Load Frequency Control in Shipboard Power Systems: Design and Simulation

A Thesis
Submitted to the Faculty
of
Drexel University
by
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in partial fulfillment of the
requirements for the degree
of
Master of Science in Electrical Engineering
May 2014
Dedications

To my first teacher, Soma.
Acknowledgements

I thank my advisors Dr. Karen Miu and Dr. Harry G. Kwatny for giving me the opportunity to work with them. This thesis would not have been a reality without their wonderful support and guidance whenever needed. I would also like to thank Dr. Chika Nwankpa for serving on my committee and for all the help during the time at CEPE laboratory. I also extend warm gratitude to Dr. Thomas Halpin for believing in me and Dr. Dagmar Niebur for cheering up my days.

I would like to acknowledge the help from all my friends especially the wonderful people at CEPE lab for their support and help through good and bad times. I thank Christian in particular for being a great colleague and friend.

I thank my family, especially my grandmother for teaching me that no dream is too big. I also extend my thanks to Regina and Sabu for being there for me every single time. Nothing would have ever been possible if not for the unconditional support and love of my parents, my parents-in-law, Meenu, and Renjith. Thank you for being there for me.
# Table of Contents

List of Tables .................................................................................................................................. vi
List of Figures .................................................................................................................................. vii
Abstract ........................................................................................................................................... x

1 Introduction ................................................................................................................................... 1
  1.1 Motivation ................................................................................................................................. 1
  1.2 Background ............................................................................................................................... 2
  1.3 Objectives ............................................................................................................................... 4
  1.4 Contributions ........................................................................................................................... 4

2 System Modeling ....................................................................................................................... 5
  2.1 DDG51 Benchmark System ...................................................................................................... 5
  2.2 Differential Algebraic Model for Shipboard Systems ............................................................... 8
  2.3 Models of Components ........................................................................................................... 8
    2.3.1 Reference generator and turbine model .............................................................................. 8
    2.3.2 Transmission lines ........................................................................................................... 14
    2.3.3 Load models ................................................................................................................... 16
    2.3.4 Synchronous machine excitation system (Automatic Voltage Regulator or AVR) .......... 19
  2.4 Network and Power Flow Equations ....................................................................................... 20
    2.4.1 Power flow equations ....................................................................................................... 20
    2.4.2 Newton-Raphson (N-R) method for solving power flow equations ................................. 22
  2.5 Equivalent Reduced Network .................................................................................................. 22

3 Load Frequency Controller ................................................................................................. 25
  3.1 Fundamentals of Governor Control ........................................................................................ 26
    3.1.1 Governor action on generating units .................................................................................. 26
### List of Tables

2.1 Transmission line parameters

2.2 Load at different mission requirements

2.3 Load demand on the electrical system in EPS

3.1 Types of buses in power systems with LFC

4.1 Simulation details

4.2 Participation factors and power output at constant load ($T_{simulation} = 200$ sec)

4.3 Propulsion load and power output at constant participation factors ($T_{simulation} = 200$ seconds)

4.4 Bus number in network structure 1 and 2

B.1 Parameter values used in simulation

B.2 Sensitivity coefficients
List of Figures

1.1 Interconnected terrestrial power system with scheduled power interchange between areas........3

2.1 Single line diagram of DDG51 benchmark system .................................................................7

2.2 Effect of changing $\delta$ on terminal voltage ...............................................................10

2.3 Classical machine model .............................................................................................11

2.4 Reference generator model for bus $i$ ...........................................................................12

2.5 Turbine model .............................................................................................................13

2.6 Short transmission line model .....................................................................................14

2.7 Admittances of transmission lines in the benchmark system ........................................16

2.8 Hybrid Electric Drive on bus 6 ..................................................................................17

2.9 Automatic Voltage Regulator ....................................................................................20

2.10 5 bus reduced equivalent model using the Kron reduction ........................................24

3.1 Governor/LFC action on a generating unit ....................................................................27

3.2 Static speed-power curve of turbine ..........................................................................28

3.3 LFC model and network ............................................................................................33

3.4 Load Frequency Controller block diagram .............................................................36

3.5 Linearized generator model ......................................................................................37

3.6 Block diagram representation of linearized generator model ....................................37

3.7 Reduced block diagram representation of linearized generator control ....................38

3.8 Block diagram representation of the interconnected generating units .......................39

4.1 Steps involved in creating the Simulink models .........................................................41

4.2 Network structure 1 ..................................................................................................44

4.3 5 bus reduced network model .....................................................................................45

4.4 Actual power output and generator set point of the units at $P_{\text{total}} = 0.6805$ pu with varying participation factors .................................................................47

4.5 Frequency of the generating units at $P_{\text{total}} = 0.6805$ pu with varying participation factors ......48
4.6 Frequency of units G1 and G2 returning to nominal value after changing $k$ at $t=50$ seconds.................................................................................................................... 49

4.7 Actual power output and generator set point of the units at $P_{\text{total}}=1.0296$ pu with varying participation factors.................................................................................................................... 50

4.8 Frequency of the generating units at $P_{\text{total}}=1.0296$ pu with varying participation factors ............. 51

4.9 Voltage profile at the internal buses of G1 and G2 at $P_{\text{total}}=0.6805$ pu with varying participation factors............................................................................................................... 52

4.10 Voltage profile at buses 3, 4, and 5 at $P_{\text{total}}=0.6805$ pu with varying participation factors ........ 53

4.11 Actual power output of the generating units following the generator set point at $k_1 = k_2 = 0.5$ with varying load.......................................................................................................................... 55

4.12 Frequency of units G1 and G2 point at $k_1 = k_2 = 0.5$ with varying load ......................................... 56

4.13 Power output of units G1 and G2 deviating from generator set points at $P_{\text{total}}=1.0296$ pu with $k_1 = 0.9$ and $k_2 = 0.1$ ..................................................................................................................... 57

4.14 Frequency of generating units deviating from nominal value at $t=150$ seconds when $P_{\text{total}}=1.0296$ pu with $k_1 = 0.9$ and $k_2 = 0.1$ ..................................................................................................................... 58

4.15 Voltage profile at the internal buses of G1 and G2 at $k_1 = k_2 = 0.5$ with varying load ............... 59

4.16 Voltage profile at buses 3, 4, and 5 at $k_1 = k_2 = 0.5$ with varying load ........................................ 60

4.17 Comparison of frequency of G1 and G2 obtained using 5 bus and 11 bus models-constant load.......................................................... 61

4.18 Difference in frequency obtained using 5 bus and 11 bus models-constant load.......................... 62

4.19 Comparison of power outputs of G1 and G2 using 5 bus and 11 bus models-constant load.......................................................... 63

4.20 Difference in power output using 5 bus and 11 bus models- constant load ..................................... 64

4.21 Comparison of the voltage profile at buses 1and 2 using 5 bus and 11 bus models-constant load.......................................................................................................................... 65

4.22 Comparison of the voltage profile at buses 3, 4, and-5 using 5 bus and 11 bus models-constant load.......................................................................................................................... 66

4.23 Comparison of frequency of G1 and G2 obtained using 5 bus and 11 bus models – constant $k_1$ and $k_2$ .......................................................................................................................... 67
4.24 Difference in frequency of G1 and G2 obtained using 5 bus and 11 bus models-constant $k_1$ and $k_2$ ........................................................................................................................................... 68

4.25 Comparison of power outputs of units G1 and G2 obtained using 5 bus and 11 bus models-constant $k_1$ and $k_2$ ........................................................................................................................................... 69

4.26 Difference in power outputs of units G1 and G2 obtained using 5 bus and 11 bus models-constant $k_1$ and $k_2$ ........................................................................................................................................... 70

4.27 Comparison of the voltage profile of internal buses obtained using 5 bus and 11 bus models-constant $k_1$ and $k_2$ ........................................................................................................................................... 71

4.28 Comparison of the voltage profile at buses 3-5 obtained using 5 bus and 11 bus models-constant $k_1$ and $k_2$ ........................................................................................................................................... 72

4.29 Network structure 2 ........................................................................................................................................... 74

4.30 Frequency of generating units in network structure 1 and 2 ........................................................................................................................................... 75

4.31 Power outputs of generating units in network structure 1 and 2 ........................................................................................................................................... 76

4.32 Voltage profile of buses 1 and 2 in network structure 1 and 2 ........................................................................................................................................... 77

4.33 Voltage profiles of buses 3-5 in network structure 1 and 2 ........................................................................................................................................... 78

A.1 Algorithm for N-R method ........................................................................................................................................... 83

B.1 Sensitivity coefficients and power generated at internal buses of units $i$ and $j$ ........................................................................................................................................... 86
Abstract
Load Frequency Control in Shipboard Power Systems:
Design and Simulation.
Uthara Mary Reji

In order to ensure quality of power supply and safe operation of components in a power system, it is necessary to maintain the frequency of the system as close as possible to the nominal value. Load Frequency Control (LFC) aims to tackle these problems through governor control on prime movers of generating units. Due to the inherent differences between terrestrial and marine power systems, it is necessary to investigate LFC on shipboard power systems separately. This thesis proposes a controller designed to maintain the nominal frequency of a marine power system while achieving load sharing between units using participation factors.

Proper modeling of the components that constitute the power system is necessary to capture the characteristics of the system with accuracy. Thus, mathematical models for various components for a DDG51 benchmark shipboard system are also presented in this work. A Simulink© based simulation platform for the benchmark system that incorporates the generator controls as well as the network is developed with a focus on LFC.

Simulation results for various loading conditions, participation factors and location of generator units are provided to successfully demonstrate the effectiveness of the controller and scope of the developed simulation platform. Results obtained using these tools can be used to obtain economic dispatch schedules, stable operating points etc. of the system which paves the way for proper management of a shipboard power system.
Chapter 1: Introduction

The quality of power supply in any system can be gauged through the balance of power generation and demand. Thus, for successful operation of any power system it is necessary to match total generation with total load demand and associated system losses. In addition to maintaining the power balance, it is also important to maintain system frequency close to nominal value. This is due to deteriorating performance or failure of frequency dependent components of the power system like stream turbines, electric clocks, power electronic devices etc. The set of control actions that maintain power balance at nominal frequency is called Load Frequency Control (LFC).

With the development of hybrid propulsion in ship systems that use electric and mechanical sources for propulsion, modeling of these systems has gained interest [13]. Various principles and assumptions of power system studies has to be tailored differently for marine power systems. This thesis proposes a model for implementing Load Frequency Control in shipboard systems taking into account the basic differences between terrestrial and shipboard power systems. A simulation platform for realizing this model for various conditions is also developed for this work.

1.1 Motivation

LFC is a major component of power systems and the set of actions executed by this controller regulates the frequency and power output of the generating units to accommodate the changes in load demands. Control principles and various methods of implementing these controls are investigated through much literature that is available. Only a minor fraction of these work discuss load frequency control for shipboard systems in particular. There are major inherent differences between terrestrial and shipboard systems that necessitate a separate study in this regard. Some of the major differences between terrestrial and marine power systems are mentioned below [3]:

- Unlike terrestrial systems that expand over a vast area between generation and consumption, shipboard system generating units are located close to the loads. Hence, the transmission line
losses and other associated dynamics play a less significant role in the analysis of these systems.

- Due to the above mentioned reason, faster controls are possible in the case of marine systems as compared to terrestrial systems. This calls for revised control objectives for shipboard systems.

- The number of generating units available onboard a ship is limited. Consequently, the generation capacity and system inertia due to the generators are low.

- It is not justifiable to make the classical assumptions of infinite bus with constant voltage and frequency in marine systems. This is in contrast to large grids in terrestrial systems with thousands of generating units and much higher system inertia.

- Also, due to the limited generating capacity and nature of loads specific to shipboard power systems like propulsion motors, rail guns etc, it is common for individual loads to be a significant fraction of the total generation available.

