Remedial Action Schemes for Power System Performance Enhancement Using Protective Relaying

By

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Abstract

Nowadays, according to the improvement of industries, and the growth of the population, the need for high-quality energy is felt more and more. One of the significant challenges in designing distributed power networks is providing reliable protection with the target of decreasing blackouts. This goal can be achieved by detecting faults in the power system and action to correct or remove the faults. In most cases, taking correct and quick remedial action to protect the power system is done by tripping. Generally, the protective relaying equipment is responsible for tripping in a power system.

In this thesis, various types of remedial action schemes for power system performance enhancement using protective relaying are studied in detail. The concept of power system protection consists of protection components, and their functionality is illustrated. Furthermore, several types of protective relays, and their general operating and design considerations are briefly investigated. Several protective relays such as analog overcurrent relay, digital overcurrent relay, and digital under-over frequency relay are investigated, modeled, and simulated in this thesis.

To study the power system frequency response, the System Frequency Response (SFR) model is derived and simulated in MATLAB Simulink environment, and the effect of some parameters of a generator on the system's frequency response is examined. Additionally, a new method to model power system frequency response is proposed based on the factorial design method using the Design of Expert. The actual system and the final model are simulated, compared, and validated. The result shows that the model based on the proposed method can be used to estimate the system frequency response.

The concept of load curtailment (load shedding) and its different methods are discussed. A conventional underfrequency load shedding relay is simulated in MATLAB software to show how load shedding relays can enhance power system performance.

The significant factors which affect power system stability are identified. To show the effect of significant factors on power system stability, a standard IEEE 9-Bus and the IEEE 10-Generator 39-Bus New England Test System are simulated in the PowerWorld.

Finally, the concept of autoreclosing is studied in detail. An autorecloser relay is designed, simulated, and examined in MATLAB Simulink, and the proposed relay’s units are explained. Optimal autoreclosing methods are also presented in this thesis.

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Introduction

1.1. Background of the Research

Nowadays, due to the fast-growing of modern industrial society, electrical energy becomes as one of the most important resources of energy. To have reliable electrical power, it must be at the correct level of voltage and frequency.

A power system faces some problems in abnormal conditions due to constant disturbances created by random load changes, by faults created by natural reasons, and sometimes as a result of equipment or operator failure. Therefore, some protective equipment must be used to have the best function in order to keep the power system stable and also to prevent damages to power equipment. The functions of the protective scheme to have automatic control and regulation systems in the electric power systems include:

- Maintaining the values of state variables within a feasible region – when normal conditions are controlled.
- Bringing these values to the feasible region – when emergency conditions are controlled.

In this way, using protective relaying equipment can be useful to correct and take quick remedial action.

Typical of such methods taken by the protective relaying equipment are underfrequency load shedding, undervoltage load shedding, out-of-step tripping, and blocking. In Ref. [1], the concept of relaying is defined as “The branch of electric power engineering concerned with the principles of design and operation of equipment (called “relays” or “protective relays”) that detects abnormal power system conditions and initiates corrective action as quickly as possible in order to return the power system to its normal state.”

Electromechanical relays are the first protective relays used to protect the primary power systems. Then, solid-state relays have been used since 1950. The advent of new protection technologies methods created the digital relays in the power system protection. These types of relays provided various types of protection methods. One of the most important protection methods is load shedding. Load shedding means removing some loads connected to the network in order to prevent damages to the transmission lines and maintain the system stability and control the frequency and voltage of the network.

Summarizing the previous works in this area, the main aspects of this research are power system protection, protective relays, power system frequency response modeling, load curtailment, and power system stability.

1.2. Objectives of the Research

The purpose of this research is to give a comprehensive study of methods and schemes that increase power system performance by using Protective Relays. The main goals of the research are listed below:

- Reviewing the basics of power system protection
- Studying power system frequency behavior
- Study on load shedding methods consist of Under Voltage Load Shedding (UVLS), Under Frequency Load Shedding (UFLS), and Under Current Load Shedding (UCLS), the theory and recent work
- Discussion on Relay Modeling and case studies using PowerWorld and MATLAB Simulink
- Evaluate the power system transient stability

1.3. Organization of the Thesis

The focus of my research is to study different remedial action schemes for power system performance enhancement using protective relaying. The thesis hopes to propose useful relay strategies for power system operation. The research is based on theoretical analysis and computer simulation. The following topics are covered: (1) The concept of power system protection (2) Background information on the relays include of fundamental of relaying and relay's hardware, (3) Protective Relays Modelling, (4) Power system frequency response, (5) Load shedding techniques, and (6) Power system transient stability.

Related knowledge is learned first. Related literature is reviewed to gain an overall knowledge of the research. Then, the necessary simulation is conducted to investigate the topics by using PowerWorld Simulator or MATLAB software, which can model various relays include undervoltage, undercurrent, and underfrequency relays. Then, I am summarizing the simulation results and make conclusions. Finally, a comprehensive study is included in the final part of the thesis.

The chapters of the thesis are organized as (1) Introduction to the Thesis; (2) Principle of Power System Relaying; (3) The Hardware of the Relays; (4) Power System Frequency Protection; (5) Load Curtailment on Isolated Power System; (6) Power System Stability; (7) Using Autoreclosing Relays to Enhance Power System Stability (8) Conclusion and future work.

Chapter 2

Principle of Power System Relaying

2.1. Introduction

Protective relays are essential to all power systems. The main goal of using relays in power systems is to remove the fault element or isolate the hazard area, so the remaining portion of the power system continues working in normal conditions. A power system consists of six different zones, including generators, step-up transformer, transmission line, step-down transformer, busbars, and distribution feeders. Usually, the protection system uses different relays with various functionality to clear divers types of faults. The purpose of this chapter is to illustrate the principle of power system protection relaying. In [2], the concept of protective relaying is defined as "The term used to signify the science as well as the operation of protective devices, within a controlled strategy, to maximize service continuity and minimize damage to property and personnel due to system abnormal behavior."

One of the oldest and simplest protective devices is a fuse that operates as a level detector and can be considered a sensor and interrupting device [1].

2.2. Power System Protection

The need for high-quality energy is felt more and more considering how industries and the population are growing. One of the significant challenges in designing distributed power networks is providing reliable protection to decrease blackouts. This goal is achieved by detecting a fault in the power system and taking action to correct or remove the faults. In most cases, taking the correct action to protect the power system is done by a circuit breaker [3]. So, the use of some methods and facilities to protect the power system has become essential. The functions of the automatic control and regulation systems in the electric power systems include:

- Maintaining the values of state variables within a practical region – when normal conditions are controlled.
- Bringing these values to the feasible region – when emergency conditions are controlled.

Conventional protection is dedicated to a specific piece of equipment such as: line, transformer, generator, or bus bar, etc. The Power System Relaying Committee defined the concept of the System Integrity Protection Scheme (SIPS) with the following definition: ”To protect the integrity of the power system or strategic portions thereof, as opposed to conventional protection systems that are dedicated to a specific power system element” [4]. Typical methods are underfrequency load shedding, undervoltage load shedding, Out-of-step tripping and blocking, Congestion mitigation, Static var compensator (SVC)/static compensator (STATCOM) control, Dynamic braking, Generator runback, Black start of gas turbines, and System separation.

The two types of protective systems are reactionary devices and safeguard devise. Reactionary devices are designed to find a specific fault in the power system and then operate due to predetermined actions to clean the fault by removing the faulty component or isolating the hazardous portion of the system so that the rest of the system can continue working normally.

Safeguard devices detect a specific fault in the power system, and then, operate a predetermined action that decreases a hazardous condition in the power system environment such as fire sprinkler systems, apparatus supplementary cooling systems, and detectors used to monitor unbalanced currents or voltages in equipment.

2.3. The Operation of Protective Device

Generally, protective devices include some basic elements used to recognize the system situation based on the measurement of special parameters of the system, make a decision due to the system's condition, and send operation commands as required. Figure 2.1 shows the basic elements of a protective device.

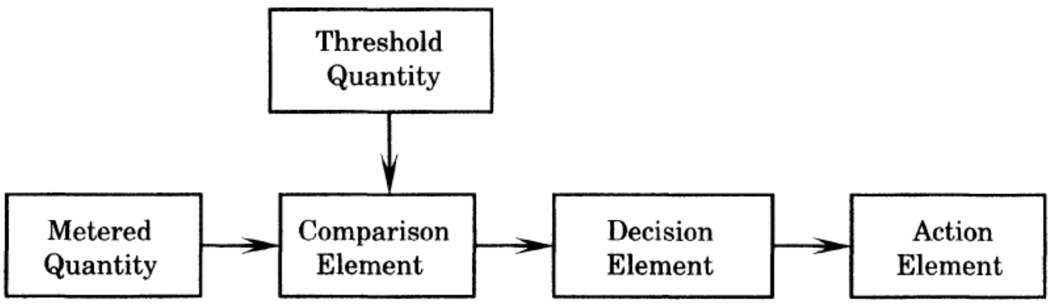


Figure 2.1 The elements of a protective device [2]

Ordinarily, the protective devices continuously monitor a specific parameter such as voltage or current and compare the value of that parameter to a predetermined threshold, which is calculated and set by the protection engineer. The decision element is triggered if the result of the comparison identifies a hazardous condition. Usually, a time delay used in the decision element to make sure the hazardous condition is permanent and also a protective device may need to check the other location of the system in its network. Eventually, the action element operates when all checks are complete. The action element usually operates to isolate the fault section by opening a circuit breaker.

In protection devices, the definition of clearing time is the total required to remove or isolate the hazardous portion from the system. The clearing time is computed by Equation 2.1.

$$T_c=T_p+T_d+T_a \tag{2.1}$$

Where T_c is clearing time, T_p is comparison time, T_d is decision time and T_a is action time consists of the time needed for the circuit breaker operates. The clearing time is very important due to the following reasons [2]:

- The clearing time is one of a kind restraint for the protective devices used to prioritize the sequence of the protective devices in the case of hazardous situations in specific areas.
- The protective devices must clear the fault depending on many factors, such as location and type of the fault in proper time and with correct action. To preserve system stability, the speed of a protective operation is very important.

2.4. The Component of System Protection

Generally, protection systems consist of three basic components: an Instrument transformer, relays, and circuit breakers. A sample over current system protection is shown in Figure 2.2, which includes a current transformer (CT), an overcurrent relay (OC), and a circuit breaker (CB). The CT converts the current kilo amp range at the primary winding into the smaller range of 0~5 amps, at the secondary winding. In other words, the CT maps a higher-value and wider range of current in comparison to the smaller range due to the convenience of measurement, safety, economic reasons, and accuracy [5]. The CT is used to transform current, and potential transformers (PT) are used to map voltage.

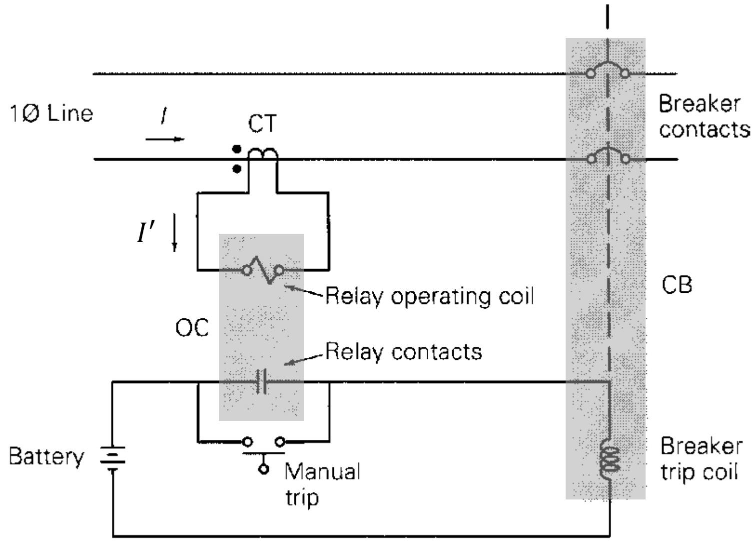


Figure 2.2 A sample over-current protective device [5]

2.4.1. The Functionality of a Protective Device

In a simple over-current protective device, which is shown in Figure 2.2, the OC is used to determine the fault condition by continuously monitoring the quantity current (metered quantity) and taking corrective action regarding the clearing of fault.

The CT converts current I to a smaller value, current I', at secondary winding, connects to the relay operating coil.

The normally open operating coil of the OC will be closed by Decision Element when the absolute value of I' exceeds a predetermined value equal to the Threshold Quantity, which is done within the limits of the comparison elements and causes the trip coil of the circuit breaker to energize. The circuit breaker (CB) can be opened either manually or by energizing its trip coil, which is done by Action Element.

2.5. The Basic Concepts of a Power System Relay

A power system relay is a black box with some inputs, usually current and voltage, as measured quantities, and user-settable inputs utilized for Comparison Element and outputs used for Action Element. Generally, the output of a protective relay resembles the closure of normally open contact connected to a circuit breaker. The protective relay compares the provided input by CT or PT based on the predetermined constraints (input setting) to take a trip or no-trip decision. Figure 2.3 shows a protective relay.

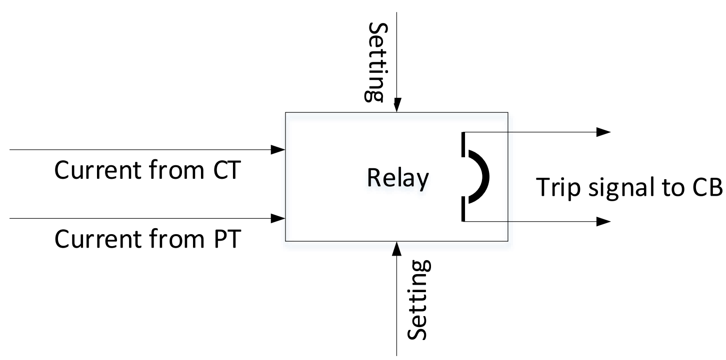


Figure 2.3. Conceptual diagram of a relay [6]

2.6. The Nature of Relaying

In this section, a common characteristic of the protective relays is discussed. Generally, relays operate to remove any faulty elements from the power system in the expected time. The main goals of using protective relays are:

- Curbing the damage to equipment as much as the relay possibly can
- Minimizing the danger to people
- Reducing stress on system equipment
- Removing any faulty equipment from the power system at the fastest rate possible

2.6.1. Reliability

Reliability refers to a sense of certainty that equipment will operate as it is meant to operate [1]. In terms of protective systems, a reliable relay must operate when expected to perform. Any failure to operate or unintended operations are signs of unreliability.

2.6.1.1. Dependability vs. Security

Dependability refers to the amount of certainty that a relay performs in a correct way when it faces specific faults in which the relay is designed to clear them while security refers to the amount of certainty that a relay will not operate in an incorrect way. Currently, to design a relay, dependability is more important than security, with regards to the fact that removing a power system element is less serious than the presence of a sustained fault [1].

2.6.2. Zone of protection

Generally, a zone of protection is referred to as a specific area in the power system where the protective system and relays within that region are responsible just for that area. In terms of security, a relay is called secure when it operates only for the faults in its zone of protection. Generally, the boundary of the zone of protection is defined by CT and CB within the designed protection systems. The CTs enable the protection system to identify the fault and CBs enable the protection system to isolate the faulty area. To have a reliable power system protection, all elements of the power system must be covered by at least one protection zone. There are two types of protection zones, closed and open. A closed protection zone is dedicated to an area through the power system, which is monitored and protected at the entrance of the zone. Conversely, if the zone of protection is open and not unambiguously defined by the CTs, the border of the zone can be changed with the fault current.

2.6.3. Primary Protection Vs. Backup Protection

Primary protection is the main protection system for a specific zone of protection. The primary protection must clear the fault as soon as possible and disconnect the equipment as little as possible. Based on the fact that generally, the dependability in the power system is not 100 percent, the designed protection system needs some alternative paths to operate in the case of a protection system failure. These alternative paths essentially are summarized as duplicate, backup, and breaker failure protection systems.

2.6.3.1. Duplicate Protection Systems

Duplicate protection systems are used as primary protection systems and operate in the case of an element of the primary protection failure. The duplicate element performs in the same operation time as the primary protection system. To duplicate the primary protection, the designers may use relays from different manufacturers, or relays based upon different principles of operation [1].

2.6.3.2. Backup Protection Systems

Regards to the high cost of the transducers or the CBs, it is not economical to duplicate all equipment of the primary protection system. Backup relaying is the cheaper way used in this situation. Compare to primary protection, backup relaying operates slower and sheds more elements in the case of detecting a fault in the power system.

2.6.3.3. Breaker Failure Relays

The breaker failure relays operate in the case of any fault in CBs operation. A common and simple way to implement the breaker failure relays system is using a timer which is started when the breaker trip coil energized and the timer is reset when the fault vanishes. The breaker failure relay system is considered as a subset of local backup relays [1].

2.7. Illustration Using an Example

Figure 2.4 shows a simple 3-bus power system. Consider the fault F1 on the transmission line between Bus 2 and Bus 4. The fault at F1 should be cleared by relay R11 by sending a trip command to the corresponding circuit breaker, B11. If these relays fail to operate due to fault F1, it has become unreliable through a loss of dependability. Also, if relay R6 operates for the fault F1 before relay R11, it has become unreliable through a loss of security.

The fault F2 is inside the closed zone of the transmission line and will cause CBs B8 and B6 to operate. The fault F3 lies inside the overlap between two closed zones and will cause CBs B6, B8, B5, B9, and B7 to perform. However, it is not necessary to send a trip command to B5, B9, and B7. The fault at F1, being inside to an open zone and will cause B11 to trip.

