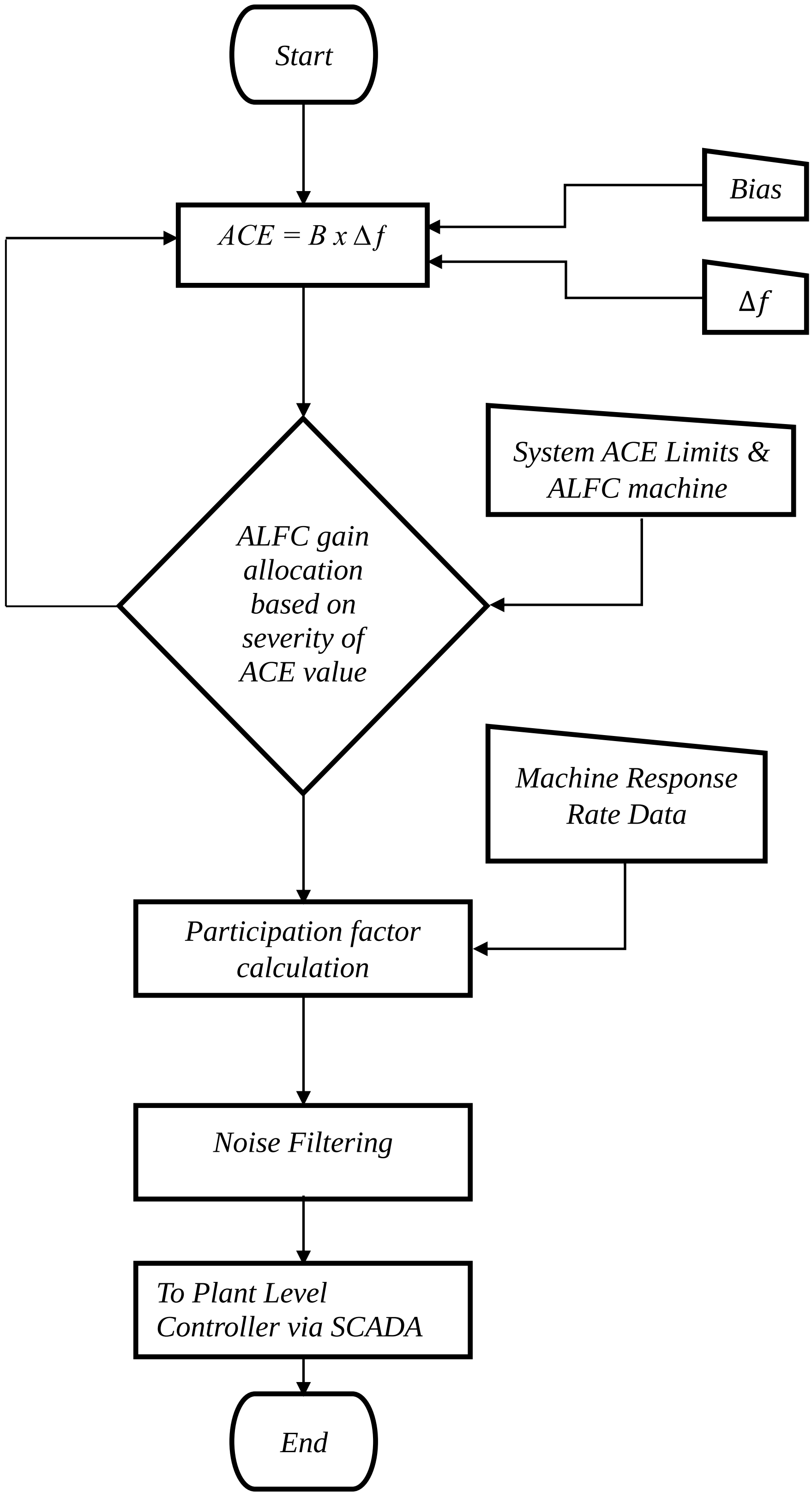


Figure 6.5: Detailed signal flow chart of ALFC scheme

6.4 Power System Bias

Like the composite regulation characteristic which is represented the load-frequency behavior, the system bias is a parameter which represents generation-frequency characteristics. In simple terms bias is defined as amount of active power needed to change the system frequency by 0.1 Hz from an any initial status. Equation 6.4 represents the relationship between the bias and system frequency variation [9].

$$System\ Frequency\ Bias(B) = \frac{\Delta P_{(e)}}{\Delta f_s} \qquad \text{eq. 6.4}$$

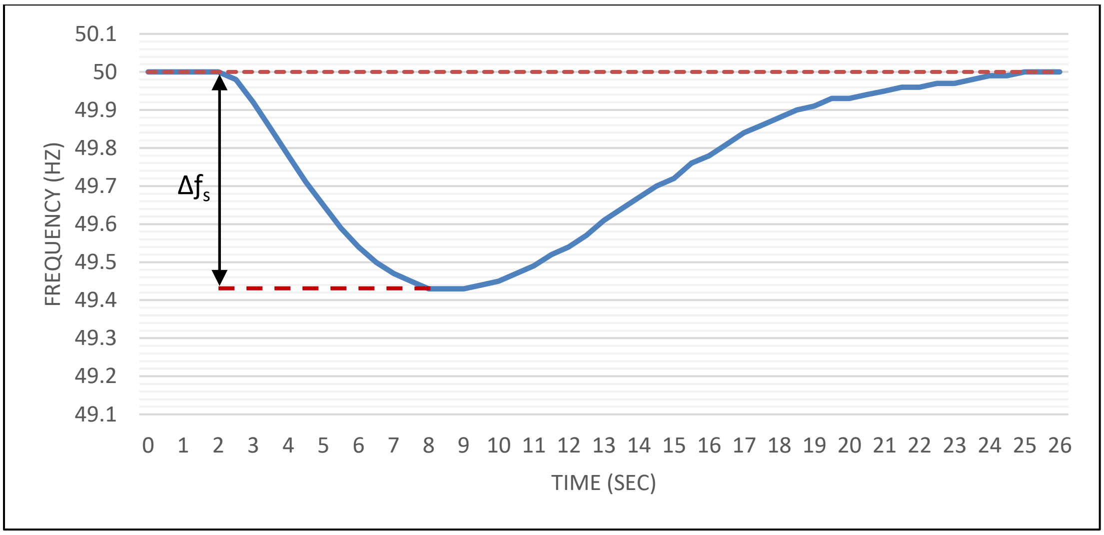


Figure 6.6: Frequency variation during typical generation rejection

The Δf_s is calculated by taking difference between 'frequency just before the disturbance' and 'end point of drifting frequency during disturbance' as shown in Figure 6.6. Thus, Δf_s is very depended on system condition so as frequency bias. Hence it could be represented as a state response. The controlling decision of ALFC scheme is highly depended on the bias value in order to determine the effective MW value to be changed in an area. Therefore, error in tuning bias value would largely affected the frequency regulation quality though well-tuned ALFC is there.

The frequency bias value is estimated based on the system disturbance measurements similar as depicted in Figure 6.6. separate excel model is developed to identify the Δf_s during each such disturbances and bias value is calculated based on equation 6.4.

there are about 26 number of disturbance record were taken an analysed. The out come of bias value with respect to different generation condition is tabled in Table 6.1. Here, any one could wonder why the generation rejections data are only being used to estimate the bias value. As per Sri Lankan system data availability is very significant for generation rejection rather than load rejection. Apart from that, load rejection data cannot be ensured purely as load rejection since the penetration of embedded generation is throughout the country.

Table 6.1: Summary of recorded data and bias calculation.

	Date	Time	Total Generation (MW)	Scenario	ΔP (MW)	Δf (Hz)	Bias (MW/0.1Hz)
1	20.06.2016	06:23	1840.00	Day-Time	90	1.30	6.92
2	28.05.2016	13:11	1480.00	Day-Time	40	0.68	5.88
3	26.05.2016	15:19	1650.00	Day-Time	38	0.52	7.31
4	26.05.2016	02:06	1010.00	Off-Peak	38	0.64	5.94
5	25.05.2016	21:24	1790.00	Night-Peak	38	0.58	6.55
6	01.10.2016	18:22	2110.00	Night-Peak	46	0.45	10.22
7	16.07.2016	19:10	2150.00	Night-Peak	70	0.75	9.33
8	17.10.2016	17:33	1930.00	Day-Time	58	0.80	7.25
9	18.10.2016	08:02	1520.00	Day-Time	37	0.43	8.60
10	19.10.2016	06:39	1630.00	Day-Time	55	0.56	9.82
11	25.11.2016	16:33	1809.00	Day-Time	58	0.60	9.67
12	14.11.2016	15:36	1263.00	Day-Time	50	0.44	11.36
13	28.11.2016	18:20	2320.00	Night-Peak	55	0.52	10.58
14	11.12.2016	13:17	1370.00	Day-Time	80	1.02	7.84
15	27.12.2016	19:32	2201.00	Night-Peak	100	1.27	7.87
16	18.01.2017	21:45	1640.00	Day-Time	40	0.35	11.43
17	24.01.2017	16:47	1770.00	Day-Time	52	0.74	7.03
18	18.05.2017	14:34	1410.00	Day-Time	110	1.17	9.40
19	27.06.2017	03:20	1050.00	Off-Peak	54	0.87	6.21
20	26.07.2017	05:30	1920.00	Day-Time	115	1.19	9.66
21	31.08.2017	08:35	1840.00	Day-Time	62	0.87	7.13
22	27.09.2017	01:15	974.00	Off-Peak	40	0.59	6.78
23	15.11.2017	03:16	1080.00	Off-Peak	25	0.35	7.14
24	19.11.2017	03:21	920.00	Off-Peak	37	0.6	6.17

As per the results obtain based on table 6.1, it could be noted that the system bias is also varying from 6.94 to 11.43. Therefore, same methodology which was adopted during the system inertia estimation is used here as well. The variation of obtained bias values are filtered based on three different demand scenario such as day-time, night-peak and off-peak. The variation of bias values on different demand scenario are shown on Figure 6.7 (a),(b),(c).

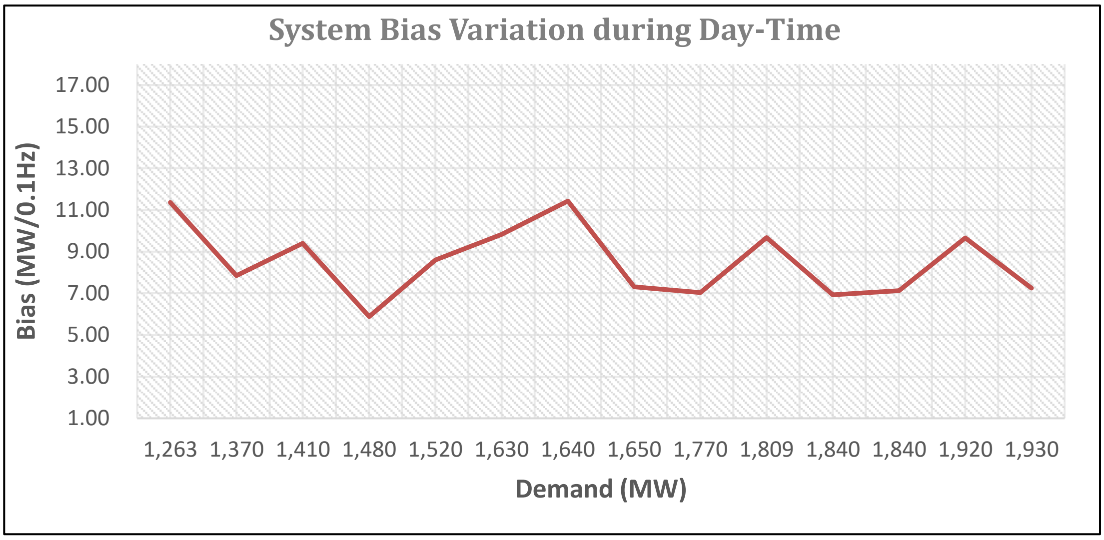


Figure 6.6 (a)

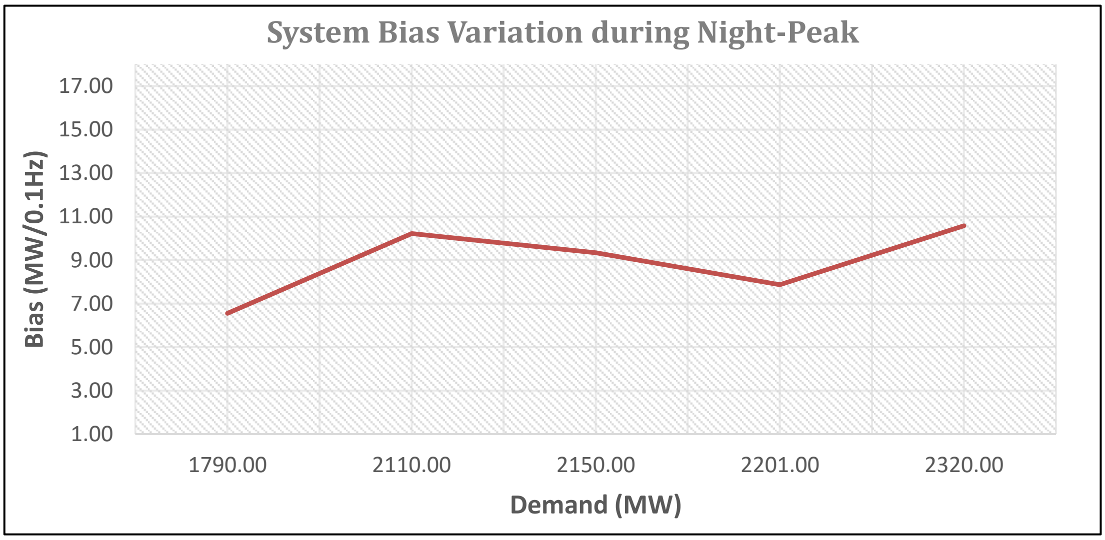


Figure 6.6 (b)