Simulation tools provide a platform to represent real-world systems using mathematical models and are useful in capturing the system operation under various conditions. Simulation provides insight on the behavior of the actual system, range of parameter values for stable operation etc. This makes it possible to analyze the system without having to actually build the system. In order to demonstrate the effect of the controller on a shipboard power system, a simulation model is also proposed in this thesis.

1.2 Background

Load frequency control issues have been a vastly researched topic through different times. Many controller designs that maintain frequency deviations within an area to a minimum and regulate tie-line flows are proposed in these works. As the complexity of power systems grew, the problem was approached from many levels such as optimal control [15], variable structure control [25, 16], fuzzy logic, neural networks [17, 18] etc. Detailed description of literature available on LFC is presented in [19]. With deregulation, interest in LFC has attained more momentum in recent past.
Most of these works concern load frequency control across different control areas. Assuming one control area to be a single cohesive generating unit is one of the frequent assumptions made in these cases as it is justified for terrestrial systems. [8] gives a good overview of AGC model for two area power systems. In [9], Chatterjee proposes a dual mode PI controller for multi-area systems to maintain frequency at nominal values while controlling scheduled power flow between areas. All these works assume that generators in an area are coupled internally and swing in unison [4]. Area Control Error or ACE is used to manifest the generation change required at the control area to meet the load change and scheduled tie-line power flow at permissible frequency deviations.

\[ \text{ACE}_i = (P_{\text{scheduled},ij} - P_{\text{actual},ij}) + B_i \Delta f_i \]  

(1.1)

Where

- \( \text{ACE}_i \): Area Control Error of area \( i \)
- \( P_{\text{scheduled},ij} \): Scheduled tie-line power interchange between area \( i \) and \( j \)
- \( P_{\text{actual},ij} \): Actual tie-line power flow between area \( i \) and \( j \)
- \( B_i \): Frequency bias factor for area \( i \)
- \( \Delta f_i \): Frequency deviation of area \( i \) from nominal frequency.

As discussed, it is necessary to study load frequency control in shipboard systems separately. In [11], Sun et. al proposes as model for load frequency controller in shipboard systems without considering the power system network to which the units are connected. The model put forth by Hansen et. al in [14] considers the interconnection between the units as a load module. Thus to
incorporate the power system and transmission network through which the generating units are interconnected, a combined Differential Algebraic model for shipboard systems is presented in this work.

1.3 Objectives

This thesis aims to meet the following objectives:

- Propose a model for load frequency controller in shipboard power systems that meets the following objectives:
  - Maintain the system frequency at the nominal value.
  - Match generation and load demand through successful load division among available units based on participation factors.
- Provide a DAE model for shipboard system that incorporates the generator controls and power flow equations.
- Provide details on the mathematical models used to represent each component of the system.
- Develop a simulation tool that captures the necessary aspects of a shipboard power system and demonstrate the action of load frequency control on it.
- Provide simulation results of the model under different situations of interest.

1.4 Contributions

The major contributions of the work presented in this thesis are:

- The design of a PI controller for achieving load frequency control in shipboard power system.
- A Simulink© based simulation platform for a benchmark shipboard system that integrates differential and algebraic component of the power system for pseudo-steady state analysis.

This platform can be utilized to perform load and participation factor sweeps to study optimal control problems such as economic dispatch for generators/energy sources in shipboard systems.
Chapter 2: System Modeling

The DDG51 class destroyer was chosen as the benchmark model for a shipboard system in this thesis. Load Frequency Control (LFC) was implemented on this benchmark system as a Differential Algebraic (DA) model using the Simulink platform. Detailed modeling of the dynamic load frequency controller will be presented in Chapter 3. This chapter describes the modeling of all the other components used for simulation. In particular, a focus on modeling the synchronous machine as a ‘reference’ generator model to enable LFC is presented in detail. For analysis purpose it is assumed that the system is in balanced three phase operation. Hence, single phase models represented by single line diagrams are proposed for each component.

The modeled components presented in this chapter include:

- Reference generator model for synchronous machines to enable LFC.
- Transmission lines
- Load models
- Automatic Voltage Regulator (AVR)
- Network equations of the network to which the generators are connected.

2.1 DDG51 Benchmark System

Figure 2.1 shows the single line layout of the benchmark system selected for modeling LFC in shipboard systems. The benchmark configuration was obtained from [14]. The network consists of three Gas Turbine Generating Sets (GTGs) rated at 2500 KW and supplying 450 V AC, three phase 60 Hz power. All the parameter values in the models are expressed in per unit. For doing so, the base value was chosen to be the total power rating of two generating units, \( S_{\text{base}} = 5 \text{ MW} \). Hence, the normal generation capacity of each generating unit can be expressed as 0.5 pu. Overloading capacity of the GTGs is 4500MW or 0.9pu [23]. The gas turbines could be used for both propulsion (through Hybrid Electric Drive) and ship service electrical power generation.
The internal buses of these GTGs were numbered as 1, 2, and 3 respectively. These units were connected to the external buses of the synchronous machines labeled as Buses 4, 5, and 6 in the network. The loads were attached to buses 7 through 12. In general, loads could be attached to any bus except the generator internal buses.

Under normal operating conditions, two of the generating units would be online supplying the electric power requirement of the ship network. The third generator could be spinning, offline or act as synchronous condenser for voltage control. Along with GTG3, Bus 4 also had a Hybrid Electric Drive (HED) connected to it. This is being considered as a dynamic load in the later sections. All the other loads connected to the rest of the buses were modeled as static loads. The interconnection between the loads and generating units was through lines that were characterized by their admittance values.

Details on modeling these components are given in the following sections. Calculations involved in finding the parameter values of different components are shown in Appendix B.
Figure 2.1 Single-line diagram of DDG51 benchmark system
2.2 Differential Algebraic Model for Shipboard Systems

In order to demonstrate the action of LFC, a shipboard benchmark system was modeled as a DA model in MATLAB/Simulink. In this approach the algebraic equations are treated as the network module to which the generators along with their LFC controllers are attached. Dynamics of this power system can be expressed as a set of differential algebraic equations given by:

\[
\dot{x} = f(x, y) \\
0 = g(x, y)
\]

(2.1)

where 
- \(x\): Set of continuous states
- \(y\): Set of algebraic states
- \(f\): Set of differential equations
- \(g\): Set of algebraic equations

The swing equations representing the generator dynamics and power flow equations that define the network constitute the DA model used in this thesis. Rest of the sections in this chapter are organized provide insight into the models involved in the setup of a DA model that combines generator dynamics with the network.

2.3 Models of Components

2.3.1 Reference generator and turbine model

At steady-state, the rotor angle of a synchronous machine rotating with synchronous frequency \(\omega_0\) can be expressed as \(\theta(t) = \omega_0 t + \theta_0\) with respect to a synchronously rotating reference frame. \(\theta_0\) is the angle between the rotor axis and the reference frame and it is a constant. Due to a change in the mechanical input (or prime mover output) to the machine, there will be a change \(\Delta \theta(t)\) in the rotor angle and it becomes \(\theta(t) = \omega_0 t + \theta_0 + \Delta \theta(t)\). From [2], the excitation voltage of the synchronous machine is given as \(E_f(t) = E_{f,\text{max}} \angle [\omega_0 t + \theta_0 + \Delta \theta(t) - \frac{\pi}{2}]\) or \(E_{f,\text{max}} \angle \delta(t)\) where \(\delta(t) = \omega_0 t + \theta_0 + \Delta \theta(t)\). Hence, the rotor angle change can be translated as the internal voltage
angle change in the synchronous machine. This angle is controlled dynamically by the LFC to change the power input to the network by the generator as

\[ P_g(t) = \frac{|E_f(t)|V_T}{X_G} \sin(\delta(t) - \vartheta_T) \quad (2.2) \]

where
- \( P_g \): Electrical output of the generator
- \( E_f(t) \): Excitation voltage
- \( \delta(t) \): Excitation voltage angle
- \( |V_T| \angle \vartheta_T \): Terminal voltage of the generator
- \( X_G \): Synchronous reactance of the generator

Assuming that the generator has no internal resistance i.e., \( R_G = 0 \), the synchronous admittance is given by, \( Y_G = \frac{1}{jX_G} \).

Assuming that the excitation voltage \( E_f(t) \) can be considered constant for a short interval of interest, the power output of the generator can be controlled by controlling the power angle \( \delta(t) \). It is clear from Equation 2.2 and Figure 2.2 that as delta is varied, with constant excitation voltage \( E_f \), it is possible to regulate the power injected at the terminal bus and consequently, the terminal voltage drops. This voltage is kept at a reference value by Automatic Voltage Regulator (AVR) discussed in Section 2.3.4.
In order to implement LFC action dynamically, the internal buses of the generating units should also be included in the network as voltage and frequency at these buses can be controlled. To do so, the reference generator model for generating units on LFC is proposed. It is called the ‘reference’ model because one of these internal buses can be arbitrarily chosen to be the reference bus for the power flow equations. It is to be noted that at least one generator should be modeled as reference generator in the network to account for losses or slack.

The equations for a generator modeled as voltage behind reactance in Classical Machine Model is given as:

\[
\begin{align*}
\frac{d\delta(t)}{dt} &= \omega(t) - \omega_b \\
\frac{d\omega(t)}{dt} &= \frac{1}{2H} \left( P_m(t) - P_G(t) - D(\omega(t) - \omega_b) \right) \\
\text{where } P_G(t) &= \frac{|E_f|}{\left| \frac{1}{Y_G} \right|} \sin(\delta(t) - \theta_F)
\end{align*}
\]

(2.3)
\( \omega(t) \) : Electrical frequency of the synchronous machine, \( \text{rad/s} \)

\( \omega_0 \) : Synchronous frequency of the unit, \( \text{rad/s} \)

\( \delta(t) \) : Internal voltage angle of the synchronous machine, \( \text{rad} \)

\( P_m(t) \) : Mechanical power of the generator shaft, \( \text{pu} \)

\( P_G(t) \) : Electrical power output of the generator, \( \text{pu} \)

\( D \) : Load damping coefficient, \( \% \)

\( H \) : Intertia constant of the generating unit, seconds

\( E_f \) : Internal voltage of the generating unit, \( \text{pu} \)-assumed to be constant for a short window of time

\( V_T \) : Voltage at the terminal bus of the generating unit, \( \text{pu} \)

\( \theta_T \) : Voltage angle of the terminal bus, \( \text{rad} \)

\( Y_G \) : Synchronous admittance of the generating unit, \( \text{pu} \)

Figure 2.3 Classical machine model
For LFC, the internal reactance of the generator $Y_G$ was also included in the network algebraic equations. Hence, a generator $i$ is modeled in Simulink as a function block with the following inputs and outputs:

**Inputs:**
- $E_{fi}$ from Automatic Voltage Regulator (AVR)
- $P^{\text{LFC}}_{mi}$ from LFC center
- $P^{\text{LFC}}_{Gi}$ from power flow solutions

**Outputs:**
- $\delta_i$ to the network as the voltage angle
- $\omega_i$ to LFC center

![Figure 2.4 Reference generator model for bus $i$.](image-url)
If there was a generating unit not participating in LFC under any circumstances i.e.; acting as spinning reserve or acting as a constant active power source, it could be modeled as a PQ generator model with constant real power output and the external bus to which the generator was connected could be treated as PV bus or PQ bus.

The benchmark system had aero-derivative gas turbines as prime movers to the synchronous machines. These are highly efficient and fast gas turbines which have response times higher than industrial turbines [12]. The turbine heating cycles, fuel valve action, hydraulic amplifiers and temperature dynamics are fast and hence, are not considered for the LFC model presented in this document.

A simple non-reheat model for a turbine with time constant $T_r$ was used for the modeling purposes. $T_r$ is usually 0.4-1 second. Valve limits were used to constrain the fuel input to the turbine because the fuel valve cannot be more than fully open or fully closed.