The Relay R12 is a duplicate primary relay for R11 and is installed to operate in the case of the relay R11 fail to trip. The primary duplicate relay R12 operates at the same time as R11 and removes the same elements as R11. The relay R14 is the primary backup relay for R11, which operates slower than primary relays R11 and R12 but removes more elements from the power system.

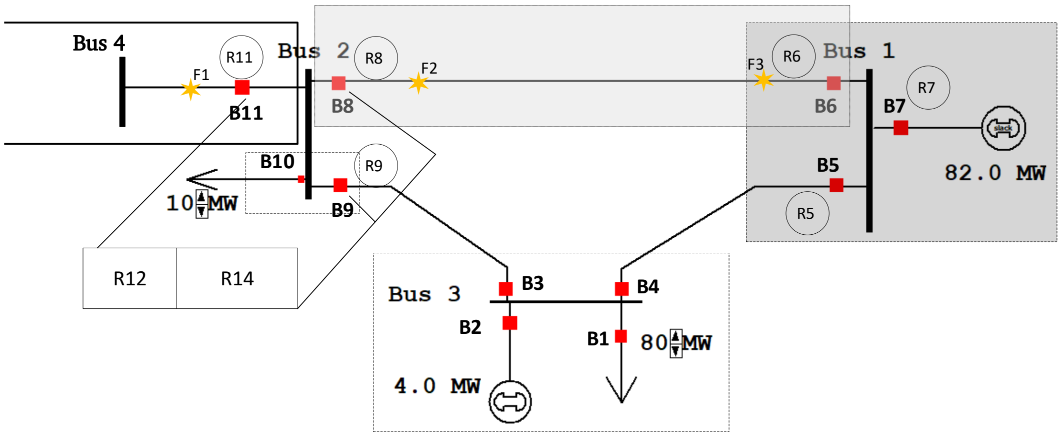


Figure 2.4. 3-bus designed power system protection

2.8. Conclusion

In this chapter, first, the essential of power system protection has been discussed, followed by studying the operation and component of power system protection. The basic concepts of relaying for a power system such as reliability, dependability, security, and zone of protection have been investigated. The ways which are used to cover the possibility that the protective relays in a power system fail to operate have been illustrated using a 3-bus power system example.

Chapter 3

The Hardware of the Relays

3.1. Introduction

Generally, the protective relays are designed to identify a specific hazardous situation in the power system and operate due to predetermined action to remove or isolate the hazardous area from the system so that the rest of the system continues working in a normal condition. So a protective relay is considered as a device with several logical parts.

Understanding the capability and limitations of protective relays needs to obtain a comprehensive knowledge of the construction of the protective relay and its logical elements. In general, the protective relays consist of the fault detection unit, decision unit, and regards to the situation, the required logic network and the auxiliary unit will be added to the relay. These units are widely used in the protective relays and considered as basic units. The basic units of the relays can be classified into major groups: electromechanical units, sequence networks, solid-state units, integrated circuits, and microprocessor architecture, which are used to construct a protective relay [7].

3.2. Electromechanical Relays

Essentially the relays work due to actuating force that can be generated by electromagnetic interaction or expansion of a metal caused by a temperature rise. The electromechanical relays use actuating force to operate, which is generated by joining the input signals, stored energy in springs, and dashpots. The electromagnetic relays are categorized into two groups: Plunger type and induction type [1].

3.2.1. Plunger-Type Relays

The plunger-types relays operate based on the rotation of the inductive disk, which is located inside a stationary electromagnet. A plunger-type relay is shown in Figure 3.1. In the normal situation, the force of spring, ξs, holds the plunger outside of the coil, but in the case of fault condition where the current is usually has a high value, the coil will be energized and generated force ξm. The plunger moves when ξm is higher than ξs. Equations 3.1 to 3.3 is used to calculate ξm [1].

$$W(\lambda, i)=W^{'}(i,x)=\frac{1}{2}Li^{2} \tag{3.1}$$

$$L=\frac{\mu_0 \pi d^2 N^2}{4(x+gd/4a)} \tag{3.2}$$

Where W and W' are the energy and co-energy stored in the magnetic field, respectively. λ is the flux linkage of the coil, μo is the permeability of free space ($4.\pi.10^{-7}$), N is the number of turns, and L is considered as the inductance of the coil in Henries. Co-energy is defined as a non-physical quantity utilized for theoretical analysis of systems to transform and store energy. Co-energy is considered as the dual of energy with the same units that used for calculation of magnetic forces and torque in rotating machines [8]. The force ξ_m is calculated from Equation 3.3.

$$\xi_m = \frac{\partial}{\partial x} W'(i,x) = K \frac{i^2}{(x+gd/4a)^2} \tag{3.3}$$

Where K is a constant and a is the height of the pole-piece.

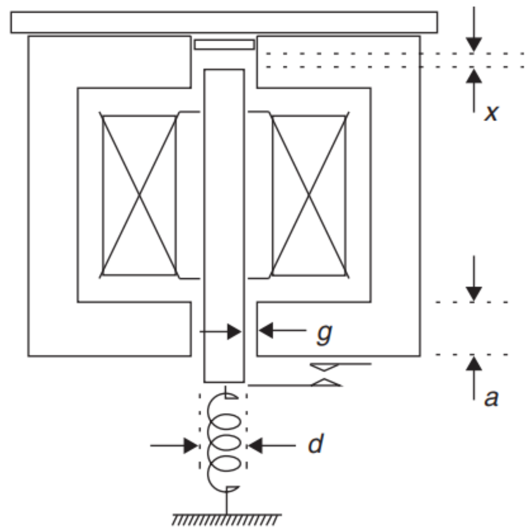


Figure 3.1 Plunger-type relay [1]

There are two important settings in the plunger-type relays, pickup current(I_p), and dropout current(I_d). Pickup current is the value of the current at which the plunger starts moving, and dropout current is the amount of current at which the plunger can return to its original position. I_p and I_d are calculated from Equations 3.4 and 3.5.

$$I_p = \sqrt{\frac{\xi_s}{K}} * (x_0 + \frac{gd}{4a}) \tag{3.4}$$

$$I_d = \sqrt{\frac{\xi_s}{K}} * (x_1 + \frac{gd}{4a}) \tag{3.5}$$

Where x_0 is the movement of the plunger at no current situation in the coil and x_1 is the location of the plunger just before it closes its contacts. Figure 3.2 shows the operating time of a plunger-relay type as a function of its current. Note that the amount of the I_d is always smaller than that of the I_p.

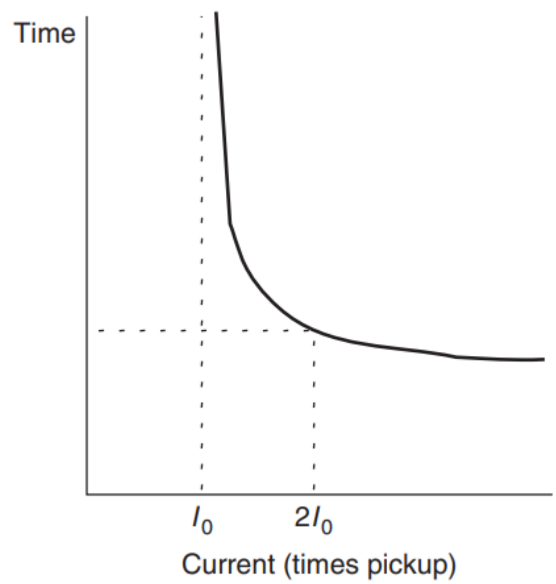


Figure 3.2 Operating time versus current of a plunger relay [1]

3.2.2. Inductive-Type Relays

The principle of inductive type relays is similar to a single-phase AC motor. Inductive-type relays are composed of rotary and stationary sections. The stationary section is the site of the magnetic circuit, and the iron, which is related to the rotor, is in the middle of the stationary magnetic elements, which are moving elements that operate as a carrier of the rotor current. There are standard types of inductive relays, one with an inductive disk and the other has an inductive cup. Figures 3.3 and 3.4 show the general construction of the two types.

3.6.

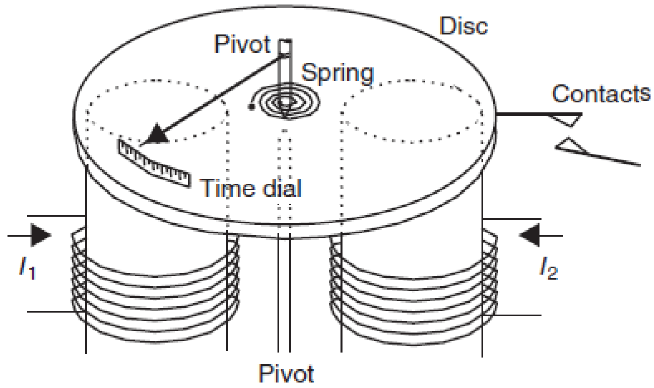


Figure 3.3 Principle of construction of an induction disc relay [1]

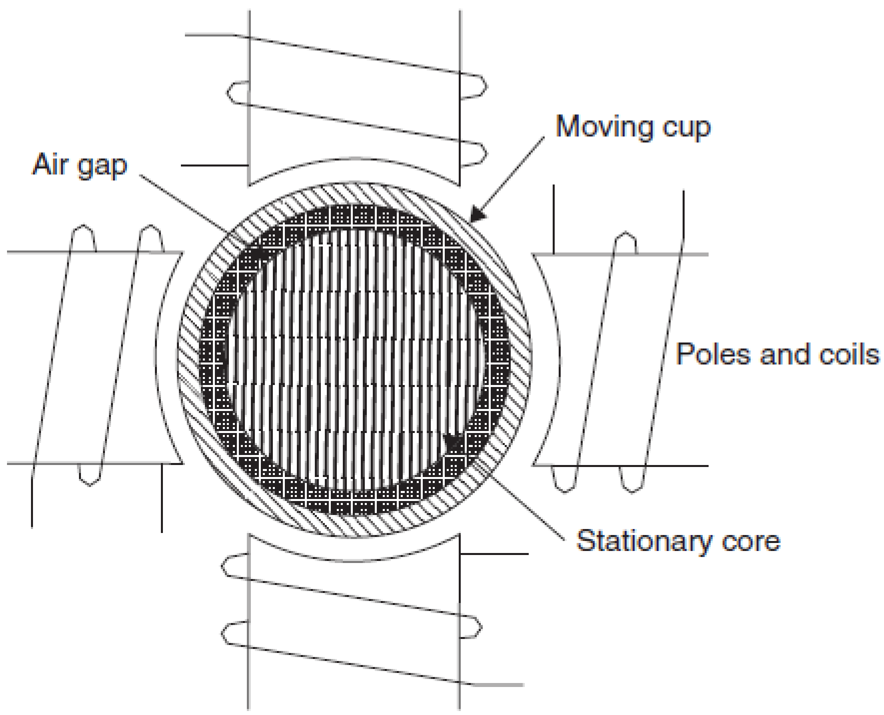


Figure 3.4 Moving cup induction relay [1]

Inductive-type relays require two sources of alternative magnetic flux with different phases to turn the moving section. The phase difference between the sources of alternative magnetic flux generates operating torque. The torque, which is generated by I_1 and I_2, is computed by Equation 3.6.

$$\tau = K_{\tau} I_{m1} I_{m2} \sin\Theta \qquad (3.6)$$

Where K_{τ} is a constant, and Θ is the different phase between I_1 and I_2. Equation 3.6 shows that the torque is constant and does not vary with time regardless of the rotary movement [1].

The inductive-type relays are widely used in different protective schemes such as level detectors, directional relays, or ratio relays, whose names relate to the source of the two coil currents. Figure 3.5 shows an induction relay designed to perform as an overcurrent relay, which will be defined in the next sections.

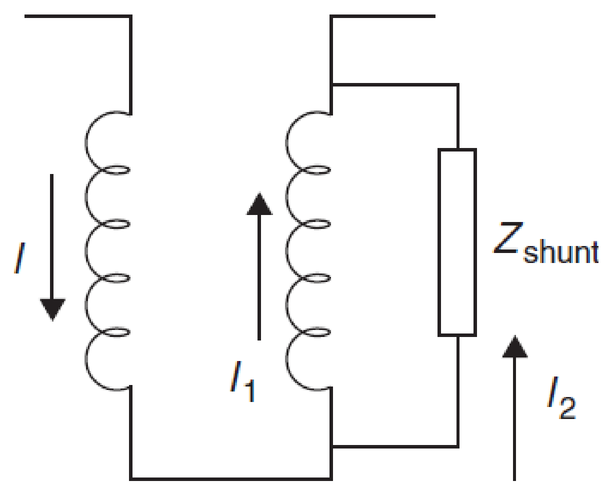


Figure 3.5 Inductive-type relay designed to perform as an overcurrent relay

In this design, which is used as a level detector for current, a shunt resistor is placed parallel with one of the coils with an impedance to make a phase difference angle Θ between two currents related to two coils. The torque generated by the two currents is calculated from Equation 3.7.

$$\tau = K_1 I^2 \qquad (3.7)$$

Where K_1 is considered as a constant includes of $sin\Theta$, within the relay.

In a normal situation, the torque produced by the current is equal to the spring torque, τ_s, which means the spring prevents the disk from turning. When the current causes the τ increases, the pickup current of the relay which causes the τ to exceed the τ_s, then the disk begins to turn. After disk turns an angle ϕ, which is considered as a delay time in the design, the relay operates and closes its contacts.

3.3. Solid-State Relay

Because of the recent growth of modern power systems and their complexity, the use of more efficient protective relays with more sophisticated characteristics are being used around the world. Semiconductors and other associated elements can be very useful in designing a relay. This kind of relay is called a solid-state relay. Generally, solid-state relays are static relays that do not have any armature or other moving parts [2]. The pros and cons of using solid-state relays compared to electromechanical relay are listed in Table 3.1.

Table 3.1 pros and cons of using solid-state relays

Pros	Cons
Cover all the functions and characteristics of the electromechanical relay	Restricted ability to stand with a hostile environment, or with severe overvoltage and overcurrent
The components of solid-state relays consume less power	Require an independent power supply
Higher performance, more economical, more flexible, more accurate	___
Their settings are more programmable	___
Performance is not influenced by vibration or dust.	___
Can be mounted in a smaller place	___

3.3.1. Solid-State Relay Logic Circuit

The solid-state relay circuits are divided into two groups, analog circuits and digital circuits, and the solid-state relay hardware includes both groups of circuits because of the analog input.

The analog circuits used in electronic protection relays usually contain an operational amplifier (op-amp). The op-amps are widely used in relays that use analog hardware as an isolator, comparator, or level detector, summer, integrator, and active filter. The op-amp is an electronic part that consists of 20 or more transistors and gives a stable gain at low frequency [2].

The high degree of reliability and lower price of logic devices, caused the use of digital protective devices to trend. The digital circuits used in electronic protection relays are generally logic gates (AND, OR, NOT or Negative Logic, Buffer, Exclusive OR, NOR, and NAND), Time Delay Units, Flip-Flops, and Analog-to-Digital (A/D) Converters.

3.3.2. Analog Relaying Applications

There are many types of protection relays designed based on analog circuits, such as instantaneous overcurrent relays, phase comparison distance relays, and directional comparison pilot relays, but it is not possible, nor is it necessary to investigate all of those relays.

Instantaneous overcurrent relay is the easiest type of protection relay to understand. In an analog instantaneous overcurrent relay, the input signal is current, which is then passed through a shunt resistor used to convert current to voltage. The converted signal is then filtered, amplified, and rectified for use in the related analog circuits. Eventually, the output signal is compared with a reference signal in the level detector section where the relay commands the trip signal so that the output signal reaches the threshold setting (reference signal). Figure 3.6 shows a sample analog circuit design of an instantaneous overcurrent relay.

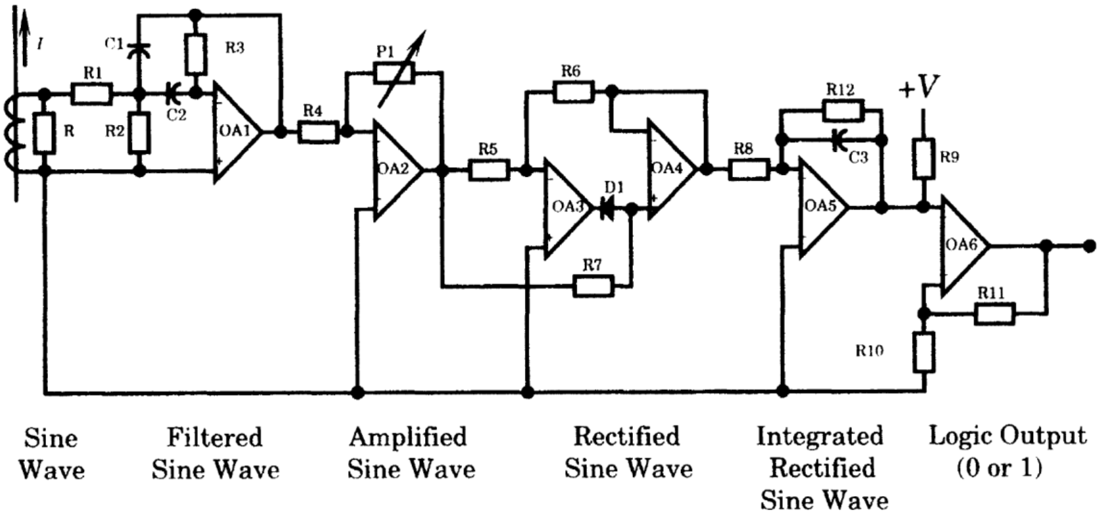


Figure 3.6 An instantaneous overcurrent unit [2]

3.3.3. Illustration Using an Example

Figure 3.7 shows an application of analog solid-state instantaneous overcurrent relay in a power system. The 2-Bus power system includes two loads, a generator, and an ideal transmission line. Bus 2 is connected to the transmission line with a normally-closed circuit breaker. An analog instantaneous overcurrent relay monitors the current of bus A and opens the circuit breaker in the case of a fault (over current at Bus A). A short-circuit type fault occurs at time t=0.5 s at Bus 2 causes the overcurrent relay to operate and open the circuit breaker. The characteristic of the 2-Bus power system is given in Table 3.2.

