Frequency and Damping Characteristics of Generators in Power Systems

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Abstract

A power system stability is essential for maintaining the power system oscillation frequency within a small and acceptable interval around its nominal frequency. Hence, it is necessary to study and control the frequency for stable operation of a power system by knowing the characteristics within a power system. One approach is to understand the effectiveness of frequency and damping characteristics of generators in power systems. Hence, the simulation analysis of IEEE 118-bus power system is used for this study. The analysis includes theoretical analysis with a mathematical approach and simulation studies of swing equation to determine the characteristics of damped single-machine infinite bus, which is represented as a generator connects to a large network system with a small signal disturbance by line losses. Additionally, mathematical derivation of Prony analysis is presented in order to estimate the frequency and damping ratio of the simulation results. In the end, the results demonstrate that the frequency and damping characteristics of generators are highly dependent on the system inertia constant. Therefore, the higher inertia constant is a critical factor to ensure the system is more stable.

Frequency and Damping Characteristics of Generators in Power Systems

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Abstract (General Audience)

A power system's stability is dependent on maintaining the oscillation frequency within a small and acceptable variance of its normal frequency. In order to control the frequency for the stable operation of a power system, it is necessary to study the characteristics within a power system.

One approach is to study the effectiveness of frequency and damping characteristics of generators in power systems. For this study, the simulation analysis of the IEEE 118-bus power system will be used. This includes a mathematical approach and simulation studies of swing equation. These will determine the characteristics of damped single-machine infinite bus. This is represented as a generator connected to a large network system with a small signal disturbance caused by line losses. Additionally, the mathematical basis of Prony analysis is presented in order to estimate the frequency and damping ratio of the simulation results.

In the end, the results demonstrate that the frequency and damping characteristics of generators are highly dependent on the system inertia constant. Therefore, a high inertia constant is critical to the stability of the system.

Dedication

To My Parents: Changyin Zou and Ruiqin Lin

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To all my family and friends, I would not be where I am today without all of your love and support no matter under what circumstance. Thank you for always being there for me. I will always remember and be grateful for each one of you. I will always be there and be supportive for all of you if you need me.

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Chapter 1

Introduction

Frequency is one of the most crucial factors to determine the stability and security of the power system. For the stable operation, the frequency should be maintained within a very small and acceptable interval around its nominal frequency value, 50 Hz or 60Hz. Normally, oscillation frequency of local-area modes is in the range of 0.7 to 2.0 Hz and inter-area modes is in the range of 0.1 to 0.8 Hz [1]. In recent years, frequency related stability problems have attracted more attention due to the rapid development of integrating renewable energy into the grid. The contribution of system inertia constant is inherent from the rotating synchronous generator. The overall system inertia constant will be dropped after replacing a generator by a renewable energy source, such as solar and wind power. Hence, it is necessary to study and control the frequency range for a stable power system by knowing the characteristics within a power system. One approach is to understand the frequency and damping characteristics of generators in the power system in order to build up better background in controlling the frequency in the future study.

The perturbation of a power system can be caused by fault events such as line losses or generator losses. The dynamic behavior of frequency deviation of a power system due to the disturbance depends on the real power of the generator. The initial generator output power is controlled by the system inertia constant. Therefore, it is important to understand the relationship between frequency and the system inertia constant H and the role of system inertia constant in the power system. In addition, the results of dynamic simulation in this document has also determined that the location of where a transmission line is tripped is important and directly affects the frequency and damping characteristics of generators in the power system.

1.1 Literature Review

Problems related to frequency stability and frequency response of reducing power system-order have been identified by many researchers for several decades. A simple two machine system and system frequency response(SFR) were described in [2] by P. M. Anderson and M. Mirheydar in 1990. It is very similar to the approach that is described in this document for reducing a large network system to a single-machine infinite bus system. The mathematical approach of single-machine infinite bus system and the power system stability problem related to small-signal stability analysis were introduced by P. Kundur in [3]. In the past decades, many researchers have worked on power system frequency regulation in [2]-[5] by inroducing renewable generations in the power system. Therefore, the frequency issues have been re-addressed under new paradigm in [6] to analyze the load-damping characteristic in power system frequency regulation. Even though much research has been done to find the effect on the system frequency due to perturbation of the power system, generator losses or load shredding in [7], only a small portion of this research focuses on the actual frequency and damping characteristics of generators in power systems. It is necessary to analyze the frequency characteristics of generators under the stable operation of power systems to help us to investigate the relationship between dynamic behavior of generators and the system inertia constant.

1.2 Outline of this Thesis

This thesis documents the simulation analysis of the generator output power in IEEE 118-bus power system, which determines the frequency and damping characteristics of generators in power systems. Chapter 2 describes the detailed processes of a mathematical approach through swing equations to determine that single-machine infinite bus is an approximate representation of a real power system; the system is a second order model system. It also concludes the relationship between frequency and inertia. Chapter 3 provides the mathematical method to derive Prony analysis, along with the considerations for applying Prony analysis to estimate the frequency and damping ratio of the transient waveforms in Chapter 4. Chapter 4 provides the results of all the dynamic simulation with detailed analysis included. In addition, a proper IEEE 118-bus power system is developed with description of detailed model information. Chapter 5 is the summary of the thesis. It also includes the conclusion of all the simulation results from Chapter 4 and future work is presented. Next is the list of references. In the end, there is a set of appendices. The appendices provide models of exciters and governors for the power system and useful information related to the simulations.

Chapter 2

Characteristic Analysis of Generators through Second Order model of Machine in Power System

Modern power systems are very complex and nonlinear. It is difficult to analyze a large power system with numerous machines, lines and loads. It is also difficult to determine the results of any impact from any disturbance, such as transmission system faults, load change, loss of generators and loss of lines or tripping lines. Therefore, when the behavior of one synchronous machine is studied in a very large system, the big system can be reduced to an equivalent single-machine against an infinite bus for the rest of the system, which is also described as single-machine infinite bus(SMIB) in power systems. The single-machine infinite bus power system is an approximate representation of a real power system, where a power plant with a generator or a group of generators are connected by transmission lines to a very large power network. In this research, the focus will be on a generator that is connected to a large power network through a transmission line to study the oscillation frequency of the generators output power of the power system in dymnamic analysis. The one-line diagram of the single machine infinite bus system is illustrated in Figure 2.1, which describes the generator on the left delivers power to a large network. The capacity of the generator is much smaller compared to the capacity of the large network on the right. The operation of the large network is not affected at all by any change made by the generator on the left. As a result, the large network system is able to be repredented an infinite bus refer to the point of view of the left hand side generator. The infinite bus is considered as a generator with infinite inertia, fixed voltage and zero impedance [3].

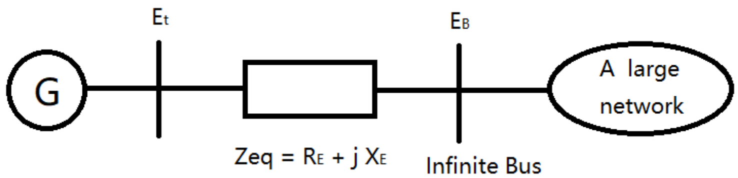


Figure 2.1: Single Machine Infinite Bus

2.1 Classical Model Definitions of Generators

The classical model is the simplest model of all the synchronous machine models. It can also be called the constant voltage behind the transient reactance model [8]. In order to achieve the idea of the classical model, the dynamics of exciter, damper windings, rotor windings, dynamic of turbines, and turbine speed governor need to be neglected. Therefore, the assumption of the classical model of a synchronous generator can be represented mathematically below [3]:

1. The induced voltage of the generator stator has to be constant all the time by controlling the field current to be constant and to ignore the dynamic of exciter.

2. The effects of damper windings, which is shown on the rotor of the synchronous generator, is neglected.

3. The input mechanical power to the generator is assumed to be constant during the simulation.

2.2 Equivalent Swing Equation for A Large Network System

The swing equation describes the relative motion that is caused by rotor deceleration or acceleration with respect to the motion of the rotor of a synchronous machine during the disturbance. The prime mover from synchronous generators converts mechanical energy to electrical energy based on magnetic coupling. The accelerating torque is produced by the moment of inertia from the rotating rotor and its angular acceleration [9]. The rotational dynamic swing equation can be represented below:

$$J \cdot \frac{\partial^2 \theta_m}{\partial t^2} = T_a = T_m - T_e \quad N \cdot m \tag{2.1}$$

Where,

- J is the moment of inertia for the rotating masses in kg-m^2;
- θ_m is the angular displacement of the rotor respect to a stationary axis in radians;
- t is the time in s;
- T_m is net mechanical torque produced by prime mover in N-m;
- T_e is net electrical torque or load torque in N-m;
- T_a is net accelerating torque in N-m.

The angle θ_m increases continuously with time since the rotor is continuously rotating at synchronous speed in steady state. Therefore, θ_m can be defined:

$$\theta_m = \omega_{sm} t + \delta_m \tag{2.2}$$

where,

- ω_{sm} is the synchronous speed of the machine in rad$\cdot s^-1$;
- δ_m is the angular displacement of the rotor respect to the synchronous rotating reference axis in radians.

Then, differentiate both sides Eq. (2.2) with respect to time:

$$\begin{gathered} \frac{\partial \theta_m}{\partial t} = \omega_{sm} + \frac{\partial \delta_m}{\partial t} \\ \frac{\partial^2 \theta_m}{\partial t^2} = \frac{\partial^2 \delta_m}{\partial t^2} \end{gathered} \tag{2.3}$$

The rate of change of mechanical rotor angle is the speed of the rotor. Thus, the angular velocity of the rotating rotor can be expressed:

$$\omega_m = \frac{\partial \theta_m}{\partial t} \tag{2.4}$$

Next, multiply both side of Eq. (2.1) by ω_m. Power can be achieved by multiplying torque with angular velocity. Hence, we can write:

$$J \cdot \omega_m \cdot \frac{\partial^2 \delta_m}{\partial t^2} = P_a = P_m - P_e \quad W \tag{2.5}$$

Where,

- P_m is the mechanical input power in watts;
- P_e is the electrical output power in watts;
- P_a is the accelerating power refers to the power difference between mechanical power and electrical power in watts.

Then, the new parameter M, which is called inertia constant of the machine, is denoted to be J·s·radˆ-1 since M is the product of J and ω_m. Then, the swing equation can be rewritten below:

$$M\frac{\partial^2\delta_m}{\partial t^2} = P_a = P_m - P_e \tag{2.6}$$

M is assumed to be constant because ω_m is only slightly off from synchronous speed ω_{ms} when the synchronous machine is stable. M can also be obtained from:

$$M = \frac{2H}{\omega_{sm}} \cdot S_{mach} \quad MJ/mech \quad rad \tag{2.7}$$

Where H is known as machine inertia constant in second, or as rotational inertia, and is defined as the equation below:

$$H = \frac{\text{Stored kinetic energy in MJ at synchronous speed}}{\text{Machine rating in MVA}} \tag{2.8}$$

The mathematical expression for H is described as:

$$H = \frac{\frac{1}{2}J\omega_{sm}^2}{S_{mach}} = \frac{\frac{1}{2}M\omega_{sm}}{S_{mach}} \quad [MJ/MVA] \tag{2.9}$$

By combining both Eq. (2.6) and Eq. (2.7), the swing equation can be rearranged with respect to rotating inertia H:

$$\frac{2H}{\omega_{ms}}\frac{\partial^2\delta_m}{\partial t^2} = \frac{P_a}{S_{mach}} = \frac{P_m - P_e}{S_{mach}} \tag{2.10}$$

and

$$\frac{2H}{\omega_s} \cdot \frac{\partial^2\delta_o}{\partial t^2} = P_a = P_m - P_e \quad p.u. \tag{2.11}$$

Where,

- δ_o is the rotor angle of the synchronous machine in radians
- ω_s is the synchronous speed of the machine in radians per second
- H is machine inertia constant in second

The machine angular speed is equal to the synchronous speed in the steady state. Hence, we change ω_{ms} to ω_s in Eq. (2.11). When the damping constant K_d is introduced to the power system due to the friction from the prime mover, damping windings, or any other damping sources, the swing equation can be obtained below to express the dynamic behavior of a synchronous machine:

$$\frac{2H}{\omega_s} \cdot \frac{\partial^2\delta_o}{\partial t^2} = P_a = P_m - P_e - K_d\frac{\partial\delta_o}{\partial t} \tag{2.12}$$

Next, when consider the small signal disturbance to the power system, a small incremental displacement angle δ_Δ would be introduced to the rotor angle δ_o, which is under steady-state operating point:

$$\delta = \delta_o + \delta_\Delta \tag{2.13}$$

Then, the new electrical power P_e can be derived from the power-angle equation for the general two machine system:

$$\begin{aligned} P_e &= P_{max}\sin(\delta) \\ P_e &= P_{max}\sin(\delta_o + \delta_\Delta) \\ P_e &= P_{max}(\sin\delta_o\cos\delta_\Delta + \cos\delta_o\sin\delta_\Delta) \end{aligned} \tag{2.14}$$

Where $P_{max} = \frac{V_{inf}E}{X}$, is referring to Figure 2.1 above. For small signal approximation:

$$\sin\delta_\Delta \cong \delta_\Delta \quad and \quad \cos\delta_\Delta \cong 1 \tag{2.15}$$

After substituting Eq. (2.15) into Eq. (2.14), the Eq. (2.14) becomes:

$$P_e = P_{max}\sin\delta_o + P_{max}\cos(\delta_o)\delta_\Delta \tag{2.16}$$

Where $P_m = P_{max}\sin\delta_o$. By substituting Eq. (2.16) into Eq. (2.12), the Eq. (2.12) can be rewritten as:

$$\frac{2H}{\omega_s} \cdot \frac{\partial^2\delta_\Delta}{\partial t^2} = -P_{max}\cos(\delta_o)\delta_\Delta - K_d\frac{\partial\delta_\Delta}{\partial t} \tag{2.17}$$

Since δ_o is a constant value, the derivative of a constant number will be always zero. This is why the equation can be simplified as Eq. (2.17). It can be noted the Eq. (2.17) is a second order differential equation after rearrangement of equation:

$$\frac{2H}{\omega_s} \cdot \frac{\partial^2 \delta_\Delta}{\partial t^2} + K_d \frac{\partial \delta_\Delta}{\partial t} + P_{max} \cos(\delta_o) \delta_\Delta = 0 \tag{2.18}$$

It can also be noted that the equation is in second order standard form. Therefore, the power system dynamic characteristics for one machine and infinite bus with second order model by the expression for δ_Δ as a function of time can be studied. The approximated angular frequency and corresponding damping ratio for the machine can be derived:

$$\omega_n = \sqrt{\frac{\omega_s \cdot P_{max} \cdot \cos \delta_o}{2H}} \tag{2.19}$$

$$\zeta = \frac{1}{2} K_d \sqrt{\frac{\omega_s}{2H \cdot P_{max} \cdot \cos \delta_o}} \tag{2.20}$$

2.2.1 Equivalent Inertia of Coherent Machines in Power System

The two machines are defined as coherence machines when two machines swing together with their transient waveforms under a fault or multiple faults occur within an area, and their angular difference is constant within a certain tolerance over a certain time interval [11]. The characteristic of generators swinging together is illustrated in Fig. 2.2 as an example, which displays the swing curves for a coherent group of three generators, when a fault occurs in the IEEE-118 bus system. The swing equations of coherent machines can be combined to reduce the number of swing equations for analysis in stability study for a large system[9]. Therefore, the overall system equivalent rotating inertia can be estimated by summing rotating inertia H of each generator together.