![Figure 2.5 Turbine model](image-url)

Figure 2.5 Turbine model
2.3.2 Transmission lines

The transmission lines were modeled as short lines using a $\pi$-equivalent model.

![Diagram of Short Transmission Line Model]

**Figure 2.6** Short transmission line model

- $V_{\text{sending}} \angle \theta_{\text{sending}}$: Complex Voltage at sending end
- $V_{\text{receiving}} \angle \theta_{\text{receiving}}$: Complex Voltage at receiving end
- $Z$: Impedance of the transmission line
- $Y$: Admittance of the transmission line

For the benchmark shipboard system, the admittance values were calculated based on the maximum power handling capability, $P_{\text{max}}$ of the lines and reasonable assumptions of angle swing between sending and receiving buses. These parameters are shown in Table 2.1. $V_{\text{max}}$ was assumed to be 1.05 pu for all buses except the internal buses where the maximum voltage was 1.5 pu. Susceptances were calculated using

$$ B = \frac{P_{\text{max}}}{V_{\text{sending, max}} \cdot V_{\text{receiving, max}} \cdot \sin(\theta_{\text{sending, max}} - \theta_{\text{receiving, max}})} \quad (2.4) $$

Conductance (G) values were assumed to be 1% the susceptance values except for the line connecting generator internal bus and terminal bus. This was assumed to be lossless transmission.
Admittance of the transmission line between buses $i$ and $j$ in the network is then calculated as

$$Y_{ij} = G_{ij} + jB_{ij}.$$ 

### Table 2.1 Transmission line parameters

<table>
<thead>
<tr>
<th>Transmission Line</th>
<th>Maximum Expected Power Transfer ($P_{max}$)</th>
<th>$(\theta_{sending} - \theta_{receiving})_{\text{max}}$</th>
<th>$V_{sending,\text{max}}$</th>
<th>$V_{receiving,\text{max}}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator internal bus to terminal bus(G)</td>
<td>1 pu</td>
<td>10°</td>
<td>1.5 pu</td>
<td>1.05 pu</td>
</tr>
<tr>
<td>Generator terminal bus-adjacent bus or tie-line 1 (Tie1) Between all other buses or tie-line 2 (Tie2)</td>
<td>1 pu</td>
<td>1°</td>
<td>1.05 pu</td>
<td>1.05 pu</td>
</tr>
<tr>
<td></td>
<td>0.5 pu</td>
<td>1°</td>
<td>1.05 pu</td>
<td>1.05 pu</td>
</tr>
</tbody>
</table>

In order to simplify notation, the admittances of lines with similar parameters could be classified into three, namely:

$Y_G$: Synchronous admittance of the GTGs

$Y_{Tie1}$: Admittance of the line connecting generator terminal bus and adjacent buses

$Y_{Tie2}$: Admittance of the line connecting load bus to generator terminal bus and other load buses

The admittances of the transmission lines in the DDG51 benchmark system based on this classification is shown in Figure 2.7.
2.3.3 Load models

The analysis of LFC on the benchmark system was performed for different propulsion loads. This load was treated as a constant power load and the rest of the loads as static constant admittance loads.

Hybrid Electric Drive (HED) configuration allows the ship propulsion shaft to be driven through mechanical drive and electric drive. In mechanical drive configuration, dedicated prime movers or propulsion turbines supply the required mechanical power to maintain the speed of the ship. Here, Permanent Magnet Synchronous Machine (PMSM) acting as motor supplies the necessary power required for propulsion in the case of electric drives. Depending on the drive supplying power to the propulsion shaft, the Propulsion Operational Mode (POM) could be Trail Shaft, Full Power, Electric Propulsion System, Cross Connected, or Hybrid Generation. Details on POM are provided in
The HED configuration connected to Bus 6 is shown in Figure 2.8. There are losses in the electric system due to the generator losses, frequency converter losses and PMSM losses.

For the analysis presented in this thesis, the POM is assumed to be Electric Propulsion System in which the propulsion mechanical power is supplied through the electrical drive. The electrical equivalent of the mechanical power required at the propulsion shaft is seen as a constant power demand by the electrical network. This is made possible through power electronic devices like converters. The dynamics of these components are faster than LFC and are hence not considered in the current analysis.

All the static loads treated as constant admittance loads were incorporated in the admittance matrix of the network. The total static load was assumed to be distributed equally between the load buses 7-12.

\[
Y_{Li} = \frac{(S_{Li}^{\text{total}})^{\text{S}}}{\sqrt{\sum_{i=7}^{12} Y_{Li}^{\text{non}}}} ; \quad i = 7 \text{ to } 12
\]  

(2.5)
where $S_{L}^{\text{total}}$: Total static load demand.

$V_{L}^{\text{nom}}$: Nominal voltage at load bus $i$

### Table 2.2 Load at different mission requirements

<table>
<thead>
<tr>
<th>Mission</th>
<th>Max. Propulsion Load, pu</th>
<th>Max. Ship Service load, pu</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surge to Theater (ST)</td>
<td>1.2</td>
<td>1.2</td>
</tr>
<tr>
<td>Economical Transit (ET)</td>
<td>3.6</td>
<td>1.2</td>
</tr>
<tr>
<td>Operational Presence (OP)</td>
<td>0.4</td>
<td>1.2</td>
</tr>
</tbody>
</table>

Table 2.2 shows the propulsion and ship service load requirements for different missions of the ship. The portion of this requirement supplied by the electric system is limited by the available electric generation capacity. The propulsion load considered for the work presented here is the portion of propulsion system demand on the electrical system through Hybrid Electric Drive (HED) while in EPS configuration. Please see Table 2.3 for the selected scenarios for this work.

### Table 2.3 Load demand on the electrical system in EPS

<table>
<thead>
<tr>
<th>Operating Condition</th>
<th>Propulsion Load, pu (Constant P)</th>
<th>Ship Service Load, pu (Constant Z)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Normal(Generating units within P limits)</td>
<td>0.0 -0.4</td>
<td>0.6</td>
</tr>
<tr>
<td>Emergency(Generating units overloaded*)</td>
<td>0.4-1.2</td>
<td>0.6</td>
</tr>
</tbody>
</table>

*up to 5 minutes
The (12×12) network admittance matrix, $Y_{bus}$ with the constant admittance non-propulsion loads included can be expressed as shown below.

$$
Y_{bus} = 
\begin{bmatrix}
Y_g & 0 & 0 & -Y_g & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\
0 & Y_g & 0 & 0 & -Y_g & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & Y_g & 0 & 0 & -Y_g & 0 & 0 & 0 & 0 & 0 & 0 \\
-Y_g & 0 & 0 & (Y_g+2Y_{rel}) & 0 & 0 & -Y_{rel} & -Y_{rel} & 0 & 0 & 0 & 0 \\
0 & -Y_g & 0 & 0 & (Y_g+2Y_{rel}) & 0 & 0 & 0 & -Y_{rel} & -Y_{rel} & 0 & 0 \\
0 & 0 & -Y_g & 0 & 0 & (Y_g+2Y_{rel}) & 0 & 0 & 0 & -Y_{rel} & -Y_{rel} & 0 \\
0 & 0 & 0 & -Y_{rel} & 0 & 0 & (Y_{rel}+Y_{rel}+Y_{rel}) & 0 & -Y_{rel} & 0 & 0 & 0 \\
0 & 0 & 0 & -Y_{rel} & 0 & -Y_{rel} & 0 & (Y_{rel}+2Y_{rel}+Y_{rel}) & 0 & -Y_{rel} & 0 & 0 \\
0 & 0 & 0 & 0 & -Y_{rel} & 0 & 0 & -Y_{rel} & 0 & (Y_{rel}+2Y_{rel}+Y_{rel}) & 0 & -Y_{rel} \\
0 & 0 & 0 & 0 & -Y_{rel} & 0 & 0 & -Y_{rel} & 0 & (Y_{rel}+2Y_{rel}+Y_{rel}) & 0 & -Y_{rel} \\
0 & 0 & 0 & 0 & -Y_{rel} & 0 & 0 & -Y_{rel} & 0 & (Y_{rel}+2Y_{rel}+Y_{rel}) & 0 & -Y_{rel} \\
\end{bmatrix}_{42×42}
$$

The actual network admittance matrix values are given in Appendix B.

2.3.4 Synchronous machine excitation system (Automatic Voltage Regulator or AVR)

An excitation system supplies the voltage and current to the field windings of the synchronous machine. This could be separately excited as shown in Figure 2.9 or self-excited. AVR is part of a synchronous machine control system and is used to actively control the voltage at the terminal bus at a desired value, $V_{ref}$. Figure 2.9 gives the block diagram representation of the excitation system employed in the simulation of the 12-bus system. The controller keeps the voltage at the terminal buses ($V_T$) closer to $V_{ref} = 1.05$ pu by regulating the voltage at the internal bus of the synchronous machine, $E_f$. 

The voltage error between the reference value and the actual terminal voltage is fed into the regulator. The regulator amplifies and forms the appropriate control signal \( V_R \) for the exciter from the error. Saturation limits are provided for the regulator so that \( V_{R,max} \leq V_R \leq V_{R,min} \). The power to the synchronous machine field windings is provided by the exciter which constitutes the actual power stage of the excitation system. \( S_E(E_f) \) is the function that represents the departure of the load saturation curve from the linear open-circuit voltage versus the field current characteristic of dc generator. This is due to the loading of the exciter by the synchronous machine field winding.

### 2.4 Network and Power Flow Equations

This section presents the power flow equations of the network to which generators with LFC action are connected. These equations constitute the algebraic part of the DA model.

#### 2.4.1 Power flow equations

The principal information obtained from power flow study is the magnitude and phase angle of the voltage and the power injection at each bus \( i \) [6]. There are four states at bus \( i \) in a network, namely

- Voltage magnitude, \( |V_i| \)
Voltage angle, $\theta_i$

Real power injection, $P_i$

Reactive power injection, $Q_i$

Restricting our attention to a balanced three phase network so that per phase analysis is valid, for a $n$-bus system, power flow equations can be represented in terms of the $4n$ algebraic variables $y$ as:

$$ g(y) = 0 \quad \quad \quad (2.6) $$

where

$$ g_{2nx1} = \begin{bmatrix} P_i - P_i(y) \\ \vdots \\ Q_i - Q_i(y) \end{bmatrix} \quad ; \quad i = 1, 2, 3...n $$

$$ P_i(y) = \sum_{j=1}^{n} |V_j||V_j| [G_{ij} \cos(\theta_i - \theta_j) + B_{ij} \sin(\theta_i - \theta_j)] \quad (2.7) $$

$$ Q_i(y) = \sum_{j=1}^{n} |V_j||V_j| [G_{ij} \sin(\theta_i - \theta_j) - B_{ij} \cos(\theta_i - \theta_j)] \quad (2.8) $$

If two out of the four states are known at each bus solution to the power flow equations can be found to determine the unknown states of the system. The power flow equations in (2.6) can be written in terms of the known states $y_u$ and unknown states $y_v$ as

$$ g(y_u, y_v) = 0 \quad \quad \quad (2.9) $$

where

$$ y_u = \begin{bmatrix} y_{u1} \\ y_{u2} \\ \vdots \\ y_{u,2n} \end{bmatrix} \quad y_v = \begin{bmatrix} y_{v1} \\ y_{v2} \\ \vdots \\ y_{v,2n} \end{bmatrix} \quad \text{and} \quad y = \begin{bmatrix} y_u \\ y_v \end{bmatrix}_{4nx1} $$
This system of equations is a non-linear function of states. In this thesis, Newton-Raphson method is used to solve these equations.