Table 3.2 2-bus power system characteristic

Generator	400 V, 50 Hz, 1Mw
Bus A	400 V
Bus B	400 V
Load A	100 kW, 1k Var
Load B	100 kW, 1k Var

The input of the relay's circuit is I (current of the Bus A), which crossed the resistance R to convert current to voltage. A full-bridge rectifier and R-C filter are used to fullwave rectifier and remove the ripple from the input signal. A comparator circuit using op-amp is used as a level detector and compares the input signal with an adjustable reference voltage. The output of the comparator passed through a time-delay circuit to prevent relay operates with a deceptive transient signal (noise) in the input circuit. The time delay in the overcurrent relays used to increase the security of the relay. The block diagrams of the over-current relay and waveform diagrams of the circuit are shown in Figure 3.8 and Figure 3.9 correspondingly.

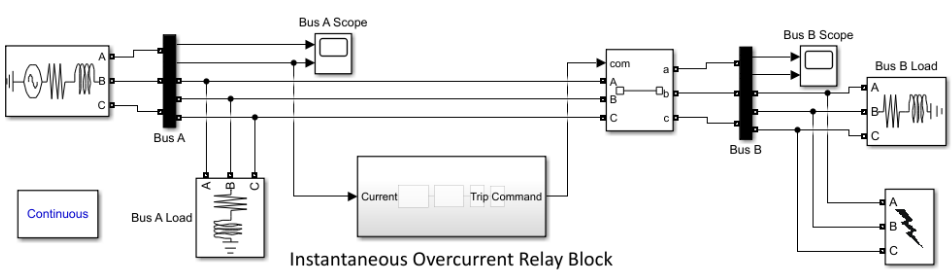


Figure 3.7 2-Bus power system in MATLAB Simulink

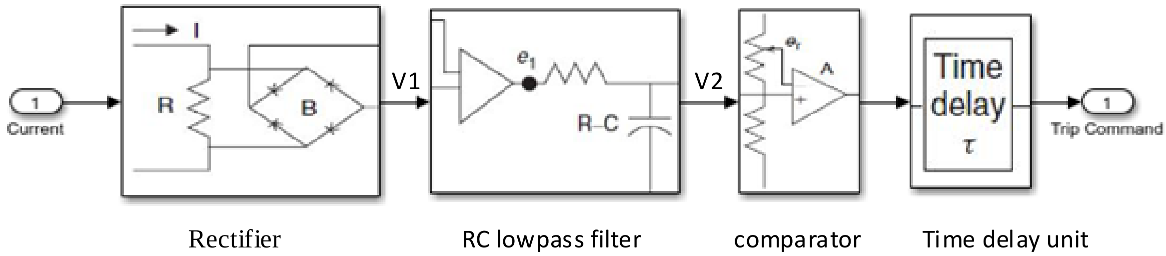


Figure 3.8 A sample blocks used for an analog solid-state instantaneous overcurrent relay

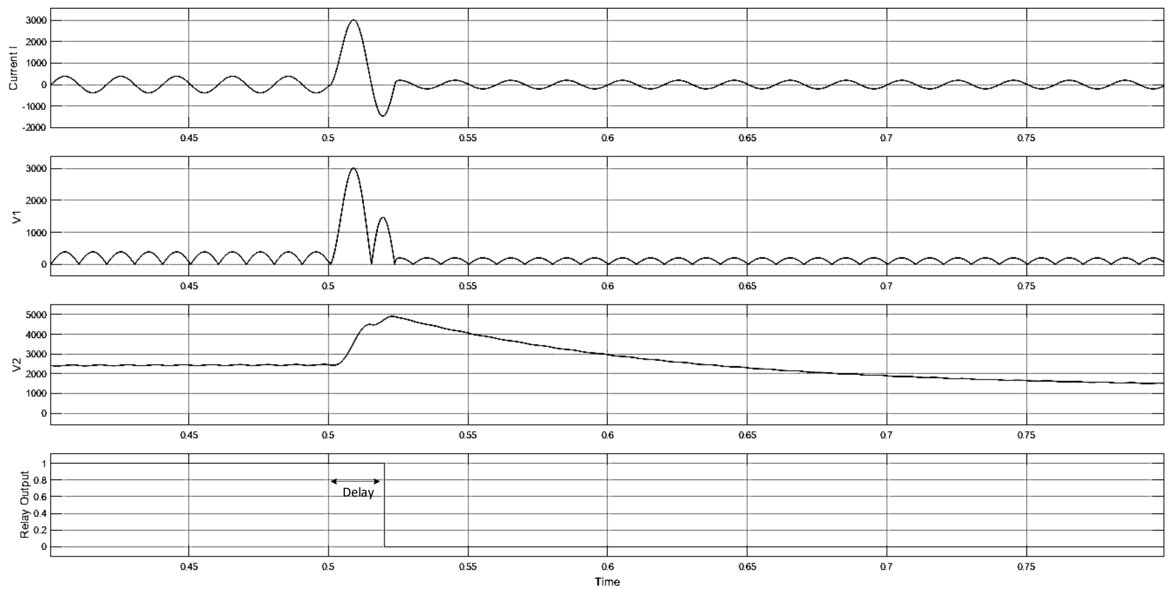


Figure 3.9 Waveforms of an analog solid-state instantaneous overcurrent relay

3.3.4. Digital Relay

With the growing technology and advent of high-performance microprocessors, using the digital computer in protective relays can be beneficial. The investigation to use the digital computer in the power system relaying is started in 1960. Digital computers are widely used in several types of power system relays due to their significant advantages such as cost, self-checking and reliability, functional flexibility and adaptive relaying, and also compatibility with lots of digital elements used in the power system [9]. The digital protective relays are programmable that provide the designer to implement different algorithms. Digital overcurrent protection relays, digital distance relays, transformer protection relays, generator protection relays, and digital substation protection relays are good examples of the digital relays.

3.3.5. Digital Computer Relay Architecture

Computer relays include several subsystems with an identified function integrated to perform as a protective device in the abnormal condition in the power system. Figure 3.10 shows the principal subsystems of a computer relay.

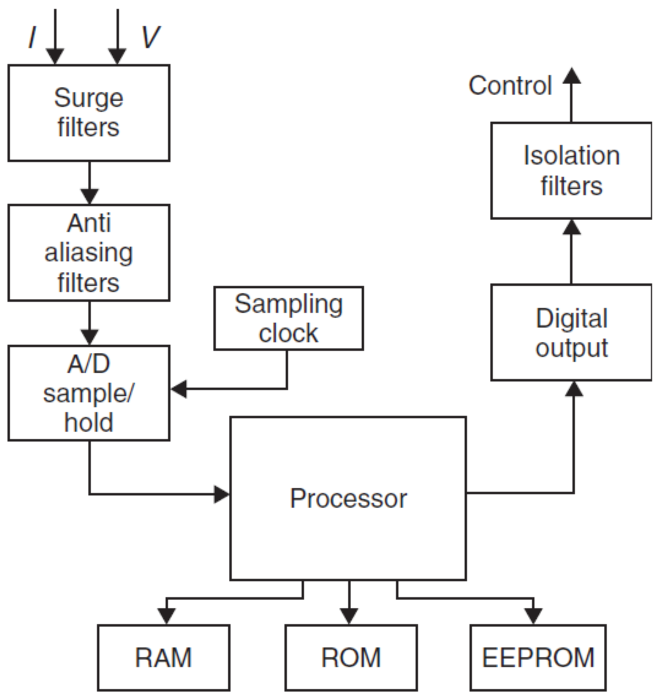


Figure 3.10 Major subsystems of a computer relay [1]

In computer relays, the power systems voltage and current are the most command inputs. To process these analog signals in a digital environment, using an analog to digital converter (A/D) is necessary. Note that due to isolating the computer relay from the harsh substation environment, surge filtering and (or) optical isolation are used. Also, anti-aliasing filters with a low cut-off frequency, avoid passing the high-frequency transients through the A/D convertor.

3.3.6. Illustration Using an Example

Figure 3.11 shows an application of digital solid-state instantaneous overcurrent relay in a power system. The 2-Bus power system was described in section 3.3.3. A short-circuit type fault occurs at time t=0.5 s at Bus 2 causes the digital overcurrent relay to operate and open the circuit breaker. The block diagrams of the digital computer over-current relay and waveform diagrams of the circuit are shown in Figure 3.12 and Figure 3.13, respectively.

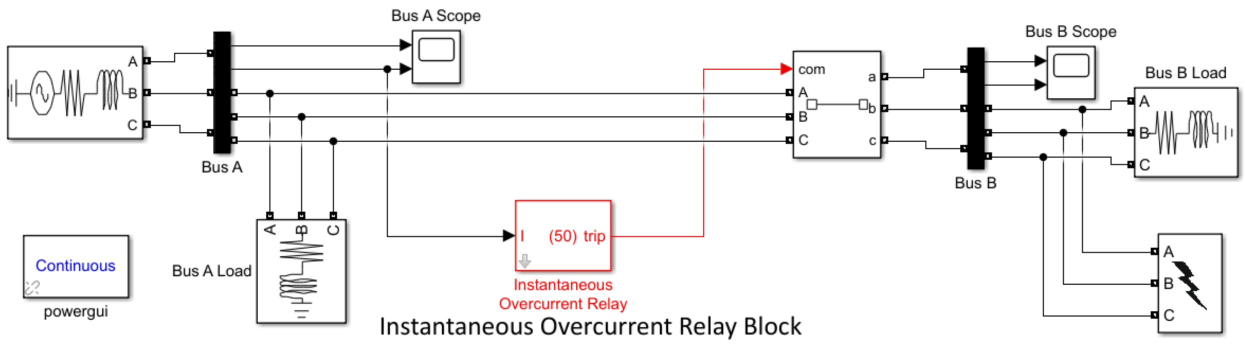


Figure 3.11 Application of a digital instantaneous overcurrent relay in a 2-Bus power system

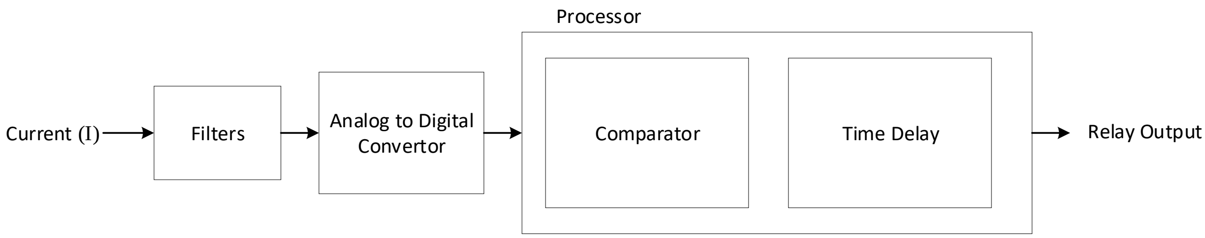


Figure 3.12 A sample blocks used for an analog solid-state instantaneous overcurrent relay

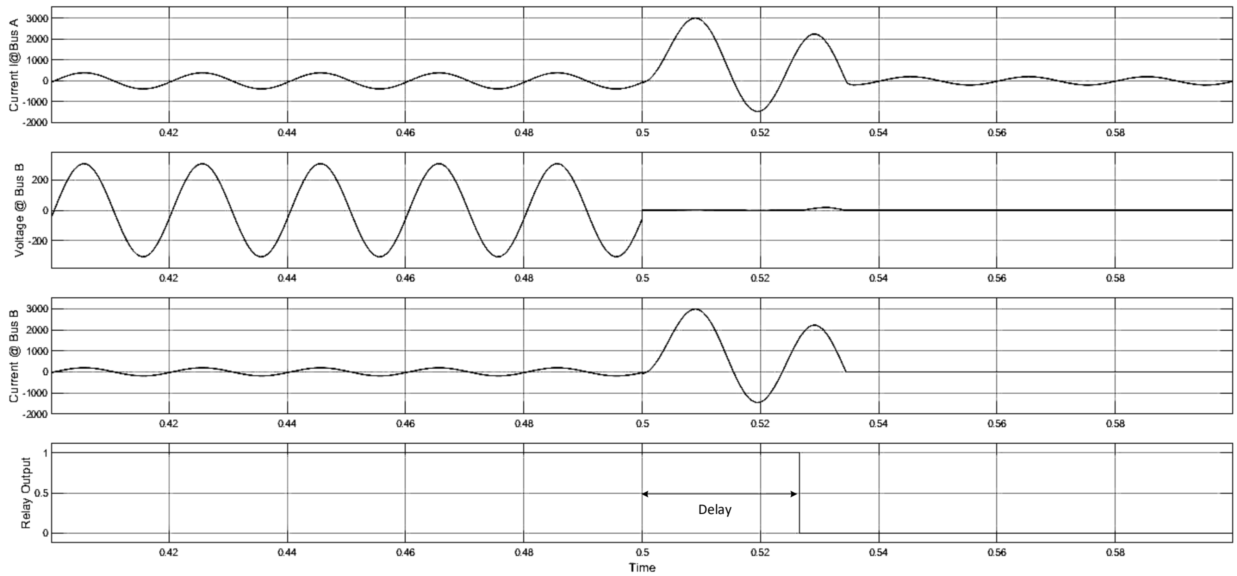


Figure 3.13 Waveforms of a digital solid-state instantaneous overcurrent relay

3.4. Conclusion

In this chapter, first, the essential of power system protection has been discussed, followed by studying the operation and component of power system protection. The basic concepts of relaying trough a power system such as reliability, dependability, security, and zone of protection have been investigated. Different types of protective relays categorized based on their hardware into two groups, mechanical relays, including inductive-type relay and plunger-type relay, and solid-state relays, including analog and digital relays. The functionality of analog and digital protective relays is illustrated using two examples, and their effect on power system performance is shown in MATLAB Simulink environment.

Chapter 4

Protection Against Abnormal System Frequency Using Factorial Design Method

4.1. Introduction

The power system network faces some problems in abnormal conditions; therefore, there should be some protective schemes that can be used to have the best function in order to prevent damages to power equipment and customer’s facilities.

This chapter focuses on a type of problems found in the power transmission system related to the frequency of the system. Protective systems are designed for watching power system function and increasing the lifetime of generating unit by detecting the fault and take quick action to an emergency system condition.

To study the power system and its behavior in the hazard situation where the frequency has abnormal value, and also to design a protective scheme for the power system, a mathematical model can be useful. The system model should be simple and also retain the essential dynamic characteristic of the model at the same time.

In this chapter, first, the effect of abnormal frequency situation on generator and single reheat steam turbine is discussed. After that, a simplified minimum order model of a reheat generation with typical time constant and active speed governing is presented.

The presented system frequency response (SFR) model is used to compute the frequency deviation as a function of load imbalance. In addition, the effect of each parameter of the turbines SFR model on system frequency deviation is studied. Also, the different underfrequency load shedding methods used for frequency load shedding relays are reviewed. Finally, this chapter investigates two situations where a power system faces an underfrequency condition. In this way, two different underfrequency load shedding methods are compared as a case study.

4.2. Abnormal Frequency Operation

Generally, there are two types of abnormal frequency conditions in power systems. The first is related to the generator and generator step-up transformer. This type of abnormal frequency condition is detected and protected by volts per hertz relays. The second type, which will be discussed in this chapter, is the effect of heavy load lines and may cause cascaded tripping of other lines and separate the interconnected system into two or more islands.

4.3. Effects of Over-frequency

In this section, the effects of over-frequency on the operation of the generator and the turbine due to tripping is discussed. Over-frequency in power systems is the result of the loss of the load. This kind of disturbance is often named load rejection. The effect of load rejection on generating unit is an increase in speed, which should be regulated very fast by the prime mover speed governors. The generator is usually not in a dangerous situation because there is an increase in the cooling system, which is the result of increasing speed. Also, in comparison with a normal condition, the generation units operate in a lower loading situation after interconnected system separation due to tripping. Moreover, the voltage increases due to load rejection resulting in reduced excitation, which is protected by loss-of-excitation protection that can trip the generator in case of loss of excitation.

In an over-frequency island, the effects of load rejection on the turbines are not very critical because after losing a significant amount of load for example 50%, the frequency increase about 1.5 hertz and based on most turbine lifetime curve, as shown in Figure 4.2, they can operate for a long time (about 30 minutes) at this situation, which is considered as enough time for the governor to response or for the operator to take manual control and change the governor load reference setting. In addition, an over frequency relay can be used in the case of higher frequency excursions. Figure 4.1 shows the effect of over-frequency on the generator.