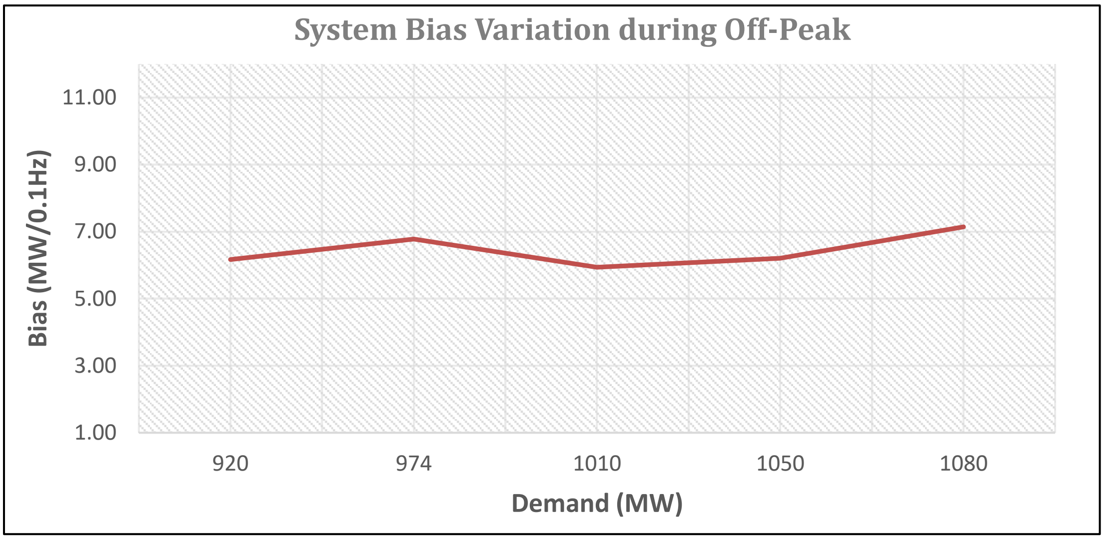


Figure 6.6 (c)

Figure 6.6: System Bias variation during different demand condition.

The average value of system bias is taken from above trend analysis in order to use as an input for AFLC model. Table 6.2 shows the average values of calculated system bias value for different demand scenario as interested.

Table 6.2: Average of Calculated system bias

Scenario	**Averaged Bias (MW/0.1Hz)**
Day Time	8.52
Night Peak	8.91
Off Peak	6.45

These finding are used as its on developed ALFC model based on associated demand scenario. The bias is manual setting which is to be tuned by system operator once in a while as per system conditions. Best approach is to keep on updating the bias variation as much as possible and to keep the track of record on the changes in bias variation. There are much detailed trends can be generated with such records and more precise bias value can be obtained.

6.5 ALFC Decision Making Algorithm

Once the bias value is known for particular demand scenario, now ALFC decision making algorithm must be developed as shown figure 6.5. Frequency regulation quality is very depended on the ALFC algorithm being used. Hence, it should be formed such a way that of make changes in MW references of committed machines in order to correct the error in steady state frequency, limit the frequency run-away up to some extent and speed up the system frequency recovery.

The ALFC output must be weighted as proportional as to the severity of error in the frequency. Means, higher the frequency error, bigger and faster the changes required at plant level. While giving weightage of frequency error into ALFC, the unique constraints persisted in Sri Lankan system must also be accounted. Some of such constraints are listed in here;

1. ALFC is not necessarily regulate the frequency within the range of frequency from 49.85 Hz to 50.15 Hz (refer section 1.3).
2. ALFC regulation must be weighted differently for the operational frequency band and emergency frequency band.
3. ALFC must be suspended if the disturbance is much severe. Yields, ALFC shall be suspended if system frequency shoots beyond 51.20 Hz, as FCB protection threshold setting of LVPS Unit-02 is set on 51.30 Hz. Likewise, ALFC shall be suspended if system frequency falls beyond 48.75 Hz, as under frequency load shedding stage-I is about to triggered.
4. The supervisory control facility for the ALFC is only possible in limited number of large hydro generator belongs to Laxapana, Samanalawewa, Kothmale and Victoria power stations.

Taking above consideration into an algorithm development, decision point or mode of ALFC is differentiated based on the ALFC feed forward gain. The idea of weighting the ALFC output based on severity of frequency error is expressed in frequency spectrum shown in Figure 6.7.

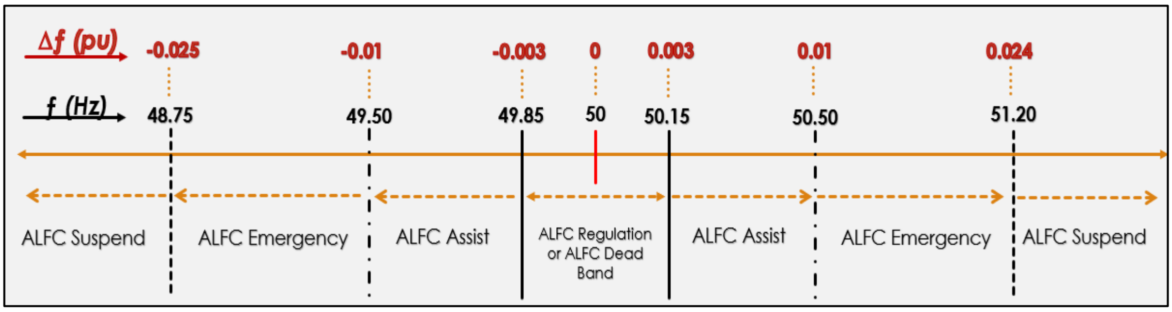


Figure 6.7: ALFC Mode vs severity of frequency error.

The developed ALFC model analysis are to be done in per unit values and please refer frequency values in per unit as shown in Figure 6.7. The ALFC regulation band ($\Delta f_{pu} = 0 \pm 0.003$) is special circumstances where system operator either decides to have regulation to keep the system frequency relatively close to nominal value or let the ALFC in idle mode considering it as a dead band. Strick regulation within this interval may tend to produce steady state oscillation and may also produce unwanted governor actions which in turns increases the maintenance of governor equipment as wear and tear increases. Then, the tradeoff between the above two must be selected by system operator. Here, the developed ALFC model comprised of dedicated integral loop with less weighted feedforward gain to produce limited error correction changes in a slow process such that to keep the system frequency relatively close to nominal frequency. Still, such control will may not be suitable when system is demand is rapidly oscillating with in regulation band.

The ALFC assist band should be activated when (Δf_{pu}) falls either of $-0.01 < \Delta f_{pu} < -0.003$ or $0.01 > \Delta f_{pu} > 0.003$ range. Still, the system frequency is on operational limit. Hence, the change of MW output based on ACE value can either be transmitted as its or relatively modified with respect to real time demand trend. It takes about 4 to 10 secs to of complete the one ALFC cycle. If demand is varying very significantly with in this interval the end point frequency would differ from what we expected. Such demand change could also be incorporated with right section of feed forward gain for ALFC assist band. For better understanding, consider system is on night peak and demand is increasing rapidly rather then sending ACE value as it is, better to send bit increased ACE value (e.g Gain = 1.2) in order to catch up the demand increment during the operational cycle.

Likewise, when system frequency falls either of $-0.025 < \Delta f_{pu} < -0.01$ or $0.024 > \Delta f_{pu} > 0.01$ range, ALFC is activated as ALFC emergency mode. Here, the quick recovery of system frequency into regulation band must be ensured. Thus, the ACE value is used to amplify by assigning large gain (e.g. Gain = 1.8) which according changes the WM at plant level and hence brings the frequency back to regulation band. Evidently, these ALFC gain values are also needed to be modified by operators based on the regulation requirement. The impacts on frequency due to changing these gains will be exhibited in ALFC model simulation analysis.

As discussed above, once the tuned ACE value is determined by ALFC decisions, MW values to be sent out to committed power plants in on proper composition. That is looked after by 'Participation Factor(α) calculation logic.

6.6 Participation Factor (α)

The PF is a plant level parameter defined by the rate of response (MW/MIN) of individual turbines. The equation 6.5 defines the participation factor.

$$\text{Participation Factor } (\alpha) = \frac{\text{Plant Response Rate}}{\text{Total Available Response Rate of committed machines}} \qquad \text{eq. 6.5}$$

As a result, plant having higher the response rate will undergo more MW change. Table 6.3 represents the collected data for the plant response rates. The calculated response rates may vary as per plant operational condition. But during this study it is consider as constant at an any operating point.

Table 6.3: Response Rates of Individual Turbines

	Machine	Response Rate (MW/Min)
01	Victoria Gen-01	78
02	Victoria Gen-02	72
03	Victoria Gen-03	84
04	Kothmale Gen-01	55
05	Kothmale Gen-02	150
06	Kothmale Gen-03	75
07	New Laxapana Gen-01	250
08	New Laxapana Gen-02	180
09	Samanalawewa Gen-01	117
10	Samanalawewa Gen-02	162

Consequent to above findings, the ALFC model has been developed and simulation results are obtained as explained in this chapter.

CHAPTER 07

SIMULATION RESULTS

7.1 Simulation Results

The ALFC model has been developed with all findings explained above. The simulation results are obtained such that to have better, in depth and illustrative understanding. There are four actual cases were taken for analyse the ALFC scheme behavior.

1. Case 01: Frequency response with ALFC for Base Case.
    I. *Model outcome with and without ALFC*
    II. *AFLC behavior with different number of machines*
    III. *AFLC behavior with different ALFC triggering time*
    IV. *AFLC behavior with different ALFC gain*
2. Case02: Frequency response with ALFC in Off-Peak scenario.
3. Case03: Frequency response with ALFC in Night-Peak scenario.
4. Case04: Frequency response with ALFC in Day-Time scenario.
5. Case05: Steady state Frequency response with ALFC

7.2 Case 01: ALFC Model Results for Base Case

The general case had been chosen such a way that to cover up to the emergency band so it could ease the analysis of ALFC behaviour in full extent. To address such requirement, 110 MW generation rejection case is selected as it was brought the system frequency up to 49.28 Hz (Δf_{pu}= -0.0144) as shown in Figure 7.1. The interested disturbance was caused by KPS GT7 at 11:30 hrs. Hence primary regulation model validated for day-time scenario is used with ALFC scheme.

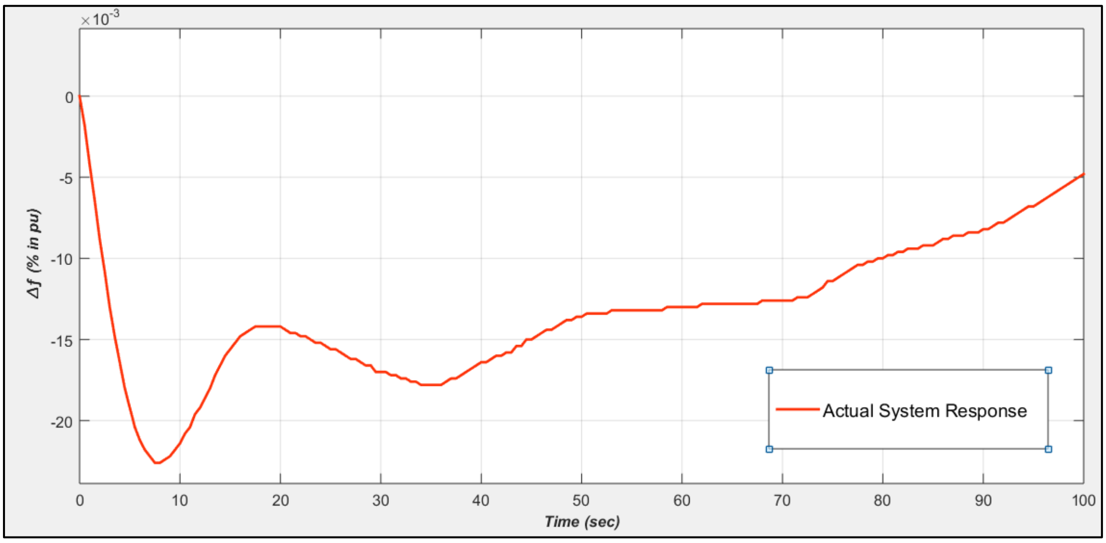


Figure 7.1: Actual system frequency variation during 110 MW rejection at 11:30 hrs.

As per results obtained for system bias calculation presented in chapter 6.0/ Table 6.2 bias can be selected as B = 8.52 MW/0.1 Hz. Subsequently limits of ACE values for ALFC band is calculated based on equation 6.3 and tabled in Table 7.1.