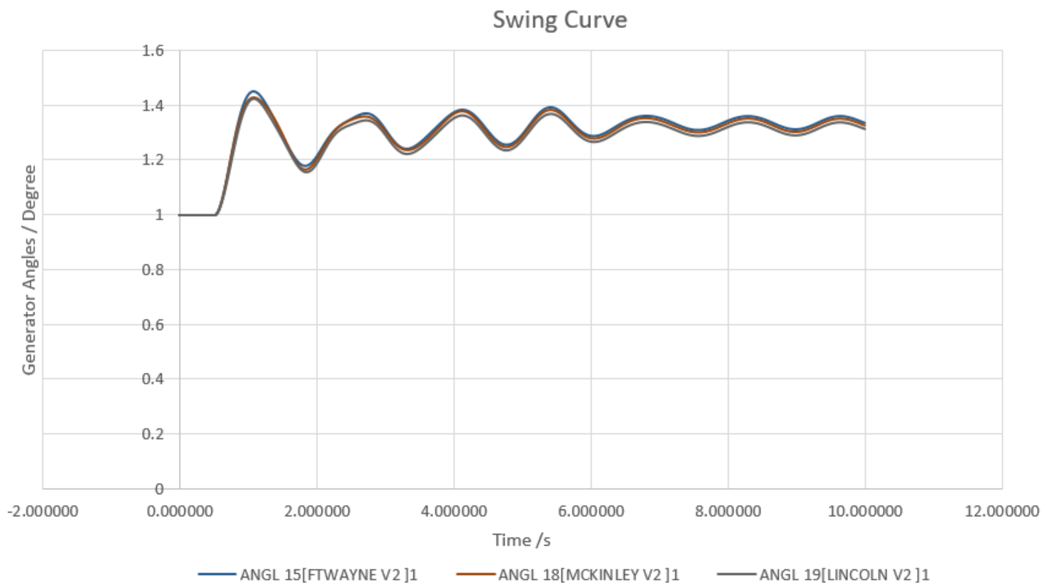


Figure 2.2: Swing Curve for a Group of Generators in IEEE-118 Bus

2.2.2 Equivalent Inertia of Non-Coherent Machines in Power System

Non-coherent machines are contrary to coherent machines. The two machines do not swing together for non-coherent machines under a fault or multiple fault within an area. This research mainly focuses on non-coherent machines dynamic behaviors. For any pair of machines, one machine has rotor angle δ_1 and another machine has rotor angle δ_2. The swing equation for each of the machine can be obtained based on Eq. (2.11):

$$\frac{2H_1}{\omega_s} \cdot \frac{\partial^2 \delta_1}{\partial t^2} = P_{m1} - P_{e1} \quad p.u. \tag{2.21}$$

$$\frac{2H_2}{\omega_s} \cdot \frac{\partial^2 \delta_2}{\partial t^2} = P_{m2} - P_{e2} \quad p.u. \tag{2.22}$$

When we subtracted Eq. (2.21) from Eq. (2.22) and divide the coefficient before second derivative of δ, the new equation becomes:

$$\frac{\partial^2\delta_1}{\partial t^2} - \frac{\partial^2\delta_2}{\partial t^2} = \frac{\omega_s}{2}(\frac{P_{m1}-P_{e1}}{H_1} - \frac{P_{m2}-P_{e2}}{H_2}) \tag{2.23}$$

Then, multiply both side with $\frac{H_1H_2}{H_1+H_2}$ and rearrange the equation:

$$\frac{2}{\omega_s}(\frac{H_1H_2}{H_1+H_2})\frac{\partial^2(\delta_1-\delta_2)}{\partial t^2} = \frac{P_{m1}H_2-P_{m2}H_1}{H_1+H_2} - \frac{P_{e1}H_2-P_{e2}H_1}{H_1+H_2} \tag{2.24}$$

Eq. (2.24) can be simplified further as following:

$$\frac{2}{\omega_s}\cdot H_{12}\frac{\partial^2\delta_{12}}{\partial t^2} = P_{m12} - P_{e12} \tag{2.25}$$

$$\delta_{12} = \delta_1 - \delta_2 \tag{2.26}$$

$$H_{12} = \tfrac{H_1H_2}{H_1+H_2} \tag{2.27}$$

$$P_{m12} = \tfrac{P_{m1}H_2-P_{m2}H_1}{H_1+H_2} \tag{2.28}$$

$$P_{e12} = \tfrac{P_{m2}H_2-P_{e2}H_1}{H_1+H_2} \tag{2.29}$$

Where δ_{12} is the angle difference between two machines and H_{12} is the equivalent constant inertia for two machines. Eq. (2.25) can be applied to a two-machine system when a generator is connecting to a synchronous motor with a pure reactance in between [9]. The power, generated by the generator, is always absorbed by the motor in responding to conversion of energy. We obtain:

$$P_{m1} = -P_{m2} = P_m \tag{2.30}$$

$$P_{e1} = -P_{e2} = P_e \tag{2.31}$$

By substituting Eq. (2.30) and Eq. (2.31) back to Eq. (2.28) and Eq. (2.29) respectively to get $P_{m12} = P_m$ and $P_{e12} = P_e$. Then, we can reduce the simplified combined swing equations for two machine as follows:

$$\frac{2}{\omega_s} \cdot H_{12} \frac{\partial^2 \delta_{12}}{\partial t^2} = P_m - P_e \tag{2.32}$$

Hence, we can conclude from Eq. (2.32) that two synchronous machine in a system can be reduced to an equivalent of one machine against an infinite bus refer to Eq. (2.11). The inertia constant of equivalent machine is H_{12} as defined in Eq. (2.27). Similarly, there is an existing damping constant K_D to the equivalent machine. Then, the swing equation can be described as a second order differential equation for two synchronous machines under small signal application to the power system,:

$$\frac{2H_{12}}{\omega_s} \cdot \frac{\partial^2 \delta_{12}}{\partial t^2} + K_D \frac{\partial \delta_{12}}{\partial t} + P_{max} \cos(\delta_o) \delta_{12} = 0 \tag{2.33}$$

$$\omega_n = \sqrt{\frac{\omega_s \cdot P_{max} \cdot \cos \delta_o}{2H_{12}}} \qquad [rad/s] \tag{2.34}$$

$$\zeta = \frac{1}{2} K_D \sqrt{\frac{\omega_s}{2H_{12} \cdot P_{max} \cdot \cos \delta_o}} \tag{2.35}$$

Eq. (2.33) describes the dynamic behavior of an equivalent machine, which is derived from two non-coherent synchronous machines system.

It can be concluded that the overall system oscillation frequency of the system is inversely proportional to the inertia constant of the overall system. The system with larger inertia constant would be difficult to perturbed by the disturbance. On the contrary, the system with smaller inertia constant would be more easily perturbed by the same disturbance. Therefore, the larger power system with larger inertia constant is more stable. The system constant inertia is directly related to the generator output power. This document emphasizes on each generator's characterization based on analyzing the dynamic simulation of generator power output in the dynamic system. A reduced two-machine system problem in a large network system will be studied as well. Ideally, the original swing equation demonstrates how one machine with finite inertia swings against an infinite bus. However, there is no infinite bus in reality. Therefore, we assume a large power system as a infinite bus, when it connects to a generator with finite inertia. Hence, the dynamic behavior analysis of a generator is studied in a IEEE-118 bus system when a line tripping or a generator disconnecting from the system by continuously operating the system for a certain period of time. Chapter 4 contains a more detailed discussion.

Chapter 3

Prony Analysis

Prony Analysis is a signal analysis technique that is widely used in the area of power systems to model damped signals. Prony Analysis is used to estimate oscillation modes by decomposing a signal into a sum of sinusoidal components. For each component, the analysis can directly estimate the frequency, damping ratio, and relative phase of the given signal [14].

3.1 Analytical Approach

A set of linear differential equations can be represented as a Linear-Time Invariant (LTI) power system dynamics for an operation point [15]:

$$\dot{x}(t) = Ax(t) + Bu(t) \tag{3.1}$$

$$y(t) = Cx(t) + Du(t) \tag{3.2}$$

$x \in \mathcal{R}$ is the state of the system and $y \in \mathcal{R}^n$ is the output of the system. Consider the system has the initial state $x(t_0) = x_0$ at the time t_0 for the state representation of system as shows above. If the system has homogeneous solution with input $u(t) = 0$ for all t or there is no disturbance to the system, the dynamic system can be written as:

$$\dot{x}(t) = Ax(t) \tag{3.3}$$

$$y(t) = Cx(t) \tag{3.4}$$

The solution of the homogenous system which is described as Eq. (3.3) and Eq. (3.4) will result in a series of damped exponential terms [15]:

$$y(t) = \sum_{i=1}^{n} c_i e^{\lambda_i t} = \sum_{i=1}^{n} c_i e^{(-\alpha_i \pm j\omega_i)t} = \sum_{i=1}^{n} A_i e^{-\alpha_i t} \cos(\omega_i t + \theta_i) \tag{3.5}$$

Eq. (3.5) represents the transient response that is caused by suddenly changing the system operating condition by disconnecting a line, a load, or a generator. The n is the number of damped sinusoidal components necessary to estimate $y(t)$. λ_i are the eigenvalues of the system in the s-domain or the dynamic modes of the oscillation of the system. For each i-th damped sinusoidal signal components:

- α_i is the damping factor;
- ω_i is oscillatory angular frequency;
- A_i is the amplitude;
- θ_i is the phase angle.

Eigenvalues can be translated from s-domain to z-domain:

$$z = e^{\lambda_i t_s} \tag{3.6}$$

When sampling the transient response with N samples by creating a discrete linear signal that corresponds to the measurements, assuming the sampling time interval is t_s [14].

This can be written as follows:

$$y(t) = y(kt_s) = \sum_{i=1}^{n} B_i e^{(\lambda_i t_s)k} = \sum_{i=1}^{n} B_i z_i^k \quad \text{for} \quad k = 1, 2, ..., N \tag{3.7}$$

where,

- z_i is the eigenvalues of the system in the z-domain;
- B_i is the residual of z_i;
- k is the number of samples.

Eq. (3.7) can be expressed in more details by applying each t_s in Eq. (3.7) to form following equation [14]:

$$ZB = Y \tag{3.8}$$

$$\begin{bmatrix} B_1 z_1^0 & + & ... & + & B_n z_n^0 \\ B_1 z_1^1 & + & ... & + & B_n z_n^1 \\ & & \vdots & & \\ B_1 z_1^{N-1} & + & ... & + & B_n z_n^{N-1} \end{bmatrix} = \underbrace{\begin{bmatrix} z_1^0 & z_2^0 & ... & z_n^0 \\ z_1^1 & z_2^1 & ... & z_n^1 \\ \vdots & \vdots & & \vdots \\ z_1^{n-1} & z_2^{n-1} & ... & z_n^{n-1} \end{bmatrix}}_{Z} \underbrace{\begin{bmatrix} B_1 \\ B_2 \\ \vdots \\ B_n \end{bmatrix}}_{B} = \underbrace{\begin{bmatrix} y(0) \\ y(1) \\ \vdots \\ y(N-1) \end{bmatrix}}_{Y} \tag{3.9}$$

Where Z is Vandermonde matrix, which is a matrix with the terms of a geometric progression in each row [16]. The z_i is the roots of the n-th order characteristic polynomial function and z_i might be complex number as well. Then, the n-th order characteristic polynomial equation can be formed with the coefficient a_i:

$$z^n - (a_1 z^{n-1} + a_2 z^{n-2} + ... + a_n z^0) = 0 \tag{3.10}$$

Next, construct the n-th order characteristic polynomial equation in matrix form:

$$\underbrace{\begin{bmatrix} 1 & -a_1 & -a_2 & .. & -a_n \end{bmatrix}}_{\overline{A}} \underbrace{\begin{bmatrix} z^n \\ z^{n-1} \\ z^{n-2} \\ \vdots \\ z^0 \end{bmatrix}}_{\overline{z}} = 0 \tag{3.11}$$

The $\overline{A}$ matrix can be express as a $(1 \times N)$ array $\begin{bmatrix} 1 & -a_1 & -a_2 & .. & -a_n \end{bmatrix}$. After that, multiply matrix $\overline{A}$ to Eq. (3.8) in both sides and apply Eq. (3.8) into the new equation. A linear prediction model can be formulated below after minor reordering:

$$\begin{aligned} \overline{A}Y &= y(n) - [a_1 y(n-1) + a_2 y(n-2) + ... + a_n y(0)] \\ \overline{A}Y &= \overline{A}ZB \\ \overline{A}Y &= [z_1^n - (a_1 z_1^{n-1} + a_2 z_1^{n-2} + ...+) a_n z_1^0] B_1 + ... \\ \overline{A}Y &= 0 \times B_1 + 0 \times B_2 + ... \\ \overline{A}Y &= 0 \\ y(n) &= a_1 y(n-1) + a_2 y(n-2) + ... + a_n y(0) \end{aligned} \tag{3.12}$$

When the time is selected arbitrarily, the signal from n step to $(N-1)$ step can be applied repeatedly to form:

$$\underbrace{\begin{bmatrix} y(n-1) & y(n-2) & ... & y(0) \\ y(n-0) & y(n-1) & ... & y(1) \\ y(n+1) & y(n-0) & ... & y(2) \\ \vdots & \vdots & \vdots & \vdots \\ y(N-2) & y(N-3) & ... & y(N-n-1) \end{bmatrix}}_{T} \underbrace{\begin{bmatrix} a_1 \\ a_2 \\ a_3 \\ \vdots \\ a_n \end{bmatrix}}_{\overline{a}} = \underbrace{\begin{bmatrix} y(n+0) \\ y(n+1) \\ y(n+2) \\ \vdots \\ y(N-1) \end{bmatrix}}_{\overline{b}} \tag{3.13}$$

where T is Toeplitz matrix, which means each descending diagonal has constant values [17]. Eq. (3.13) can be used to solve for an unknown vector $\overline{a}$ by using pseudoinverse if matrix T is not a square matrix. The solution of matrix $\overline{a}$ is polynomial coefficients and calculated below:

$$\overline{a} = inv(T'T) * T'\overline{b} \tag{3.14}$$

Furthermore, $\overline{z}$ can be found from the roots of polynomial function in Eq. (3.10) in z-domain. Then, Vandermonde matrix Z can be formulated. The residual B are able to be calculated since matrix Y is known measurements by applying Eq. (3.8). It is necessary to use pseudoinverse if Z is not always a square matrix, $n \times n$.

$$B = inv(Z'Z)Z'Y \tag{3.15}$$

The eigenvalues are usually translated back to s-domain for power system application. Then, the signal y(t) can be estimated through reconstructing y(t) based on oscillatory angular frequency ω and damping ratio ζ. Oscillatory angular frequency is really close to the imaginary part of eigenvalue in s-domain when the damping ratio is very small. The damping ratio is defined:

$$\zeta = \frac{\alpha}{\sqrt{\alpha^2 + \omega^2}} \tag{3.16}$$

For Prony Analysis, additional modes may be required to fit signal offset or noise and the number of prediction modes n is usually smaller than the total number of samples N. However, the reconstructed signal $y(t)$ does not usually completely fit the original signal $y(t)$ in order to avoid over-fit of the signal [14]. In this case, it cannot predict too many modes using Prony analysis.