2.4.2 Newton Raphson (N-R) method for solving power flow equations

Newton Raphson method can be used to solve for power flow equations, \( g(y_u, y_v) = 0 \) given in (2.9). The update equation for N-R method is given by:

\[
g(y_u, y_v) = -J\Delta y_v
\]  

(2.10)

\( J_{2n \times 2n} \) : Jacobian of \( g(y_u, y_v) \)

\[
J = \begin{bmatrix}
\frac{\partial g_1}{\partial y_{v1}} & \frac{\partial g_1}{\partial y_{v2}} & \cdots & \frac{\partial g_1}{\partial y_{v,2n}} \\
\frac{\partial g_2}{\partial y_{v1}} & \frac{\partial g_2}{\partial y_{v2}} & \cdots & \frac{\partial g_2}{\partial y_{v,2n}} \\
\vdots & \vdots & \ddots & \vdots \\
\frac{\partial g_{2n}}{\partial y_{v1}} & \frac{\partial g_{2n}}{\partial y_{v2}} & \cdots & \frac{\partial g_{2n}}{\partial y_{v,2n}}
\end{bmatrix}
\]

\[
\Delta y_v = \begin{bmatrix}
\Delta y_{v1} \\
\Delta y_{v2} \\
\vdots \\
\Delta y_{v,2n}
\end{bmatrix}
\]

With an initial guess for the state variables, \( y_u^0 \) and \( y_v^0 \), the update equation can be used to find solution to \( g(y_u, y_v) = 0 \). The algorithm for N-R method for power flow solution is shown in Appendix A.

2.5 Equivalent Reduced Network

Though there are three units available for power generation in the 12 bus benchmark system, only two of them were considered to be online at any given time. The third unit was offline and available in cases of emergency, which are not considered here. Hence the internal bus of the unit that is offline could be removed from the network. For simplicity, it was assumed that GTG1 was always online and the second unit could be GTG2 or GTG3. The benchmark model could be modified to have any pair of GTGs as the active units. The simulation model is set up to capture this feature and results for the cases (GTG1, GTG2) and (GTG1, GTG3) are presented in Chapter 4.
For example, two generating units, GTG1 (or G1) and GTG2 (or G2), are connected to Buses 4 and 5. GTG3 was assumed to be spinning and not connected to the network. Constant power propulsion load was connected to Bus 6 and the rest of the buses had constant admittance load connected to them. Hence the network had 11 buses:

- **Bus 1 and 2** – Internal bus of G1 and G2 respectively
- **Bus 4 and 5** – Terminal bus of G1 and G2 respectively
- **Bus 6** – Constant Power load bus.
- **Buses 7 to 12** – Constant Admittance load buses.

It was beneficial to reduce this 11 bus network to an equivalent network using the Kron reduction technique to demonstrate LFC action because:

- A 11 bus system has Jacobian matrix of size $22 \times 22$. This large size of the Jacobian will make solving the power flow equations computationally intense.
- Non-zero load current injection happens at only Bus 6 as all other load buses have constant admittance loads.
- For showing LFC action, behavior of the internal buses, terminal buses and the propulsion load bus are only of specific interest.
- The admittance matrix is quite sparse due to the topology of the network.

Hence the 11 bus network was reduced to a 5 bus network using the Kron reduction technique. Details on the Kron reduction are shown in Appendix C.
Figure 2.10 5 bus reduced equivalent model using the Kron reduction
Chapter 3: Load Frequency Controller

This chapter discusses the proposed LFC model objectives, integrating it with the network and steps followed in designing a Proportional Integral (PI) controller for implementing LFC action.

An index of terms used in this chapter is as follows:

\( H \) : Per unit inertia constant
\( \omega_0 \) : Synchronous frequency of the generator, rad/s
\( \omega \) : Angular frequency of the generator, rad/s
\( \delta \) : Internal angle of the generator, rad
\( P_m \) : Mechanical power from the prime mover in pu
\( P_G \) : Electrical power generated at the generator internal bus in pu
\( D \) : Load damping constant, pu
\( R \) : Regulation of the units, %
\( n \) : Number of buses in the system (including generator internal bus)
\( a \) : Number of generator internal buses in the network
\( b \) : Number of PV buses
\( c \) : Number of PQ buses
\( P_i \) : Active power injection at Bus \( i \)
\( Q_i \) : Reactive power injection at Bus \( i \)
\( P_{Gen,i} \) : Active power generated at Bus \( i \)
\( P_{Di} \) : Active power demand at Bus \( i \)
\( P_{Loss} \) : Active power loss in the network
\( P_{D,total} \) : Total active power load of the network
\( P_{PV,i} \) : Power input at PV bus \( i \)
\( P_{PV} \) : Total power input at PV buses
\( P_{LFC}^{total} \) : Total active power demand on LFC units by the network, pu
\( GCE_i \) : Generator Control Error of Unit \( i \), pu
\( B_i \) : Frequency bias factor for Unit \( i \), MW/(rad/s)
\( \Delta \omega \) : Frequency deviation of Unit \( i \) from nominal frequency, rad/s
\( k_i \) : Participation factor of Unit \( i \)
\[ |V_i| \quad : \text{Voltage magnitude at Bus } i \]
\[ \theta_i \quad : \text{Voltage angle at Bus } i \]
\[ y \in \mathbb{R}^{4n} \quad : \text{Algebraic states of the system} \]
\[ y_{v_{2 \text{mol}}} \quad : \text{Unknown State Variables} ; \quad y_v \subset y \]
\[ y_{u_{2 \text{mol}}} \quad : \text{Known State Variables}; \quad y_u \subset y \]
\[ G_{ij} \quad : \text{Conductance of the line connecting Bus } i \text{ and } j \]
\[ B_{ij} \quad : \text{Susceptance of the line connecting Bus } i \text{ and } j \]
\[ \Delta F \quad : \text{Change in fuel-inlet valve position of the turbine.} \]

### 3.1 Fundamentals of Governor Control

3.1.1 Governor action on generating units

The set of differential equations representing generator dynamics are given by the swing equation as shown below:

\[
\begin{align*}
\frac{d\omega(t)}{dt} &= \frac{1}{2H}(P_m(t) - P_G(t) - D(\omega(t) - \omega_b)) \\
\frac{d\delta(t)}{dt} &= \omega(t) - \omega_b
\end{align*}
\]

where \( P_0(t) = \frac{|E_i| |V_i|}{(1/|Y_i|)} \sin(\delta(t) - \theta_i) \) \hspace{1cm} (3.1)

At steady state, when \( P_m = P_G \), the rotor acceleration will be zero and it will rotate with constant angular velocity \( \omega_b \). Any change in load at this point will cause a change in electric power demand at the generator internal bus. This causes a mismatch between mechanical input and electrical output of the unit. Unless a balance between \( P_m \) and \( P_G \) is reached, the frequency of the generator will deviate from its nominal value, \( \omega_0 \). Thus a change in frequency is a measure of power imbalance in the network. This change is limited by the inertia of the unit, \( H \) and the damping constant, \( D \). To match generation to load demand and consequently bring \( \omega \) back to \( \omega_0 \), the prime mover of the generating unit has to be regulated to change its mechanical power output to match the load such that \( P_m = P_G \) again and steady state is achieved. Hence, with a frequency feedback controlling the prime
mover input, it is possible to meet load demand while maintaining desired steady state frequency. This control action is achieved through a governor or load frequency controller.

A governor is that part of the power system that senses change in frequency and converts it into appropriate valve action to regulate the fuel input of the prime mover and control the generator output and frequency. Governor movements alone are not strong enough to cause changes in the input valves to huge prime movers. Hydraulic amplifiers are used to convert governor controls into high power forces. Dynamics of servomotors, amplifiers and sensors are faster than governor dynamics and they are not included in the analysis presented in this thesis.

![Figure 3.1 Governor/LFC action on a generating unit](image)

3.1.2 Droop and isochronous governor control

Droop and isochronous are the two fundamental methods of turbine-generator speed control. Isochronous control means that changes in load results in no resulting speed change of the turbine-
generator from the set reference. This requires immediate and fast control actions via the fuel valve. Isochronous control is not usually recommended in the case of systems with more than one generator supplying the total load. This is because all the units will try to impose their set reference frequency on the system and any mismatch in parameters or ratings of the units will lead to instability [1, 5]. Typically, for interconnected units droop control is used. The following discussion is limited to droop control of turbine-generator units.

Governor action using droop control implies that any change in the electrical power output of the generator and frequency is associated with a linear decrease in the speed of the prime mover. This linear decrease in speed can be controlled using a factor $R$, the speed regulation or droop of the governor. For any governor, $R$ is termed as the ratio of speed deviation ($\Delta \omega$) to change in inlet valve gate position ($\Delta F$) or power output of the prime mover ($\Delta P_m$).

$$R = \frac{\Delta \omega}{\Delta P_m}$$  \hspace{1cm} (3.2)

Speed Regulation, $R$ can be found by sketching static speed/frequency - power curves for the turbine-governor. For linear droop control, these linear curves relate mechanical power output of the turbine to frequency and slope of these curves gives regulation, $R$. 

![Diagram showing the relationship between speed, frequency, and power output.](image)
Figure 3.2 Static speed-power curve of turbine

From (3.2), \( \Delta P_m = \frac{1}{R} (\Delta \omega) \). At steady state when balance between load and generation has been achieved, there would no longer be any change in frequency and prime mover output. In other words, \( \Delta P_m = 0 \) is a condition for steady state operation at nominal frequency. Therefore, an appropriate control signal for the turbine is \( \frac{1}{R} \Delta \omega \) and at steady state:

\[
\frac{1}{R} \Delta \omega = 0 \quad (3.3)
\]

3.2 Load Sharing

Another objective of LFC is to match the total real power demand with generation by regulating the output of the generating units and dividing this generation among participating units based on their participation factor, \( k \). This section establishes the control signal necessary to achieve this objective at steady state.

The power injected into the network at bus \( i \) is expressed as \( P_i \) and it can be written as:

\[
P_i = P_{\text{Gen},i} - P_{Di} \quad (3.4)
\]

The physical constraint of balance of active power gives the following relation:

\[
\sum_{i=1}^{a} P_i = P_{\text{Loss}} \quad (3.5)
\]

Or

\[
\sum_{i=1}^{a} P_{\text{Gen},i} - \sum_{i=1}^{b} P_{Di} = P_{\text{Loss}} \quad (3.6)
\]

The active power sources in the network include the ‘\( a \)’ generating units that have controllable active power injection by participating in LFC. Other sources of constant real power are connected to ‘\( b \)’ PV buses. The total power generation can be expressed in terms of these sources as

\[
\sum_{i=1}^{a} P_{\text{Gen},i} = \sum_{i=1}^{a} P_{\text{Gen},i}^{LFC} + \sum_{i=a+1}^{a+b} P_{PV,i} \quad (3.7)
\]
Using (3.7) and $\sum_{i=1}^{a} P_{Di} = P_{D_{total}}$, equation (3.6) can be rewritten as

$$\sum_{i=1}^{a} P_{Gi}^{LFC} + \sum_{i=a+1}^{a+b} P_{PV,i} - P_{D_{total}} = P_{Loss} \quad (3.8)$$

Since no load can be connected to the internal buses of the generators, $\sum_{i=1}^{a} P_{Di} = 0$. Thus the total active power demand of the network that has to be supplied by the ‘$a$’ generating units on load frequency control can be calculated as:

$$P_{Gi}^{LFC} = \sum_{i=1}^{a} P_{Gi}^{LFC} = P_{Loss} + P_{D_{total}} - \sum_{i=a+1}^{a+b} P_{PV,i} \quad (3.9)$$

This total load is to be distributed among the participating units based on their participation factors $k_i$. These factors can be based on any control objective or constraints like economic dispatch, quality of service etc [13, 21, 22]. Thus, the electrical power output of a generating unit $i$ will be $k_i$ times the total load.