Table 7.1: ACE Limits for ALFC band

Frequency Limit	Δf_{pu}	ACE (in MW)	ACE_{pu}	ALFC Band	Error Type
51.20	0.024	102.24	0.056	Emergency	Over Frequency
50.50	0.01	42.6	0.023	Assist	
50.15	0.003	12.78	0.006	Regulation	
50.00	0	0	0	Idle	Idle
49.85	-0.003	-12.78	0.006	Regulation	Under frequency
49.50	-0.01	-42.6	0.023	Assist	
48.75	-0.025	-106.5	0.056	Emergency	

ALFC decision making algorithm is drawn based on above ACE_{pu} value which was obtained by using base value as total MW generation at the time of the disturbance. Figure 7.2 and 7.3 shows the developed ALFC base case model and ALFC feed forward gain allocation block respectively.

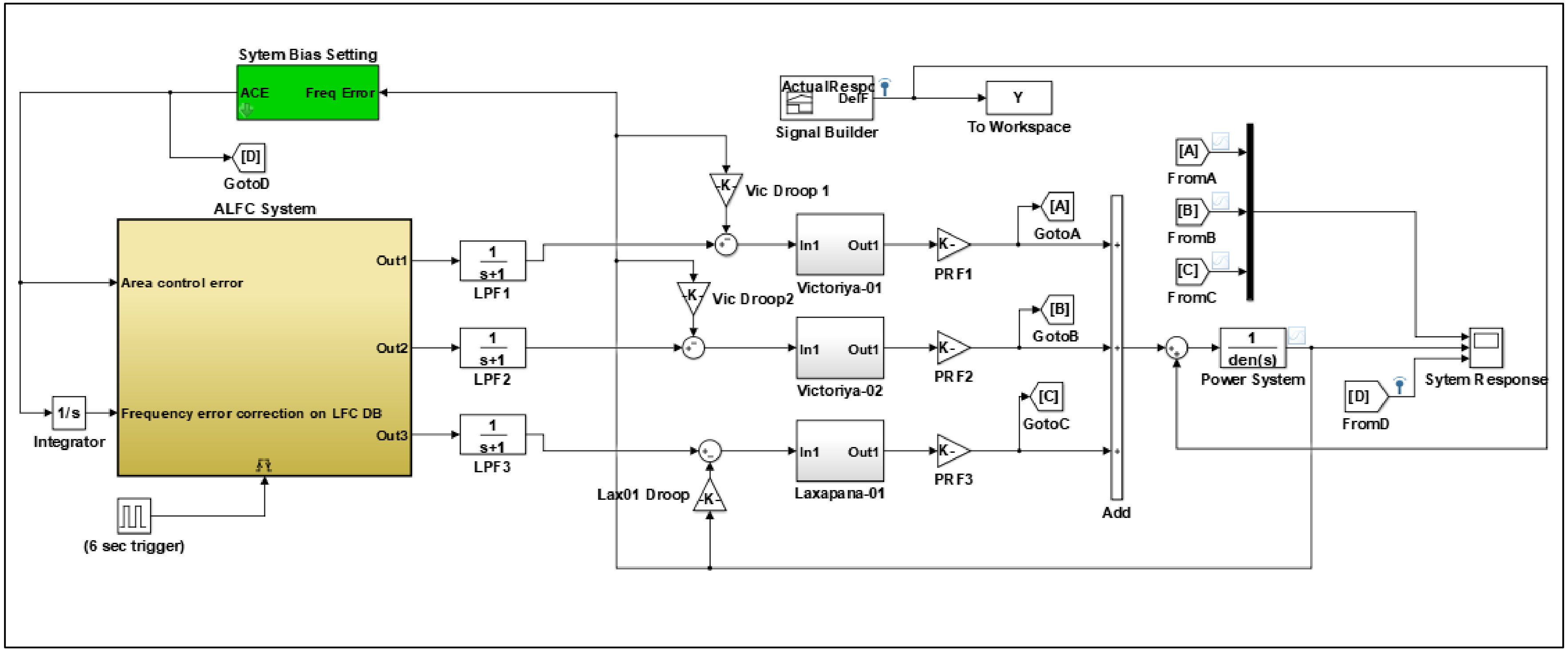


Figure 7.2: Base Case Model with ALFC scheme

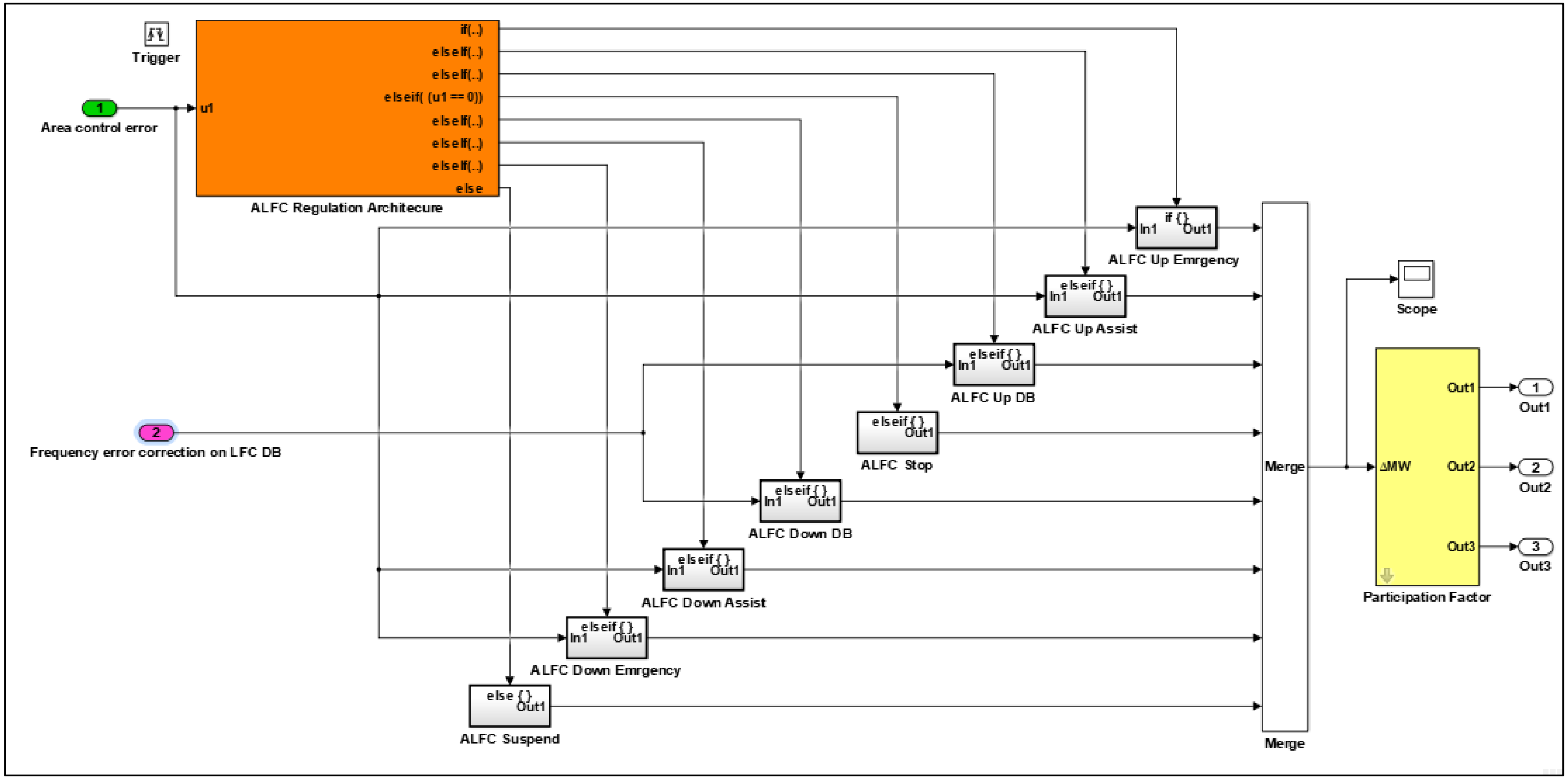


Figure 7.3: Conditional Algorithm to Allocated Feed Forward Gain for Different ALFC Bands

The committable generators into ALFC scheme during concerned disturbance were Victoria unit-01, Unit-02 and New-Laxapana Unit-01. Hence Primary regulation model comprises these units along with their droop characteristics as shown in Figure 6.2. Subsequently, Figure 6.3 represents the feed forward gain allocation algorithm based on ALFC band as explained by Table 7.1. the participation calculator block uses data from Table 6.3 and equation 6.5 to determine the effective α and assign required MW change in desired composition. Finally, the input to the governor is sent through a first order low pass filter which removes high frequency noises and avoids unwanted gate movement [1].

Further, the ALFC control with the regulation band is very sensitive control action as discussed in section 6.5. In this study, external integrator loop is used to address the control action separately inside this regulation band in order to keep the frequency relatively closer to nominal value while ensuring the recovery time adequately smooth and slow. Also, the 110 MW generation rejection is fed as step input at t=0 by disturbance block. The workspace variable Y is to represent the actual frequency tend shown in figure 7.1. The ALFC triggering cycle is assumed as 6 secs for initial simulations.

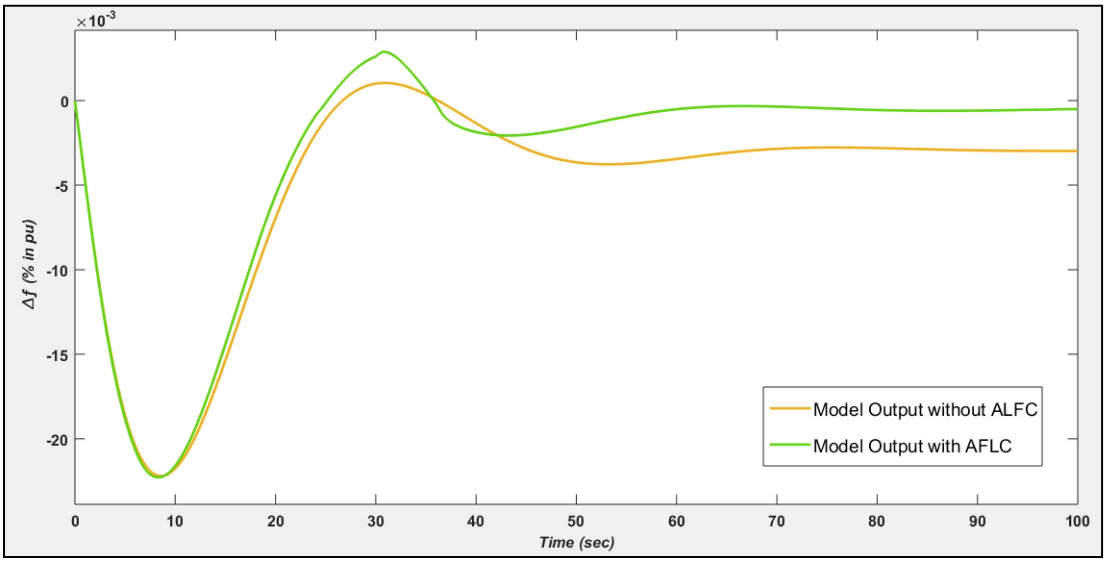


Figure 7.4: Model outcome with and without ALFC scheme for 110MW step change.

The Figure 7.4 comperes the model outcome with and without ALFC scheme for 110 MW step rejection. It evidently enhancing the frequency regulation and by achieving prime objective of ALFC which is correction of steady state frequency error. Once proper output is obtained with model simulation, then the associated ALFC parameters must be varied in order to tune the ALFC scheme into best suitable design.

7.2.1 Base Case ALFC Scheme Response with Number of Committed Units

Number of machines associated in ALFC regulation is varied from one machine to five machines in same base case model itself. The output obtained in each time is compared in Figure 7.5

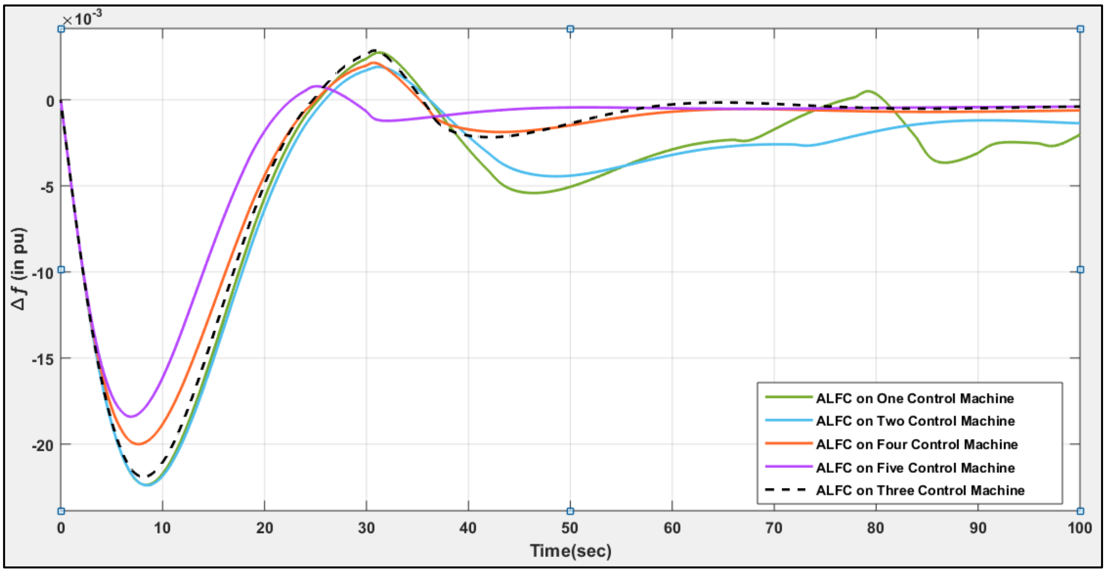


Figure 7.5: ALFC Base Model Behaviour with Different Number of Machines

Eventually, lesser number of machines produce unwanted oscillation and large time for frequency correction. Result also reveals that higher number of machines on ALFC scheme, it provides better regulation on system frequency. As can be seen from Figure 7.5, in addition to the steady state frequency error correction, higher number of machines limit the frequency run-away while making frequency recovery faster.