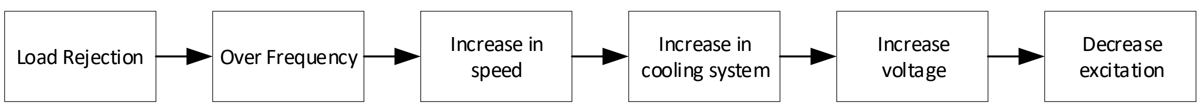


Figure 4.1 The effect of over-frequency on a generator

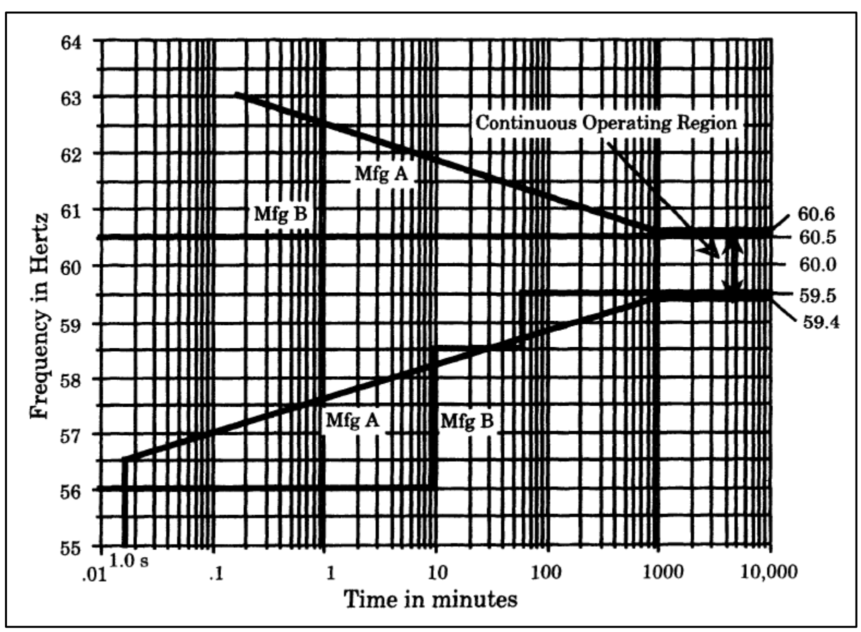


Figure 4.2. Turbine frequency lifetime [2]

4.4. Effects of Underfrequency

Operating in an underfrequency island is a very hazardous situation that can result in a complete blackout condition. Usually, the underfrequency condition is caused by two phenomena in an interconnected power system or in an islanded system, generator unit tripping, or overload condition.

In an underfrequency island, all generating units are overloaded that decreases the speed, and so on, the cooling performance decreases as well. In this case, the voltage value is below the normal amount that causes an increase in generator excitations. Eventually, the generators may be tripped from the power system because of the following faults:

- Stator overheating
- Rotor overheating
- Overexcitation
- Generator underfrequency protection relays (volts/hertz)

A trip at a generation unit can bring about a rapid deterioration and cause of the other generators to trip cascadingly. The effects of underfrequency on the turbine are shown in Figure 4.3.

Moreover, the underfrequency condition affects the amount of turbine life. Hence, using some underfrequency protection schemes, such as relaying, is needed [3]. In this way, two assumptions should be made. First, it must be assumed that all relays are installed, so an estimation of predefined separation systems can be made. The second assumption is the amount of load variation disturbance. So, for a significant disturbance results in a high-frequency decay, the protection scheme must shed a higher amount of the load.

Under or over frequency does not affect hydro turbines. In this chapter, only steam turbines are discussed.

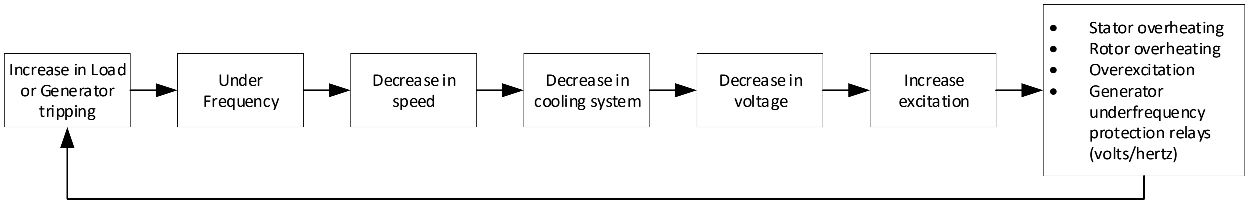


Figure 4.3The effect of underfrequency on the generator

4.5. System Frequency Response Model

Modeling the speed control of an island can estimate the dynamic frequency behavior, which can be expanded to the total system [4]. Before developing the normalized equation of an island to the whole system, two assumptions should be made as below:

1- The system base volt-ampere magnitude is the sum of the ratings.

2- Most of generating units are steam turbine.

The purpose of modeling the system frequency response (SFR) is to provide the minimum order model without losing the essential dynamic characteristics, as shown in Figure 4.4 [5] [6]. Pe, Pm, H, and D represent electrical power, mechanical power, inertia constant, and damping constant, respectively, which are balanced in a steady-state condition.

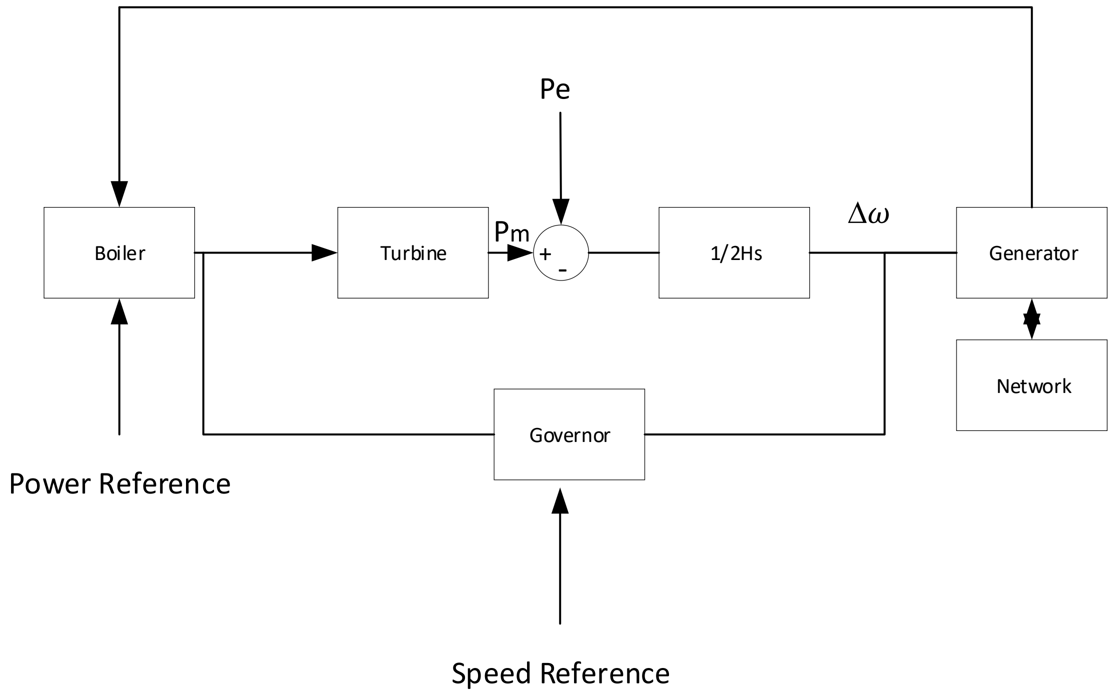


Figure 4.4. Generating Unit Frequency Control [1]

4.5.1. Single reheat steam turbine model

The turbines were assumed as a single reheat turbine in developing the SFR model. A simple mathematical model of the reheat turbine is shown in Figure 4.5, where TR is the reheat time constant, Km is an overall gain constant used for tuning of the turbine and FH, FI, and FL is the fraction of total mechanical power produced by High pressure, low pressure turbines, and intermediate pressure respectively.

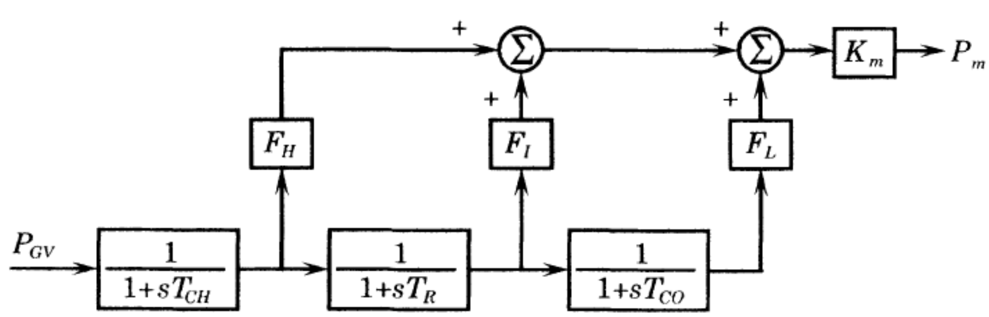


Figure 4.5. Mathematical model of the reheat turbine [1]

4.6. Simplified System Frequency Response Model

The simplified SFR model is shown in Figure 4.6, where all parameters are in per unit on an MVA base equal to the total rating of all generating units. The model behavior depends on the following factors; the gain Km, the damping factor D, the inertia constant H, the average reheat time constant TR, and the high pressure power fraction of the reheat turbines FH. However, it is essential to know that the predominant physical constants are H and TR, which has a range of about 6 to 12. Hence, all other time constants are negligible. Also, H has a value in the order of 3 to 6 seconds for a typical large unit and is always multiplied by two, which increases its effectiveness.

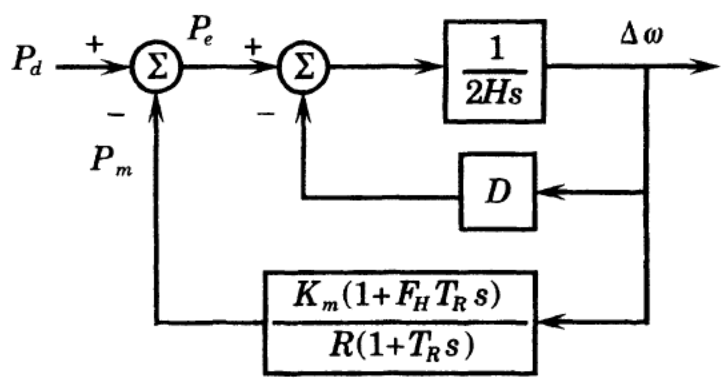


Figure 4.6. Simplified SFR Model [2]

Based on the simplified SFR model, the frequency response is computed using per unit by Equations 4.1 to 4.4.

$$\Delta\omega=\left(\frac{R\omega_n^2}{DR+K_m}\right)\left(\frac{(1+T_R s)P_{step}}{s(s^2+2\xi\omega_n s+\omega_n^2)}\right) \qquad (4.1)$$

Where

$$\omega_n^2=\frac{DR+K_m}{2HRT_R} \tag{4.2}$$

$$\xi=\left(\frac{2HR+(DR+K_mF_H)T_R}{2(DR+K_m)}\right)\omega_n \tag{4.3}$$

$$\omega_r=\omega_n\sqrt{1-\xi^2} \tag{4.4}$$

The SFR model is linear and has two main inputs; the governor's power set point, which is considered constant in the SFR model, and system load power. So, a disturbance ($P_{d)}$ as a power unbalance can be generated represents a situation where the load is higher than the generation. In the SFR model, P_D is modeled by a step function as Equation 4.5.

$$P_D(t)=P_{step}u(t) \tag{4.5}$$

Where P_{step} is the amount of disturbance in per unit based on the system base MVA.

4.7. System Frequency Response Characteristic

There are two critical characteristics in system frequency response, the maximum rate of change of slope at t=0 and the time at which the slop value is zero (t_z) which is related to the maximum frequency deviation. These parameters can be informative to discuss the effect of each variable in the SFR model and calculated by Equation 4.6 and Equation 4.7, respectively.

$$\frac{d\omega}{dt}|_{t=0}=\frac{aR\omega_nP_{step}}{DR+K_m}\sin\phi_1=\frac{P_{step}}{2H} \tag{4.6}$$

$$t_z=\frac{n\pi-\phi_1}{\omega_r}=\frac{1}{\omega_r}\tan^{-1}\left(\frac{\omega_rT_R}{\xi\omega_nT_R-1}\right) \tag{4.7}$$

4.8. Simulation and Discussion

The linear system frequency response (SFR) model can present the frequency performance of the extensive power system approximately. The SFR model is considered as an average of the total system and represents the behavior of the whole machines in the system. This model is simulated in MATLAB software using block diagrams. To simulate the SFR model, all related parameters are presented in per unit. The SFR model has two inputs; the governor's power set point and the generated electric power. The power setpoint can be considered as a constant because, in this section, only the behavior of the system over a short period of time, about a few seconds, will be investigated. Also, to simulate a disturbance, a generated electric power with a negative sign is used. In this section, to show the effect of disturbance size, governor drop, inertia and reheat time constant, different level of each item is applied to an SFR model while the other parameters are constant and based on the result, the values of the maximum rate of change of slope at t=0, $\frac{d\omega}{dt}|_{t=0}$, and also the time at which the slop value is zero (t_z) are compared with the calculated value using Equations 4.6 and 4.7.

4.8.1. Effect of Disturbance Size, P_{step}

To show the effect of disturbance size (P_{step}) on the frequency behavior of a system, different disturbance value is applied to an SFR model. The value of P_{step} is varied from -0.1 to -0.3 in the decrement of 0.1 per unit. The results are shown in Figure 4.7. Based on the result shown in Table 4.1, it is observed that the assumed P_{step} does not affect the time of maximum deviation, which is constant in Figure 4.7. However, the initial slope is varied for each run.

Table 4.1 Simulation results vs. calculated results

	Simulation results			Calculated results	
	slope at t=0 (Hz/S)	t_Z (s)	Final Frequency Value (Hz)	slope at t=0 (Hz/S)	t_Z (s)
PD=-0.1(PU)	-0.0125	2.3629	59.7001	-0.0125	2.3688
PD=-0.2(PU)	-0.0250	2.3629	59.4002	-0.0250	2.3688
PD=-0.3(PU)	-0.0375	2.3629	59.1003	-0.0375	2.3688

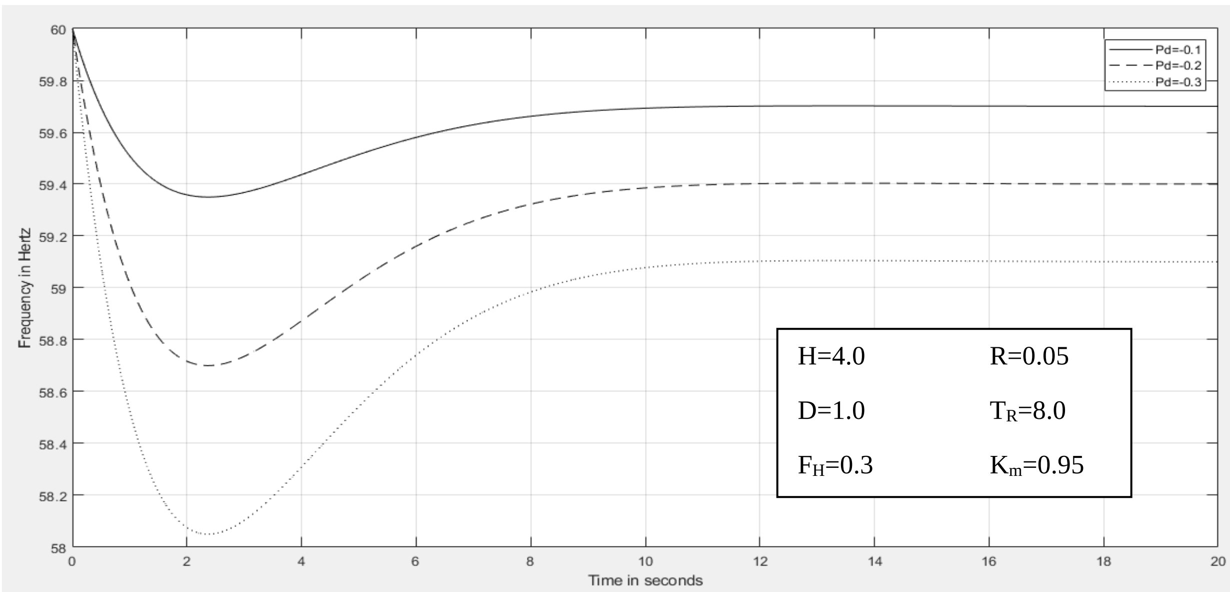


Figure 4.7. Frequency response for different values of P_{step}

4.8.2. Effect of Governor Droop, R

Another constant in SFR model is speed drop or regulation of the governor, which is shown by R and considered as inverse feedback. The typical value of R in North America is set to about 0.05 that creates constant feedback with gain 20. In an islanded condition, based on actually observed system responses, R-value for the total system may be around to 0.1 indicate that some generators are operating with governor value block [1]. The effect of R is tested by applying normal values for all parameters and modifying R from 0.06 to 0.10 in an increment of 0.02 per unit. The results are shown in Figure 4.8. The assumed droop setting R does not affect the initial slope of frequency response. However, the time of maximum deviation is varied for each run. Table 4.2 shows the result of applying different governor drop values on the SFR model.