$$P_{Gi}^{LFC} = k_i P_{total} \quad (3.10)$$

Since the entire $P_{total}$ has to be supplied by the participating units to reach steady state, $\sum_{i=1}^{a} k_i = 1$ and $0 \leq k_i \leq 1$. Equation (3.11) gives the control signal for LFC to control the turbine output so that the power output at steady state matches the load demand and is equal to the desired value set using participation factors.

$$k_i P_{total}^{LFC} - P_{Gi}^{LFC} = 0 \quad (3.11)$$

At steady state operating condition, swing equations ensure that mechanical power output of the generating unit is equal to the electrical output. Hence (3.11) can also be expressed as

$$k_i P_{total}^{LFC} - P_{mi}^{LFC} = 0 \quad (3.12)$$
3.3 Generator Control Error (GCE)

From the above sections, the objectives of LFC for shipboard systems can be mathematically stated as:

- Match real power demand and generation at nominal frequency.

\[ B\Delta \omega_{ss} = 0 \quad \text{where} \quad B = \frac{1}{R} \]

- Control power output of the generating units to match the value set by participation factors.

\[ k_i p_{LFC}^{\text{total}} - p_{mi}^{LFC} = 0 \]

Thus the appropriate feedback control signal for LFC of unit \( i \) in ship board systems is as shown in equation (3.13). At steady state the load frequency controller should ensure that \( GCE = 0 \).

\[ GCE_i = (k_i p_{LFC}^{\text{total}} - p_{mi}^{LFC}) + B\Delta \omega \quad (3.13) \]

3.4 Bus Terminology Used for LFC

Based on the known and unknown states, buses in a network can be categorized into one of the following for implementing LFC:

<table>
<thead>
<tr>
<th>Bus type</th>
<th>Known States(( y_u ))</th>
<th>Unknown States(( y_v ))</th>
</tr>
</thead>
<tbody>
<tr>
<td>LFC bus</td>
<td>( \begin{bmatrix} E_f \ \delta_i \end{bmatrix} )</td>
<td>( p_{Gi}^{LFC}, Q_{Gi} )</td>
</tr>
<tr>
<td>PQ Bus</td>
<td>( P_{Di}, Q_{Di} )</td>
<td>( V_i, \theta_i )</td>
</tr>
<tr>
<td>PV Bus</td>
<td>( P_{PV,i},</td>
<td>V_i</td>
</tr>
</tbody>
</table>

PQ and PV buses in Table 3.1 are the conventional bus terminology used in power flow studies. PV buses are called the voltage control buses. At these buses there are specified voltage and
real power generation. In the benchmark system considered in this work, there are no PV buses as the generators on LFC are assumed to be the only active power sources.

PQ bus is called the load bus as the loads of the network are connected to these buses. The active and reactive power demands at these buses are specified as the known states.

LFC bus refers to the buses with controllable real power injections and participating in Load Frequency Control. These are the internal buses of the synchronous generators in the voltage source behind reactance model. Detailed discussion on this is presented in Section 2.3.1.

### 3.5 Proposed LFC Model

The dynamic Load Frequency Controller of the generating units and algebraic network model can be combined to get the DA model is shown in Figure 3.3.

At the LFC center, the total real power demand by the network from the generating units is calculated from the solution to power flow equations. Higher level energy management algorithms decide the participation factors, $k_i$. Based on this information, LFC employs governor action to change the output power of each unit and frequency. This change in frequency reflects as change in voltage angle at the LFC buses to control the power generated at these buses. Assuming that AVR is keeping $E_f$ constant, using this updated $\delta_i$ power flow solutions are again calculated to find the active power demand of the network. This continues until a balance between active power demand and generation is reached at $\omega_0$. 
Figure 3.3 LFC model and network
3.6 Sensitivity Analysis for Active Power Control

The solutions to power flow equations using Newton-Raphson method are dependent on the values of the known states $y_u$ at the beginning of an iteration. Hence, this subset of the state variables in the network equations i.e.; the known state variables $y_u$, can be considered as control variables that regulate the value of the rest of the state variables at convergence. In the case of integrating load frequency control with network equations, this set of control variables includes the internal angle $\delta$ of the synchronous machines.

If $g(y_u^0, y_v^0) = 0$ represent the power flow equations at steady state, any change $\Delta y_u$ in the control variables will result in a change $\Delta y_v$ in the rest of the state variables. In order to maintain steady state operation, the following condition should be satisfied.

$$g(y_u^0 + \Delta y_u, y_v^0 + \Delta y_v) = 0$$

(3.14)

Using Taylor series expansion and neglecting higher order terms,

$$g(y_u^0, y_v^0) + \frac{\partial g(y_u^0, y_v^0)}{\partial y_u} \Delta y_u + \frac{\partial g(y_u^0, y_v^0)}{\partial y_v} \Delta y_v = 0$$

(3.15)

Since the system was in steady state operation prior to change in control variables, (3.15) can be rewritten as

$$\Delta y_v = E \Delta y_u$$

(3.16)

where $E = - \left( \frac{\partial g(y_u^0, y_v^0)}{\partial y_v} \right)^{-1} \frac{\partial g(y_u^0, y_v^0)}{\partial y_u}$ is the sensitivity matrix that relates the sensitivity, $\varepsilon$, of the system state variables $y_v$ to the control variables $y_u$ i.e. $\varepsilon_{ij}$: Sensitivity of $\Delta y_{vi}$ to $\Delta y_{ui}$ [20].

Sensitivity values can be used to evaluate the dependence of power injection at LFC bus $i$ to the change in $\delta_i$ and $\delta$ at the internal buses of other units connected to the network. These sensitivity values are dependent on the steady state values prior to change in control variables.
3.7 Design Procedure for Load Frequency Controller

Generator Control Error (GCE), derived in Section 3.3 is the appropriate control input for the load frequency controller to meet its objectives.

\[ GCE_i = (k_i P_{t_{\text{total}}}^{LFC} - P_{m_{i}}^{LFC}) + B\Delta \omega \]  \hspace{1cm} (3.13)

As GCE becomes zero, the power output of the generator will match the reference value set by the participation factor and frequency will reach the nominal value by achieving power balance in the network.

Proportional-Integral (PI) controllers provide zero steady state error in the feedback signal and faster response. Hence, the model proposed in this document for LFC in shipboards systems is a PI controller which governs the input valve of the turbine/prime mover to control frequency and load assignment between generators. This PI controller governs the fuel-inlet valve of the prime mover to change the mechanical output and consequently, \( P_{Gi} \).

For the PI controller,

\[ \Delta F = K_p GCE(t) + K_i \int GCE(t) \, dt \]  \hspace{1cm} (3.18)

where \( \Delta F \): Change in fuel-inlet valve position

\( K_p \): Proportional gain

\( K_i \): Integrator gain

Rearranging (3.18)

\[ \Delta F = K_p \left[ GCE(t) + \frac{K_i}{K_p} \int GCE(t) \, dt \right] = K_p \left[ GCE(t) + \alpha \int GCE(t) \, dt \right] \]  \hspace{1cm} (3.19)

where \( \alpha = \frac{K_i}{K_p} \).

In frequency domain, \( \Delta F(s) = K_p \left[ 1 + \frac{\alpha}{s} \right] GCE(s) \)
Designing of the controller involves picking the appropriate $K_p$ and $\alpha$ for desired responses.

The controller design for a single generating unit is discussed step by step. The same procedure can be extended for designing controller considering the cross-coupling between the generating units.

Steps for designing the controller for a single generating unit:

1. For the very short interval of time for which the system is linearized, change in frequency and internal angle can be represented as $\Delta \omega$ and $\Delta \delta$. The swing equations can be expressed as:

   \[
   \frac{d\Delta \omega(t)}{dt} = \frac{1}{2H} (P_m(t) - P_c(t) - D(\Delta \omega(t)))
   \]

   \[
   \frac{d\Delta \delta(t)}{dt} = \Delta \omega(t)
   \]

Using Laplace transform,

\[
\Delta \omega(s) = \left(\frac{1}{2Hs + D}\right)(P_m(s) - P_c(s))
\]

\[
\Delta \delta(s) = \frac{1}{s} \Delta \omega(s)
\]

Hence the linearized model for the generator can be shown in block diagram as in Figure 3.5.
2. Linearize the entire system involving differential and algebraic equations around an operating point with state variables $x^0$ and $y^0$ to obtain the block diagram shown in Figure 3.6.

3. Evaluate the sensitivity value $\varepsilon_{ii}$ that relates the power generated at the internal bus $P_{G_i}$ to the change in angle $\delta_i$ at the same bus for the operating point $[y_u^0, y_v^0]$.

4. The PI controller introduces a pole at the origin and increases the system type by 1. In order to bring back the angular contribution of the poles to $180^\circ$, zero of the PI controller, $\alpha$ is
placed close to this pole at the origin. To ensure this pole-zero cancellation, arbitrarily choose \( \alpha \) to be a real positive value closer to the origin.

5. Once all the system parameters including sensitivity values are known, reduce the block diagram given in Figure 3.5 using standard block reduction techniques. The resulting block diagram is shown below.

\[
\begin{align*}
K_p(s + \alpha) & \quad \alpha K_p(H(s) - 1) - s(1 - K_p(H(s) - 1) + T_e s) \\
& \quad \frac{K_p(s + \alpha)}{\alpha K_p(H(s) - 1) - s(1 - K_p(H(s) - 1) + T_e s)}
\end{align*}
\]

where \( H(s) = \frac{B_s}{2H s^2 + D(s) + \tilde{e}_u} \)

Figure 3.7 Reduced block diagram representation of linearized generator control

6. Using Routh Hurwitz criterion, estimate the values of \( K_p \) for which the system is stable.

7. Appropriate gain \( K_p \) can then be chosen from the values in Step 5 using trial and error method or root locus technique. If needed, after picking \( K_p \) the system response can be fine tuned by varying \( \alpha \).

Similar steps can be used to design controllers by considering the cross-coupling between the generating units. The linearized system in that case would be a two-port model as shown in Figure 3.7. For the benchmark system considered in this thesis, the controller parameters chosen by the analysis
of a single unit gave reasonable response at all operating conditions. Thus, the same $K_p$ and $\alpha$ were used for implementing the load frequency controller in the three synchronous machines of the benchmark system.

Figure 3.8 Block diagram representation of the interconnected generator units
Chapter 4: Simulation Details and Results

This chapter presents the results of simulation of a DDG51 benchmark shipboard system in MATLAB/Simulink.

4.1. Simulation Setup and Assumptions

The swing equations for representing the dynamics of a generating unit on LFC and power flow equations for representing the network to which these units are connected constitute the differential and algebraic parts of the DA model considered in this thesis.

\[
\frac{d\omega(t)}{dt} = \frac{1}{2H} \left( P_n(t) - P_0(t) - D(\omega(t) - \omega_b) \right) \quad \text{where} \quad P_0(t) = \left[ \frac{E_f}{|V_r|} \right] \sin(\delta(t) - \theta_i) \tag{2.3}
\]

\[
\frac{d\delta(t)}{dt} = \omega(t) - \omega_b
\]

\[
P_i(y) = \sum_{j=1}^{n} |V_i||V_j| \left[ G_y \cos(\theta_i - \theta_j) + B_y \sin(\theta_i - \theta_j) \right] \tag{2.7}
\]

\[
Q_i(y) = \sum_{j=1}^{n} |V_i||V_j| \left[ G_y \sin(\theta_i - \theta_j) - B_y \cos(\theta_i - \theta_j) \right] \tag{2.8}
\]

This model was setup in Simulink using the models described in Chapters 2 and 3. The following sections present the setup of this DA model.