7.2.2 Base Case ALFC Scheme Response with Different Triggering Time

The recommended ALFC triggering time for large system is 4 secs [1], but for a small system like Sri Lankan, best fir has to be found out. Till now 6 secs is used as triggering time for ALFC schme for all above simulations. To understand the effect of ALFC triggering time, it sweeps from 3 sec to 10 sec as shown in Figure 7.6.

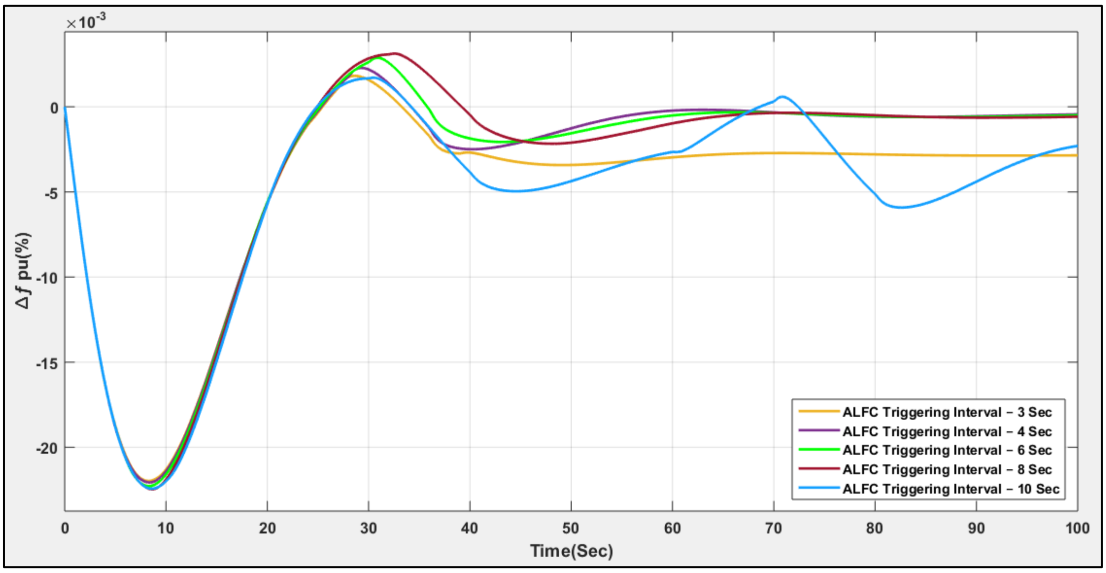


Figure 7.6: ALFC Base Model Behaviour with Different Triggering Time

Apparently, if time is less 4 sec the ALFC is not even happening while it is grater then 8 sec steady state oscillation starts as can be seen from Figure 7. 7. As a result, 6 to 8 secs would be best fit for ALFC triggering time.

7.2.3 Base Case ALFC Scheme Response with Different ALFC Gain

To obtain the ALFC scheme behaviour with respect to different ALFC gain five number of combinations are considered as shown in Table 7.2;

Table 7.2: Options for ALFC gain allocation

Options	Run-01	Run -02	Run -03	Run -04	Run -05
Under ALFC Emergency	1	1	2.5	4	6
Under ALFC Assist	0.5	0.5	2	2	3
ALFC Regulation/ DB	0	-0.3/+0.3	-0.3/+0.3	-0.8/+0.8	-1.5/+1.5
Over ALFC Assist	-0.5	-1	-2	-2	-3
Over ALFC Emergency	-1	-1.5	-2.5	-4	-6

As given in Table 7.2, the difference between Run-01 and Run-02 must be the effect of ALFC scheme within the regulation band only. Likewise difference between Run-02 and Run-03 provides effect of allocating high gain for assist and emergency modes. Similarly, each combination could be analysed. Figure 7.7 show the ALFC scheme output for the data shown in Table 7.2.

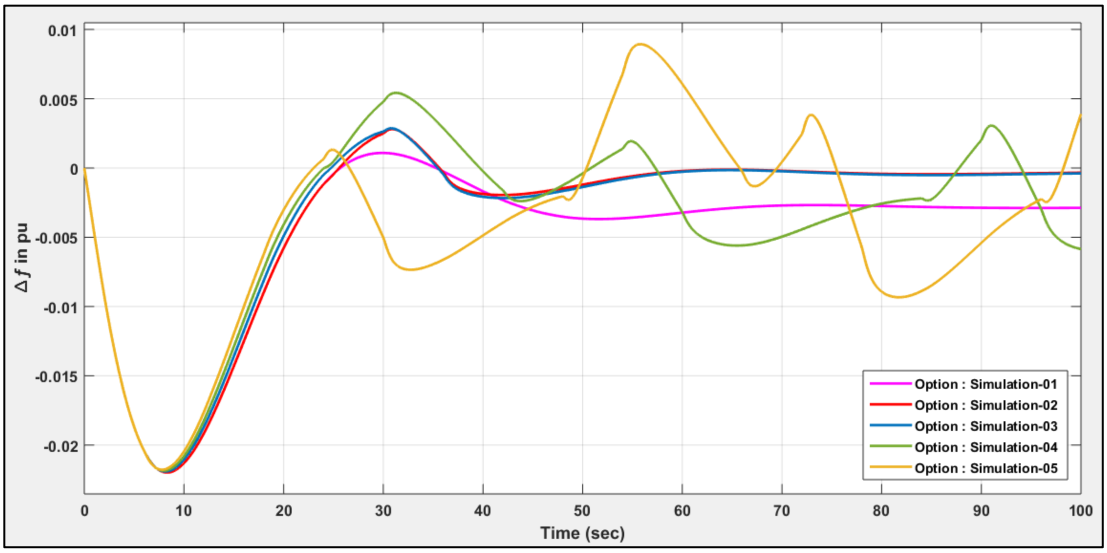


Figure 7.7: ALFC Base Model Behaviour with Different ALFC Gain

Figure 7.7 shows that, if the ALFC gain is too low (from unity value) then error correction is much slower. On the other hand, if the ALFC gain too big (from unity value) then steady state overshoot goes up. As can be seen from these observation, ALFC gain must be kept around unity gain but according to the system regulation requirement (refer section 6.5) as to provide expected outcome. The future simulations are done with the gain allocation as assigned for Run-02 on Table 7.2.

Subsequently, same model is now fed with actual frequency response obtained during 110 MW generation rejection (as shown Figure 7.1) instead of step changing disturbance. This methodology would reveal what would be the system frequency variation if developed ALFC scheme was there in action. The associated input change in a model is shown in Figure 7.8 and corresponding simulation results are given in Figure 7.9.

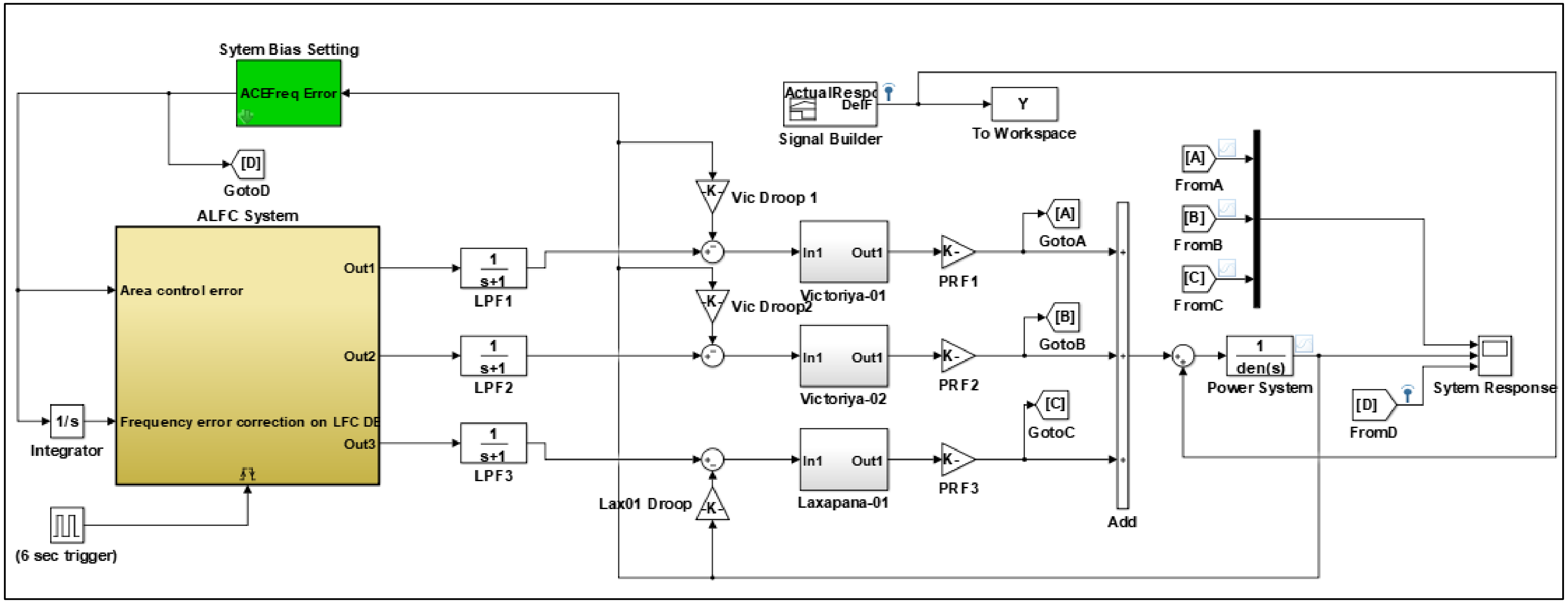


Figure 7.8: Base case Model with actual frequency variation during the disturbance as input.

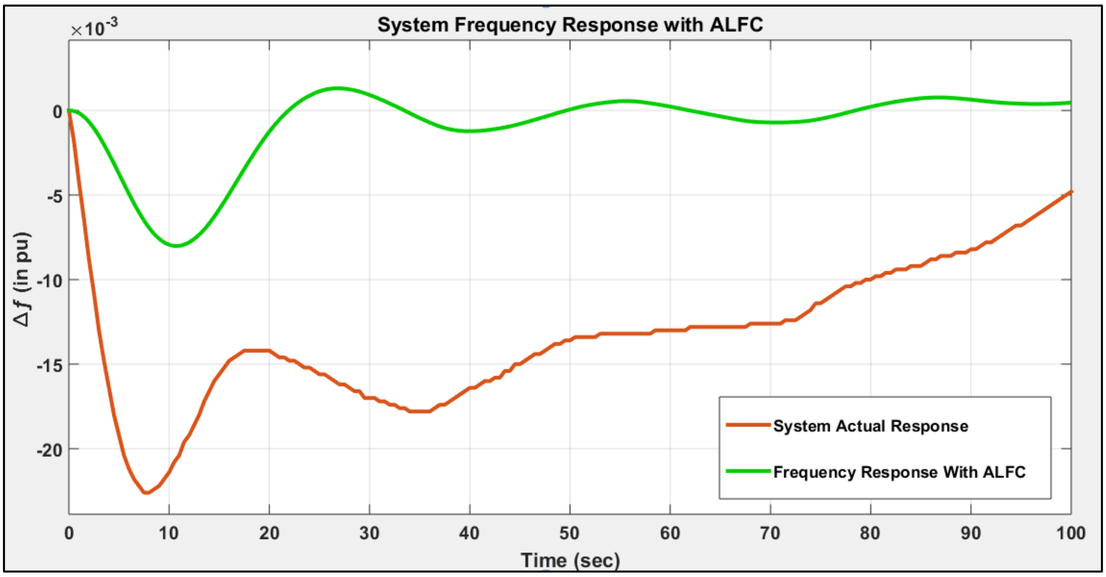


Figure 7.9: Base case ALFC scheme outcome with actual frequency variation as input.

Evidently, developed ALFC scheme, it provides better regulation on system frequency by providing faster recovery in system frequency while limits the frequency run-away. The regulation quality of system frequency would be much improved with designed ALFC scheme. Though the model shows well clipped frequency run-away response, in actual situation such response is bit difficult to be obtained as there are number delays associated in all the way of signal flow path. These delays can only be assumed for the purpose of implementation of ALFC. Still the object and benefit of tuned ALFC scheme is well exhibited as per simulation results driven.

Now it time to combine the ALFC scheme with sperate models validated for three different demand scenarios detailed in Chapter 05.

7.3 Case02: Frequency response of Off-Peak Model with ALFC

The validated off-peak model is combined with ALFC scheme and associated parameters H, D and B values are chosen accordingly. The Off-Peak ALFC model is exhibited in Figure 7.10 and corresponding ALFC Gain allocation along with ACE limits are represented in Figure 7.11.