Table 4.2. Simulation results vs. calculated results

	Simulation results			Calculated results	
	slope at t=0 (Hz/S)	t_Z (s)	Final Frequency Value (Hz)	slope at t=0 (Hz/S)	t_Z (s)
R=0.06(PU)	-0.0250	2.6744	59.2877	-0.0250	2.6626
R=0.08(PU)	-0.0250	3.1850	59.0710	-0.0250	3.1930
R=0.10(PU)	-0.0250	3.6454	58.8667	-0.0250	3.6676

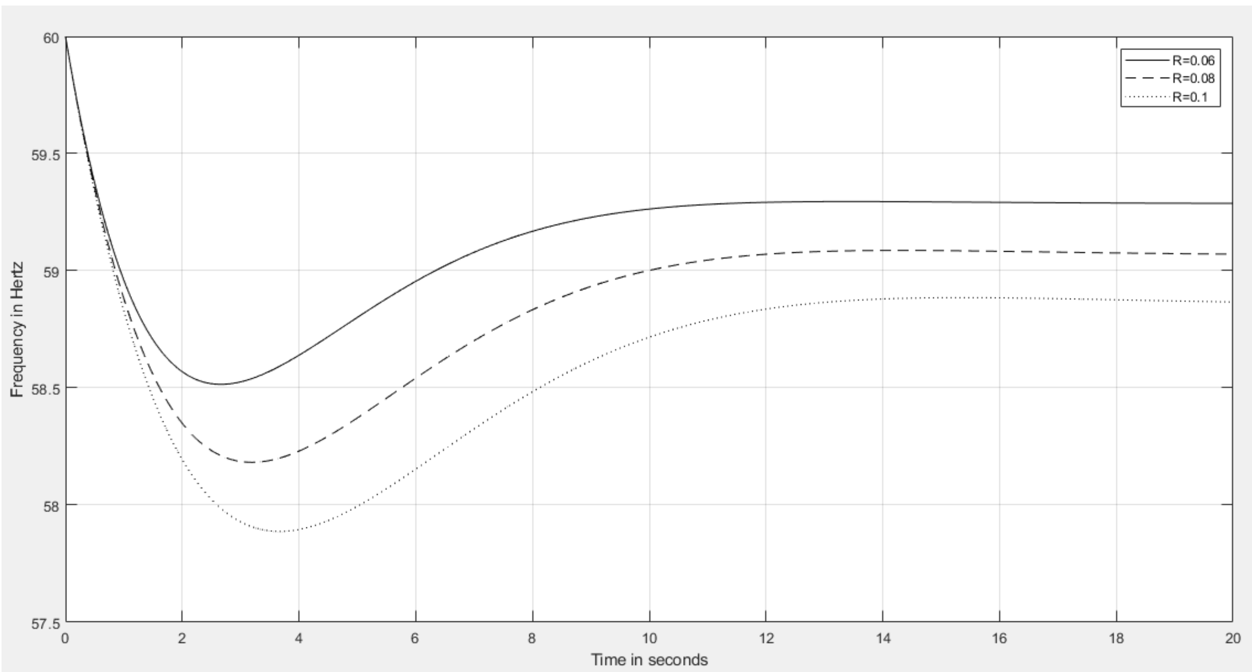


Figure 4.8. Frequency response for different values of R

4.8.3. Effect of Inertia, H

To show the effect of the inertia, the value of inertia (H) is varied from 5.0 to 3.0 in a decrement of 1.0. Almost all parameters of frequency response are affected by varying the amount of H, but the most notable effects are the initial frequency decline slop and the amount of t_Z because the higher inertia causes lower frequency deviation that provides governor more time to respond.

Based on Figure 4.9 and the values in Table 4.3, it is observed that the value of H has no significant effect on the final value of frequency.

Table 4.3. Simulation results vs. calculated results

	Simulation results			Calculated results	
	slope at t=0 (Hz/S)	t_Z (s)	Final Frequency Value (Hz)	slope at t=0 (Hz/S)	t_Z (s)
H=5.0	-0.0200	2.7567	59.2887	-0.0200	2.7657
H=4.0	-0.0250	2.3562	59.2887	-0.0250	2.3688
H=3.0	-0.0333	1.9546	59.2887	-0.0333	1.9374

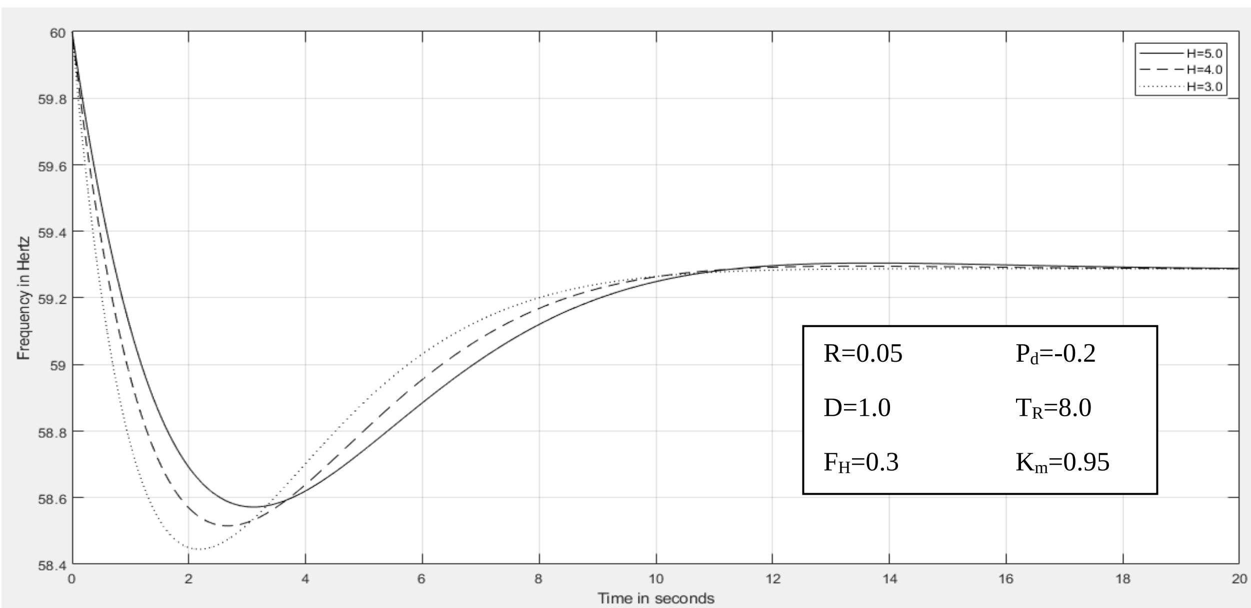


Figure 4.9. Frequency response for different amounts of H

4.8.4. Effect of Reheat Time Constant, T_R

Reheat Time Constant, T_R, has a noticeable effect on frequency response and consider as an essential parameter in the single reheat turbines. Changing this parameter generates a delay in response following its initial dip, which can increase the maximum frequency deviation domain.

T_R does not affect the first frequency slop and also on the setting of underfrequency relays as well, but increasing this parameter extends the cumulative time of susceptibility to low frequency. The effect of the different values of reheat time constant is shown in Table 4.4 and Figure 4.10.

Table 4.4. Simulation results vs. calculated results

	Simulation results			Calculated results	
	slope at t=0 (Hz/S)	t_Z (s)	Final Frequency Value (Hz)	slope at t=0 (Hz/S)	t_Z (s)
T_R =4.0	-0.0250	1.9281	59.2871	-0.0250	1.9128
T_R =5.0	-0.0250	2.0591	59.2871	-0.0250	2.0501
T_R =6.0	-0.0250	2.1541	59.2871	-0.0250	2.1690

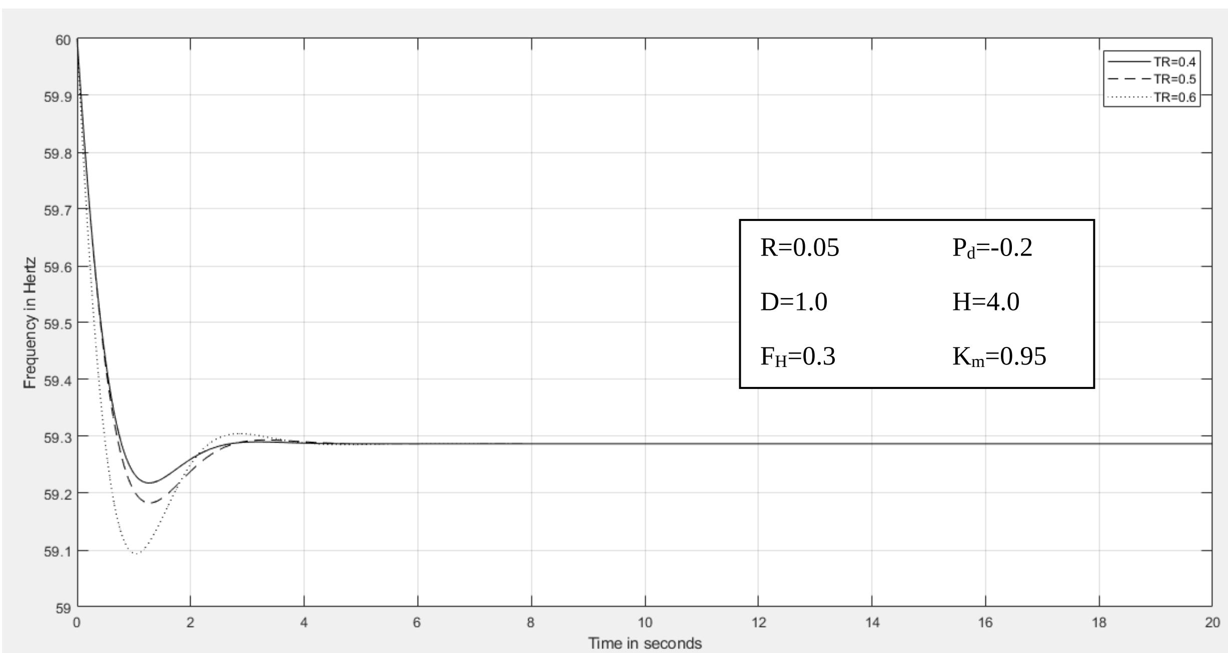


Figure 4.10. Frequency response for different amounts of T_R

4.8.5. The Effect of High-Pressure Fraction, F_H

To show the effect of high-pressure fraction constant (F_H), a different level of F_H is applied to an SFR model while the other parameters are constant. As shown in Figure 4.11, the constant

F_H affects the value ξ, which is calculated by Equation 4.3, significantly. The system will be overdamped, ξ>1, for the higher value of F_H. The constant F_H is related to the part of shaft power generated by the high-pressure turbine on a single reheat system, which is not delayed by reheating. The effect of the different values of high-pressure fraction constant is shown in Table 4.5 and Figure 4.11.

Table 4.5 Simulation results vs. calculated results

	Simulation results			Calculated results	
	slope at t=0 (Hz/S)	t_Z (s)	Final Frequency Value (Hz)	slope at t=0 (Hz/S)	t_Z (s)
F_H =7.0	-0.0250	2.5257	59.99	-0.0250	2.4950
F_H =5.0	-0.0250	2.6323	59.99	-0.0250	2.2750
F_H =6.0	-0.0250	2.1879	59.98	-0.0250	2.1701

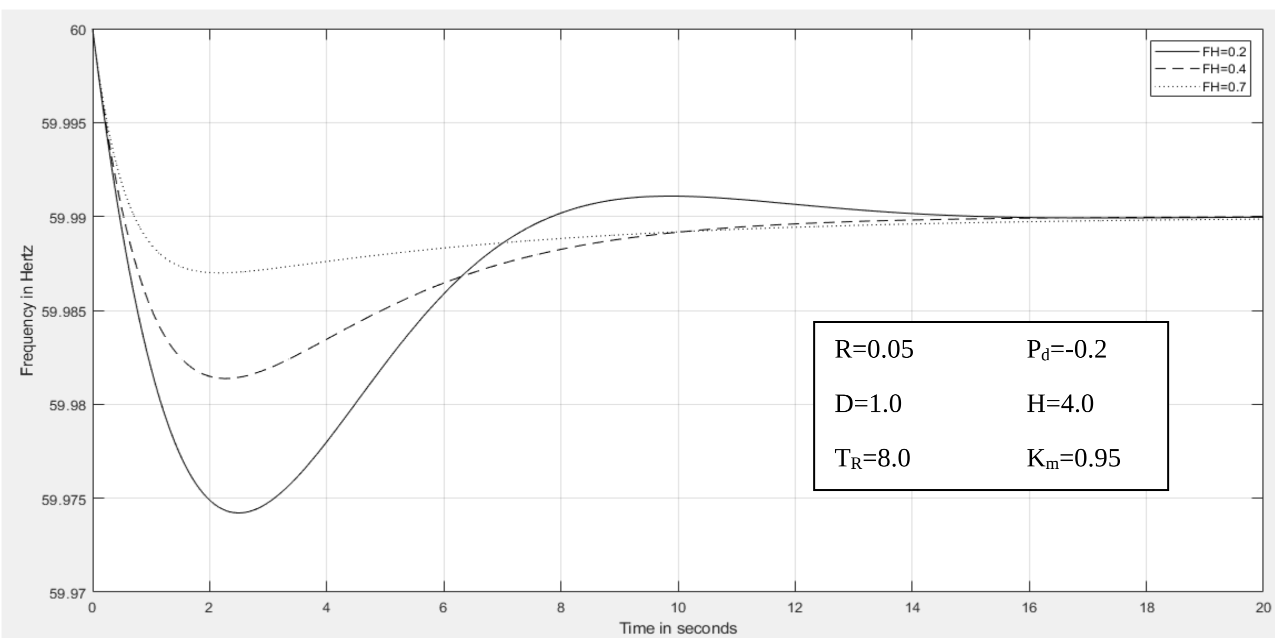


Figure 4.11 Frequency response for varying values of F_H

4.8.6. The Effect of Damping, D

Another constant in SFR model is the damping factor, which is shown by D. To show how the damping factor affects the system frequency response, a different level of S is applied to an SFR model while the other parameters are constant. As shown in Figure 4.12, factor D does not affect the system's response significantly. The effect of the different values of high-pressure fraction constant is shown in Table 4.6 and Figure 4.12.

Table 4.6 Simulation results vs. calculated results

	Simulation results			Calculated results	
	slope at t=0 (Hz/S)	t_Z (s)	Final Frequency Value (Hz)	slope at t=0 (Hz/S)	t_Z (s)
D =0.0	-0.0250	2.4958	59.98	-0.0250	2.4974
D =1.0	-0.0250	2.3562	59.99	-0.0250	2.3688
D =1.0	-0.0250	2.2836	59.99	-0.0250	2.2552

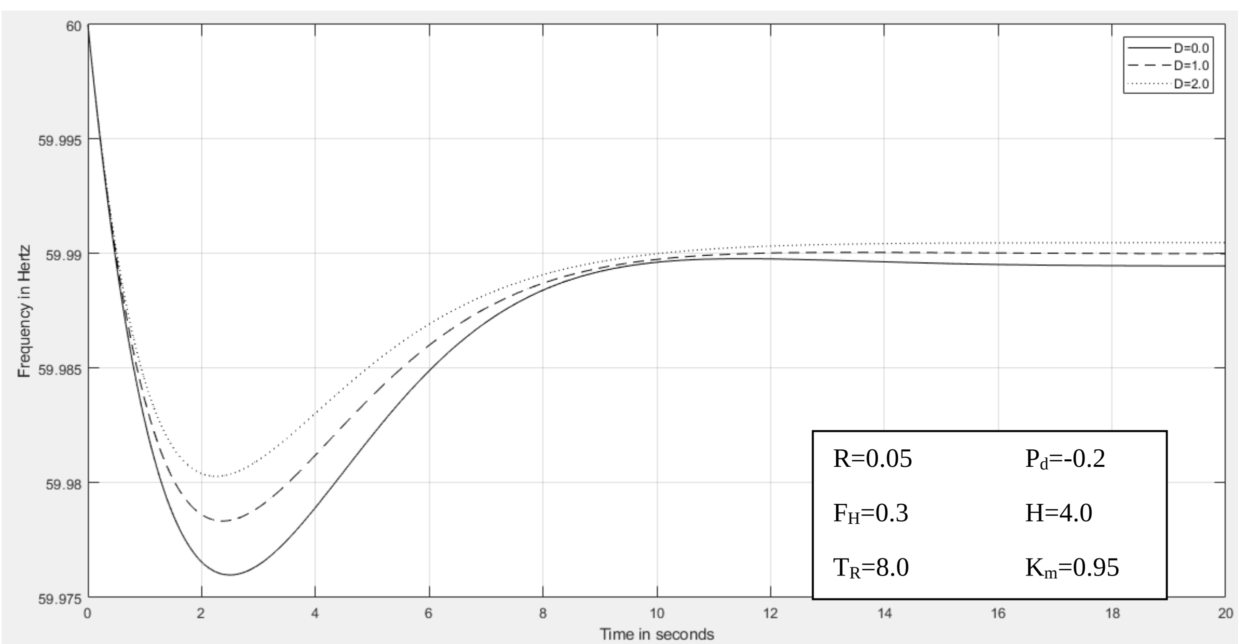


Figure 4.12 Frequency response for varying values of D

4.9. Off Normal Frequency Protection

Abnormal frequency circumstances impressed on most parts of the plant systems such as generator, unit step-up transformer, turbine, and station auxiliaries. So, using abnormal frequency protection is very important. Over one-third of the generating units have underfrequency protection, which is not coordinated with the system underfrequency load shedding relays in most cases [3]. Abnormal frequency protection follows two main objectives based on recently prepared standards, protect equipment from damage due to abnormal frequency, and stop cascaded tripping that may result in a general blackout [3, 7].