4.1.1 Model creation

Mathematica was used for defining the models using equations and these models were then converted into Matlab EXecutable (MEX) files that can be accessed in Simulink. Figure 4.1 shows the steps involved in creating the Simulink models for the different components of the benchmark system.
41

4.1.2 Solving the DA model

MATLAB’s differential equation solver ode45-Dormand Prince [24] was used to solve the swing equations through numerical integration. This is a variable-step solver that solves for the continuous states in the DA model. The model is setup to perform one iteration of algebraic equations at inherited time steps decided by this solver.

The algebraic power flow equations are solved using Newton-Raphson (N-R) method. N-R method solves for the unknown algebraic states \( y_v \) in the power flow equations \( g(y_v) = 0 \) using the formula

\[
J^T \Delta y_v^* = -g(y_v^*)
\]  \hspace{1cm} (4.1)
where $J$: Jacobian matrix of the power flow equations evaluated at $y_v^\tau$.

$\tau$: Iteration counter.

$\Delta y_v^\tau = y_v^{\tau+1} - y_v^\tau$

This equation can be rewritten as

$$J^\tau y_v^{\tau+1} + \{-J^\tau y_v^\tau + g(y_v^\tau)\} = 0 \quad (4.2)$$

Equation (4.2) is of the form $A\chi + B = 0$ where $A = J^\tau$, $B = -J^\tau y_v^\tau + g(y_v^\tau)$ and $\chi = y_v^{\tau+1}$. The dgesv routine from LAPACK was used to solve (4.2) at discrete time steps. Linear Algebra PACKage or LAPACK [15] is a collection of routines in FORTRAN for solving a variety of equations like simultaneous linear equations, least squares solutions of linear systems of equations etc. Other details of the software and tools used for simulation are shown in Table 4.1.

### Table 4.1: Simulation details

<table>
<thead>
<tr>
<th>Operating System</th>
<th>Windows 7, 32 bit, 4GB RAM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Softwares</td>
<td>MATLAB©R2009b/Simulink</td>
</tr>
<tr>
<td></td>
<td>Mathematica©7</td>
</tr>
<tr>
<td></td>
<td>LAPACK©3.5.0</td>
</tr>
</tbody>
</table>

4.1.3 Assumptions

The following assumptions were made to show LFC action on the benchmark system through simulation:

1. All the ship service loads are constant admittance loads and propulsion load is the only constant power load. Ship service load is assumed to be 0.6 pu and is distributed equally among the corresponding load buses. This makes it easier to change the total load by varying propulsion load.
2. AVRs keep the voltage at the internal buses constant so that the focus can be on the effect due to LFC.

3. All the synchronous machines in the network have similar rating and characteristics to enable the use of same LFC controller on all the three units.

4. Dynamics associated with power electronic devices and converters are not considered since these operate at a smaller time scale of interest than LFC.

5. The system is operating at steady state before any change in load or participation factors are made. This facilitates analysis one event in the network at a time.

6. No generation rate constraints (GRC) were considered in the simulation model because the dynamics involved in using GRC were not modeled in while designing controller. The ramping of load and participation factors was done with arbitrary slopes.

7. The generator power output and voltage limits were assumed to be as shown below:

   \[ P_{\text{normal}, \text{max}} = 0.5 \text{ pu} \]

   \[ P_{\text{overload}, \text{max}} = 0.9 \text{ pu} \text{ (up to 5 minutes [23] ).} \]

   \[ V_{\text{max}} = 1.05 \text{ pu} \]

   \[ V_{\text{min}} = 0.95 \text{ pu} \]

   In order to simulate the DA model an initial guess for algebraic state values, \( x_0 \) are necessary. This is calculated by solving the algebraic power flow equations with flat start values of \( V = 1.0 \angle 0^\circ \) as the initial condition until convergence is achieved. This solution is then used as \( x_0 \) for the DAE model. It is noted that there are larger transients at the beginning of simulation (\( t=0 \)) due to the imperfect initial conditions calculated using only the algebraic equations.
4.2 Simulation Results

This section provides the results obtained by simulating the benchmark system with LFC action using reduced network model. Results for the following cases are discussed in the sections to follow:

- Changing participation factors $k$ of the generating units with constant load.
- Changing load with constant participation factors $k$ of the units.
- Changing the pair of active generating units in the network and performing a sample case.

A comparison between the reduced 5 bus network (Figure 4.3) and its original 11 bus system (Figure 4.2) is also presented.

Sections 4.2.1 and 4.2.2 uses the following network configuration with GTG1 and GTG2 online, and GTG3 offline. The reduced 5 bus model shown in Chapter 2 was derived using the Kron reduction and was used for simulation.

Figure 4.2 Network structure 1
4.2.1 Varying participation factors with constant load

Participation factor $k_i$ of the generating unit $i$ determines the portion of total active power demand of the network that should be delivered by the unit, i.e. $P_{Gi} = k_i P_{total}$. [16] recommends that the starting point for the determination of successful load distribution using governor control to be at 0.75 pu nominal real power load with each generator carrying its proportionate load. Hence in Case 1, the propulsion load was set to 0.15 pu and ship service load to 0.6 pu. At this nominal real load of 0.75 pu, the participation factors of the units were varied to demonstrate the action of LFC in successfully distributing the load demand among the generating units. At the beginning of simulation, both the units were sharing the total load equally i.e. $k_1 = k_2 = 0.5$. This was then changed at different points in time as the simulation progressed. Table 4.2 gives an account of the participation factors at different time intervals and power output of the generating units.

An interesting observation is that even though the total nominal load was set to 0.75 pu, the actual load demand of the network during simulation of the DAE model was less than that. This difference between nominal and actual values are due to the constant admittance loads in the network that are voltage dependent and their power demands vary with voltage at the corresponding buses. For
simplicity, it was assumed that there is no significant change in this load demand with participation factors after \( t = 0 \) second. In Case 2, there was no propulsion load at bus 5 or the total load was just ship service load and losses. In Case 3, a propulsion load of 0.4 pu was applied at bus 5 resulting in a total load of 1 pu. In this case, participation factors greater than 0.5 would result in overloading the generator. Any attempt to increase the output of the generator above \( P_{\text{overload, max}} \) by the controller resulted in a mismatch between the generator set point and actual power output and the nominal frequency was not attained until the participation factors were changed to redistribute the load. In Case 4, the propulsion load was 0.5 pu resulting in total nominal power of 1.1 pu.

Table 4.2 Participation factors and power output at constant load (\( T_{\text{simulation}} = 200 \text{ sec} \))

<table>
<thead>
<tr>
<th>Computed ( P_{\text{total}} ) (pu)</th>
<th>Time (s)</th>
<th>( k_1 )</th>
<th>( k_2 )</th>
<th>( P_{\text{reference}} = P_{\text{actual}} ) (pu)</th>
<th>( P_{\text{reference}} = P_{\text{actual}} ) (pu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 1: 0.6805 ( (P_5 = 0.15 \text{ pu}) )</td>
<td>0</td>
<td>0.5</td>
<td>0.5</td>
<td>0.3403</td>
<td>0.3403</td>
</tr>
<tr>
<td></td>
<td>50</td>
<td>0.9</td>
<td>0.1</td>
<td>0.6123</td>
<td>0.6123</td>
</tr>
<tr>
<td></td>
<td>100</td>
<td>0.75</td>
<td>0.25</td>
<td>0.5103</td>
<td>0.5103</td>
</tr>
<tr>
<td>Case 2: 0.5307 ( (P_5 = 0 \text{ pu}) )</td>
<td>0</td>
<td>0.5</td>
<td>0.5</td>
<td>0.2654</td>
<td>0.2654</td>
</tr>
<tr>
<td></td>
<td>50</td>
<td>0.9</td>
<td>0.1</td>
<td>0.4776</td>
<td>0.4775</td>
</tr>
<tr>
<td></td>
<td>100</td>
<td>0.75</td>
<td>0.25</td>
<td>0.3980</td>
<td>0.3980</td>
</tr>
<tr>
<td>Case 3: 0.9299 ( (P_5 = 0.4 \text{ pu}) )</td>
<td>0</td>
<td>0.5</td>
<td>0.5</td>
<td>0.4649</td>
<td>0.4649</td>
</tr>
<tr>
<td></td>
<td>50</td>
<td>0.9</td>
<td>0.1</td>
<td>0.8366</td>
<td>0.8366</td>
</tr>
<tr>
<td></td>
<td>100</td>
<td>0.75</td>
<td>0.25</td>
<td>0.6973</td>
<td>0.6973</td>
</tr>
<tr>
<td>Case 4: 1.0296 ( (P_5 = 0.5 \text{ pu}) )</td>
<td>0</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5148</td>
<td>0.5148</td>
</tr>
<tr>
<td></td>
<td>50</td>
<td>0.9</td>
<td>0.1</td>
<td>0.9222</td>
<td>0.9022</td>
</tr>
<tr>
<td></td>
<td>100</td>
<td>0.75</td>
<td>0.25</td>
<td>0.7720</td>
<td>0.7720</td>
</tr>
</tbody>
</table>
It can be seen from Table 4.2 that the load distribution among the generating units are done successfully using participation factors and the controller. A limit on the maximum participation factor at a loading level can be determined based on the overloading capacity of the generating units. Figures 4.4 and 4.5 show the power outputs and frequency of the generating units in Case 1. The generator set point and actual output of the units are shown in Figure 4.4. It can be seen that the output follows the set point at steady state for all $k$’s.

Figure 4.4 Actual power output and generator set point of the units at $P_{\text{total}}=0.6805$ pu with varying participation factors
According to IEEE STD-45 [16] frequency deviation from nominal value of 60 Hz should be within ±3%. This is achieved in the simulation model and is clear from Figure 4.6. Also, the speed should return to within 1% of the final steady state speed in a maximum of 5 seconds. The results using the controller satisfy these required mandates. From Figure 4.4 it is also seen that the power output follows the reference value and reaches the final value in approximately 15 seconds. This was considered to be an acceptable time period for the generator to ramp up its output to meet load demand.

The controller design can be considered robust and effective for varying participation factors $k$ at constant load. The results clearly demonstrate load distribution among units as prescribed by the
participation factors and frequency returning within acceptable limits in within 5 seconds after an event as long as the generator power limits are not violated.

Figure 4.6 Frequency of units G1 and G2 returning to nominal value after changing $k$ at $t=50$ seconds

Power output and frequency of the synchronous machines in Case 4 are shown in Figures 4.7 and 4.8. These figures depict the case where the controller fails to meet the objectives of LFC when trying to overload the generators. The mismatch between the generator set point and actual output can be seen in Figure 4.7. Also, from Figure 4.8 it can be seen that the frequency does not return to its nominal value until the participation factors are changed $t=100$ seconds.
Figure 4.7 Actual power output and generator set point of the units at $P_{\text{total}} = 1.0296$ pu with varying participation factors
The voltage profile of all the buses in the network in Case 1 is shown in Figures 4.9 and 4.10. It can be seen that the terminal bus voltages are regulated by AVR. An interesting observation is that the voltage at the propulsion load bus 5 is lesser than the much lower than accepted voltage limits. This could be due to the network topology which results in no active power generation closer to the load bus or incorrect estimation of the line parameters. If it is the former, V5 could be improved by various compensation methods like using G3 as a synchronous condenser, providing a load compensator in AVR, capacitor placement etc. This thesis does not consider voltage improvement at any of the buses and currently this is left uncompensated.
Figure 4.9 Voltage profile at the internal buses of G1 and G2 at $P_{total} = 0.6805$ pu with varying participation factors
4.2.2 Varying load with constant participation factors

In this case, the participation factors of the units were kept constant and the propulsion load was varied to analyze LFC action under varying load. In Case 1, the participation factors were kept at \( k_1 = k_2 = 0.5 \) to equally distribute the load among the two generators. Propulsion load at various time intervals and power distribution among generating units are given in Table 4.3. Cases 2 and 3 show the scenarios for two other participation factors.