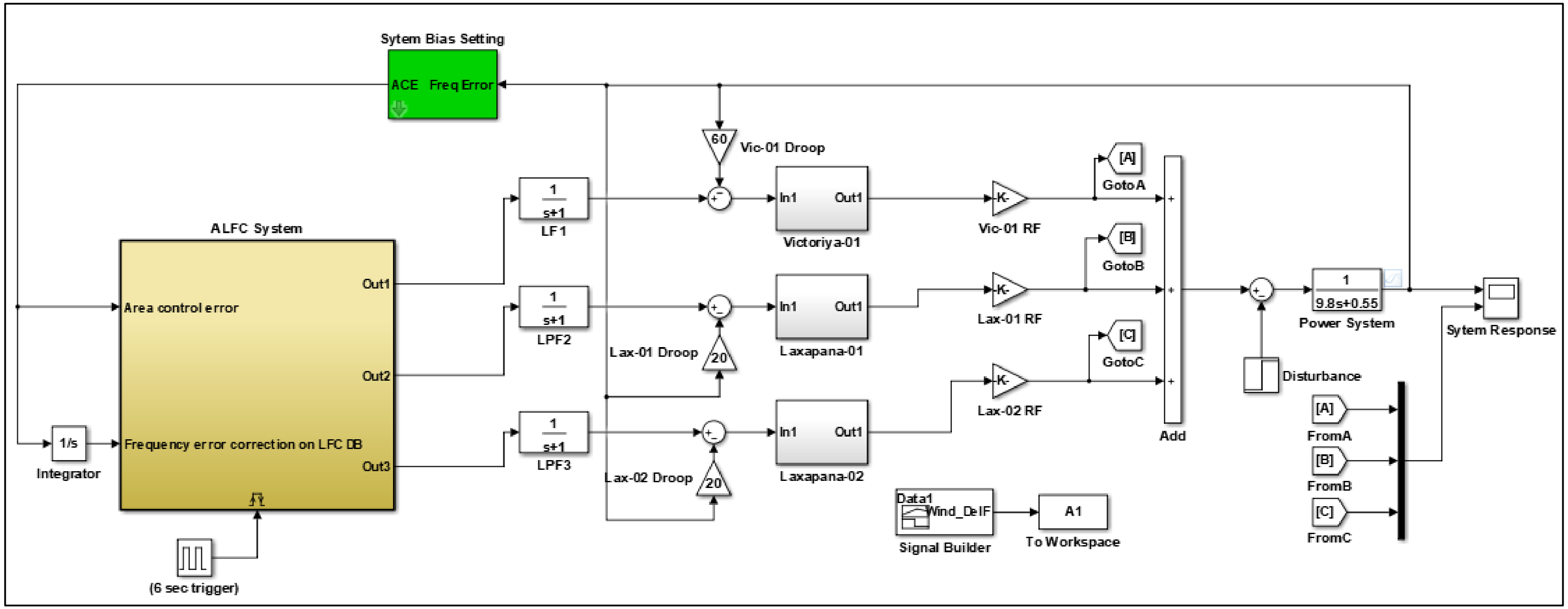


Figure 7.10: Off-Peak Model with ALFC scheme

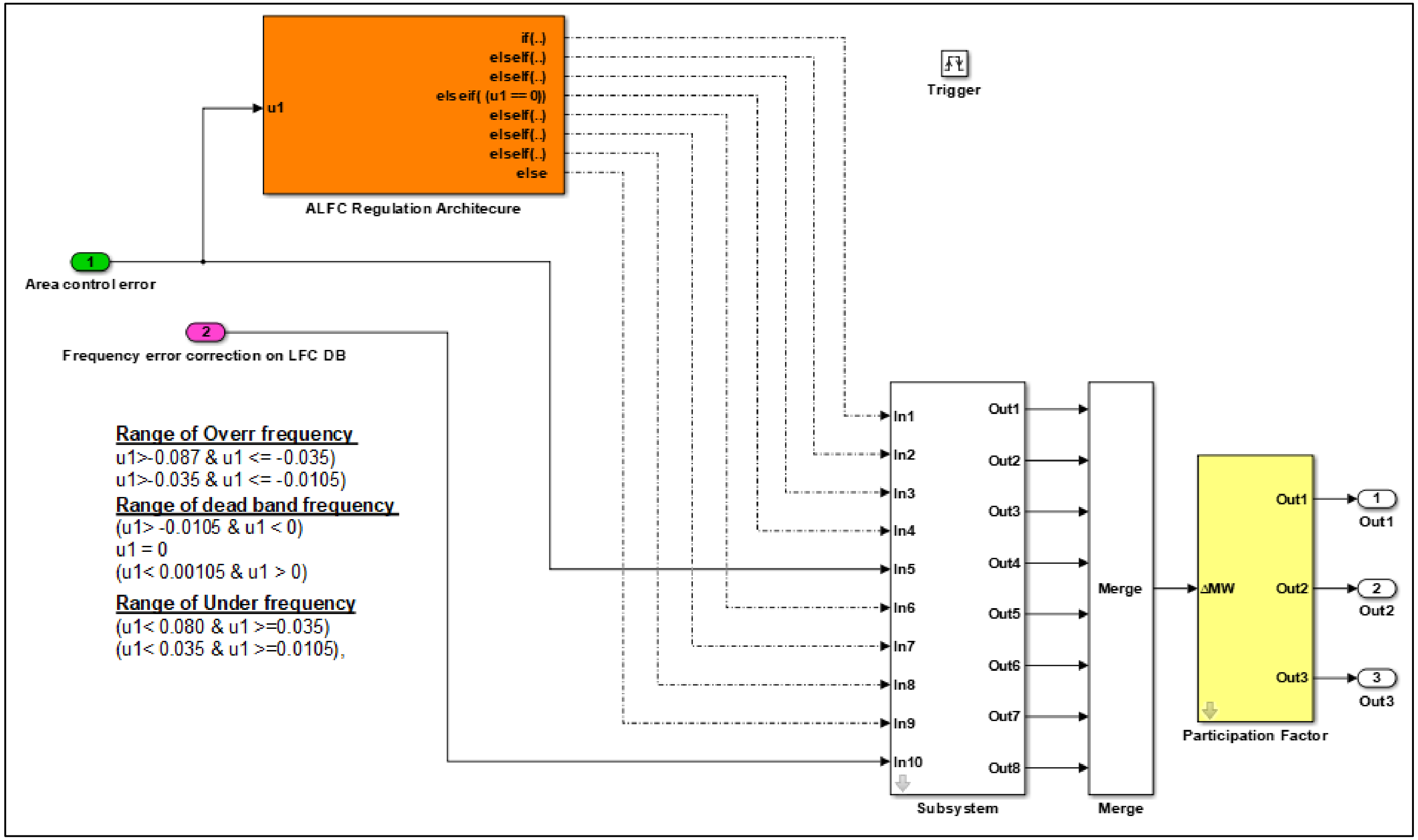


Figure 7.11: ALFC Gain Allocation Map for Off-Peak Scenario

The off-peak model simulation results are given in Figure 7.12 which compares the model output with/without ALFC scheme for the step rejection of 54 MW generation. Simliraly Figure 7.13 represents the ideal frequency response of the system for the actual frequency variation as input.

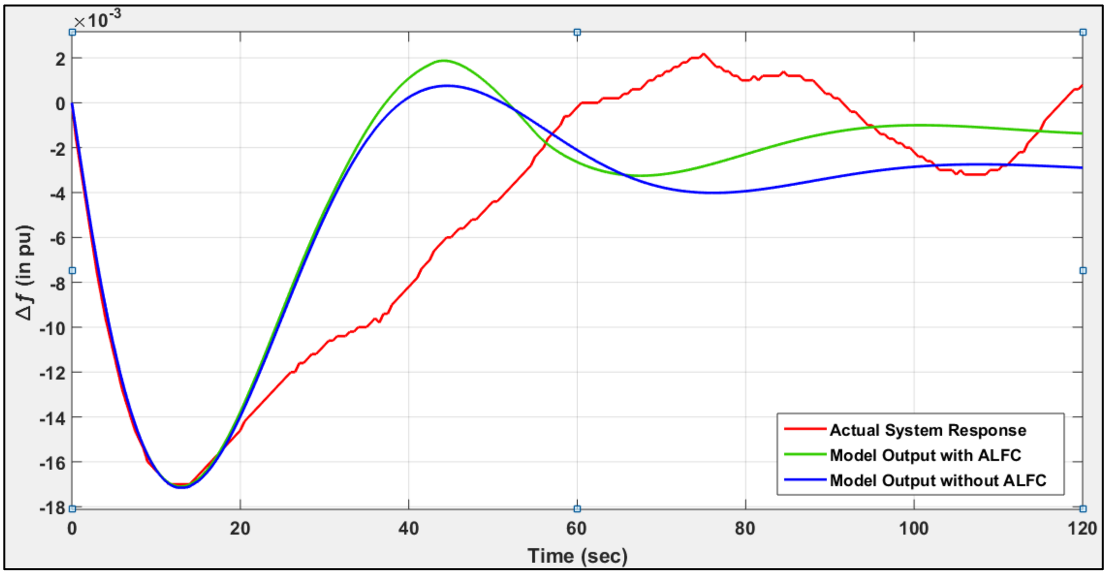


Figure 7.12: Off-Peak Model outcome with and without ALFC scheme for 54MW as step change input.

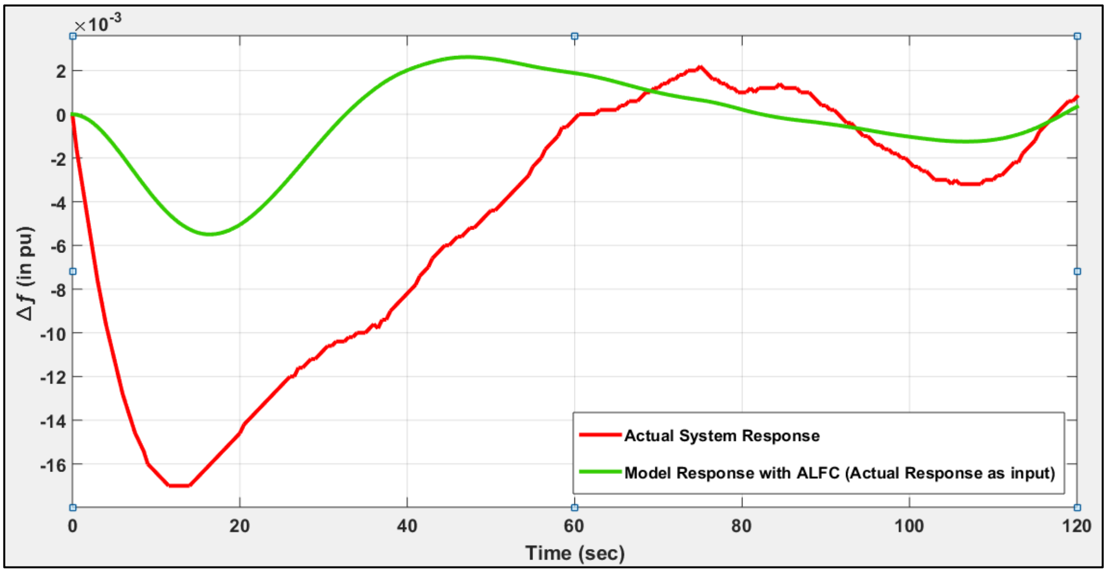


Figure 7.13: Off-Peak ALFC scheme outcome with actual frequency variation as input.

7.4 Case03: Frequency Response of Day-Time Model with ALFC

The validated Day-Time model is combined with ALFC scheme and associated parameters H, D and B values are chosen accordingly. The Day-Time ALFC model is exhibited in Figure 7.14 and corresponding ALFC Gain allocation along with ACE limits are represented in Figure 7.15.

The Day-Time model simulation results are given in Figure 7.16 which compares the model output with/without ALFC scheme for the step rejection of 80 MW generation. Simliraly Figure 7.17 represents the ideal frequency response of the system for the actual frequency variation as input.

7.5 Case04: Frequency Response of Night-Peak Model with ALFC

The validated Night-Peak model is combined with ALFC scheme and associated parameters H, D and B values are chosen accordingly. The Night-Peak ALFC model is exhibited in Figure 7.18 and corresponding ALFC Gain allocation along with ACE limits are represented in Figure 7.19.

The Night-Peak model simulation results are given in Figure 7.20 which compares the model output with/without ALFC scheme for the step rejection of 52 MW generation. Similarly Figure 7.21 represents the ideal frequency response of the system for the actual frequency variation as input.