Chapter 4

Dynamic Simulation Test with IEEE-118 Bus in PSS/E

In order to study the effect of a single-line trips on the oscillation frequencies in the power system, the IEEE 118-bus system was used. Initially, faults were applied to the network with the purpose of determining the coherent groups of generators within the system. As a result, three different coherent groups were identified. Then, the dynamic simulation of single-line trips with PSS/E was performed and the oscillations experienced by each generator in each of the three areas was recorded. Prony analysis was applied to the samples collected of real power output of each generator to estimate the oscillation frequencies of each signal. In order to generalize the findings and visualize them properly, averaging and polynomial curve fitting were performed on all the highest oscillation frequency for all the generators with all the events in three different case studies. Three case studies are defined by dividing the transmission lines into three groups based on which areas they are located. The branch numbers were listed in progression from bus 1 to bus 118, refer to Table D.2. The study demonstrates that partitioning into areas makes sense since line tripping within areas cause larger frequency oscillations in generators within the area, and had minor effect in out-of-area generators. Tripping of tie-lines on the other hand would affect generators from both areas.

4.1 Develop A Proper IEEE 118-bus Model in PSS/E for Analysis

A proper power system model is developed for 118-bus system for analyzing the frequency and damping characteristics of generators in power systems. A system description of the IEEE 118-bus modified power system follows. It has 54 synchronous machines with IEEE type 1 excitation system model and Steam turbine-governor model. Fifteen of the synchronous machines are motors and 20 of the synchronous machines are synchronous condensers, which are only used to support reactive power in the system. Furthermore, the 118-bus system also contains 118 buses, 186 transmission lines, 9 transformers, and 91 constant impedance loads[18]. The total loads of the system consume 3668 MW real power and 1438 MVAr reactive power. The swing bus of 118-bus power system is bus 69. There are three different zones in 118-bus power system. The one-line diagram of the IEEE 118-bus test system is visualized in Figure 4.1 and was modified from its original one-line diagram in [19] in order to match the power system that this report used for dynamic simulations.

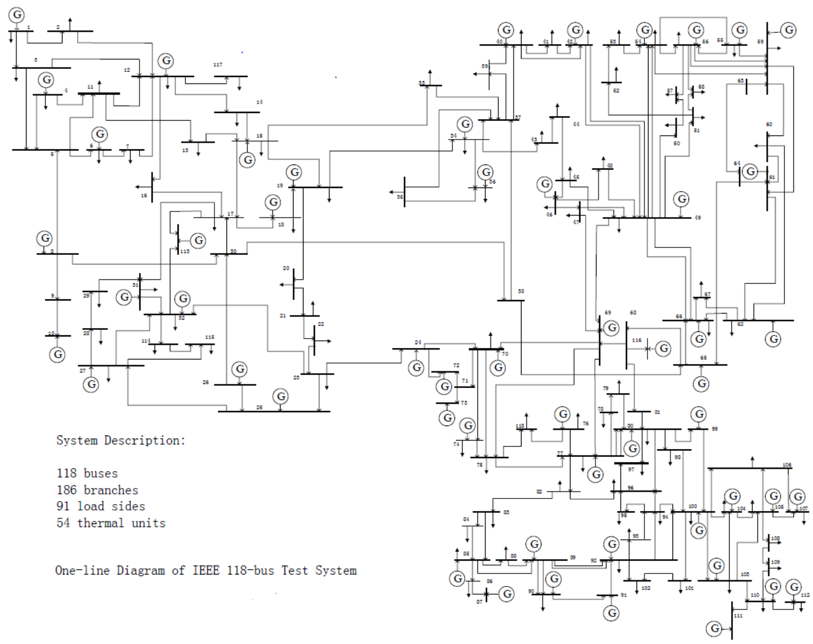


Figure 4.1: One-Line Diagram of IEEE 118-Bus Test System

The different types of synchronous machines in different zones have been identified in Table 4.1. Only the generators connect to the buses 10, 25, 26, 61, 65, 69, 87, 89, and 111, which have no loads connecting to the same bus, can be applied with swing equations, derived from Chapter 2.

Table 4.1: Types of Different Synchronous Machines in Different Zones

Bus Number	**Machine Type**	**Zone**
1, 6, 15, 18, 19, 32	Synchronous Compensator	One
4, 8, 24, 27, 113	Motor	One
10, 12, 25, 26, 31	Generator	One
34, 36, 49, 55, 56, 62, 70, 74, 76, 77	Synchronous Compensator	Two
40, 42, 72, 73, 116	Motor	Two
46, 49, 54, 59, 61, 65, 66, 69, 80	Generator	Two
85, 92, 104, 105, 110	Synchronous Compensator	Three
87, 89, 100, 103, 111	Generator	Three
90, 91, 99, 107, 112	Motor	Three

4.1.1 Machine Model

The type of machine that is used in PSS/E for dynamic simulation for all 54 machines is a round rotor generator model. The dynamic data setting for this model is described in Table 4.2. All the machines have the same dynamic setting and their inertia constant H all have the value 3.2. All the dynamic models of the exciters are IEEE Type 1 excitation systems, which are called IEET1 in PSS/E. And all the dynamic models of governors are steam turbine-governor models, which are called TGOV1 in PSS/E. A detailed explanation of both exciter and governor is covered in Appendix A with both one-line diagrams and dynamic data setting.

Table 4.2: Dynamic Data Setting for GENROU

Parameters	GENROU	Description [12]
T'_{do}	4.8000	d-axis transient rotor time constant
T''_{do}	0.35000E-01	d-axis sub-transient rotor time constant
T'_{qo}	1.50000	q-axis transient rotor time constant
T''_{qo}	0.7000E-01	q-axis sub-transient rotor time constant
H	3.2	Inertia constant
D	0	Damping factor (p.u.)
X_d	1.8000	X_d-axis synchronous reactance
X_q	1.750000	X_q-axis synchronous reactance
X'_d	0.30000	X_d-axis transient reactance
X'_q	0.470000	X_q-axis transient reactance
$X''_d = X''_q$	0.23000	X_d-axis sub-transient reactance, X_q-axis sub-transient reactance
X_l	0.15000	stator leakage reactance
S(1.0)	0.1	saturation factor at 1.0 pu flux
S(1.2)	0.4	saturation factor at 1.2 pu flux

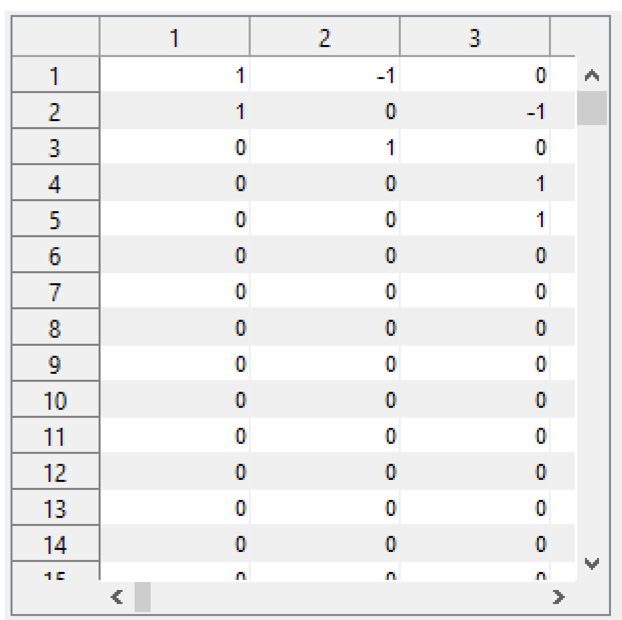
4.1.2 Create an Network Matrix $\hat{A}$ to Avoid Island Power System

In order to perform a small signal analysis, a transmission line with low power flow was disconnected and simulated using PSSE. Tripping of a line should never create an island or isolated power system due to the limitation of the numerical solution provided by the simulation package. For a small system, it is easy to identify the island system problem by checking on the one-line diagram. However, it is more complicated to identify the same problem in a one-line diagram with a large network power system. Hence, a network matrix $\hat{A}$ can be created to solve this power system problem. The form of the network matrix is depending on the frame of reference, bus or loop [20]. In here, a bus incidence matrix $\hat{A}$ is created. The total number of buses represent the number of columns (N_{Bus}) and the total number of rows represent the total number of branches (N_{Branch}). Then, the dimension of the matrix $\hat{A}$ is $N_{Branch} \times N_{Bus}$, which is equal to 186×118 refer to the introduction of IEEE

118-bus in Chapter 3.1. The element of matrix are described as below:

- a_{ij} = 1 if the i_{th} branch is the path that is oriented away from the j_{th} bus.
- a_{ij} = -1 if the i_{th} branch is the path that is oriented toward to the j_{th} bus.
- a_{ij} = 0 if the i_{th} branch is not in the path.

The bus incidence matrix $\hat{A}$ can be used to identify the bus or buses with a single-line connecting them to the system. Those are the single lines that cannot be removed from the system for the dynamic study as it will create two independent systems and the simulation will fail. The matrix can be displayed in a GUI table as showed in Figure 4.2. The completed matlab example code and generated matrix image for the bus incidence matrix are listed in Appendix B. The full matrix can be viewed by scrolling through the columns or rows by using a slider uicontrol in the GUI table.



	1	2	3
1	1	-1	0
2	1	0	-1
3	0	1	0
4	0	0	1
5	0	0	1
6	0	0	0
7	0	0	0
8	0	0	0
9	0	0	0
10	0	0	0
11	0	0	0
12	0	0	0
13	0	0	0
14	0	0	0

Figure 4.2: Incidence Matrix Part2

After running the Matlab code in Appendix B, bus number 10, 73, 87, 111, 112, 116, and 117 have been identified as having only one transmission line connecting to these buses. All the line segments associated with radially connected buses cannot be disconnected as they will result a system islanding. As a result, the system has 9 branches that cannot be disconnected in the simulation. The detailed list of 9 branches is displayed in Table 4.3 with the corresponding buses that will be isolated if the branch is disconnected. The detailed connections of 186 transmission lines have been listed in Appendix D.

Table 4.3: Branches Cannot be Disconnected due to Island System Problem

Branch Number	**From Bus**	**To Bus**	**Isolated Bus**
12	8	9	9 and 10
14	9	10	10
19	12	117	117
108	68	116	116
116	71	73	73
137	85	86	86 and 87
140	86	87	87
175	110	111	111
176	110	112	112

4.1.3 Define Proper Disconnecting Line Events for Dynamic Simulation

In addition to the transmission lines which involve a bus break up into an island power system problem, there are three more situations that need to be considered in order to prepare the case study by disconnecting proper transmission lines for dynamic simulation with small signal disturbance.

- First, if two parallel transmission lines are connected between two buses, it is redundant work to disconnect each of parallel lines for studying the dynamic systems separately. This is because the behavior of the system for each event will be the same for all the parallel transmission lines. The 118-bus system has 7 pairs of transmission lines connecting in parallel as shown in Table 4.4. Therefore, there will be only one transmission line that is disconnected from each pair of parallel transmission lines during the case study for dynamic simulation.

- Second, some buses are connected by two-winding transformers, which is listed at Table D.1 in Appendix D from branch 178 to branch 186. These nine branches will also be excluded from the dynamic simulation study.

- Finally, all the transmission lines that transfer more than 100 MW real power between two buses will be excluded from the dynamic simulation case study in this research with exception of the tie-lines.

As a result, there are only 142 branches left for the dynamic study, which consists of disconnecting one branch at a time to analyze the frequency characteristic of each generator of the power system with small signal disturbance. All 142 branches have been listed in Table D.2 in Appendix D.

Table 4.4: Seven Pairs of Transmission Lines Connected in Parallel

From Bus	To Bus
42	49
49	54
49	66
56	59
77	80
89	90
89	92

4.2 Case Study for Dynamic Simulation

All the case studies for dynamic simulation will be run in PSS/E through Python code. For each event, there is only one transmission line that is disconnected from the system. Then, the data for dynamic behavior of rotor angles, power, field voltage, bus voltage, and frequency deviation of each generator can be extracted from PSS/E. The total simulation time is $15s$ for each event and the time step used in the simulation run was equal to a half cycle for a 60-Hz system. Therefore, each signal has 1806 points. The oscillation is always returning back to steady state after 10s for most of the simulation signals, so the study will only analyze the results of the initial $10s$ of simulation, which means 1205 data points in total. For each event, there are 54 dynamic simulation waveforms of output power of each individual generator. All the data will be processed and all the waveforms generated. Not all of data will be shown in this report.

The dynamic behavior of the power of each individual generator will be analyzed to determine the frequency and damping associated with each generator for each event. Dynamic behavior of power for generator 10 by disconnecting branch 10, which is from bus 7 to bus 12 refer to Table D.2, is illustrated in Figure 4.3. The output power in per unit produced by each generator is displayed in the y-axis, while the x-axis represents the simulation time in seconds. In the first 0.5 second of the simulation, the power system is operating without any disturbance. The $0.5s$ simulation is done to check if the system is under steady state prior to the event. Following the loss of a transmission line, the change of frequency and response of the generator output is evaluated. The generator output power is dominantly influenced by machine inertia constant with fast response soon after the disturbance. Meanwhile, the governor has a minor effect at this point because governor and exciter has a relatively long time constant to respond.