4.10. Steam Turbine Frequency Protection

Automatic load shedding is the primary protection scheme for the steam turbines, which is distributed within the power system. This protection approach provides a balance between load and generation. It should be noted that although turbines are protected by load shedding relays, they still need their protection just in the case of failure of the load shedding process.

4.11. Modeling the Power System Frequency Response Using Factorial Design Method

In this section, the statistical design of experiment (DOE) methodology is performed to find out the significant factors and interactions that affected the power system frequency response of a system frequency response model (SFR). A system frequency response model (SFR) presents the dynamic frequency behavior of the power system. The SFR is the model of speed control of a reheat steam turbine generation that represents the frequency response of the total system [1]. The power system frequency response consists of the rate of frequency decline and maximum deviation value of frequency, and the four factors are disturbance size, governor droop, rotating inertia, and reheat time. Design experiment Version 12 in any area, even in the non-technical area, is a useful method to be implemented to investigate the significant factors and their effect, and the quadratic model is developed to predict significant factors.

4.11.1. Experimental Design Methodology

The outcomes, models, and conclusions of an experiment depend on the techniques used for the data collection [10]. To provide enough and trustable data for the study, an appropriate design of experiment (DOE) inevitably should be applied [11]. DOE plays an important role in investigating the effect of various treatments. Also, it can estimate the effect of the significant factors for regression models and is frequently used to enhance the previous models [12].

4.11.2. The Experiment Procedures and the Investigated Factors

To be able to use a “multivariate” statistical technique, the factors and their ranges for the experiment should be determined. After that, the combination of factors based on DOE can be introduced [13]. The effect of four factors is studied on the responses consist of the maximum rate of change of slope at t=0 and the time at which the slop is zero (t_z). The factors include disturbance size (P_{step}), governor droop (R), rotating inertia (H), and reheat time (T_R). The factors and their levels are presented in Table 4.7.

Table 4.7 The factor levels regarding coded and actual unit

Factor	Name	Type	Low Level (P.U)	High Level (P.U)
P_{step}	Disturbance size	Numerical	-0.1	-0.3
R	Governor droop	Numerical	0.06	0.10
H	Rotating inertia	Numerical	3.0	5.0
T_R	Reheat time	Numerical	4.0	6.0

There are other factors in the SFR model, such as high-pressure fraction, F_H, and damping factor, D, however, these parameters do not have a pronounced effect on the system. Also, doing an experiment with fewer input factors need a lower amount of run.

4.11.3. Choice of Experimental Design

Appropriate experimental design results in a decrease in the run numbers and less experimental work in the laboratory. Moreover, it is capable of investigating several factors and their interactions at a time. As Montgomery stated in 1976, "Design methods of experiments are crucial for optimizing existing products or develop new ones." [10]. Optimization can be applied through the Response Surface Methodology (RSM) techniques such as Central Composite Design or Box-Behnken designs for significant factors [13]. Box Behnken design was chosen to illustrate the effects and interactions for this experiment. By making this choice following advantages of the method are considered for desirable design.

- Provides a reasonable distribution of data points
- Allows model adequacy, including lack of fit, to be investigated
- Allows experiments to be performed in blocks
- Provides an internal estimate of the error
- Provides precise estimates of the model coefficients
- Does not require many runs (if the number of factors is less than 5)
- Does not need too many levels of the individualistic variables
- Ensures simplicity of calculation of the model parameters [10]

For conducting the experiment, four factors are used at three levels. With the help of a kind of response surface methodology, Box-Behnken design, 27 runs are required with one block and three center points. The distribution of the factors and levels for each run are given in Appendix A.

4.11.4. Statistical Analysis of Data

To examine the impact of factors on the responses and to find any possible curvature in the design, the data were statistically analyzed using Analysis of Variance (ANOVA), and certain graphs and model adequacy testing is carried out. Design Expert 12 (Version 12.0.3.0 64bit) was used for the statistical analysis of the data. In this section, the Response Surface Methodology of Box-Behnken Design is presented. The BBD design with four factors, three levels, three center points with one blocking, including 27 runs, is selected.

4.11.5. Significant Factors and ANOVA Table

The statistical analysis of the data for two responses are tabulated in Table 4.6 and Table 4.7. The confidence interval (CI) for analyzing data was chosen 95%, and α is 0.05. Therefore, the p-values less than 0.05 exhibit significant factors in the ANOVA table, and the smaller p-values indicate, the more significant is the factor. The results show that the p-value for both responses is less than 0.05. Thus, both models of responses are significant.

Table 4.8 gives information on the result of analysis of variance (ANOVA) of BBD for the response $d\omega/dt$ (the rate of change of frequency slope at t=0), which is carried out to identify the significant factors. The ANOVA table indicates that the disturbance size (Pstep) and inertia constant(H), are the significant factors. Also, it shows that interactions are not significant. Furthermore, this table indicates that the Lack of Fit for this response is not significant.

Table 4.8 ANOVA results for the response dω/dt by Design-Expert 12

Source	Sum of Squares	df	Mean Square	F-value	p-value	
Model	0.0018	4	0.0005	356.49	< 0.0001	significant
P_{step}	0.0014	1	0.0014	1110.40	< 0.0001	
R	0.0000	1	0.0000	0.0000	1.0000	
H	0.0004	1	0.0004	315.55	< 0.0001	
T_R	0.0000	1	0.0000	0.0000	1.0000	
Residual	0.0000	20	1.297E-06			
Lack of Fit	0.0000	18	1.441E-06			
Pure Error	0.0000	2	0.0000			

As shown in Table 4.9, the result of analysis of variance (ANOVA) for the second response, the time at which the slop is zero (tz), indicates that factors P_{step}, R, H, and T_R have significant effects on the second response. Also, the ANOVA table indicates that Interaction between factors R and H are significant. In addition, this table indicates that the Lack of Fit for this response is not significant.

4.11.6. Interactions between the factors

The 2-D plot of interaction effects between factors R and H, R and T_R, and H and T_R are presented in Figure 4.13. It is illustrated in Figure 4.13(a) that by increasing R, the response t_z will be increased, but the rate of increases at a low level of factor H is lower. There is the same situation for factor T_R, as well as Figure 4.13(b) shows. Figure 4.13(c) shows that by rising Factor H(C), the value of the response t_z will be raised, but the higher value of H caused a more significant increase of the response t_z.

Table 4.9 ANOVA results for the response (t_z) by Design-Expert 12

Source	Sum of Squares	df	Mean Square	F-value	p-value	
Model	4.96	11	0.4507	2323.05	< 0.0001	significant
P_{step}	0.0038	1	0.0038	19.69	0.0007	
R	2.27	1	2.27	11714.75	< 0.0001	
H	2.14	1	2.14	11054.81	< 0.0001	
T_R	0.3423	1	0.3423	1764.40	< 0.0001	
R&H	0.0214	1	0.0214	110.39	< 0.0001	
R& T_R	0.0010	1	0.0010	5.24	0.0394	
H& T_R	0.0018	1	0.0018	9.05	0.0101	
Residual	0.0025	13	0.0002			
Lack of Fit	0.0025	11	0.0002			
Pure Error	0.0000	2	0.0000			

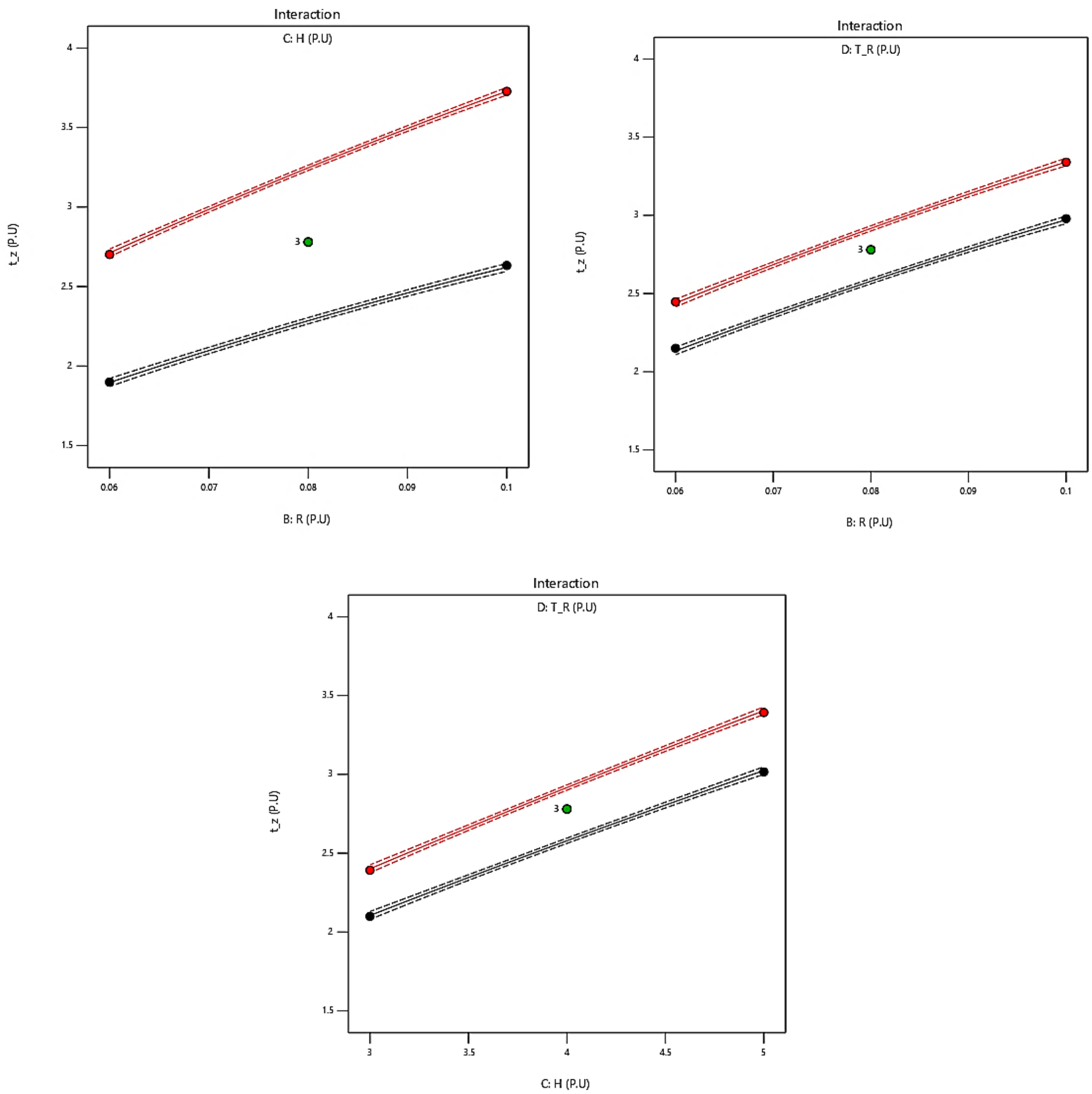


Figure 4.13 Interaction between the factors

4.11.7. System Modeling Using Actual Equation

The equation in terms of actual factors can be used to make predictions about the response for given levels of each factor. Here, the levels should be specified in the original units for each factor. This equation should not be used to determine the relative impact of each factor because the coefficients are scaled to accommodate the units of each factor, and the intercept is not at the center of the design space. The final equation in terms of actual factors for the responses (t_z and $\frac{d\omega}{dt}$) is presented in Equation 4.8 and 4.9, respectively. These equations model the frequency behavior of the system based on factors P_{step}, R, H, and T_R.

$$t_z = -1.0087 + 1.1005 * P_{step} + 13.4667 * R + 0.142406 * H + 0.336645 * T_R + -0.2205 * P_{step} * H + 3.65875 * R * H + 0.7975 * R * T_R + -64.5549 * R^2 \quad (4.8)$$

$$\frac{d\omega}{dt} = -0.027439 + 0.12 * P_{step} + -6.25964e\text{-}20 * T_R \quad (4.9)$$

To validate the proposed model, different level of P_{step} (0.5 to -0.5, with the step -0.1) is applied to the system while the other parameters are constant ($R=0.05$, $T_R=8$, $F_H=0.3$, $K_m=0.95$, $H=4.0$, $D=1.0$). The responses of the system (t_z and $\frac{d\omega}{dt}$) for SFR model vs. actual equation are shown in Figure 4.14 and 4.15, respectively. From the result, it can be concluded that the actual equations of the responses are very close to the actual system, and they can be used to model the system's frequency behavior. In addition, these equations can be used to estimate the system dynamic machine behavior, which can be used in load shedding relays to operates in an optimal manner. The concept of load shedding will be discussed in chapter 5 of this thesis.

Figure 4.14 $\frac{d\omega}{dt}$ calculated for SFR model vs. actual equation

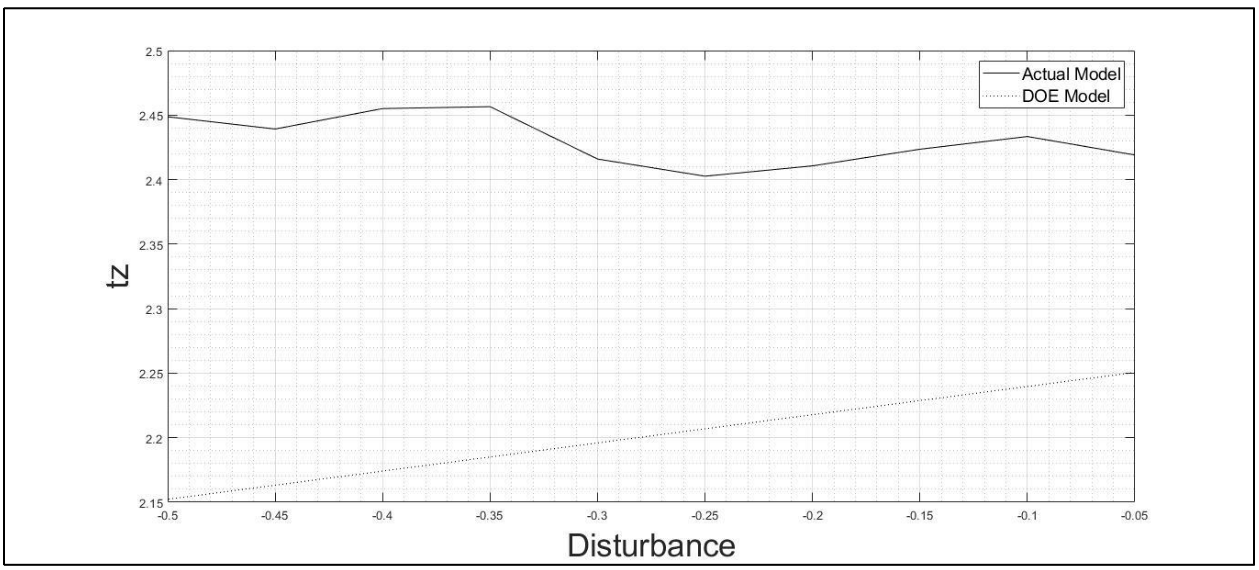


Figure 4.15 t_z calculated for SFR model vs. actual equation

4.12. Conclusion

In this chapter, the effect of abnormal frequency situation on the generator and single reheat steam turbine were investigated individually, and it was concluded that underfrequency condition is usually more critical than over frequency situation. In addition, a simplified minimum order model of a reheat generation with typical time constant and active speed governing was presented. In comparison with the actual system, the presented system frequency response (SFR) model had an acceptable result on average. Moreover, the effect of each parameter of the turbines SFR model on system frequency deviation characteristics such as the initial rate of frequency decline, maximum frequency deviation, and the final frequency value was studied as well. Finally, to model the power system frequency response and also to determine the significant factors influencing the power system frequency response, the Box- Behnken design method is used as a statistical method to find the relationship between some factors that can affect the maximum rate of change of slope at t=0 and the time at which the slop is zero (t_z) which is related to the maximum frequency deviation. The ANOVA table is performed, and the effect of each factor on the response is verified. Based on the experiment and results, the whole process of designing, conducting the model, analyzing, and validating the data taught the authors that, however, the actual equation model is very close to the SFR model, but the more accurate statistical model can be obtained from a physical system.

Chapter 5

Load Curtailment on Isolated Power System

5.1. Introduction

One of the most important protection methods is load shedding. Load shedding means removing some loads connected to the network in order to prevent damages to the transmission lines and maintain the system stability and control the frequency and voltage of the network. It is obvious that load shedding decreases the economic revenues and creates dissatisfaction in consumers; therefore, it is used as the last resort for controlling the power system. Load shedding is one of the most reliable methods for controlling the network.

The probability of fault and unfavorable conditions increases with network expansion, and thus, load shedding may be the only possible way to protect the power network in hazardous situations. These conditions can be caused by some actions in the power system such as reducing generator power output, overloading or sudden increase of load, and interruption of a transmission line. Various methods are provided for load shedding. These methods can be categorized based on their speed, quantity under control, and load shedding structure. In this chapter, all these categories and the methods used for load shedding will be reviewed.

5.2. Classification Based on the Operating Time

The operating time of the protective schemes is different, and it depends on the type and the severity of the error. This is illustrated in Figure 5.1. Different methods of load shedding can be classified into two categories of fast and slow load shedding based on their operating speed.