Figures 4.11 and 4.12 show the change in power output and frequency response of the generating units when the propulsion load changes as in Case 1 described in Table 4.3. It can be seen from these figures and results shown in Table 4.3 that the controller can effectively distribute the load.
among the generating units at varying load in all cases except in Case 2 where the generating units were given power reference values above their overloading capacity.

Table 4.3 Propulsion load and power output with constant participation factors ($T_{simulation} = 200$ seconds)

<table>
<thead>
<tr>
<th>Case</th>
<th>Time (s)</th>
<th>$P_{total}$ (pu)</th>
<th>$P_{propulsion}$ (pu)</th>
<th>$k_1$</th>
<th>$k_2$</th>
<th>$P_{1,reference} = k_1 \times P_{total}$ (pu)</th>
<th>$P_{1,actual}$ (pu)</th>
<th>$P_{2,reference} = k_2 \times P_{total}$ (pu)</th>
<th>$P_{2,actual}$ (pu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0</td>
<td>0.5307</td>
<td>0</td>
<td>0.5</td>
<td>0.5</td>
<td>0.2654</td>
<td>0.2654</td>
<td>0.2654</td>
<td>0.2654</td>
</tr>
<tr>
<td></td>
<td>50</td>
<td>0.6805</td>
<td>0.15</td>
<td>0.5</td>
<td>0.5</td>
<td>0.3403</td>
<td>0.3403</td>
<td>0.3403</td>
<td>0.3403</td>
</tr>
<tr>
<td></td>
<td>100</td>
<td>0.9299</td>
<td>0.4</td>
<td>0.5</td>
<td>0.5</td>
<td>0.4650</td>
<td>0.4650</td>
<td>0.4650</td>
<td>0.4650</td>
</tr>
<tr>
<td></td>
<td>150</td>
<td>1.0296</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5148</td>
<td>0.5148</td>
<td>0.5148</td>
<td>0.5148</td>
</tr>
<tr>
<td>2</td>
<td>0</td>
<td>0.5306</td>
<td>0</td>
<td>0.9</td>
<td>0.1</td>
<td>0.4776</td>
<td>0.4776</td>
<td>0.0531</td>
<td>0.0531</td>
</tr>
<tr>
<td></td>
<td>50</td>
<td>0.6803</td>
<td>0.15</td>
<td>0.9</td>
<td>0.1</td>
<td>0.6123</td>
<td>0.6123</td>
<td>0.068</td>
<td>0.068</td>
</tr>
<tr>
<td></td>
<td>100</td>
<td>0.9295</td>
<td>0.4</td>
<td>0.9</td>
<td>0.1</td>
<td>0.8366</td>
<td>0.8366</td>
<td>0.093</td>
<td>0.093</td>
</tr>
<tr>
<td></td>
<td>150</td>
<td><strong>1.0292</strong></td>
<td><strong>0.5</strong></td>
<td><strong>0.9</strong></td>
<td><strong>0.1</strong></td>
<td><strong>0.9222</strong></td>
<td><strong>0.9022</strong></td>
<td><strong>0.1269</strong></td>
<td><strong>0.1025</strong></td>
</tr>
<tr>
<td>3</td>
<td>0</td>
<td>0.5307</td>
<td>0</td>
<td>0.75</td>
<td>0.25</td>
<td>0.3980</td>
<td>0.3980</td>
<td>0.1327</td>
<td>0.1327</td>
</tr>
<tr>
<td></td>
<td>50</td>
<td>0.6804</td>
<td>0.15</td>
<td>0.75</td>
<td>0.25</td>
<td>0.5103</td>
<td>0.5103</td>
<td>0.1701</td>
<td>0.1701</td>
</tr>
<tr>
<td></td>
<td>100</td>
<td>0.9298</td>
<td>0.4</td>
<td>0.75</td>
<td>0.25</td>
<td>0.6973</td>
<td>0.6973</td>
<td>0.2324</td>
<td>0.2324</td>
</tr>
<tr>
<td></td>
<td>150</td>
<td>1.0294</td>
<td>0.5</td>
<td>0.75</td>
<td>0.25</td>
<td>0.7720</td>
<td>0.7720</td>
<td>0.2573</td>
<td>0.2573</td>
</tr>
</tbody>
</table>
Figure 4.11 Actual power output of the generating units following the generator set point at $k_1 = k_2 = 0.5$ with varying load

It can be seen from Figure 4.12 that the frequency of the units returned within acceptable limits in less than 5 seconds as specified in [16]. The controller meets the LFC objectives when the total load was varied at constant participation factors for Case 1 and 3. In case of Case 2, since $P_{\text{reference}} > P_{\text{overload,max}}$, LFC objectives were not achieved and this is evident in the results presented in Table 4.3. Figures 4.13 and 4.14 show the mismatch in power output from generator set point and the deviation from the nominal frequency respectively. When the participation factors were changed to that in Case 3 to redistribute the real power demand, the same higher load was managed by the controller effectively.
Figure 4.12 Frequency of units G1 and G2 point at $k_1 = k_2 = 0.5$ with varying load
Figure 4.13 Power output of units G1 and G2 deviating from generator set points at $P_{\text{total}} = 1.0296$ pu with $k_1 = 0.9$ and $k_2 = 0.1$
Figure 4.14 Frequency of generating units deviating from nominal value at $t=150$ seconds when $P_{\text{total}} = 1.0296 \text{ pu}$ with $k_1 = 0.9$ and $k_2 = 0.1$

Voltage profile at the internal buses, terminal buses and load bus are shown below in Figures 4.15 and 4.16. AVR on the units keep the terminal bus voltages close to the reference value. The change in voltage levels due to change in load demand can be seen at $t = 50, 100, \text{ and } 150 \text{ seconds}$. The voltage at bus 5 is lower than the acceptable minimum of 0.95 pu. As discussed in the previous section, no attempt has been made in this work to compensate the voltage drop at load buses.
Figure 4.15 Voltage profile at the internal buses of G1 and G2 at $k_1 = k_2 = 0.5$ with varying load
Figure 4.16 Voltage profile at buses 3, 4, and 5 at \( k_1 = k_2 = 0.5 \) with varying load

4.2.3 Comparison of simulation results using reduced 5 bus and 11 bus network models

The results presented under Section 4.2.1 and 4.2.2 were obtained using the reduced 5 bus network model of the actual 11 bus network shown in Figure 4.2 via the Kron reduction method. This section is organized to compare the results obtained in using the reduced model and the actual model.

- Varying participation factors with constant load

To compare the results using the 5 bus model and the 11 bus model, the scenario selected is Case 1 as shown in Table 4.2 when a constant propulsion load of 0.15 pu was applied at bus 5 and participation factors were varied. Figure 4.17 depicts the frequency of the generating units 1 and 2 using these two models. It can be seen that the results using 5 bus model and 11 bus model are very close to each other. The absolute differences between the results are shown in Figure 4.18, from which it can be seen that the difference is of the order of \( 10^{-3} \) pu during transients and much smaller at steady...
state. Similar results for power output, and voltage profile of the benchmark system simulated using 5 bus and 11 bus models are given in Figures 4.19 to 4.22.

Figure 4.17 Comparison of frequency of G1 and G2 obtained using 5 bus and 11 bus models-constant load
Figure 4.18 Difference in frequency obtained using 5 bus and 11 bus models-constant load
Figure 4.19 Comparison of power outputs of G1 and G2 using 5 bus and 11 bus models-constant load
Figure 4.20 Difference in power output using 5 bus and 11 bus models - constant load
Figure 4.21 Comparison of the voltage profile at buses 1 and 2 using 5 bus and 11 bus models-constant load
Varying load with constant participation factors

In order to verify the accuracy of the results obtained using the reduced network model for varying load with constant participation factors in representing the actual 11 bus system, simulation results are presented in Figures 4.23 to 4.26. These results show the comparison of results in 5 bus system and 11 bus system when the participation factors of the generating units were kept constant while the total load was changing. \( k_1 \) and \( k_2 \) were chosen to be 0.75 and 0.25 respectively, and the load values were varied as shown in Case 3 in Table 4.3.
Figure 4.23 Comparison of frequency of G1 and G2 obtained using 5 bus and 11 bus models - constant $k_1$ and $k_2$.

Figure 4.23 shows the frequency of the generating units while operating under Case 3 in Table 4.3. The results obtained using the two network models are very close to each other. The difference in frequency obtained using the two models are shown in Figure 4.24 and it is of the order of $10^{-3}$ pu.
Figure 4.24 Difference in frequency of G1 and G2 obtained using 5 bus and 11 bus models-constant $k_1$ and $k_2$. 
Figure 4.25 Comparison of power outputs of units G1 and G2 obtained using 5 bus and 11 bus models- constant $k_1$ and $k_2$.
From Figures 4.25 and 4.26 shown above, it can be seen that the actual power output of the two generating units obtained using reduced 5 bus model and its original 11 bus model are very close to each other during steady state. The difference during transients is of the order of $10^{-2}$ pu. Figures 4.27 and 4.28 displays the voltage profile at the buses obtained using the reduced and actual network models. The voltages obtained using 5 bus model closely follow the results obtained using the actual model.
Figure 4.27 Comparison of the voltage profile of internal buses obtained using 5 bus and 11 bus models- constant $k_1$ and $k_2$. 
The results obtained using the reduced network model via the Kron reduction method closely follows the results using the 11 bus model. From these results it is evident that the analysis obtained using the reduced 5 bus network model reflects the responses of the actual 11 bus system.
4.2.4 Changing the pair of active generation units in the network

Sections 4.2.1 to 4.2.3 provided results for network structure 1 as shown in Figure 4.3. In these cases the active generating units were G1 and G2. In the case of a generator being overloaded or any other similar situations there may raise a need to switch between the generating units that are online resulting in different network structures. This flexibility to switch between network structures is also incorporated in the simulation model.

In order to demonstrate the feature of the simulation platform that allows any pair of GTGs to be online, the simulation results using a different network structure is presented in this section. The objective is to have flexibility to select one topology of the network from \( N \) different network structures incorporated into a single simulation model.

A constant \( \beta_i = \{0, 1\} \) is used to select network structure \( i \) from the \( N \) available structures. As already seen in Section 4.1.2, the dgesv solver used to calculate the state variables \( y_v \) by solving the algebraic power flow equations uses the following equation.

\[
J^\tau y_v^{\tau+1} + \{ -J^\tau y_v^\tau + g(y_v^\tau) \} = 0
\]

Following steps were followed to implement selection of network structure \( i \) using \( \beta_i \):

1. Calculate the admittance matrix \( Y_{bus,i} \) corresponding to each network structure \( i \).
2. Using \( Y_{bus,i} \), setup the power flow equations \( g_j(y_{vi}) \) and evaluate the Jacobian matrix \( J_i \).
3. The Dgesv solver is then setup to solve for state variables in the network using the following equation.

\[
\sum_{j=1}^{N} \beta_j (J_{j}^\tau y_{vi}^{\tau+1} + \{ -g_{j}^\tau y_{vi}^\tau + g(y_{vi}^\tau) \}) = 0
\]

4. Setting \( \beta_i = 1, \beta_j = 0 \) where \( j = 1 \) to \( N \), \( j \neq i \), the network structure \( i \) can be selected for simulation.

The second network structure considered here has G1 and G3 as the two active units with G2 offline. The resulting network structure with the revised bus numbers is shown in Figure 4.29 below.
Using $\beta_1$ and $\beta_2$, either network structure 1 or 2 can be selected as the network topology for simulation.