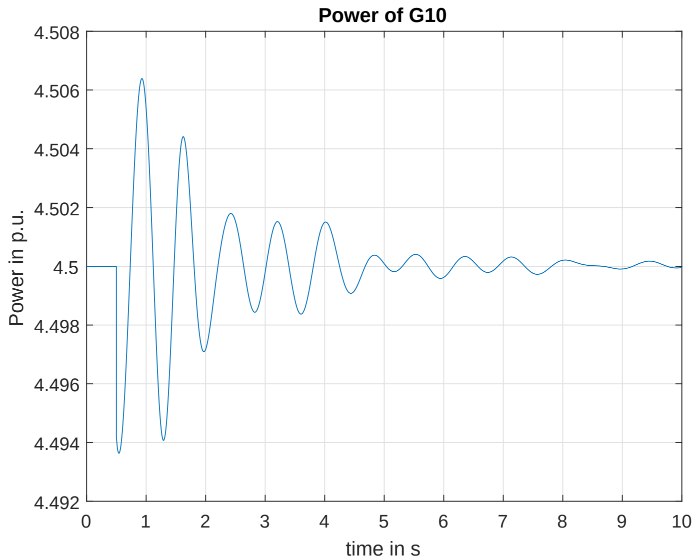


Figure 4.3: Dynamic Behavior of Power for G10 After Disconnecting Branch 10

Next, 142 events are divided into three groups for three different zones in order to investigate the dynamic simulation behavior of each generator for both local-area mode and inter-area modes. The three groups have been divided in Table 4.5. The first 41 branches and branch 142 are within Zone 1. From branch 42 to Branch 106 all are connected in zone 2. From branch 107 to branch 141 all are connected in zone 3. Therefore, based on three group of disconnecting lines in three zones, there are three case studies.

Table 4.5: Divide Branches into Three Different Zones

Case Study	Zone	Branches Are Involving
1	Zone 1	1 - 41,142
2	Zone 2	42 - 106
3	Zone 3	107 - 141

4.2.1 Case Study for Damping Characteristics of Generators between Local-Area Oscillation and Inter-Area Oscillation

From now on, the first 0.5s of all the figures will be truncated because we only want to analyze the dynamic behavior of the waveforms. We also don't want the steady state data affect the result of estimating the oscillation mode by applying Prony Analysis later on. The total simulation time that is shown in the figures will be 9.5s. In addition, initial power output condition of each generator will be subtracted from the simulation results to display power deviation as a function of time. This procedure also provides a quick check on the coherency of the generators.

When only the branches that are disconnected in zone 1 are studied, it has been noticed that the dynamic behaviors of all the generators in zone 1 resemble the response of a damped second order system. Figure 4.4 is an example of the dynamic behavior of generator 10 after disconnecting the first 5 branches in the IEEE 118-bus system with the legend 1 to 5 corresponding to the dynamic response of generator 10 to the removal of the numbered lines, refer to Table D.2. The electric link between two generators within the same zone is relatively tight and strong. Therefore, the response to the dynamic event of these generators tends to be similar and have higher oscillation frequency due to the local-area oscillation effect when the fault is in the same zone. Therefore, the second order dynamic behavior is dominated by the local-area mode. Meanwhile, it is also affected in a less degree by the weak inter-area oscillation. It is obvious to notice that the signal goes back to steady state for all five events after 4.5s for generator 10. After that time, the response to the event is dominated by inter-area oscillation.

However, the oscillation of power of all the generators in both zone 2 and zone 3 are not as second order dominated as zone 1 generators. It can be still observed that the second

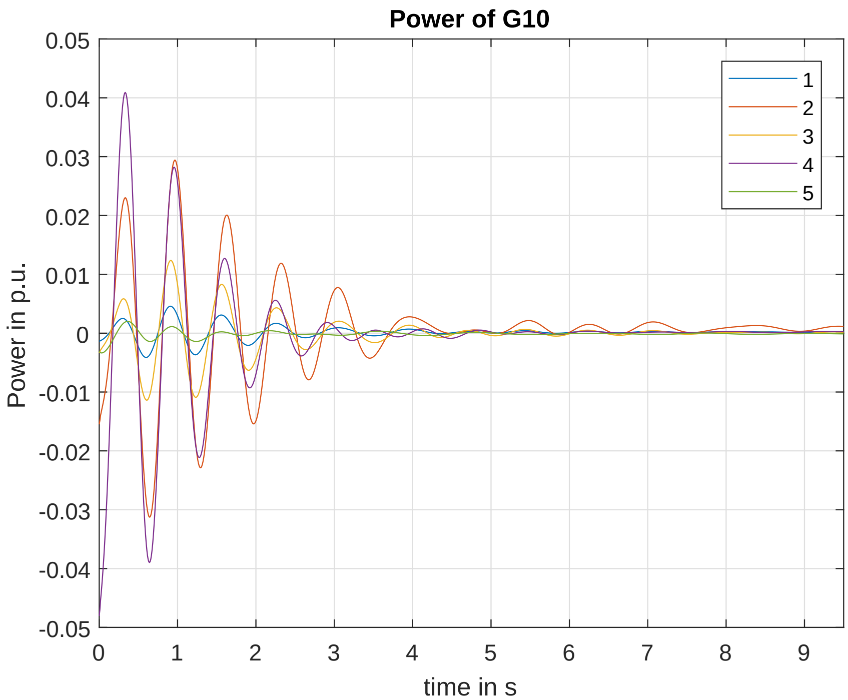


Figure 4.4: Dynamic Behavior of Power for G10 After Disconnecting First 5 Branches

order system behavior in the damped waveforms. It can be shown by randomly picking one generator from zone 2 and one generator from zone 3 to display the dynamic behavior of power with tripping first 5 lines in zone 1. The oscillation behavior of generator 61 in zone 2 is displayed in Figure 4.5. The oscillation behavior of generator 89 in zone 3 is illustrated in Figure 4.6. It is observed from both Figure 4.5 and Figure 4.6 that the oscillation values of power for all the events simulated in zone 2 and zone 3 are much smaller when compare to the oscillation value of power in zone 1. Refer to Chapter 2, the larger network with a large system inertia constant is harder to be perturbed than a smaller inertia constant in a smaller network system. Therefore, the reason for the small oscillation values in the generators in zone 2 and zone 3 is due to a swing against a larger network system than the generators in zone 1. The oscillation lasts more than 9.5s to bring the system back to steady state again for both zone 2 and zone 3. It takes more time to bring generator 61 and generator 89 back

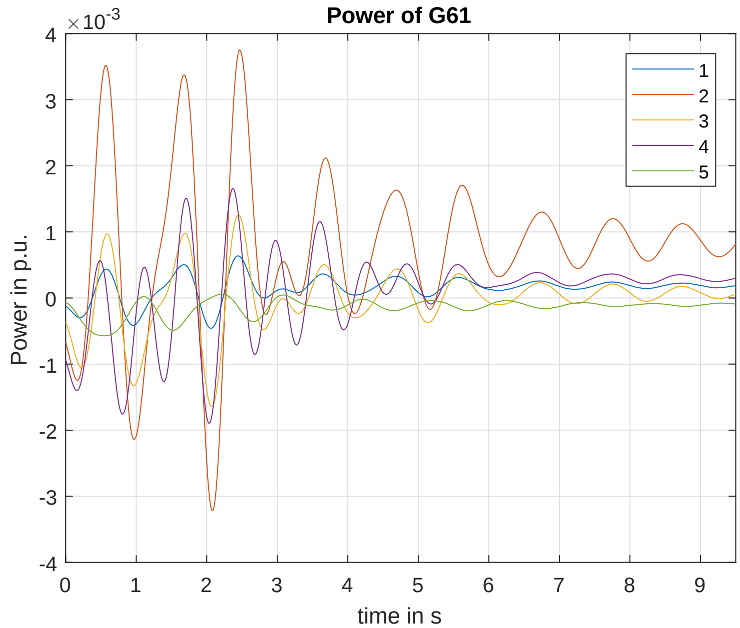


Figure 4.5: Dynamic Behavior of Power for G61 After Disconnecting First 5 Branches

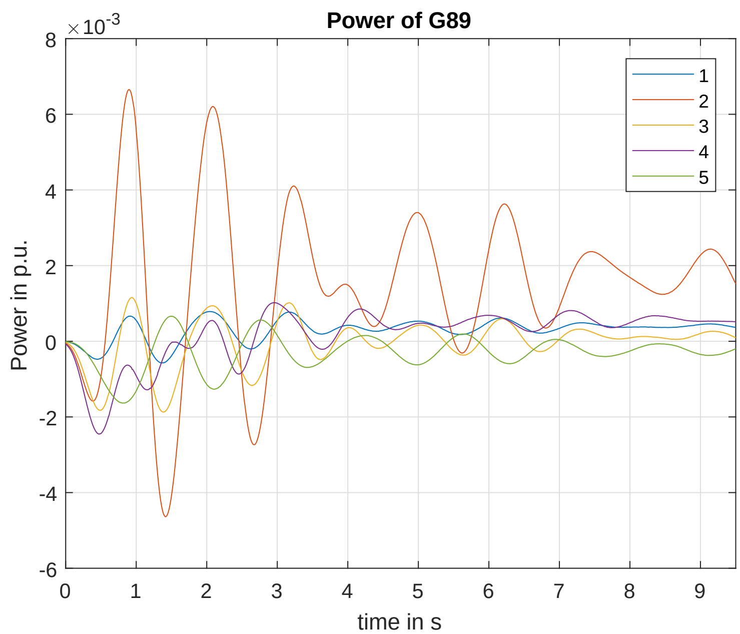


Figure 4.6: Dynamic Behavior of Power for G89 After Disconnecting First 5 Branches

to steady state than generator 10 because the oscillation for both generator 61 and generator 89 are caused by both weak inter-area mode. Zone 1 and zone 2 are oscillating against each other for generator 61. Zone 1 and Zone 3 are oscillating against each other for generator 89. It takes more time for generators to react on the events that are happening further away due to longer distance and larger power system with a larger system inertia constant from the perspective of the generators.

Similarly, when only the branches from branch 75 and 79 are disconnected in zone 2, refer to Table D.1, are studied, the dynamic response for all the generators in zone 2 will behave dominantly as a second order system. The simulation results for the generator 10 in zone 1, generator 61 in zone 2, and generator 87 in zone 3 have been shown in Figure 4.7.

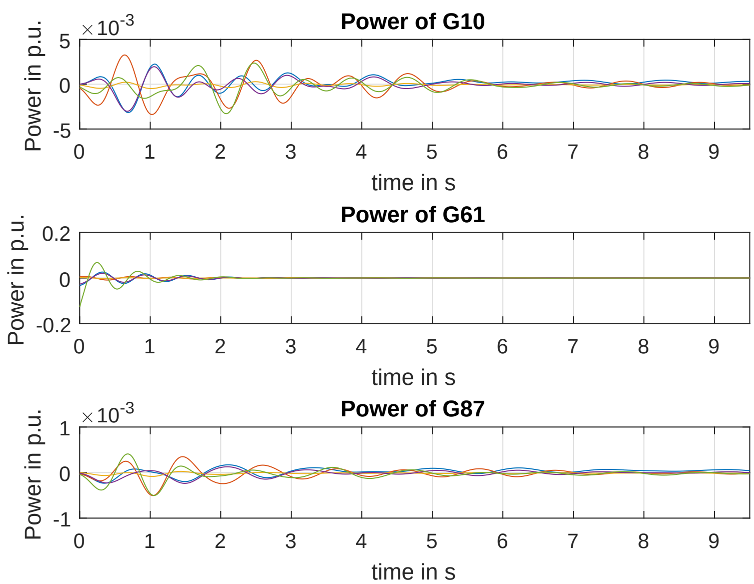


Figure 4.7: Dynamic Behavior of Power After Disconnecting 5 Branches in Zone 2

The same results are obtained for all the events happening in zone 3. The dynamic simulation of disconnecting lines from branch 135 to 139 in zone 3 by looking into the dynamic behavior of generators 25 in zone 1, generator 76 in zone 2, and generator 107 in zone 3 are shown in Figure 4.8.

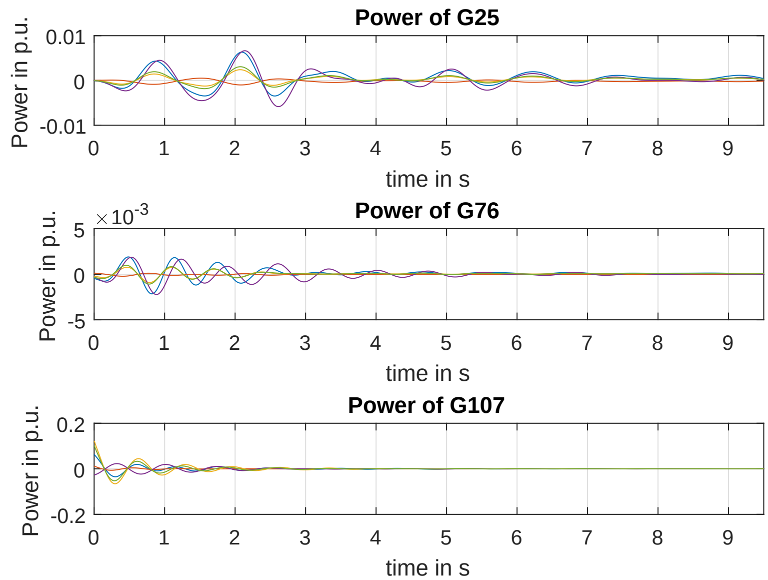


Figure 4.8: Dynamic Behavior of Power After Disconnecting 5 Branches in Zone 3

It was found that the generators near the boundary of two neighboring zones located near tie-lines, will also present a response dominated by a second order damped system. For example, generators 34, 36, 40, 42, 70, 72, 73, 74, and 76, which are located at the boundary between zone 1 and zone 2, are tightly responding to zone 1 events. Some graphical behavior of a few generators is illustrated in Figure 4.9 for zone 1 events. However, it can be noticed that the damping amplitude is still smaller.