5.2.1. Fast Load Shedding

Frequency and voltage are two important quantities in the power network, the permitted range for these two quantities are relatively small, and a small disturbance can quickly cause these two quantities being out of the permissible range; therefore, load shedding based on these two quantities should be conducted quickly in a very short period of time. This type of load shedding is regarded as fast or rapid load shedding [14].

5.2.2. Slow Load Shedding

As shown in Figure 5.1, some disturbances such as overloading of lines and transformers can be withstood for a short period of time. For example, a power transformer can withstand a 20% overload for a few minutes [15]. Therefore, a load shedding is considered slow, which it's under control quantity has slow and small changes.

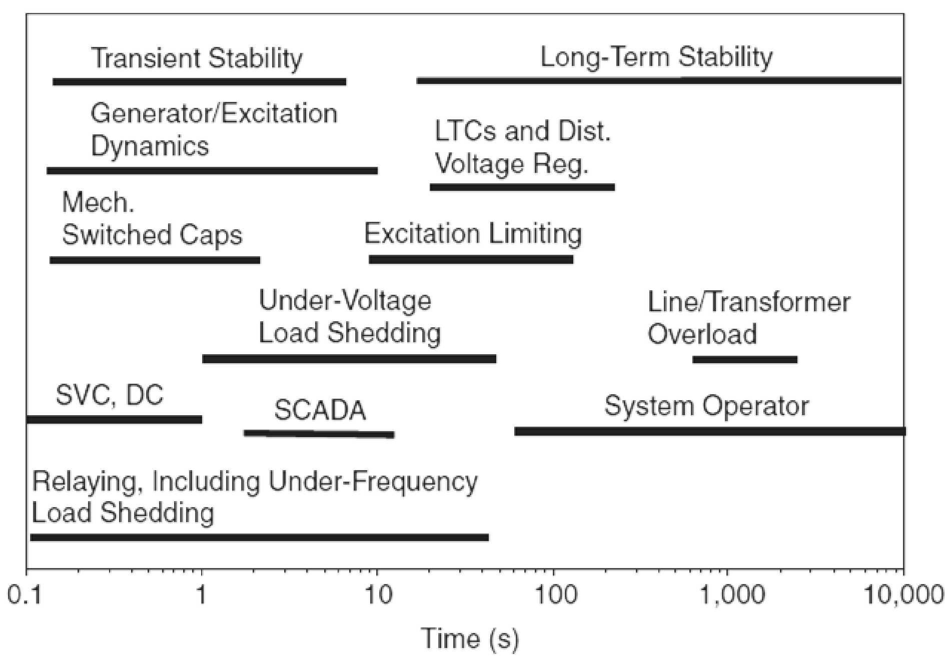


Figure 5.1 Operation time of the network security components after an error [16]

5.3. Classification Based on the Structure

Load shedding algorithms are divided into two general categories of static and dynamic load shedding due to the time and amount of load shedding.

5.3.1. Static Load Shedding

In each step of static load shedding, regardless of the rate of decrease or increase of the quantity, some lines of load are removed in a fixed time delay, and this predefined definite amount does not change for different types of faults [17]. For example, a type of load shedding (Undervoltage load shedding) is given in Ref. [16], which is used for a three-phase system. The undervoltage load shedding will be discussed in section 5.4.2 in this chapter. Figure 5.2 illustrates the overall concept of the static load shedding scheme.

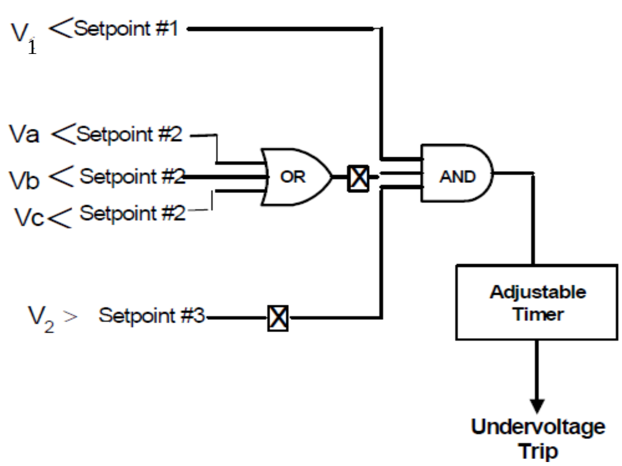


Figure 5.2 Condition of static load shedding [16]

The operation of static load shedding is presented in Figure 5.3. After the load shedding command is issued, the predefined loads are removed from the circuit in order to obtain suitable conditions, for example, lines A to D are removed, respectively, so that the quantity reach it's permissible. This type of load shedding was very common in the past; however, it has many problems such as inappropriate load shedding and creating unwanted blackouts, low accuracy, non-optimal, low reliability, and uneconomical.

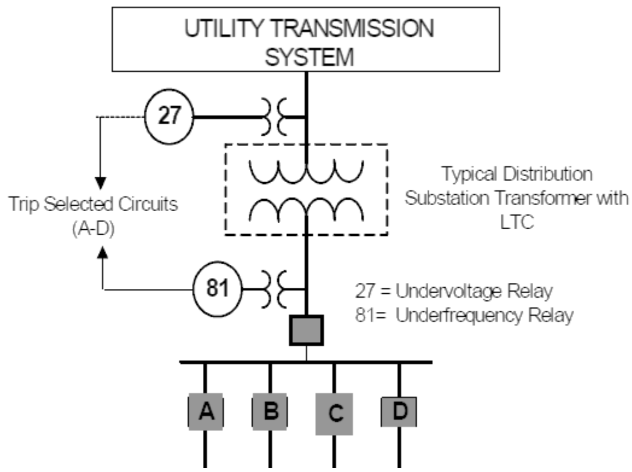


Figure 5.3 Static load shedding in power systems [16]

5.3.2. Dynamic Load Shedding

The static load shedding method causes inappropriate blackouts and is not generally optimal at all. In order to solve these shortcomings, dynamic load shedding methods are presented, which can make various decisions in different situations to decrease the blackout to the minimum amount, and it tries to make the best decision in any circumstances. Dynamic load shedding or adaptive load shedding removes a dynamic amount of load at each step due to different parameters such as the magnitude of disturbance, and the amount of voltage and frequency at each load shedding step. In other words, for a larger disturbance, much amount of load should be shed, and also the load curtailment algorithm should remove the loads faster [17]. Adaptive relaying enables protection systems to make adjustments automatically [1].

5.4. Classification Based on the Techniques

Load shedding techniques are categorized into three main groups, conventional, adaptive, and computational intelligence-based methods. Figure 5.4 shows the differences in load shedding techniques and their subset methods [18].

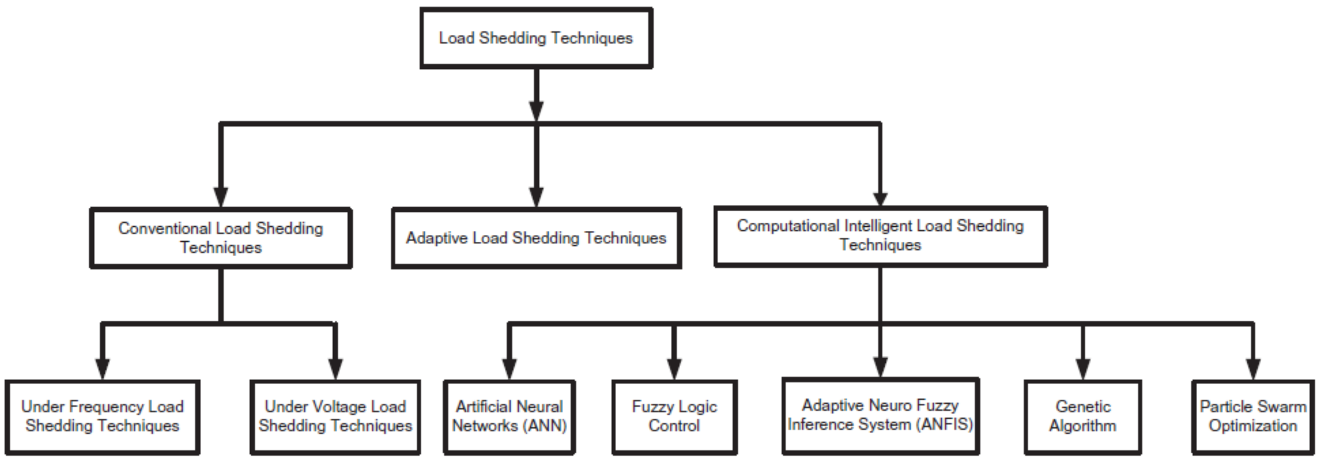


Figure 5.4 Types of load shedding techniques [18]

5.4.1. Conventional Load Shedding Techniques

Load shedding is used to control one or more important quantities in the network. The load shedding techniques maintain quantities such as voltage, frequency, and current within their allowed range; therefore, conventional load shedding methods can be classified in terms of the main quantity under control as follow: undervoltage load shedding, underfrequency load shedding, and under current load shedding.

5.5. Undervoltage Load Shedding

Voltage stability is related to the capability of the power system to maintain desirable voltages on all network buses at normal conditions and after disturbance. Voltage instability is essentially a local phenomenon that first occurs in the substation and then extends to the rest of the system. Therefore, if voltage instability were predictable, its expansion could be prevented by the appropriate corrective actions.

The main source of voltage instability is the inability of the power system to meet the demand for reactive power since reactive power cannot be transmitted long distances. In other words, if the reactive power consumption of the system increases for a load in a system with fixed power capability, the voltage drop will increase, and the system will be unstable. Voltage instability generally occurs due to either loss of a generator or the line, or overloading.

Essentially, in the under-voltage load shedding schemes, the voltage drop in the power system is considered as an indicator for the load shedding, and if voltage decreases more than a predefined amount, the output loads should be removed from the network. The predefined minimum amount for nominal operating voltage is normally defined greater than 0.95 pu, and this may be the first stage in an under-voltage load shedding scheme. It should be noted that in the case of an under-voltage situation and the absence of the voltage protection, the network moves towards the voltage collapse and may cause a general blackout in the network.

5.5.1. Undervoltage Load shedding Methodology

Generally, in the power systems occupied with under-voltage load shedding protection schemes, first, the outlet feeders send their data to the central relay through the data bus constantly, and if the voltage is decreased from the predefined value (0.95 pu), the load shedding will be operated.

5.5.1.1. Conventional Undervoltage Load Shedding Method

Distributed on Control System (DCS) is one of the common methods used for under-voltage load shedding in the power network. In this scheme, a controller is connected to each main transmission line and considered as a local controller. The controllers operate independently and disconnect the related line in emergency situations. Figure 5.5 presents the general structure of this method [19].

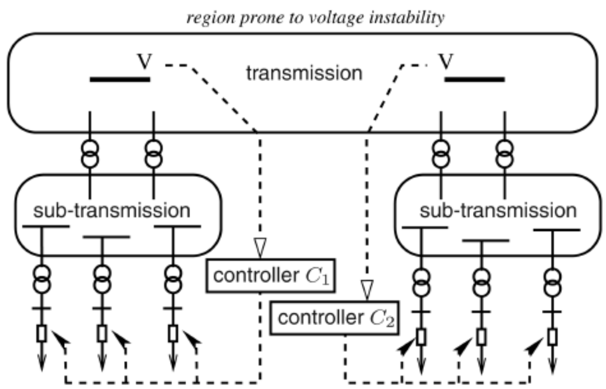


Figure 5.5 General structure of load shedding using DSC [19]

Each local controller follows a simple logic to operate load shedding, that is if the mainline voltage (V) is lesser than the defined value (V_{th}) and the fault is longer than the predefined time (T), the load shedding is operated to take the system to its primary stable and desirable state. The function of the controller is illustrated in Figure 5.6.

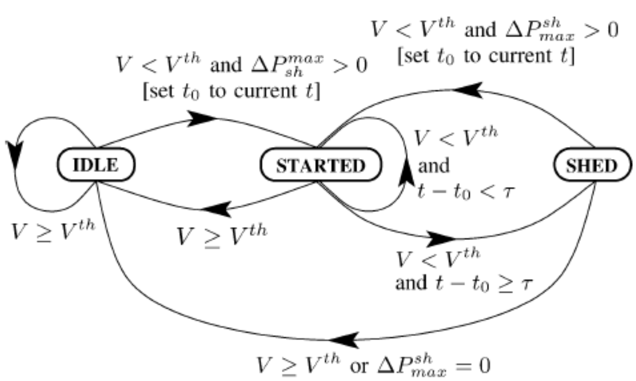


Figure 5.6 General structure of under-voltage load shedding [19]

Table 5.1 shows a regular UVLS scheme which removes a predefined amount of load (15%) at a specific voltage level after a predetermined time [20].

Table 5.1 Illustrative conventional UVLS schemes

Voltage	Load Shed	Time Delay
0.92	5%	8.0 Second
0.92	5%	8.0 Second
0.90	5%	1.5 Second

5.5.1.2. Adaptive UVLS Method

To improve the trigger time of load shedding in these local controllers, the T is computed from the amount of voltage reduction value:

$$\int_{t_0}^{t_0+T} (V^{th}-V(t))dt=C \qquad (5.1)$$

Where C is a constant value [19]. This equation expresses as the amount of voltage drop is more, the faster the load shedding operates. Also, the larger C causes, it takes longer for the integral to reach this constant means slower action.

Generally, to prevent controller react due to the faults which are related to the nearby area, a minimum limitation should be defined for T. This minimum time provides an opportunity to protections clear the fault and the voltage to recover to normal values before load shedding operates.

$$t_{\min} < T \qquad (5.2)$$

The amount of load shedding at each step is calculated from the following equations:

$$\Delta V^{av}=\frac{1}{T}\int_{t_0}^{t_0+T}(V^{th}-V(t))dt=\frac{C}{T} \tag{5.3}$$

$$\Delta P^{sh}=K.\Delta V^{av} \tag{5.4}$$

$$\min P_k < \Delta P^{sh} < \Delta P^{sh}_{max} \tag{5.5}$$

Where ΔV^{av} is the average voltage drop over $[t_0 + T]$ interval, K is another constant to be adjusted, $\Delta P^{sh}$is the value of loads chosen for shedding, P_k is the power of line k and ΔP^{sh}_{max} is the maximum amount load, which can be removed. Equations 5.3 states that the amount of load shedding is related to the voltage drop severity. The equation 5.4 transpose voltage drops into the load shedding amplitude due to constant K [19].

5.5.1.3. Computational intelligence-based UVLS techniques

Artificial neural networks (ANN) and Fuzzy logic control (FLC) are the most common intelligence-based techniques used for UVLS. In reference [21], a fuzzy technique as a fuzzy controller is used for under voltage load shedding to control voltage instability. The authors in reference [22], attempts are made for stabilizing voltage. In this way, an optimization problem in order to optimal under voltage load shedding is solved using a genetic algorithm.

5.5.2. Undervoltage Load Shedding Schemes Consideration

To design the UVLS schemes, the following criteria should be considered [23]:

- Load shedding schemes should operate in coordination with other protective devices and control schemes.
- The delay before load shedding operation should be set in second, not in cycle. The common time delay is in the range between 3 to 10 seconds.
- Redundancy and enough intelligence should be used to provide reliable under voltage load shedding.

- In the case of under voltage, enough load should be removed from the network to ensure that the voltage levels return to minimum operating voltage levels or higher.

5.5.3. Illustration Using an Example

Figure 5.7 shows an IEEE 9-bus power system used to illustrate the effect of using UVLS techniques. The pre-fault system voltage profile is shown in Figure 5.8. In this section, two UVLS schemes, static and dynamic, are applied to the test system in different case studies. The fault is created by removing the Generator 12 at t=1.0 second. Figure 5.9 shows the voltage changes of busses 5, 6, and 8 after the fault is applied to the test system.