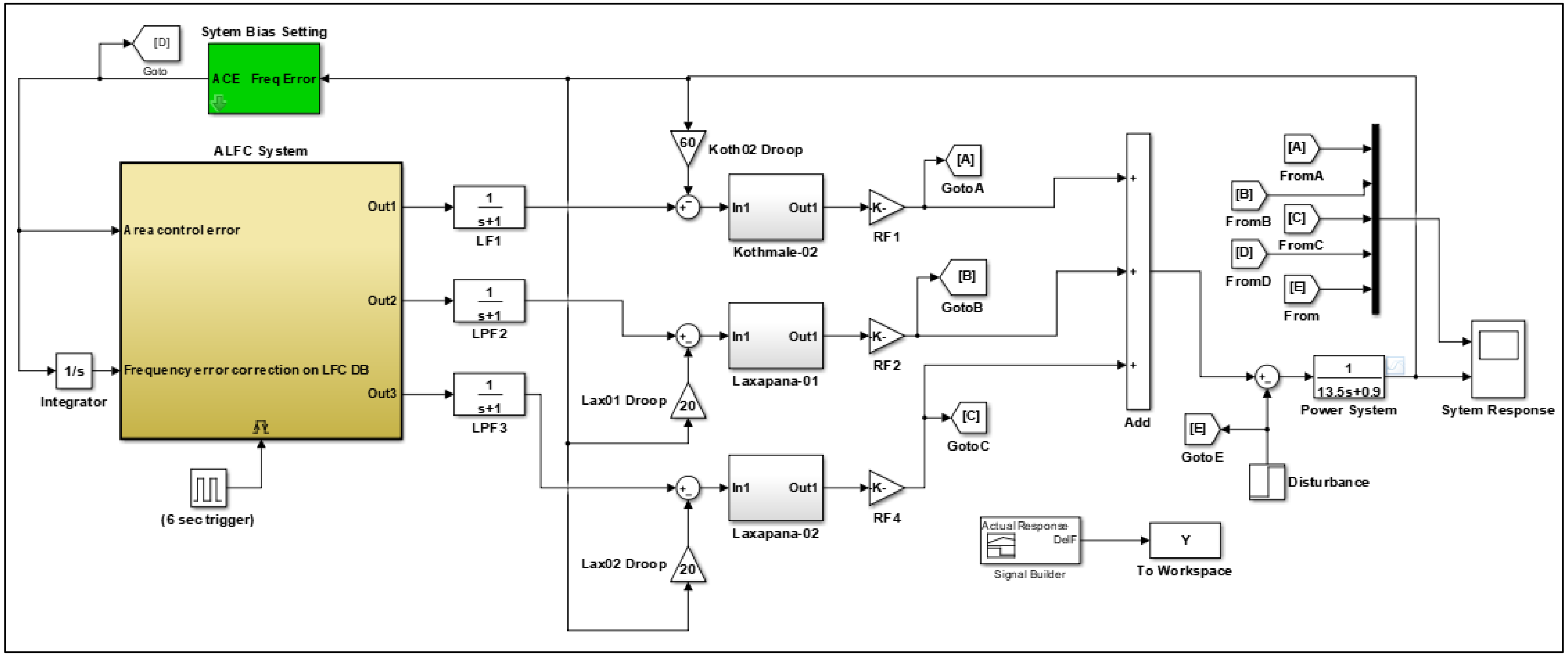


Figure 7.14: Day-Time Model with ALFC scheme

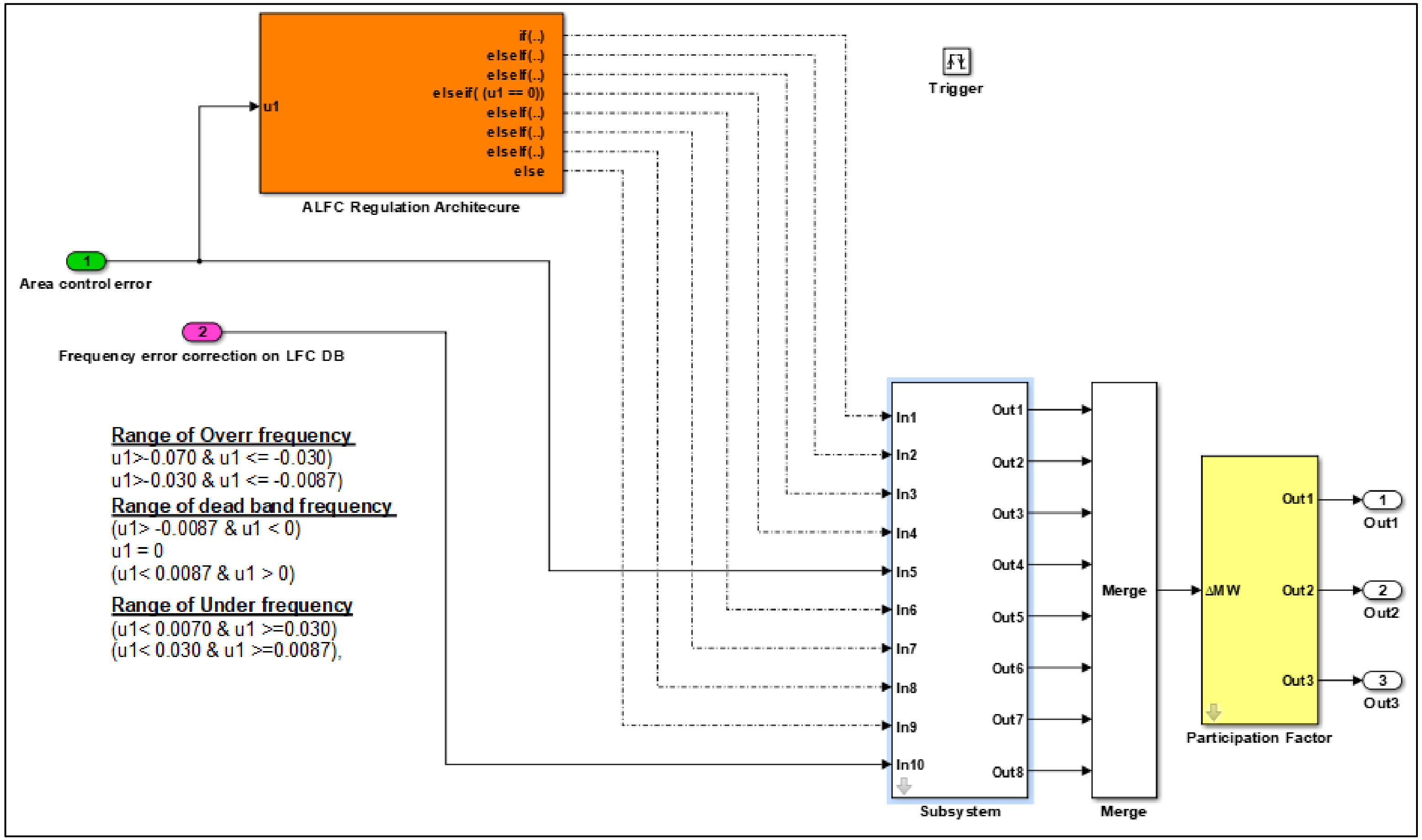


Figure 7.15: ALFC Gain Allocation Map for Day-Time Scenario

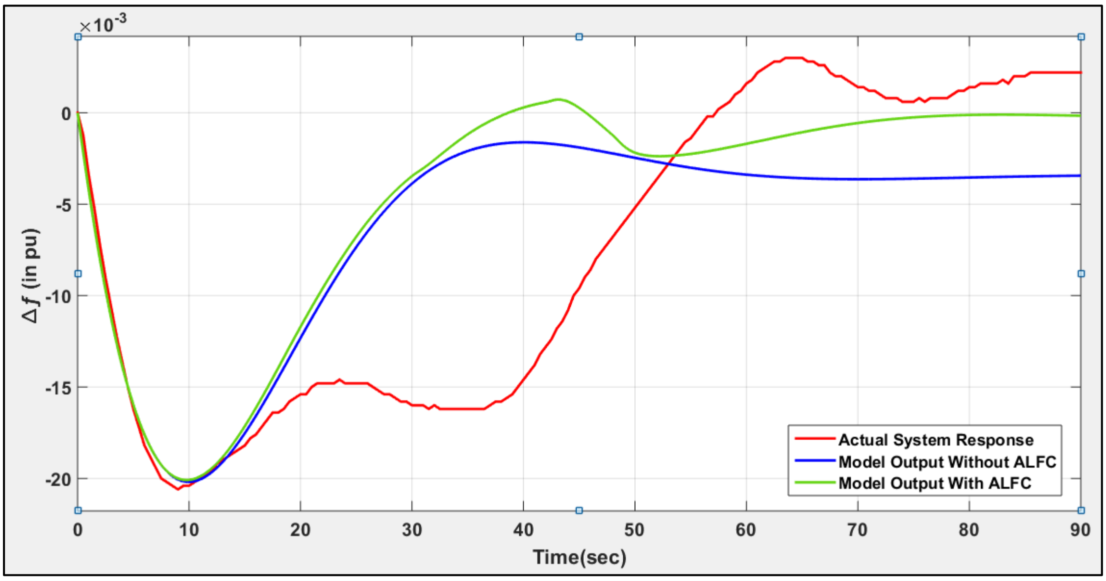


Figure 7.16: Day-Time Model outcome with and without ALFC scheme for 80MW as step change input.

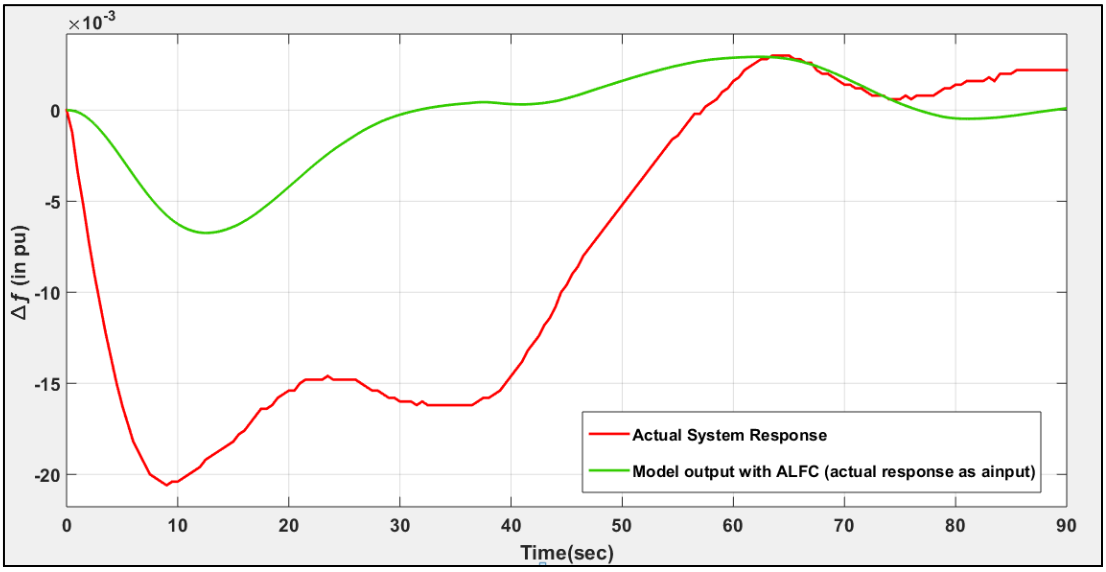


Figure 7.17: Day-Time ALFC scheme outcome with actual frequency variation as input.