Therefore, when a generator that is connected to a large system, the dynamic behavior of power for this generator is damped to be dominated by a second order system if a line tripping occurs within the same zone area. Referring to Chapter 2, it is able to assume that this generator is connected to an infinity bus, which is represented by a large network system with a small signal disturbance based on the perspective of the generator. Since the initial generator output power is mainly influenced by the machine inertia constant and machine inertia constant is tightly related to oscillation frequency, the damping characteristics of each

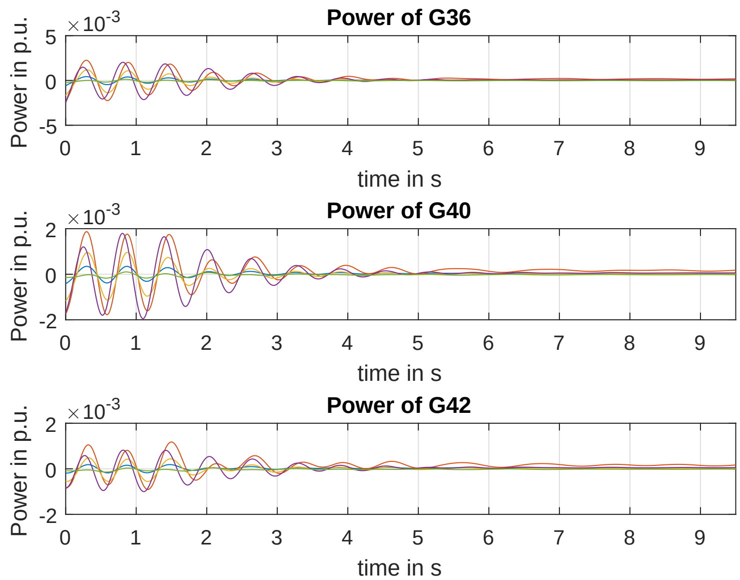


Figure 4.9: Dynamic Behavior of Power for Edge Generators in Zone Two

generator are based on the location of the line tripping event where it takes place.

4.2.2 Case Study for Frequency Characteristic of Generators under area control

Subsequently, Prony analysis, as referring in Chapter 3, is applied to all three case studies in order to estimate both oscillation frequency and damping ratio of each dynamic simulation signal for all considered events . Then, the analysis of frequency characteristics of each generator among different zones can be studied.

For the purpose of this research, a six mode order Prony analysis was used to better approximate the dynamic behavior of the generators of the system. Even though it was assumed that the response of the system for a small signal perturbation is close to a second order system (refer to chapter 2), it was better to use additional modes to obtain better estimation in order to avoid noise and offset signal. In addition, high orders where tested with results that did not prove to be a better estimation.

Thus, all the transient response of power, which is cause by suddenly disconnecting a transmission line of power system for all 54 generators, is using 6 mode order to do Prony analysis. In the Prony analysis, the transient response is sampled with 57 samples with sampling rate of 6 Hz to create a discrete signal that corresponds to the simulation measurements. For example, the oscillation frequency and damping ratio of dynamic simulation of the first five line events from section 4.2.1 is estimated in Table 4.6 for generator 10, 61, and 89. It is noted that a larger oscillation frequency corresponds to a smaller damping ratio for each generator. That is because a signal is less stable with a smaller damping ratio.

Table 4.6: Oscillation Frequency and Damping Ratio Estimation for Three Generators

Branch Number	G10 ζ	G10 $\Delta\omega$	G26 ζ	G26 $\Delta\omega$	G89 ζ	G89 $\Delta\omega$
1	0.126	11.002	2.603E-2	10.282	8.376E-2	8.723
2	0.196	10.829	2.069E-2	10.105	8.714E-2	8.288
3	0.127	10.966	2.645E-2	10.292	5.195E-2	8.868
4	0.257	9.700	1.557E-2	10.162	3.084E-2	9.609
5	9.979E-2	10.639	2.549E-2	10.211	0.109	6.421

For each loss line event, there are a total of 54 oscillating power signals needed to apply Prony analysis to estimate their oscillation frequency and damping ratio. The results will give 6 total oscillation frequency and damping ratio due to the 6 mode order. Next, the highest frequency response in complex conjugate format will be filtered out in order to check on the oscillation frequency characteristics of each generator. Then, the average oscillation frequency for each zone is calculated based on their generators. All the oscillation frequency from this point is the average oscillation frequency for each zone. All the calculated mean oscillation frequency data for disconnecting lines in zone 1 is listed in Table E.1 in Appendix F. Lastly, the data is plotted in Figure 4.10 as scatter plot.

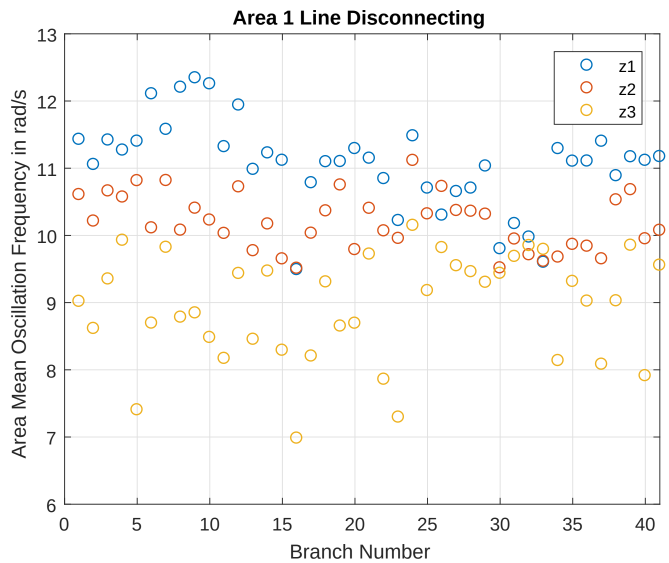


Figure 4.10: Disconnecting Zone One Transmission Line

The discription of the Figure 4.10 is stated below:

- Each blue circle is the mean oscillation frequency value for generators in zone 1 for each event. Almost all the blue circles are scattered at the top of the plot in Figure 4.10.
- Each red circle is the mean oscillation frequency value for generators in zone 2 for each event. All the red circles are spreading around between blue circles and yellow circles.
- Each Yellow circle is the mean oscillation frequency value for generators in zone 3 for each event. All the yellow circles are distributed in the bottom of the plot in Figure 4.10.

The trend of each zone can be derived by using polynomial curve fitting in matlab as shown in Figure 4.11. The polynomial curve fitting finds the best fit in a least-square sense for the data based on the degree of polynomial that best describe the curve.

Based on Figure 4.11, it indicates that the generators in zone 1 are influenced the most with having the highest oscillation frequency by having disconnecting lines events in zone

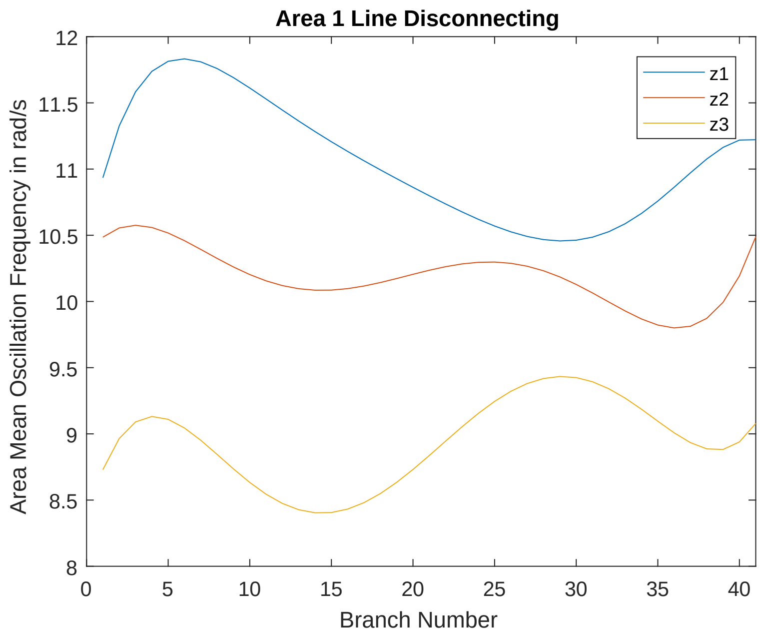


Figure 4.11: Trend of Disconnecting Zone One Transmission Line

1, refer to Table 4.5 in previous section. Generators in zone 3 are influenced the least with the lowest oscillation frequency for the same events. The influence of generators in zone 2 is somewhat in between zone 1 and zone 3. There is some abnormal distribution of mean oscillation frequency as showed in Figure 4.12. The abnormal events are defined by not having the highest mean oscillation frequency when the generator is located where the event occurs. These events are caused by disconnecting the tie-line or the transmission lines are very close to tie-line for dynamic study.

Next, let's discuss disconnecting all the lines in Zone 2, refer to Table 4.5. Repeat all the procedures and analysis at zone 1 line tripping events for zone 2. All the calculated mean oscillation frequency data for disconnecting lines in zone 2 is listed in Table E.2 in Appendix F. The scatter plot for zone 2 is illustrated in Figure 4.13.

The description of the Figure 4.13 is stated below:

- Each blue star is the mean oscillation frequency value for generators in zone 1.

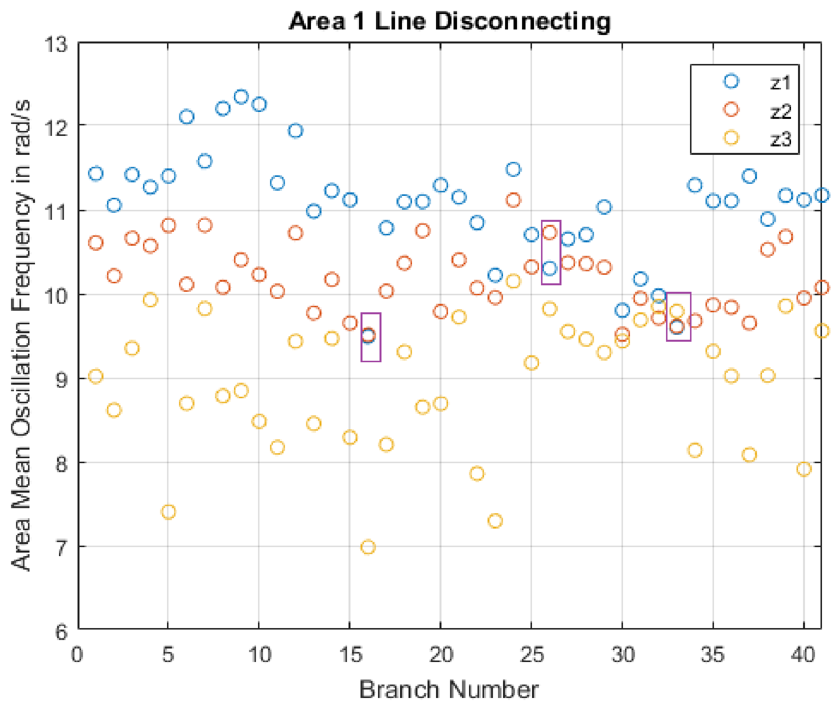


Figure 4.12: Abnormal Case for Disconnecting Zone One Transmission Line

- Each red star is the mean oscillation frequency value for generators in zone 2. The majority of the red stars are scattered at the top of the plot in Figure 4.13.

- Each yellow star is the mean oscillation frequency value for generators in zone 3.

The trend of each zone is displayed for disconnecting lines in zone 2 as shown in Figure 4.14. As the disconnecting lines in zone 2 are further away from zone 1, the mean oscillation frequency for the generators in zone 1 is smaller. This is because when the disturbance from each event gets away from zone 1, the generators in zone 1 will oscillate against with a larger network system with a larger system inertia constant based on perspective of the generators in zone 1. It also increases the impedance for the generators in zone 1 to react on the fault. That's why the mean oscillation frequency is smaller for generators in zone 1. On the contrary, as the disconnecting lines in zone 2 get closer to zone 3, the mean oscillation frequency for the generators in zone 3 is larger. From the perspective of generators in zone

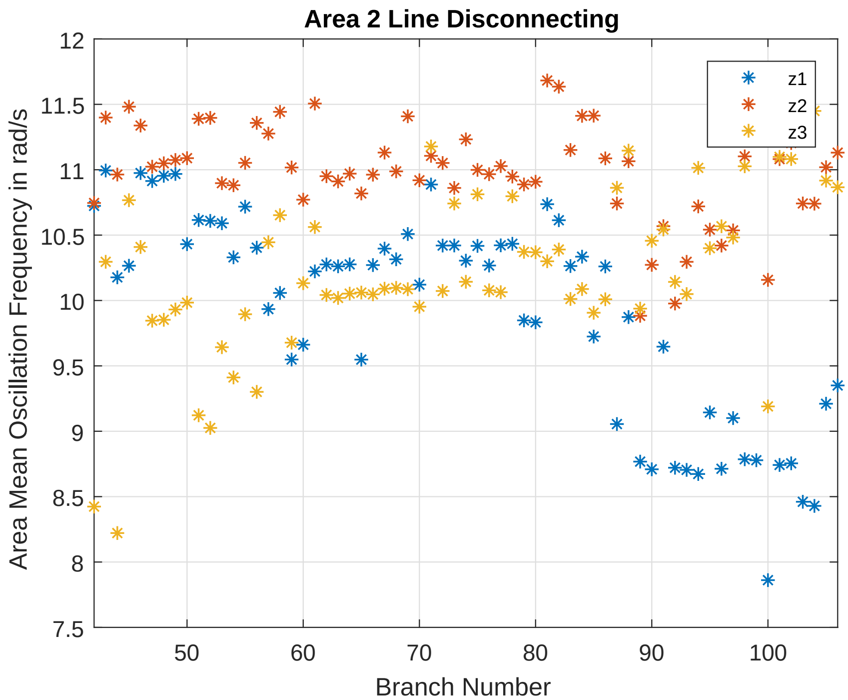


Figure 4.13: Disconnecting Zone Two Transmission Line

3, they will oscillate against with a smaller network system with a smaller system inertia constant. Moreover, it has shorter impedance for the generators in zone 3 to react on any disturbance. When disconnecting lines around branch 100, refer to Table D.2 in Appendix D, the oscillation frequency of generators in zone 3 is higher than generators in zone 2 due to the border connection tie-lines and the lines that are near tie-lines are disconnected in the system.