![Figure 4.29 Network structure 2](image)

For example, by setting $\beta_1 = 0$ and $\beta_2 = 1$ network structure 2 is selected. The simulation results for constant propulsion load of 0.15 pu and the participation factors varying as given in Table 4.2 are shown below in Figures 4.30 to 4.33. The switch from network structure 1 to 2 happens at $t = 200$ seconds. When there is a switch in network structure 1 to 2, it should be noted that the bus number of the internal buses, terminal buses and the propulsion bus get rearranged to accommodate the new generator that is online. This is shown in Table 4.4 below.
Table 4.4 Bus number in network structure 1 and 2

<table>
<thead>
<tr>
<th>Bus #</th>
<th>In network structure 1</th>
<th>In network structure 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bus 1</td>
<td>Internal bus of G1</td>
<td>Internal bus of G1</td>
</tr>
<tr>
<td>Bus 2</td>
<td>Internal bus of G2</td>
<td>Internal bus of G3</td>
</tr>
<tr>
<td>Bus 3</td>
<td>Terminal bus of G1</td>
<td>Terminal bus of G1</td>
</tr>
<tr>
<td>Bus 4</td>
<td>Terminal bus of G2</td>
<td>Terminal bus of G3 and propulsion load bus.</td>
</tr>
<tr>
<td>Bus 5</td>
<td>Propulsion load bus</td>
<td>PQ bus with no load connected</td>
</tr>
<tr>
<td>Bus 6-11</td>
<td>Constant admittance load buses</td>
<td>Constant admittance load buses</td>
</tr>
</tbody>
</table>

Figure 4.30 Frequency of generating units in network structure 1 and 2
Figures 4.30 and 4.31 show the frequency and power output of the generating units respectively. Unit 1 is G1 for the entire simulation period. The internal bus of this unit is bus 1 and the terminal bus is bus 3. Units 2 is G2 until \( t = 200 \) seconds. At \( t = 200 \) sec, the network structure switched to that as shown in Figure 4.27 and unit 2 is G3 for the rest of the simulation. The internal bus of this unit is marked as bus 2 and the terminal bus is bus 4.

The voltage profiles of buses 1 to 5 are shown in Figures 4.32 and 4.33. As shown in Table 4.4, buses 1 and 3 are the internal and terminal buses of G1 in network structure 1 and 2. Bus 2 is the internal bus of G2 in network structure 1 and internal bus of G3 in network structure 2. It should be noted that bus 4 is the terminal bus of G3 as well as the propulsion load bus in network structure 2. The change in voltage level at these buses can be seen from the figures shown below.
Figure 4.32 Voltage profile of buses 1 and 2 in network structure 1 and 2
Figure 4.33 Voltage profiles of buses 3-5 in network structure 1 and 2
Chapter 5: Conclusion

The objectives of the work presented in this thesis were to design a Load Frequency Controller for shipboard systems and develop a simulation platform for marine power systems with an emphasis on LFC. The models of various components used in simulation to build the benchmark system were discussed in detail. These components include generator models, load models, AVR etc. These models were then interconnected together in a Simulink based simulation platform to create a Differential Algebraic (DA) model. Using this model, simulation results for several scenarios of operation of the benchmark system were obtained. These results are also presented in this thesis.

5.1 Summary of Contributions

The major contributions of this thesis could be summarized as:

- Modeling and design of a controller for implementing LFC in marine systems and implementing it on a benchmark shipboard system.
- Development of a simulation platform in the MATLAB/Simulink environment for the analysis of shipboard power systems.
- Simulation setup and results for multiple scenarios using the DA model with LFC action.

This thesis proposed a DA model incorporating the dynamic generator controls and the network to which the generators are connected. The controller and the simulation setup provide an efficient and modular platform to perform various studies on shipboard power systems.

5.2 Future Work and Conclusion

This platform can be used to determine generator dispatch schedules based on mission requirements, fuel efficiency etc. Dynamics of the interconnected generating units in a shipboard power system can also be studied using this simulation tool. The component models presented in this
thesis are modular and any number and combination of these components can be interconnected depending on the benchmark system selected.

The robustness and accuracy of the controller can be increased by selecting the parameters using the two-port model. Doing so, the effect of interconnection between the generators via the transmission network can be captured in more detail and with greater accuracy. An improvement in the complete model can be brought about by designing the AVR and LFC controllers by considering the cross-coupling between them. Also, generation rate constants (GRC) and load ramping rates can also be included in the simulation platform to capture an actual shipboard system more closely. If more data on the benchmark system is available, more detailed modeling of the components like transmission line parameters could be done. With an increased focus on use of power electronic converters in shipboard power systems with HED, it will prove advantageous to model the dynamics of the power electronic converters in future work. This thesis with a focus on LFC demonstrates a step towards comprehensive modeling of shipboard power systems in modern fleets with HED.
List of References


[16] M.Yang, P.Da, W.Xiao, J.Yuanwei,”The design of Load freq variable structure controller for power systems”.


Appendix A: Newton–Raphson Algorithm

This appendix presents the algorithm for finding the unknown algebraic state variables, $y_v$, in the power flow equations $g(y_v) = 0$ using Newton-Raphson (N-R) method.

$n$: Iteration counter  
$J^n_{non}$: Jacobian of $g(y_v)$ evaluated at $y_v^n$

---

Figure A.1 Algorithm for N-R method
Appendix B: Parameter Values

This appendix provides the parameter values of various components used in the simulation of the DDG51 benchmark system.

B1 Parameter values

Table B.1 Parameter values used in simulation

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Value used in simulation</th>
</tr>
</thead>
<tbody>
<tr>
<td>$T_t$</td>
<td>0.5 sec</td>
</tr>
<tr>
<td>$H$</td>
<td>5 pu</td>
</tr>
<tr>
<td>$D$</td>
<td>0.5 %</td>
</tr>
<tr>
<td>$S_L^{\text{total}}$</td>
<td>0.6 pu</td>
</tr>
<tr>
<td>$Y_{Li}$</td>
<td>0.1 pu</td>
</tr>
<tr>
<td>$Y_G$</td>
<td>-j3.636 pu</td>
</tr>
<tr>
<td>$Y_{\text{Tie1}}$</td>
<td>0.40672-j/40.672 pu</td>
</tr>
<tr>
<td>$Y_{\text{Tie2}}$</td>
<td>0.2032-j/20.32</td>
</tr>
<tr>
<td>$K_A$</td>
<td>0.5</td>
</tr>
<tr>
<td>$T_A$</td>
<td>0.2 sec</td>
</tr>
<tr>
<td>$V_{R,\text{max}}$</td>
<td>1.05 pu</td>
</tr>
<tr>
<td>$V_{R,\text{min}}$</td>
<td>0.95 pu</td>
</tr>
<tr>
<td>$K_E$</td>
<td>1</td>
</tr>
</tbody>
</table>
Table B.1 (continued)

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>$T_E$</td>
<td>0.314 sec</td>
</tr>
<tr>
<td>$R$</td>
<td>0.2%</td>
</tr>
<tr>
<td>$B$</td>
<td>5 pu</td>
</tr>
<tr>
<td>$K_p$</td>
<td>2.2</td>
</tr>
<tr>
<td>$\alpha$</td>
<td>0.5</td>
</tr>
<tr>
<td>$\epsilon_{11}$ (for total load of 0.75 pu)</td>
<td>2.52396</td>
</tr>
</tbody>
</table>

B2 Sensitivity coefficient values

From Chapter 3, the change in state variable $Y_v$ due to change in the state variables $Y_u$ is given by

$$\Delta Y_v = E \Delta Y_u$$  \hspace{1cm} (3.16)$$

where $E = - \left( \frac{\partial g(Y_u^0, Y_v^0)}{\partial Y_v} \right)^{-1} \frac{\partial g(Y_u^0, Y_v^0)}{\partial Y_u}$ is the sensitivity matrix that relates the sensitivity, $\epsilon$ of the system state variables $Y_v$ to the control variables $Y_u$. i.e. $\epsilon_{ij}$: Sensitivity of $\Delta Y_{vi}$ to $\Delta Y_{uj}$. For LFC, this can be used to evaluate the dependence of power generated at the internal bus to the change in internal voltage angle $\delta$. 
Figure B.1 Sensitivity coefficients and power generated at internal buses of units \(i\) and \(j\)

\[
\Delta P_{Gi} = \varepsilon_{ii}\Delta \delta_i + \varepsilon_{ij}\Delta \delta_j \\
\Delta P_{Gj} = \varepsilon_{ji}\Delta \delta_i + \varepsilon_{jj}\Delta \delta_j
\]  

(B.1)

<table>
<thead>
<tr>
<th>Load (pu)</th>
<th>(\varepsilon_{ii})</th>
<th>(\varepsilon_{ij})</th>
<th>(\varepsilon_{ji})</th>
<th>(\varepsilon_{jj})</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.6</td>
<td>2.52949</td>
<td>-2.52949</td>
<td>-2.52978</td>
<td>2.52978</td>
</tr>
<tr>
<td>0.65</td>
<td>2.52782</td>
<td>-2.52782</td>
<td>-2.52824</td>
<td>2.52824</td>
</tr>
<tr>
<td>0.7</td>
<td>2.52598</td>
<td>-2.52598</td>
<td>-2.52652</td>
<td>2.52652</td>
</tr>
<tr>
<td>0.75</td>
<td>2.52396</td>
<td>-2.52396</td>
<td>-2.52464</td>
<td>2.52464</td>
</tr>
<tr>
<td>0.8</td>
<td>2.52177</td>
<td>-2.52177</td>
<td>-2.52257</td>
<td>2.52257</td>
</tr>
<tr>
<td>0.85</td>
<td>2.5194</td>
<td>-2.5194</td>
<td>-2.52034</td>
<td>2.52034</td>
</tr>
<tr>
<td>0.9</td>
<td>2.51686</td>
<td>-2.51686</td>
<td>-2.51792</td>
<td>2.51792</td>
</tr>
</tbody>
</table>
Appendix C: Kron Reduction

In a power system network, if the current injection at a bus is always zero, it is not necessary to calculate the voltage at these buses explicitly. These are the buses with no external loads or active power generating sources. These buses or nodes can be eliminated using the Kron reduction.

Consider a $n$-bus network with $p$ buses with non-zero current injection. The power system network equation can be represented in matrix form as:

$$
\begin{bmatrix}
I_1 \\
I_2
\end{bmatrix} =
\begin{bmatrix}
Y_{11} & Y_{12} \\
Y_{21} & Y_{22}
\end{bmatrix}
\begin{bmatrix}
V_1 \\
V_2
\end{bmatrix}
$$

(C.1)

where $I_1 : p \times 1$ vector of non-zero current injections

$I_2 : (n-p) \times 1$ vector of zero current injections

$V_1 : p \times 1$ voltage vector corresponding to non-zero current injections

$V_2 : (n-p) \times 1$ voltage vector corresponding to zero current injections

$Y_{ij} :$ Blocks of admittance matrix of the network, $Y_{bus}$

$Y_{11} : p \times p$ block matrix

$Y_{12} : p \times (n-p)$ block matrix

$Y_{21} : (n-p) \times p$ block matrix

$Y_{22} : (n-p) \times (n-p)$ block matrix

Since $I_2 = 0$, C.1 can be rewritten as:

$$
I_1 = Y_{11}V_1 + Y_{12}V_2
$$

$$
0 = Y_{21}V_1 + Y_{22}V_2
$$

$$
\Rightarrow V_2 = -Y_{22}^{-1}Y_{21}V_1
$$

(C.2)
\[ I_1 = [Y_{11} - Y_{12}Y_{22}^{-1}Y_{21}]V_1 \]  \hspace{1cm} (C.3)

This gives a resulting new admittance matrix \( Y_{bus,new} \) of size \( p \times p \) for the network that relates non-zero current injections to voltages.

\[ Y_{bus,new} = Y_{11} - Y_{12}Y_{22}^{-1}Y_{21} \]  \hspace{1cm} (C.3)

The voltages at the buses with zero current injection can be calculated as needed using (C.2).

The resulting power system after performing this reduction method is said to be *Kron reduced*. 