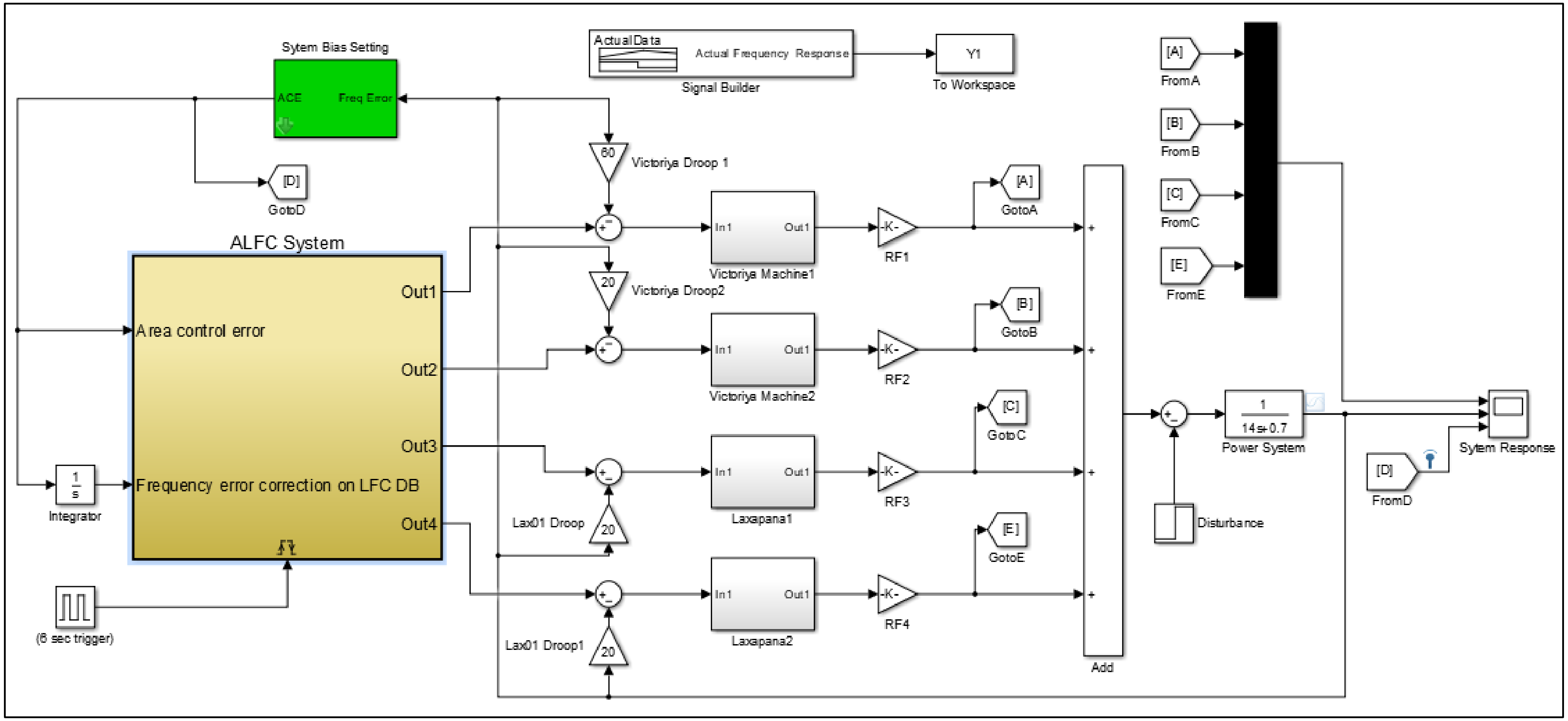


Figure 7.18: Night-Peak Model with ALFC scheme

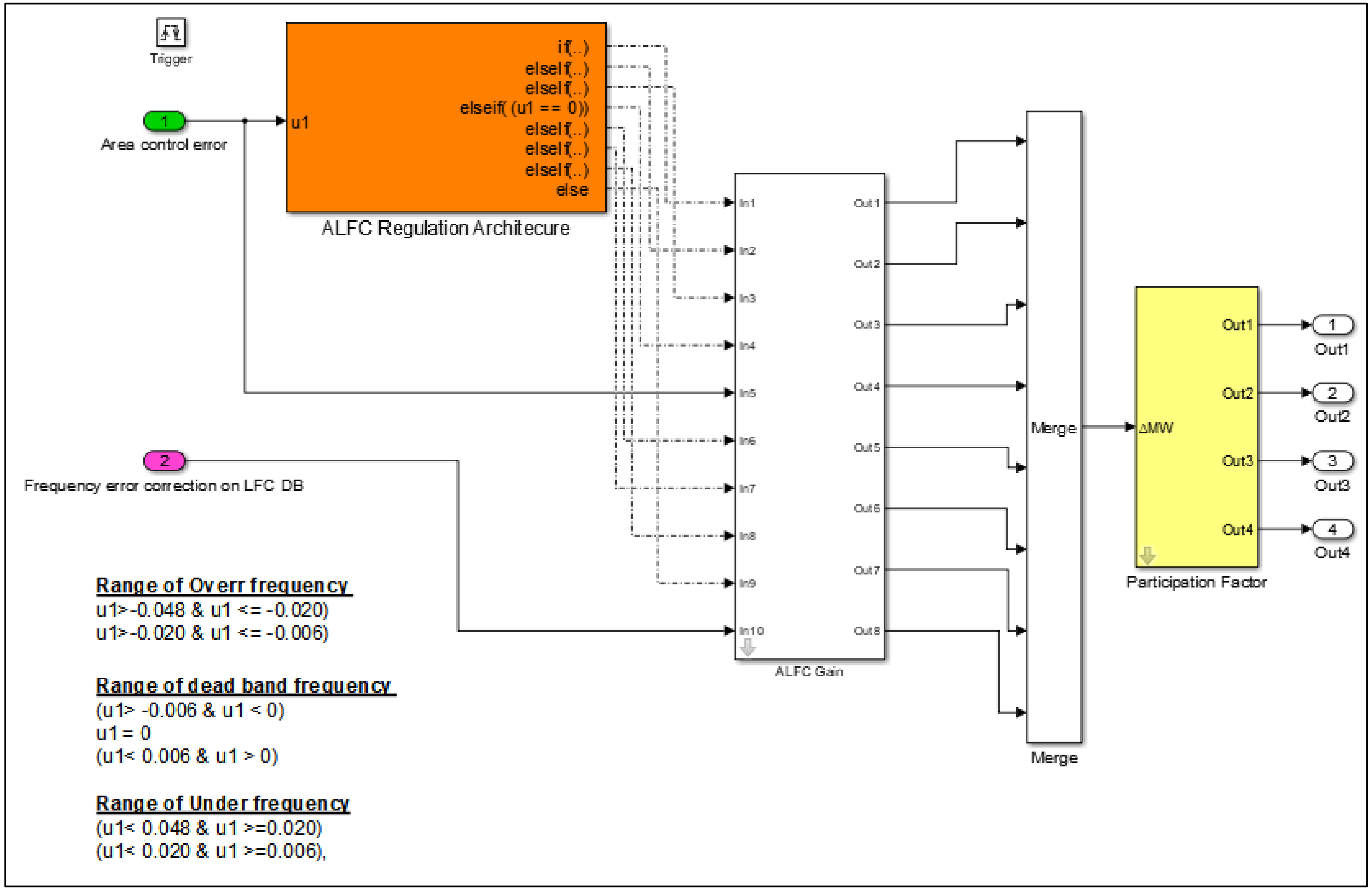


Figure 7.19: ALFC Gain Allocation Map for Night-Peak Scenario

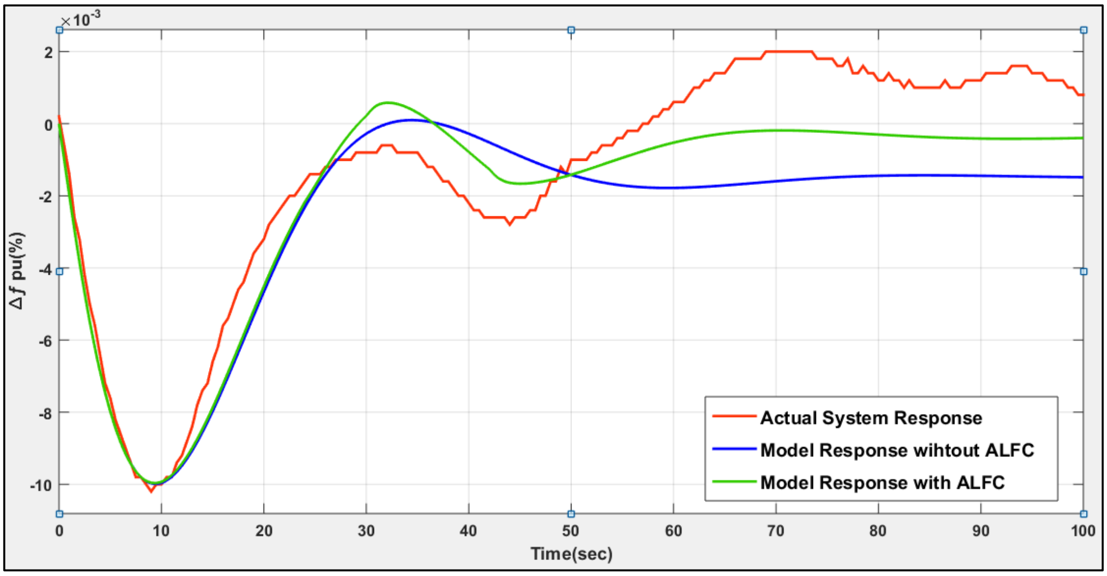


Figure 7.20: Night-Peak Model outcome with and without ALFC scheme for 52 MW as step change input.

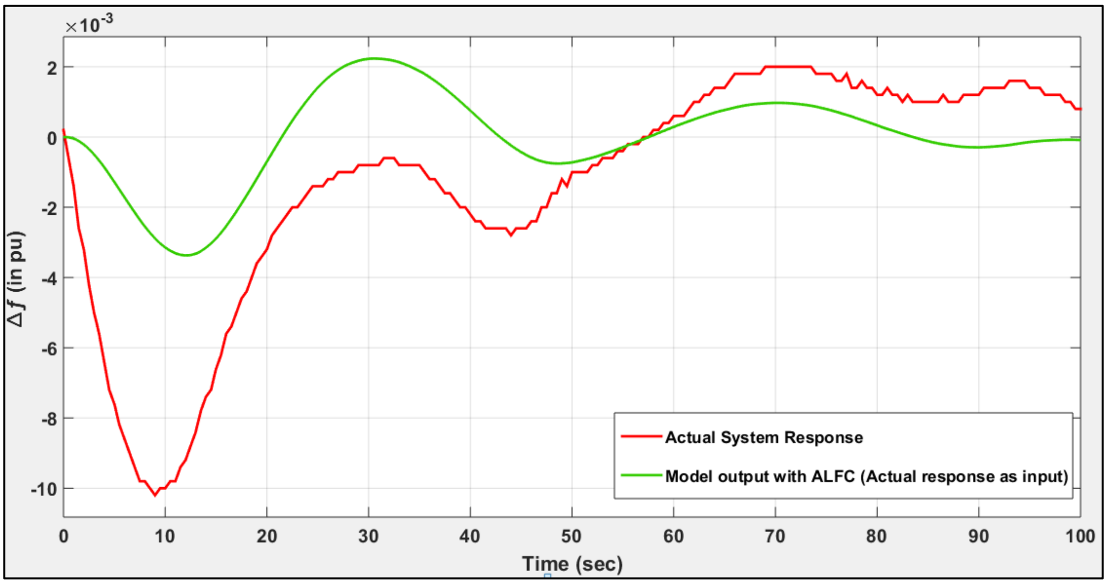


Figure 7.21: Night-Peak ALFC scheme outcome with actual frequency variation as input.

7.6 Case05: ALFC model response for actual system frequency

All above cases are providing improved frequency regulation in terms of limiting frequency run away, recovering frequency faster and improving regulated range. As a final approach before the conclusion, two hours of recorded system frequency is fed as an input to developed ALFC model. The concerned two hours is between 06:00 hrs to 08:00 hrs where system frequency encounter fast ramp ups and downs. The model outcome is shown for concerned input on Figure 7.22 and on histogram Figure 7.23

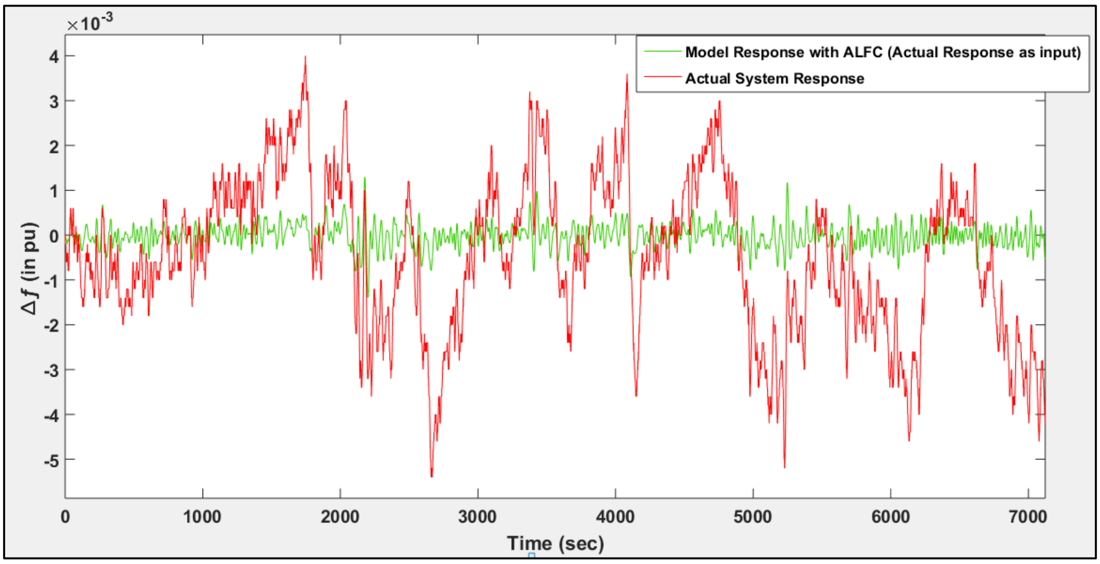


Figure 7.22: ALFC scheme outcome with 2 hrs of actual frequency variation as input

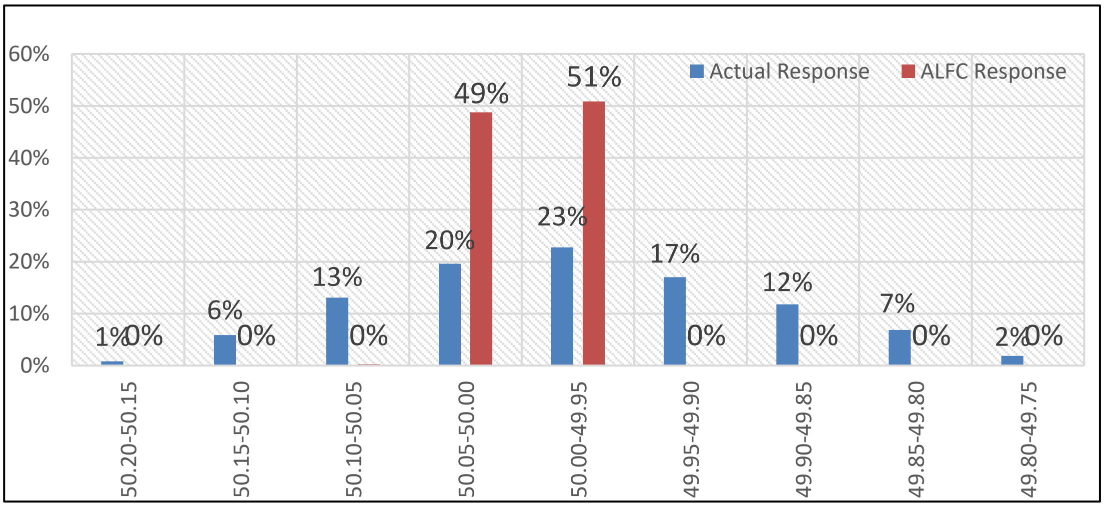


Figure 7.23: Comparison Histogram for System Actual Response vs ALFC Model Output

CHAPTER 08

RESULTS DISCUSSION SUMMARY

The results obtained via the ALFC model simulation represented in chapter 07 exhibit how frequency regulation quality can be enhanced. The outcomes driven under each endeavor are briefly discussed in here before conclusions.