The result of disconnecting lines in zone 3 is very similar to the result of disconnecting lines in zone 1 for the behaviors of generators in three different zones. The scatter plot of this case is shown in Figure 4.15. The main difference is the behavior of generators in zone 1 is opposite of the behavior of the generators in zone 3. The generators in zone 3 have the highest mean oscillation frequency when the lines are disconnected in zone 3. As disconnecting lines for zone 3 move further away from zone 1, the mean oscillation frequency

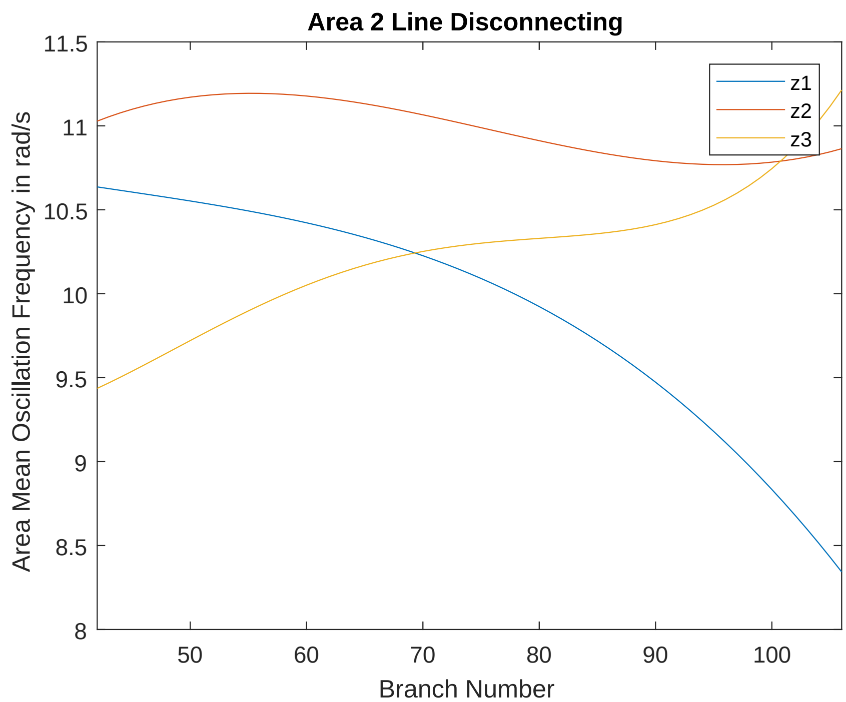


Figure 4.14: Trend of Disconnecting Zone Two Transmission Line

for generators in zone 1 is smaller. More abnormal events occur between zone 3 and zone 2 because they have more connections in the border or they have more tie-lines.

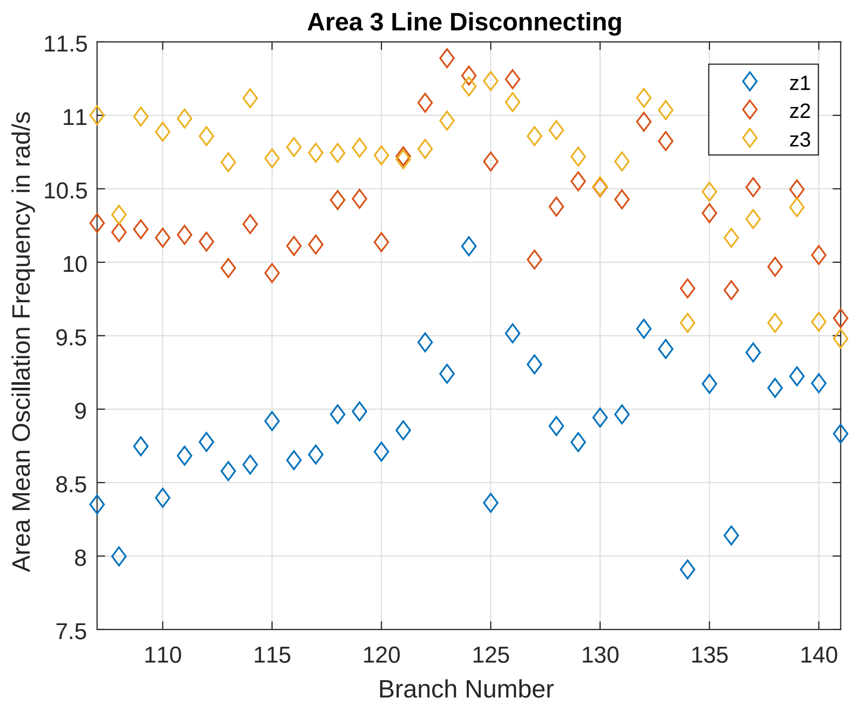


Figure 4.15: Disconnecting Zone Three Transmission Line

Finally, the data of all the line tripping events is gathered together in one figure as illustrated in Figure 4.16. The result of the estimated trend line of each zone for all the events is illustrated in Figure 4.17. Branch 142 is not included in these two figures because it is connected in zone 1, refer to Table 4.5. The mean oscillation frequency of dynamic behaviors of all the generators for different zones are divided into three colors to stand for three zones. The disconnecting line events in different zones, refer to Table 4.5, used three different shapes to represent them. They have been determined in Table 4.7.

Table 4.7: Description of Figures

Zone Number	Zone Color for Overall Events	Shape for Line Tripping in a zone
Zone 1	Blue	Circle
Zone 2	Red	Star
Zone 3	Yellow	Diamond

It is easy to determine from Figure 4.17 that the mean oscillation frequency on a zone

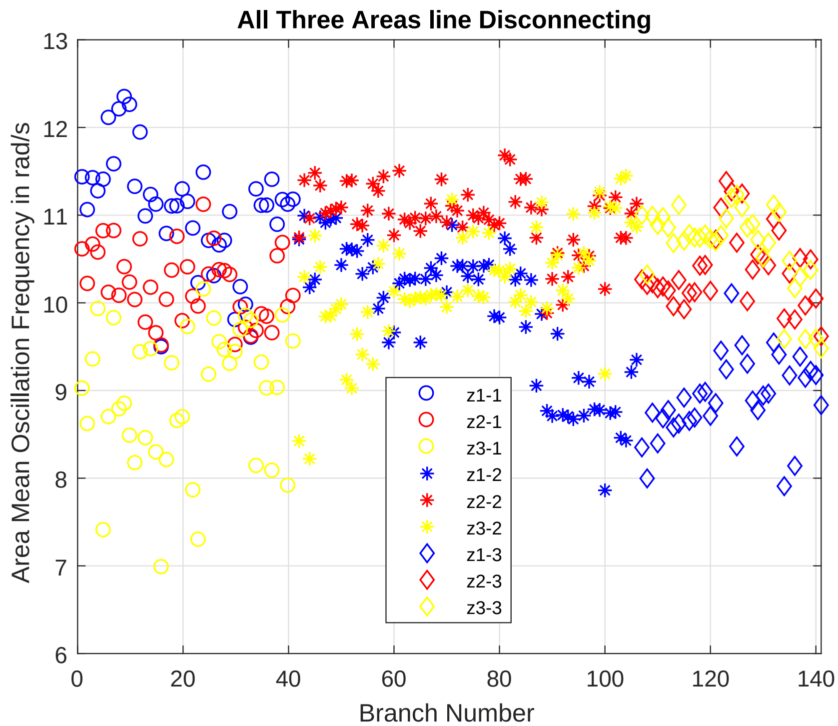


Figure 4.16: Disconnecting All 142 Branches

has the highest reading when the line is disconnected in the same zone area. In addition, when the transmission line is disconnected from the system and is moving further away from a zone, the mean oscillation frequency of that zone decreases. When a disconnected line from the system is moving closer to a zone, the mean oscillation frequency of that zone increases.

The mean oscillation frequency of zone 1 is flat in the very beginning because the line is tripped in its own zone. Then it is decreasing all the way as the line is tripped is moving away from zone 1. The mean oscillation frequency of zone 2 generators is like the shape of an arch because the tripped line is getting closer to zone 2 from zone 1 to zone 2 and then away from zone 2 to zone 3. The mean oscillation frequency of zone 3 is increasing as the line is tripped from zone 1 to zone 3. It gets flat again when the line is tripped in the same zone.

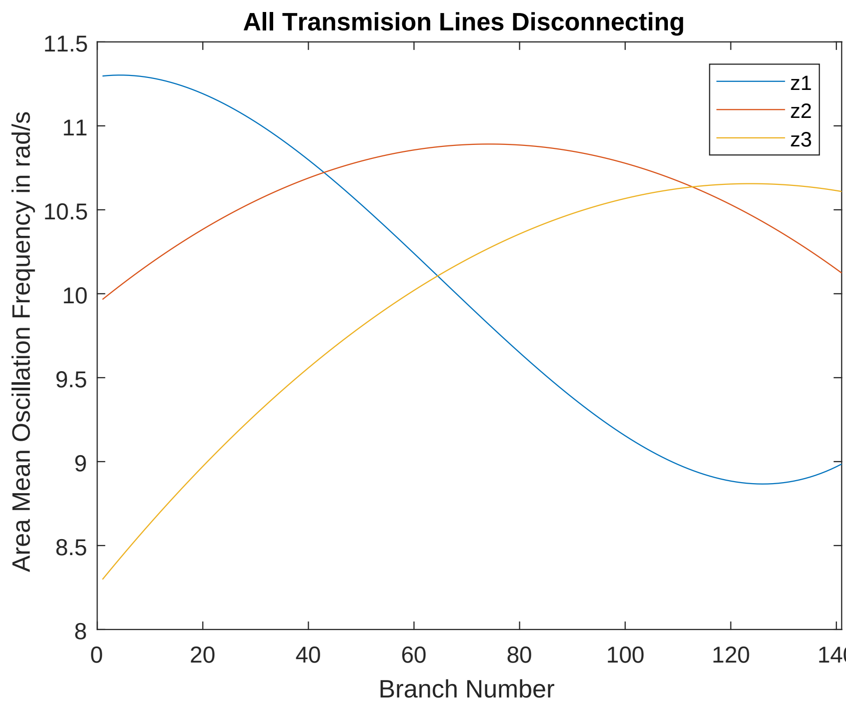


Figure 4.17: Disconnecting All 142 Branches

The oscillation frequency range for each zone in Table 4.8 is in radians and Table 4.9 is in Hz under three case studies, which is disconnecting three groups of transmission lines refer to Table 4.5.

Table 4.8: Mean Oscillation Frequency Range in Radians for Three Zones under Three Studies

	Z1_line ω_{max}	Z1_line ω_{min}	Z2_line ω_{max}	Z2_line ω_{min}	Z3_line ω_{max}	Z3_line ω_{min}
Zone 1	12.3434	9.4898	10.9942	7.8614	10.1089	7.9088
Zone 2	11.1143	9.5094	11.6425	9.8831	11.3891	9.6189
Zone 3	10.1479	6.9816	11.4495	8.2215	11.2341	9.4802

Table 4.9: Mean Oscillation Frequency Range in HZ for Three Zones under Three Studies

	Z1_line f_{max}	Z1_line f_{min}	Z2_line f_{max}	Z2_line f_{min}	Z3_line f_{max}	Z3_line f_{min}
Zone 1	1.964	1.510	1.750	1.251	1.609	1.259
Zone 2	1.769	1.513	1.859	1.573	1.812	1.531
Zone 3	1.615	1.111	1.822	1.308	1.788	1.509

Once again, when the line that is tripped moves away from a zone, both maximum and minimum values of mean oscillation frequency become smaller and the oscillation frequency range is shifting. It is the same for all three studies. The zone where the line is tripped has the highest oscillation frequency. The zone where the line is tripped is the furthest away has the lowest oscillation frequency. As a result, the larger system inertia constant will be seen by a generator as the event that it occurs is further away from the generator. The larger system inertia constant minimizes the frequency oscillation. Therefore, the larger system inertia constant will make the power system more stable with lower oscillation frequency.

Chapter 5

Conclusion and Future Work

5.1 Conclusion

With the rapid development of integrating the renewable energy in the power system, the relationship between frequency characteristics of generators and system inertia constant H will take more responsibility on frequency regulation for the power system. The primary purpose of this thesis was to analyze the frequency and damping characteristics of generators in the power systems through dynamic simulation of generator output power when a line is tripped.

This report used simulation studies and derived theoretical analysis to study that a generator connected to a large network system can be represented as the single-machine infinite bus from the perspective of the generator. From the analysis, it is noted that the location of the line tripping is very critical. The simulation results concluded that the represented SMIB system is recognized as a second order damped system when the line tripping occurred in the same area as the generator, or the generators of neighboring zones located near a tie-line. It is recognized that the larger system inertia constant will be seen by a generator as the event that it occurs is further away from that generator. It is further recognized that perturbation of dynamic damping for the initial generator output power for these generators are smaller because the system becomes more stable with larger system inertia constant from the perspective of the generator.

The dynamic simulation studies demonstrate that the oscillation frequency of generator output power has its own range for each zones when a line is tripped in different zones. The magnitude of oscillation frequency of each zone for each line loss event is based on the proximity of the loss line event takes place from the zone. The zone with the fault occurs has the highest oscillation frequency. The zone that is the furthest away from the fault occurs has the lowest oscillation frequency.

Clearly, both frequency and damping characteristics of generators are highly relevant to 2 factors as described below:

- the location of the disturbance
- the amount of damping associated to the oscillation

According to the analysis described previously, frequency and damping characteristics of generators are highly depended on the system inertia constant. Thus, the higher inertia constant is a critical factor to ensure the system is to be more stable and avoid to be perturbed.

5.2 Future Work

Future research work may be performed on the stability study of the power system by checking on the system damping ratio of the system. By defining the smallest system damping ratio that can be reached in order to keep the oscillation frequency of the system within the stability range of the system. Then, the stability of a power system can be controlled by controlling the system damping ratio. Further, the sensitivity study of frequency characteristics of generators can be approached by adding different renewable source into the power system. Further research is needed in order to estimate the system inertia constant from the perspective of a generator when is connected to a large network system.

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Appendices

Appendix A

Model of Exciter

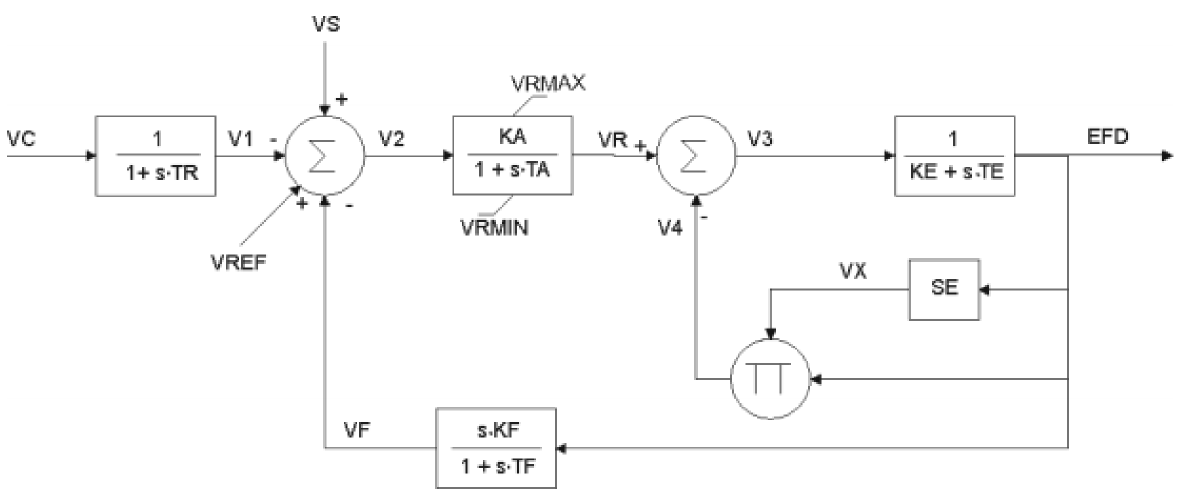

Figure A.1: IEEET1˙Exciter

Parameters Ranges:

$0 \leq TR < 0.5$	$-1 \leq KE \leq 1$
$< KA < 500$	$0.04 < TE < 1$
$0 \leq TA < 1$	$0 < KF < 0.3$
$0.5 < V_{RMAX} < 10$	$0.04 < TE < 1.5$
$-10 < V_{RMIN} < 0$	$5 < TF/KF/ge15$

Table A.1: IEEE Type 1 Excitation System - IEEET1

Parameters	Value	Description
T_R	0.06	Filter time constant in second
K_A	20	Regulator gain in p.u.
T_A	0.01	Regulator time constant in second
V_{RMAX}	5.0	Maximum voltage regulator outputs in p.u.
V_{RMIN}	-6.0	Minimum voltage regulator outputs in p.u.
K_E	1.0	Exciter constant related to self-excited field
T_E	0.67	Exciter time constant, integration rate associated with exciter control in second
K_F	0.1	Feedback gain
T_F	1.0	Feedback time constant
Switch	0.0	Exciter alternator output voltages back of commutating reactance at which saturation is defined
E_1	3.0	Exciter saturation function value at the corresponding exciter voltage, E1, back of commutating reactance
$S_E(E_1)$	0.09	Exciter alternator output voltages back of commutating reactance at which saturation is defined
E_2	4.0	stator leakage reactance
$S_E(E_2)$	0.368	Exciter saturation function value at the corresponding exciter voltage, E2, back of commutating reactance

Appendix B

Model of Governor

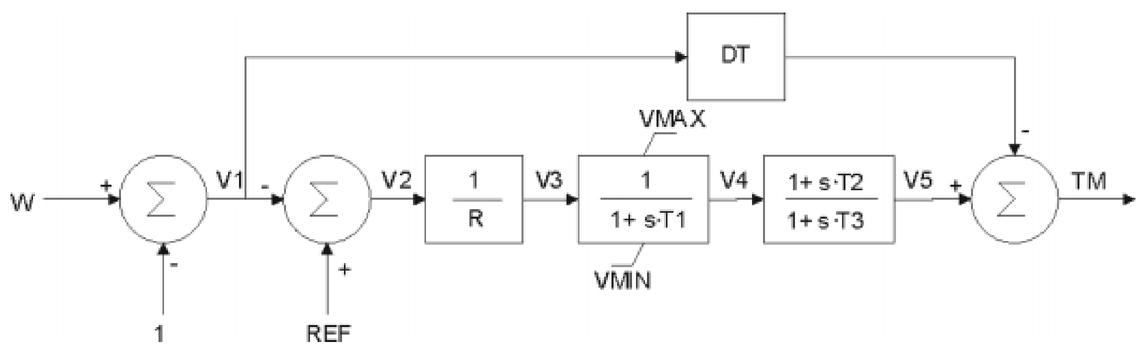

Figure B.1: Steam˙Turbine˙Governor

Table B.1: Steam turbine-governor model - TGOV1

Parameters	Values	Description
R	0.04	Permanent droop in p.u.
T_1	0.4	Steam bowl time constant in second
${V_{MAX}}^1$	Maximum valve position in p.u.	
${V_{MIN}}^1$	-1.0	Minimum valve position in p.u.
${T_2}^2$	1.5	time constant in second
${T_3}^3$	5.0	time constant in second
${D_t}^1$	0.0	Turbine damping coefficient in p.u.

[1]VMAX, VMIN, Dt and R are in per unit on generator MVA base.

[2]T_2/T_3 = high-pressure fraction.

[3]T_3 = reheater time constant.

Parameters Range:

$0 < R < 0.1$	$0 < T_2$
$0.04 < T_1 < 0.5$	$004 < T_3 < 10.0$
$0.5 \leq V_{MAX} \leq 1.2$	$T_2 < T_3/2.0$
$VMIN < V_{MAX}$	$0 \leq D_T < 0.5$
$0 \leq V_{MIN} < 1.0$	

Appendix C

Bus Incidence Matrix

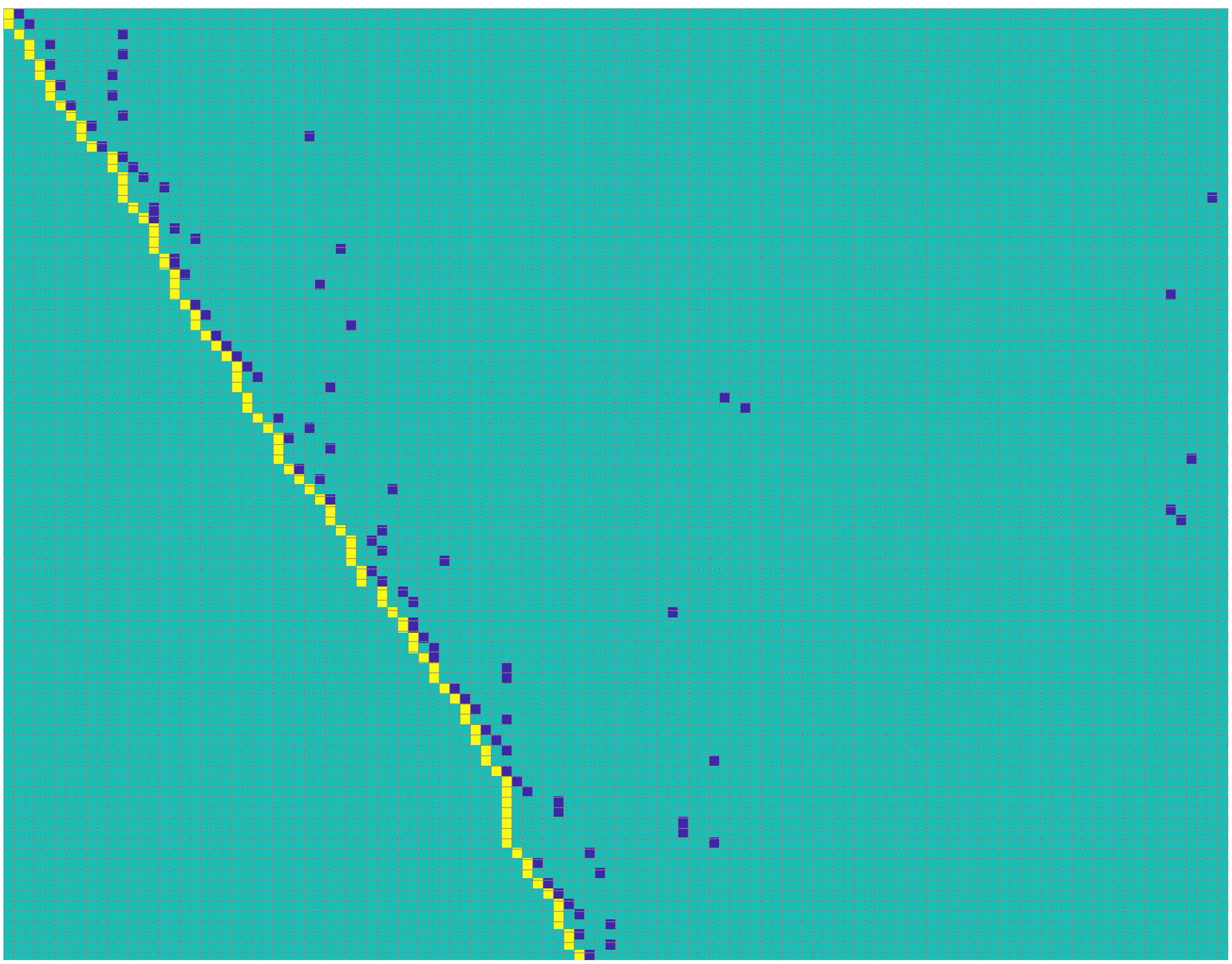

Figure C.1: Incidence Matrix Part1

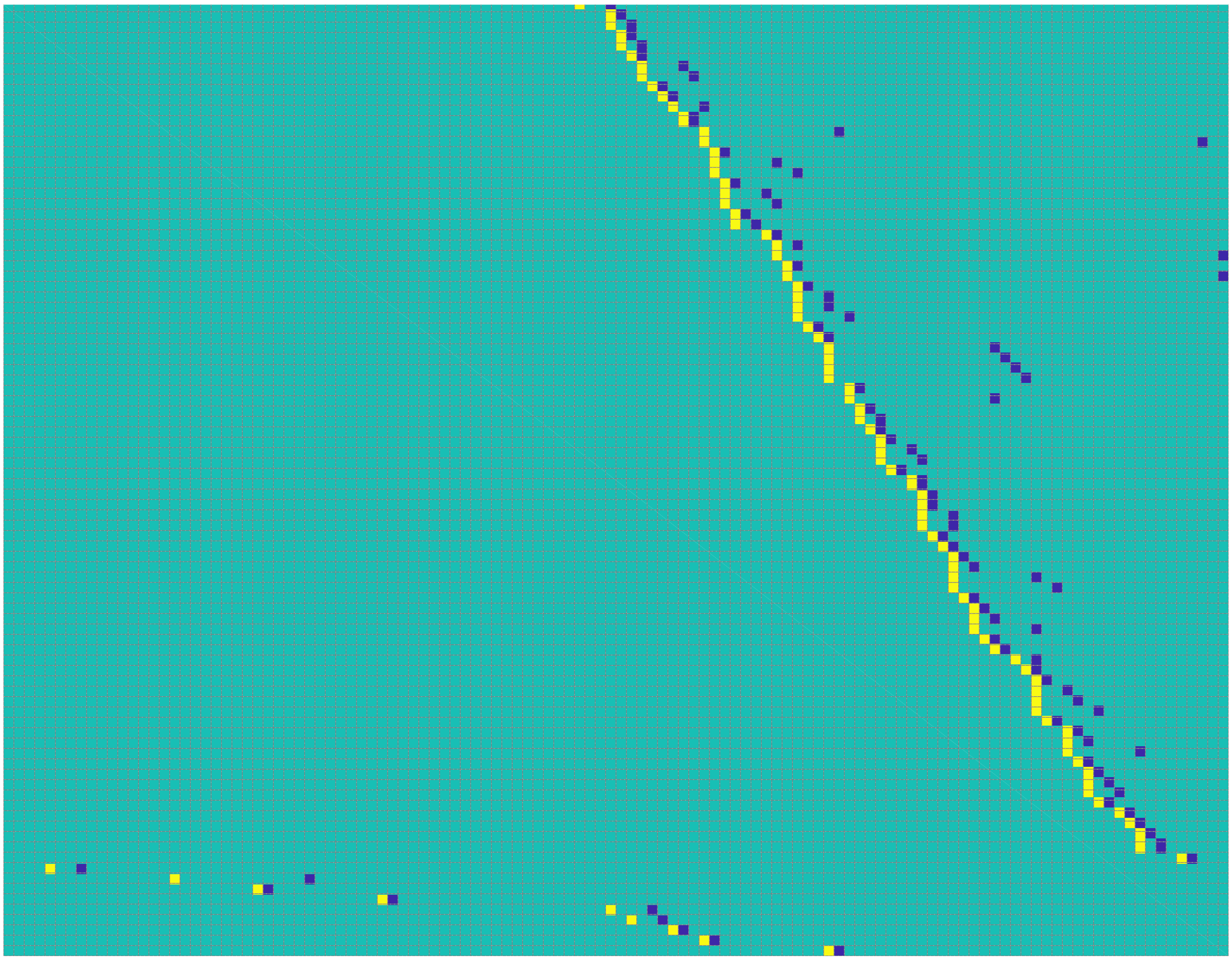

Figure C.2: Incidence Matrix Part2

It is difficult to display the values of the matrix due to the large matrix for the bus incidence matrix with dimension 186×118. Also, the matrix has to divide into two figures in order to display the full matrix. The color code has been used in this matrix. The cyan represents values 0, the yellow represents value 1, and the blue stands for value -1 in both figure C1 and figure C2.

C.1 Matlab Code for Bus Incidence Matrix

```
clc;
clear;

%% Read excel for all connecting braches between two buses.
```

```
data = xlsread('Trip_Line_Data_Source_IEEE118_Original_10_18.xlsx'
    );
A = zeros(186,118);
col1 = data(:,1);
col2 = data(:,2);
count = 1;
count2= 0;
num = length(col1);
%%% Assign a_ij values
for i = 1:num
    A(i,col1(i,1)) = 1;
    A(i,col2(i,1)) =  1;
end
%% Output island bus
for i = 1:118
    if sum(abs(A(:,i))) == 1
        output(count) = i;
        count = count + 1;
    end
end
Cname = 1:1:118;
sz = size(Cname);
Sname = strings(sz);
for i = 1:118
    Sname(i) = string(i);
end
%%% display a matrix in a matlab GUI table.
figure (1);
t = uitable('ColumnName', Sname);
set(t, 'Data', A)
%%% Use Image to represent the matrix
figure (2)
h = imagesc(A)
impixelregion(h)
figure(3)
table(A)
```

Appendix D

186 Branches from IEEE 118-Bus

Table D.1: 186 Branches from IEEE 118-Bus

Branch	From˙Bus	To˙Bus	Branch	From˙Bus	To˙Bus
1	1	2	25	16	17
2	1	3	26	17	18
3	2	12	27	17	31
4	3	5	28	17	113
5	3	12	29	18	19
6	4	5	30	19	20
7	4	11	31	19	34
8	5	6	32	20	21
9	5	11	33	21	22
10	6	7	34	22	23
11	7	12	35	23	24
12	8	9	36	23	25
13	8	30	37	23	32
14	9	10	38	24	70
15	11	12	39	24	72
16	11	13	40	25	27
17	12	14	41	26	30
18	12	16	42	27	28
19	12	117	43	27	32
20	13	15	44	27	115
21	14	15	45	28	29
22	15	17	46	29	31
23	15	19	47	30	38
24	15	33	48	31	32

Table D.1: 186 Branches from IEEE 118-Bus

Branch	From˙Bus	To˙Bus	Branch	From˙Bus	To˙Bus
49	32	113	87	54	55
50	32	114	88	54	56
51	33	37	89	54	59
52	34	36	90	55	56
53	34	37	91	55	59
54	34	43	92	56	57
55	35	36	93	56	58
56	35	37	94	56	59
57	37	39	95	56	59
58	37	40	96	59	60
59	38	65	97	59	61
60	39	40	98	60	61
61	40	41	99	60	62
62	40	42	100	61	62
63	41	42	101	62	66
64	42	49	102	62	67
65	42	49	103	63	64
66	43	44	104	64	65
67	44	45	105	65	68
68	45	46	106	66	67
69	45	49	107	68	81
70	46	47	108	68	116
71	46	48	109	69	70
72	47	49	110	69	75
73	47	69	111	69	77
74	48	49	112	70	71
75	49	50	113	70	74
76	49	51	114	70	75
77	49	54	115	71	72
78	49	54	116	71	73
79	49	66	117	74	75
80	49	66	118	75	77
81	49	69	119	75	118
82	50	57	120	76	77
83	51	52	121	76	118
84	51	58	122	77	78
85	52	53	123	77	80
86	53	54	124	77	80

Table D.1: 186 Branches from IEEE 118-Bus

Branch	From˙Bus	To˙Bus	Branch	From˙Bus	To˙Bus
125	77	82	156	95	96
126	78	79	157	96	97
127	79	80	158	98	100
128	80	96	159	99	100
129	80	97	160	100	101
130	80	98	161	100	103
131	80	99	162	100	104
132	82	83	163	100	106
133	82	96	164	101	102
134	83	84	165	103	104
135	83	85	166	103	105
136	84	85	167	103	110
137	85	86	168	104	105
138	85	88	169	105	106
139	85	89	170	105	107
140	86	87	171	105	108
141	88	89	172	106	107
142	89	90	173	108	109
143	89	90	174	109	110
144	89	92	175	110	111
145	89	92	176	110	112
146	90	91	177	114	115
147	91	92	178	5	8
148	92	93	179	17	30
149	92	94	180	25	26
150	92	100	181	37	38
151	92	102	182	59	63
152	93	94	183	61	64
153	94	95	184	65	66
154	94	96	185	68	69
155	94	100	186	80	81

The last 9 transmission lines are two winding transmission line. The rest of branches are regular transmission line between two buses.