8.1 Estimated System Parameters.

The whole ALFC system response is primarily depended on estimated system parameters System Inertia Constant(H), System Load-Damping Constant(D) and System Frequency Bias(B). The significance in the variation of these parameters with different demand condition, had taken into consideration. The power system is tended to represented by separate three models known as Night-Peak, Day-Time and Off-peak in order to address such variations.

8.1.1 Estimated System Inertia Constant(H).

The Inertia constant which responsible for ROCOF of system is estimated based on the measured transient responses as explained in section 3.5.2. The table 4.1 and Figure 4.3 (a), (b), (c) are representing the variation of inertia values with respect to different demand scenarios. The interested power system model is relatively following the actual ROCOF when the inertia values given in Table 4.2 is used as it is. At this point tuning adjustment required up until model's response matches with actual ROCOF at initial stage. This approach is closely adopted during the validation of primary regulation model for Night-Peak, Day-Time and off-peak. Tuned outcomes are depicted in Figure 5.5,5.7 and 5.9.

8.1.2 Estimated Load-Damping Constant(D).

As explained in section 3.6, the D is assumed to be 1% at an initial stage as per IEEE recommendations and intensively tuned during validation of models. The model response is tuned by starting from D=1 until simulation matches the actual response up to primary regulation support region. As per driven results, behavior of system responses with increasing D is shown Figure 4.4. Thus, the higher value for D may clip the frequency-run away while produce large steady state error and vice-versa. The best matching D values for concerned models are listed in Table 4.3 for Sri Lankan system.

8.1.3 Estimated Frequency Bias (B).

The frequency bias of the Sri Lankan system is largely depended on the system condition as the variation of B with respect to different system generation/demand condition is listed in Table 6.1. The results varied from 5.88 MW/0.1Hz to 11.43 MW/0.1Hz. The average of bias value on filtered samples based on Night-peak, Day-time and Off-peak conditions are shown in Table 6.2.

As per the explanation given section 6.1 the ALFC output is decided based on the system bias value through ACE calculation. Hence any abnormality found in bias value could adversely affected the ALFC regulation performance. Therefore, system bias must be continuously monitor and tuned throughout the lifetime of ALFC operation.

8.2 ALFC Model Outcome

The ALFC model response is studied and related parameters are varied and output is compared with base case model as detailed in section 7.2. The Figure 7.4 comperes the model outcome with and without ALFC scheme for 110 MW step generation rejection. It is evidently enhancing the frequency regulation and by achieving prime objective of ALFC which is correction of steady state frequency error.

The effect of increasing ALFC participatory generators were detailed section 7.2.1. The output obtained in each scenario is compared on same time scale in Figure 7.5. Eventually, lesser number of machines produce unwanted oscillation and delayed time for steady state frequency error correction. Hence, higher the number of machines on ALFC scheme, better the regulation on system frequency. Moreover, higher number of machines limit the frequency run-away while making frequency recovery faster. Despite of these outcome, increasing machines on ALFC in Sri Lankan system is largely depended on committable hydro generators for time being.

Such commitment is primarily determined by the water management directives decisions collaboratively taken by Mahaweli Authority, Department of Irrigation and CEB. Therefore, dedicated generators for regulation control with ALFC capability must be brought in to Sri Lankan system in future if the frequency regulation quality is compulsorily set into a tight span.

The suitable ALFC triggering time for Sri Lankan system would be 6 to 8 secs as per the outcome exhibited in section 7.2.2 and Figure 7.6. Apparently, if time is less 4 sec or greater than 8 secs, then ALFC is not properly functioning. The IEEE recommendation for large system is 4 secs whereas for a small system like Sri Lanka, it must be bit higher than that due to low number of committed units for ALFC participation. The whole this research was carried forward with 6 secs as triggering time for ALFC scheme in upcoming analysis.

The ALFC scheme behaviour with respect to different ALFC forward gain is analysed based on the data shown in Table 7.2. The impact on frequency regulation for different gain value on each band are given by Figure 7.7. As per driven outcome, the regulation control would be much better if the gain value is kept around unity value. Still it must be adjusted from unity value in each individual band in order to control overshoot and steady state oscillation while ensuring the proper frequency recovery. Literally, Figure 7.7 exhibits that, if the ALFC gain is too low (from unity value) then error correction is much slower. On the other hand, if the ALFC gain too big (from unity value) then steady state overshoot goes higher. Hence, ALFC gain adjustment could be tuned and dynamically decided by system operator based on the regulating requirement of system frequency in real time operation. Upcoming analysis is done with the gain allocation as given by Run-02 on Table 7.2.

Subsequently, same model is now fed with actual frequency response obtained during 110 MW generation rejection (as shown Figure 7.1) instead of step changing disturbance. This will show, what would be the outcome if ALFC scheme was there in operation during the disturbance. Evidently, developed ALFC scheme provides much better regulation on system frequency by providing faster recovery in system frequency while limits the frequency run-away as shown in Figure 7.9. The prime objective of ALFC scheme is well exhibited as per simulation results discussed above.

The detailed analysis shown in Section 7.3, 7.4 and 7.5 are done as same above for Off-peak, Day-time and Night-peak separately, by using individually valided ALFC models. The simulated outcomes of such models are illustrated in Figures 7.12, 7.13, 7.16, 7.17, 7.20, 7.21. These results are further evidencing the objective and benefit of ALFC in termers of better steady-state regulation quality, faster recovery during disturbances and limitation of frequency run-away.

As a final approach, actual frequency trend is fed into developed ALFC scheme in order to observe the viability of the design. The input frequency trend is selected such a way that of having high number of large variation in it. The ALFC scheme output for such input is illustrated in Figure 7.22 and 7.23 with comparison. The summary of same outcome is compared in Table 8.1 as well for better understanding.

Table 8.1: Comparison of Actual Frequency response with ALFC outcome.

Frequency Band (Hz)	% of samples for Actual Response	% of samples for Response with ALFC scheme
50.20 - 50.15	1	0
50.15 - 50.10	6	0
50.10 - 50.05	13	0
50.05 - 50.00	20	49
50.00 - 49.95	23	51
49.95 - 49.90	17	0
49.90 - 49.85	12	0
49.85 - 49.80	7	0
49.80 - 49.75	2	0

CHAPTER 09

CONCLUSION

9.1 Conclusion and Recommendations

Automatic load frequency (ALFC) scheme is developed and studied for the betterment of quality of system frequency regulation. The simulation results of system responses from the developed models with/without ALFC are evidently stating that the quality of frequency regulation is much improved if Sri Lankan system is associated with ALFC scheme. The study conclusion and recommendations are listed in here;

- If power system associated with ALFC scheme, it would enable improved regulation quality in system frequency in terms of;
  - *Better frequency regulation on steady state.*
  - *Faster frequency recovery during significant disturbances.*
  - *Limit the frequency Run-away during small disturbances.*
  - *Ensure smooth variation in steady-state system frequency.*
- Primarily, operation targets of ALFC scheme determined by system bias setting. The bias for Sri Lankan system could be used as;
  - *Day Time: 8.52 MW/0.1Hz*
  - *Night-Pea: 8.91 MW/0.1Hz*
  - *Off-Peak: 6.41 MW/0.1Hz*

  Still the system bias calculation must be keep on updated as per methodology proposed in this document or by any other measures in order to track the changes in system characteristics with a time.
- The ALFC triggering cycle time for Sri Lankan system could be used as 6 to 8 secs as such triggering time enables the desired regulation characteristics for ALFC scheme.
- More machines on ALFC, better the frequency regulation. But committing more machine for purpose of ALFC only is very difficult as operational constrains associated with hydro reserves. Anyhow, Future CEB’s system must be coupled with frequency controlling on thermal energy-based

reserves. Such situation might improve frequency regulation as it could be committed more machines for ALFC purpose alone.

- The ALFC gain adjustment could be tuned by system operator based on the regulating requirement of frequency in real time operation. Keeping unity gain in ALFC could be always produce desire results but the recovery time may be slow. As a result, ALFC gain for each regulating bands, must be dynamically allocated by system operator as discussed in section 6.2.3.
- Regulating ALFC between 49.85 Hz to 50.15 Hz (±0.003 (pu) from nominal value) largely depend on selection of regulation requirement over machine governor wear & tear problems (Oscillatory outcome on steady state).
- Output of this ALFC application could be interfaced with the SCADA system once necessary governor controls are interfaced with the central SCADA system.
- This study enables further LFC related study for Sri Lankan system to address system nonlinearity and other complex characteristics.

9.2 Limitation and Future Works

This study is conducted based on number of work boundary as listed in here in order to confined the research target only towards the interested subsystem behavior over frequency responsiveness.

- The power system model is not considered with intermachine oscillation and transient-system performance.
- The turbine-governor models are selected such as having most linear characteristics for principal dynamic effects of the energy source and prime mover associated controls.
- The total primary regulation support given by thermal system is represented by single thermal turbine-governor model.
- Rest of generators response and collective system regulation characteristics are lumped into other power system parameters like System Inertia, Load Damping, Regulation Factor and Speed-droop regulation.

- The ALFC control system is considered only for regulation of own-area frequency control though it could be extended to be associated with economic dispatch, interchange control and base-point scheduling control.
- This research does not cover into the individual plant level control parameters and its limitations in detailed level.

Further, the core architecture of ALFC is developed based on classical control techniques as this approach is widely adopted for the initialization of speed governing LFC studies. Further, this methodology would enable simplicity over control strategies and provide easy understanding of regulation control design even with advance algorithms. Still, this conventional method could not be able to possess complex information in terms of the non - linearity of system response. The ALFC feed-forward gain analysis must be linked into stability margin analysis based on gain and phase margins through bode plots analysis methodology. Then, stability margin of different ALFC gain would be clearly marked in a confined region where the regulation performance is achieved as expected while keeping the system stability way away from unstable margin. Besides, it is also recommended to analyze the system non-linearity characteristics along with individual plant level limitation over, frequency control mechanism as future work. As a conclusion, the methodology used in this study could be adopted as it is to analyse the future implementation and expansion of Sri Lankan AGC system.

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Appendix-A: Governor capability of large machines in Sri Lankan system (Source: System Control Center, CEB)

Power Station	Unit No.	Mode of frequency/MW control		Mode of Voltage / Mvar control	AVR setting
		Free Governor /Fixed load .etc	Droop Setting		
Victoria	1,2,3	Free Governor	ep1: 1.2% , ep2: 4.6%	Voltage Control	12.5kV +/- 5%
Kothmale	1,2,3	ep1/ep2	ep1: 2.4% , ep2: 8.9%	AVR	Auto
Randenigala	1,2	Fixed Load	5%	Fixed	Auto
Rantabe	1,2	Fixed Load	5%	Fixed	Auto
Ukuwela	1	Free Governor	3%	AVR	10 Mvar/- 10 Mvar
Bowathenna	1	Free Governor	5%	AVR	10 Mvar/- 0 Mvar
WPS	1,2	Free Governor	5%	AVR	11kV
Canyon	1,2	Load Limiter Operation forced Governor	5%	AVR	5%
N/Laxapana	1,2	Free Governor	5%	AVR	12.5kV
O/Laxapana	1,2,3,4,5	Free Governor	4%, 4%, 4%, 5%, 5%	MVAR	11kV
Polpitiya	1,2	Fixed Load	6%, 8%	AVR	12.5kV
Samanalawewa	1,2	Free Governor	4.50%	AVR	10.5 kV - 0.88/1.1 pu
Kukule	1,2	Free Governor	5%	Voltage Control	13.8kV +/- 10%
Puttalam Coal	1,2,3	Fixed Load	N/A	Auto/Manual	0.9-1.1 pu
Sapugaskanda A	1,2,3,4	Fixed Load	5%,7%,8%,7%	VAR Mode	Usually set at 8 Mvar subjeted to system control requirement and stator winding temperature
Sapugaskanda B	5,6,7,8,9,10,11,12	Fixed Load	7.5%, 7.7%, 7.2%, 7.2%, 8.0%, 7.5%, 7.8%, 7.5%	PF Mode	Usually set at .8 subjeted to system control requirement and stator winding temperature
KCCP GT	1		4%		
KCCP ST	1		4%		
AES GT	1	Droop mode	4%	VAR Mode	10.5 kV +/- 10%
AES ST	1	Droop mode	5%	VAR Mode	10.5 kV +/- 10%
WCP GT	1,2	Free Governor	4%		
WCP ST	1	Free Governor	4%		

End of Thesis