Table D.2: 142 Branches from IEEE 118-Bus

Branch	From˙Bus	To˙Bus	Branch	From˙Bus	To˙Bus
1	1	2	39	31	32
2	1	3	40	32	113
3	2	12	41	32	114
4	3	5	42	33	37
5	3	12	43	34	36
6	4	11	44	34	43
7	5	6	45	35	36
8	5	11	46	35	37
9	6	7	47	37	39
10	7	12	48	37	40
11	8	30	49	39	40
12	11	12	50	40	41
13	11	13	51	40	42
14	12	14	52	41	42
15	12	16	53	43	44
16	13	15	54	44	45
17	14	15	55	45	46
18	15	19	56	45	49
19	15	33	57	46	47
20	16	17	58	46	48
21	17	18	59	47	49
22	17	31	60	47	69
23	17	113	61	48	49
24	18	19	62	49	50
25	19	20	63	49	51
26	19	34	64	49	54
27	20	21	65	49	69
28	21	22	66	50	57
29	22	23	67	51	52
30	23	24	68	51	58
31	23	32	69	52	53
32	24	70	70	53	54
33	24	72	71	54	55
34	27	28	72	54	56
35	27	32	73	54	59
36	27	115	74	55	56
37	28	29	75	55	59
38	29	31	76	56	57

Table D.2: 142 Branches from IEEE 118-Bus

Branch	From˙Bus	To˙Bus	Branch	From˙Bus	To˙Bus
77	56	58	110	83	85
78	56	59	111	84	85
79	59	60	112	85	88
80	59	61	113	85	89
81	60	62	114	90	91
82	61	62	115	91	92
83	62	66	116	92	93
84	62	67	117	92	94
85	65	68	118	92	100
86	66	67	119	92	102
87	68	81	120	93	94
88	69	77	121	94	95
89	70	71	122	94	96
90	70	74	123	94	100
91	70	75	124	95	96
92	71	72	125	96	97
93	74	75	126	98	100
94	75	77	127	99	100
95	75	118	128	100	101
96	76	77	129	100	104
97	76	118	130	100	106
98	77	78	131	101	102
99	77	80	132	103	104
100	77	82	133	103	105
101	78	79	134	103	110
102	79	80	135	104	105
103	80	96	136	105	106
104	80	97	137	105	107
105	80	98	138	105	108
106	80	99	139	106	107
107	82	83	140	108	109
108	82	96	141	109	110
109	83	84	142	114	115

Appendix E

Oscillation Frequency Data for All generators with All Events Study

Table E.1: Mean Oscillation Frequency of Each Zone By Disconnecting Lines in Zone 1

Branches	Zone 1	Zone 2	Zone 3
1	11.428018774797501	10.6059520140206	9.0169803657668108
2	11.053896215112299	10.211539078470301	8.6138105094265107
3	11.4177369657827	10.660261715953601	9.3501706584197795
4	11.268031077594999	10.569214513788101	9.9259514798864892
5	11.400566594904999	10.8130914175218	7.4033257930404597
6	12.105473330423401	10.110507928443299	8.6930302900514107
7	11.5761559870416	10.815033470451199	9.8211180881628692
8	12.2031691555681	10.076150581703001	8.7815435434115408
9	12.34340175286	10.4029446775426	8.8451432031036195
10	12.2538771313966	10.2268697844854	8.4801913544294898
11	11.3188618789414	10.027965616862501	8.1681878652856099
12	11.9381868429309	10.7205021096162	9.4320624817674403
13	10.9810877980029	9.7704568188879399	8.4525679597931607
14	11.225886532547101	10.168579350376801	9.4675561196178002
15	11.1161659146209	9.6489243259006301	8.2894419976404201
16	9.4897513911117297	9.5094004705439197	6.9815827178304399
17	10.781934837285601	10.0308622453556	8.2033800882974308
18	11.0948724157009	10.3633979229985	9.30643918443735
19	11.0976008332186	10.748698765776499	8.6493885183392596
20	11.2904551069562	9.7869130877682906	8.6915068472559103
21	11.1471807480679	10.4012710396805	9.7203844319234705
22	10.843524696857401	10.0659104403542	7.8580278226520797

Table E.1: Mean Oscillation Frequency of Each Zone By Disconnecting Lines in Zone 1

Branches	Zone 1	Zone 2	Zone 3
23	10.2199355618026	9.9537665150290504	7.2943907146044102
24	11.480290542771799	11.1143139565017	10.147942395521
25	10.702325342296101	10.318631636242699	9.1771905204659401
26	10.3003262855963	10.726870056652899	9.8169673272479407
27	10.6512213258302	10.3689241556922	9.5469427484351304
28	10.702124648383901	10.3575112472125	9.4584648480000002
29	11.031068376543701	10.3139899886748	9.3004894609416908
30	9.8001005658942706	9.5151442328105205	9.4341430878206296
31	10.174652839972399	9.94431802171143	9.6858534512293506
32	9.9736588942696898	9.7101795245330802	9.8472021033197699
33	9.5989521359475898	9.6127608843380603	9.79049668486455
34	11.289988562749601	9.6756427123495303	8.1360838706454395
35	11.1030553495516	9.8647545321276802	9.3138404734444595
36	11.105088481332	9.83745092410539	9.0205146613772005
37	11.3995134619565	9.6497836226000402	8.0815438620646702
38	10.8865284113215	10.5272112400952	9.0252673169767803
39	11.168300688210699	10.6784970268133	9.8520343533827095
40	11.115522813330999	9.9479015891673299	7.9110937556527396
41	11.171761698772199	10.0741161046545	9.5550529891451905
142	11.3089677556884	11.2307054508848	11.434730201558599

Table E.2: Mean Oscillation Frequency of Each Zone By Disconnecting Lines in Zone 2

Branches	Zone 1	Zone 2	Zone 3
42	10.7236587895495	10.7456818091072	8.4239679201871809
43	10.9941707867024	11.3989634122625	10.295979343930499
44	10.176999088588	10.9633796855046	8.2215354536972605
45	10.2657483777216	11.4820482645898	10.767030470329001
46	10.974666767797601	11.3379398489186	10.409033389604
47	10.913652532251399	11.023164660718701	9.8456424943625898
48	10.9536627081592	11.0492557047099	9.8524716905740295
49	10.9677273694299	11.0743039161121	9.9311714286476995
50	10.4309936778187	11.0884456732316	9.9838268106478392
51	10.615555029921101	11.3895547689553	9.1222370966429391
52	10.608949718988899	11.3965339685133	9.0255499696877592
53	10.5906937273084	10.897273212323	9.6428286512998103
54	10.3300353402475	10.8813624031029	9.4114745059010207
55	10.7176026482897	11.0524362321061	9.8949310543879996

Table E.2: Mean Oscillation Frequency of Each Zone By Disconnecting Lines in Zone 2

Branches	Zone 1	Zone 2	Zone 3
56	10.4039591032949	11.3581476017987	9.3012385122497996
57	9.9342054672367492	11.2765606934134	10.4453462504875
58	10.0577881678221	11.442608799756099	10.6524938610021
59	9.54860766106294	11.0172452491316	9.6776936488712106
60	9.6620002138238092	10.7710327877887	10.1322154568704
61	10.2224948934675	11.506156532455501	10.561805401794199
62	10.2757455056061	10.9505584010878	10.0422592684726
63	10.2613545873534	10.9107051536149	10.019474986713099
64	10.2762124722996	10.9700891248267	10.052587228038799
65	9.5479767135926199	10.8186014140782	10.060771802546499
66	10.270856717152199	10.9622882187985	10.046942142070399
67	10.3967807772194	11.131245137460301	10.0902287580498
68	10.315064022471301	10.987376333350401	10.096744296396199
69	10.5082863733795	11.408563898372901	10.086355705618899
70	10.1212528790621	10.919291811754301	9.9526425741916107
71	10.887009434400699	11.106215622454901	11.177792783765399
72	10.4202302985295	11.0514801408036	10.0726495942541
73	10.4208570449838	10.860674480198901	10.741873904366299
74	10.304654156857699	11.232416279142701	10.1431326209131
75	10.417617101190499	10.9988690869635	10.812155920869801
76	10.267416431143999	10.9659106753438	10.0777574308733
77	10.421737811510701	11.027915533691401	10.0634818634732
78	10.433787176866399	10.947907036587701	10.7972188575368
79	9.8478395036930895	10.887571930421499	10.371689960782099
80	9.8331151149409095	10.908130081759801	10.3690539360027
81	10.736536467677301	11.6824873223132	10.299787834361499
82	10.613890417156499	11.635396125509599	10.3899280239392
83	10.263579461225699	11.1509023935981	10.011581185689
84	10.335208304441601	11.4120987297573	10.087669930947399
85	9.7244016524374608	11.413628979169401	9.9062687544644401
86	10.2604638306055	11.086971060977501	10.0093146371327
87	9.0551497987275091	10.741925183964399	10.861764507217099
88	9.8731452767504599	11.0650544822927	11.145988855252799
89	8.76790383732639	9.8830913270408001	9.9378968044519098
90	8.7091550167021996	10.272695876053501	10.4567077387841
91	9.6469793456673791	10.568330418473799	10.5431880451008
92	8.7210454611775603	9.9768966709688094	10.1420844617739
93	8.7047060923743302	10.295786893547699	10.0490838765521

Table E.2: Mean Oscillation Frequency of Each Zone By Disconnecting Lines in Zone 2

Branches	Zone 1	Zone 2	Zone 3
94	8.6731806004369396	10.719604606163299	11.014285268754399
95	9.1439960072322002	10.5418147549819	10.3999022032298
96	8.7131973767154793	10.420077405233	10.5677273361777
97	9.10083367645659	10.536155451192	10.4816601837853
98	8.7857999592554901	11.1022212563373	11.026327819921001
99	8.7783176675274603	11.224338990744901	11.265767872263099
100	7.8614094271646398	10.1576409714229	9.1900931463403293
101	8.7422519749800909	11.081224386398199	11.098344724612099
102	8.7546913096807799	11.204387658421201	11.0817839996675
103	8.4607259579356899	10.7420659140118	11.416524640050399
104	8.4292542394209509	10.7405482428317	11.449485123334499
105	9.2104853185210391	11.019174955019301	10.9170877813625
106	9.3503881834633393	11.130691130448801	10.8659862794118

Table E.3: Mean Oscillation Frequency of Each Zone By Disconnecting Lines in Zone 3

Branches	Zone 1	Zone 2	Zone 3
107	8.3512955743615507	10.266557779882501	11.000716728710101
108	7.9975877577847099	10.204530601801199	10.3234001428402
109	8.74716789606269	10.224574798738599	10.991706685338199
110	8.3966958678039099	10.167116967172101	10.888206091600701
111	8.6830882608552091	10.186679834734599	10.978546858517401
112	8.7767684502563608	10.140517955895801	10.858777184006099
113	8.5784140591673097	9.9607549202714107	10.680895101336899
114	8.6225340043279495	10.2596384321947	11.1170510335016
115	8.9189210395581995	9.9266210644145492	10.707550470578401
116	8.6526651463738098	10.1111644578121	10.7839993827212
117	8.6911618907120491	10.1206039547759	10.745377861947601
118	8.9648994083340501	10.4237520097944	10.7440178130595
119	8.9847337447978095	10.4322738574003	10.7798189582099
120	8.7106946510818997	10.1371018307723	10.7280375409697
121	8.8560435610767403	10.7212068937885	10.7008326932496
122	9.4550039956720706	11.085785504457601	10.772036043267599
123	9.24090579483269	11.3891389886618	10.963809578625201
124	10.1089108296128	11.270597263144801	11.197151335626099
125	8.3620977162884405	10.685818549891	11.234072118554399
126	9.5160863695642597	11.246257406134999	11.090119662693899
127	9.3049219013946196	10.01822658122	10.858854826843199

Table E.3: Mean Oscillation Frequency of Each Zone By Disconnecting Lines in Zone 3

Branches	Zone 1	Zone 2	Zone 3
128	8.8852125305000893	10.3789028867024	10.8995047888912
129	8.7753144964650804	10.551056959632801	10.7188744378879
130	8.9426224365160394	10.510970740918101	10.516774703319101
131	8.9645554136265009	10.4280417914837	10.6861613667276
132	9.5471881442096596	10.9565930110276	11.119150132706
133	9.4095587390832698	10.8249466567715	11.035875929244501
134	7.90884197022483	9.8220340737013903	9.5875521263963002
135	9.1725487378636803	10.334473302241999	10.4803485594076
136	8.1402461843048393	9.8100171843159796	10.166565626699599
137	9.3861394659197295	10.5111541412082	10.294093329224699
138	9.1448352901039396	9.9695308012687995	9.58748243137582
139	9.2237881331799105	10.495936506048199	10.374647511159701
140	9.1762236620569499	10.0490197322172	9.5946648102309897
141	8.8330831747654699	9.6189338424769097	9.4801754931089999