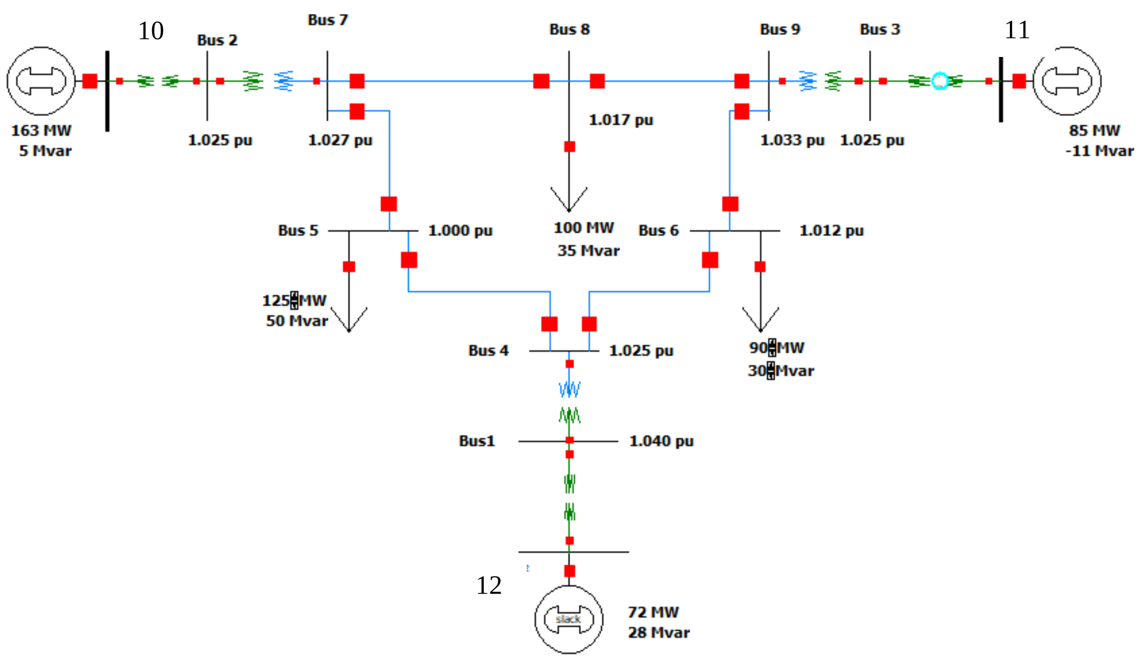


Figure 5.7 Standard IEEE 9-bus oneline diagram

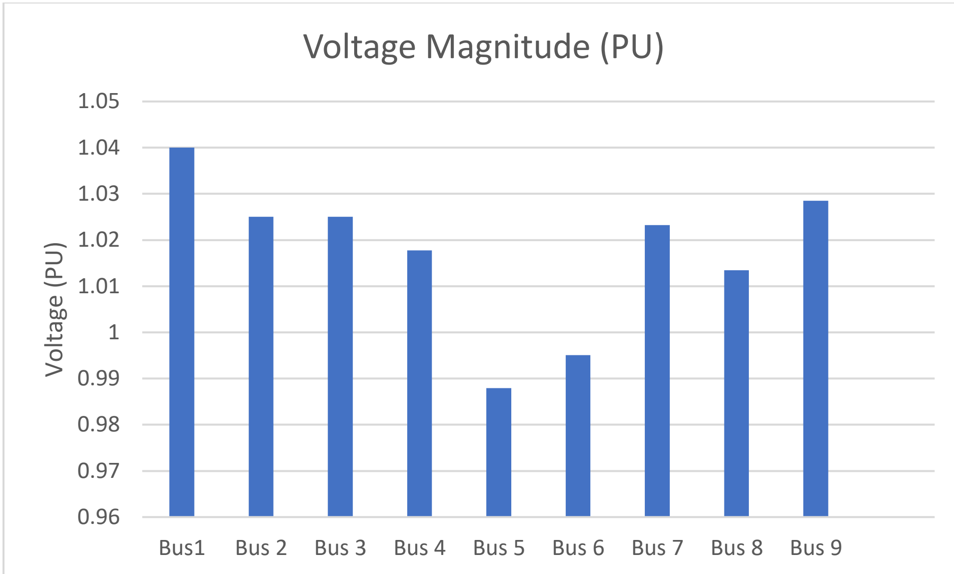


Figure 5.8 pre-fault system voltage profile

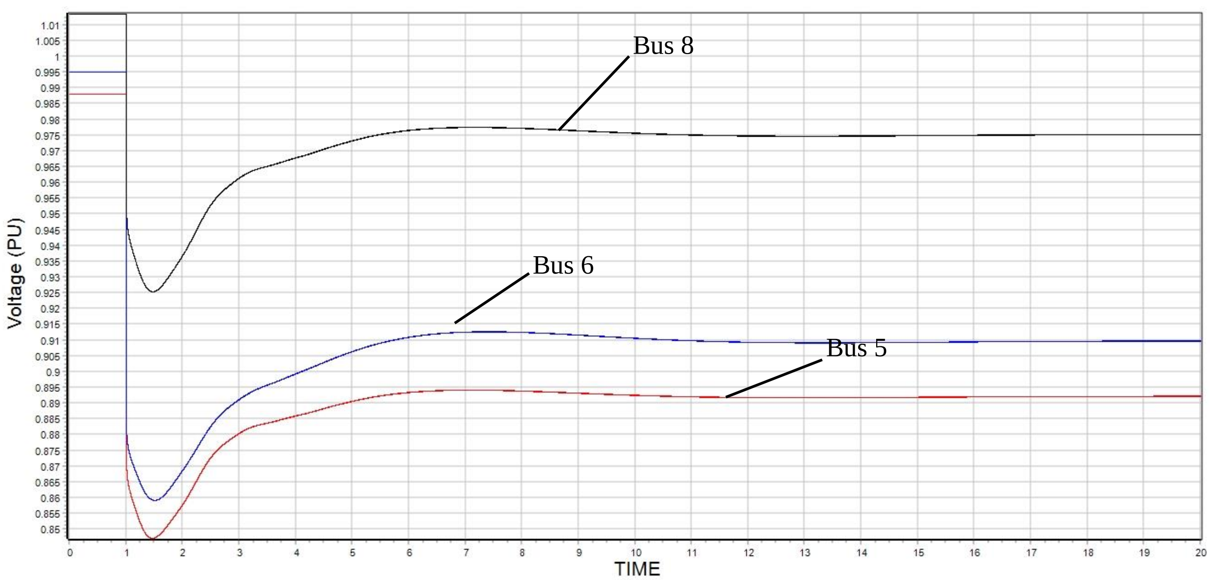


Figure 5.9 Voltage profile after the loss of Generator 12

As Figure 5.9 is shown, bus 5 has the lowest voltage level and is chosen to apply UVLS schemes in two case studies. For each case, load shedding is triggered if the voltage at any bus is lower than 0.9 PU.

5.5.3.1. Case Study 1, Static Under Voltage Load Shedding

In the first scenario, a static UVLS relay operation is simulated for bus 5. The relay removed 5% of the load, which is connected to bus 5, after 3.5 seconds. The relay operated again after 8.5 seconds and removed another 5% of the load as the voltage level of bus five is lower than the threshold. Figure 5.10 shows the voltage responses regards to the performance of the UVLS relay.

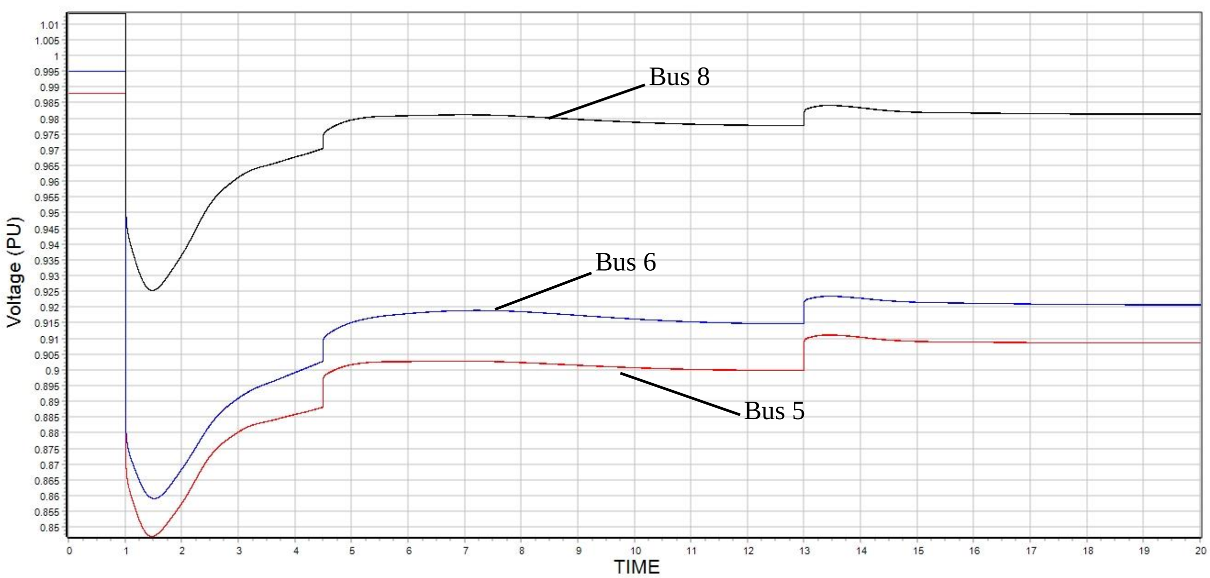


Figure 5.10 Voltage profile with static load shedding

5.5.3.2. Case Study 2, Dynamic Under Voltage Load Shedding

In this case, an adaptive under voltage load shedding relay based on [19] is modeled at bus 5. Table 5.2 shows the adaptive UVLS relay setting. According to Equations 5.1, 5.2, and 5.4, the relay should remove 40.75 MW at t=10s. Figure 5.11 shows the voltage responses regards to the operation of the adaptive UVLS relay at bus 5.

Table 5.2 Adaptive UVLS relay setting

V^{th}	C	K	t_{min}
0.9 PU	0.2 PU.S	1000 MW/PU	3 S

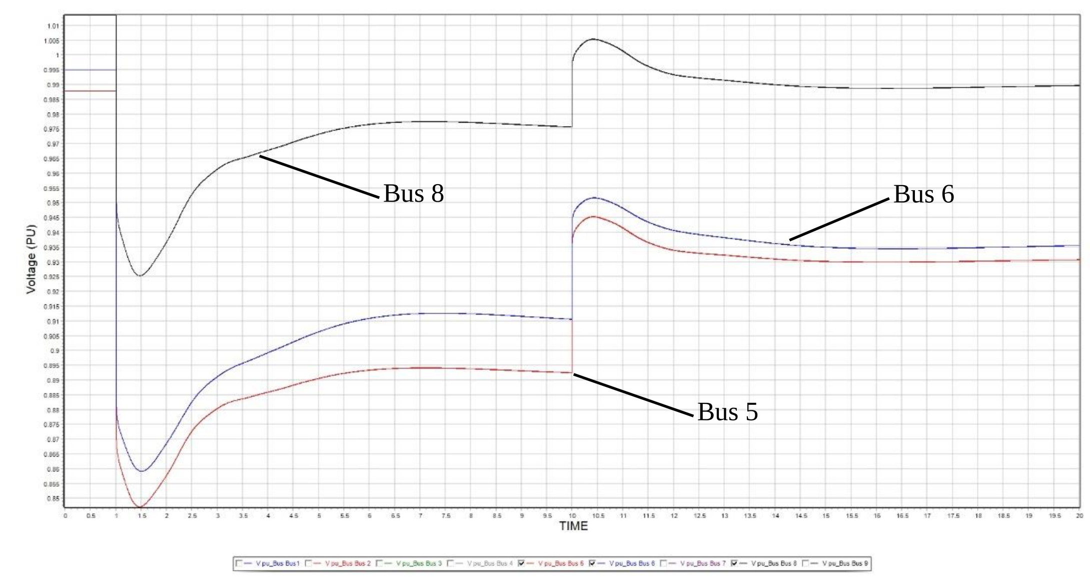


Figure 5.11 Voltage profile with adaptive load shedding

5.6. Underfrequency Load Shedding (UFLS)

A large amount of loading due to loss of a generator or disconnection of a large transmission line in the power system will cause relatively large-scale frequency variations due to the fact that the frequency variation is directly related to the active power exchange of the network. In this case, before the governor and the turbines operate and change the output value, the frequency reaches critical values quickly because the full-fledged operation of the governor and turbine response will take at least a few seconds. Therefore, in such cases, the only suitable solution to prevent the system from exiting the system is load shedding [24].

5.6.1. The time and amount of the frequency load shedding

The time and amount of the frequency load shedding differ according to the method used for load shedding and the system conditions. The amount of load chosen for load shedding can be predefined and prioritized or calculated according to the existing conditions. Also, the number of steps can be predefined or determined depending on the frequency range and its variations.

After each step of load shedding, a delay is applied to determine the effect of the previous load shedding on the frequency value. This time is fixed in some methods, and in some other cases, it will be determined due to the conditions.

5.6.2. The Effect of number of steps and Time Delay on Conventional UFLS Method

In this section, an SFR model is used to investigate the effect of the number of steps and time delay on the conventional UFLS method. The system diagram of the SFR model is shown in Figure 5.12. Table 5.3 shows the value of the parameter for the SFR model. In case 1, the load shedding scheme removes a predefined load in 4 and 6 steps, respectively, with a constant 0.1-second delay between each step. The result is shown in Figure 5.13. As a result, the number of steps in underfrequency load shedding has a very small effect on the output frequency after load shedding.

Table 5.3 SFR model specifications

P_d	R	H	T_R	F_H	K_m	H	D
-0.1(pu)	0.08(pu)	4(pu)	4(pu)	0.3(pu)	0.95(pu)	4.0(pu)	1.0(pu)

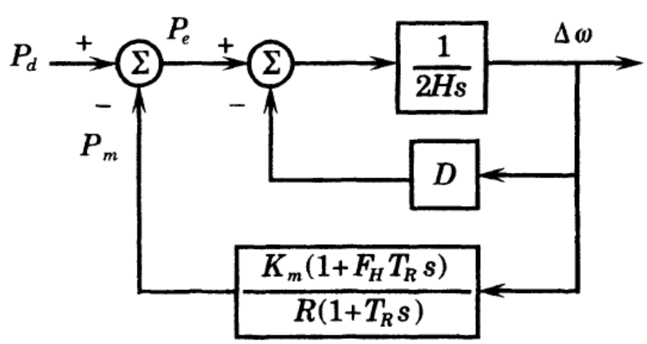


Figure 5.12 Simplified SFR Model

In case 2, the load shedding scheme removes a predefined load in 4 steps with a constant 0.1 and a 0.2-second delay between each step. The result is shown in Figure 5.14. As a result, the amount of time delay in underfrequency load shedding affects the maximum deviation value of frequency, and it can be concluded that at the greater time delay, the maximum deviation value increases.

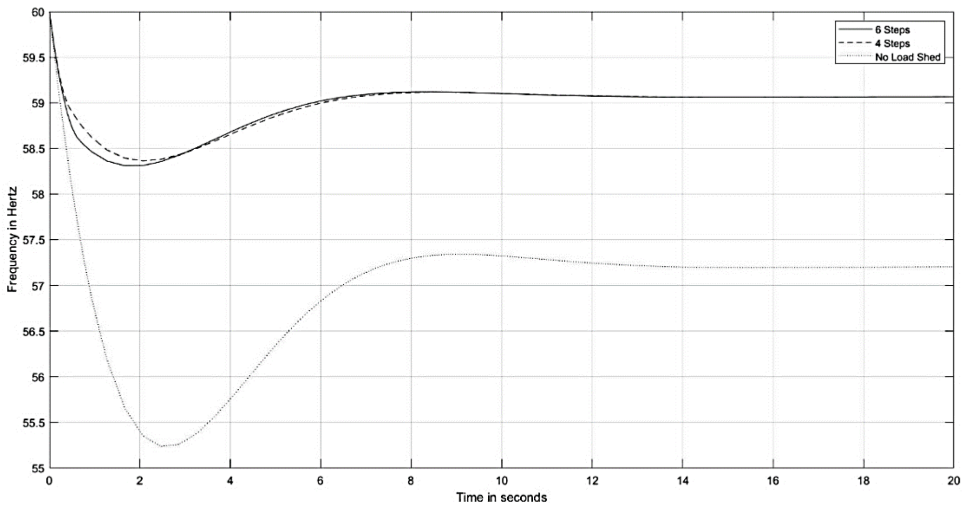


Figure 5.13 The effect of the number of steps on UFLS

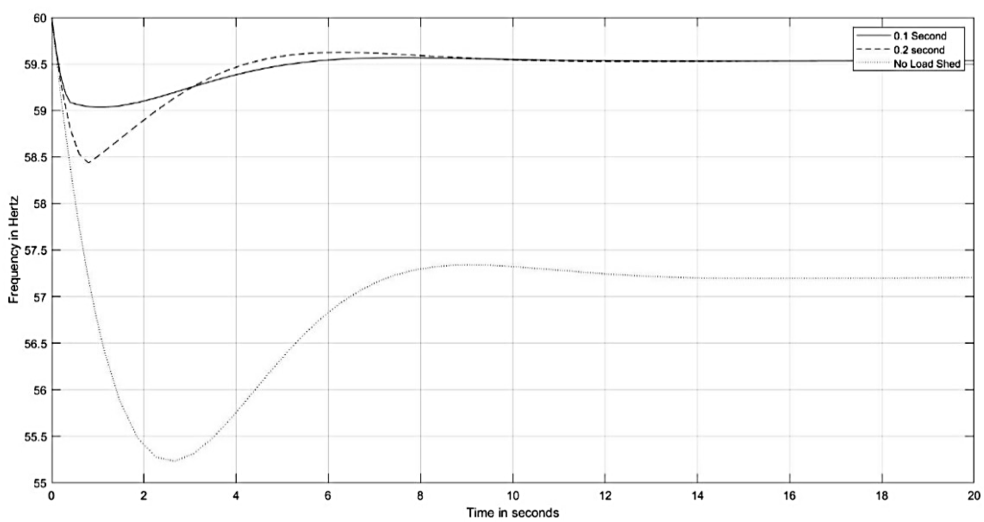


Figure 5.14 The effect of the Time Delay on UFLS

As shown in Figure 5.12, the number of steps does not have a pronounced effect on systems frequency behavior, but it may be asked why loads are removed in different stages in conventional load shedding methods. The answer is that as discussed before, although load shedding is one of the most reliable protection schemes, it creates dissatisfaction in customers. The protective system must shed the loads as less as possible due to different conditions. So, optimal load shedding is an important issue to be addressed.

5.6.3. Traditional Underfrequency Load Shedding

One of the simplest methods of load shedding is real-time checking the frequency and compare its value with a reference value, and, in the case of any difference between them, the load shedding procedure is started. Figure 5.15 illustrates this method [25][26].

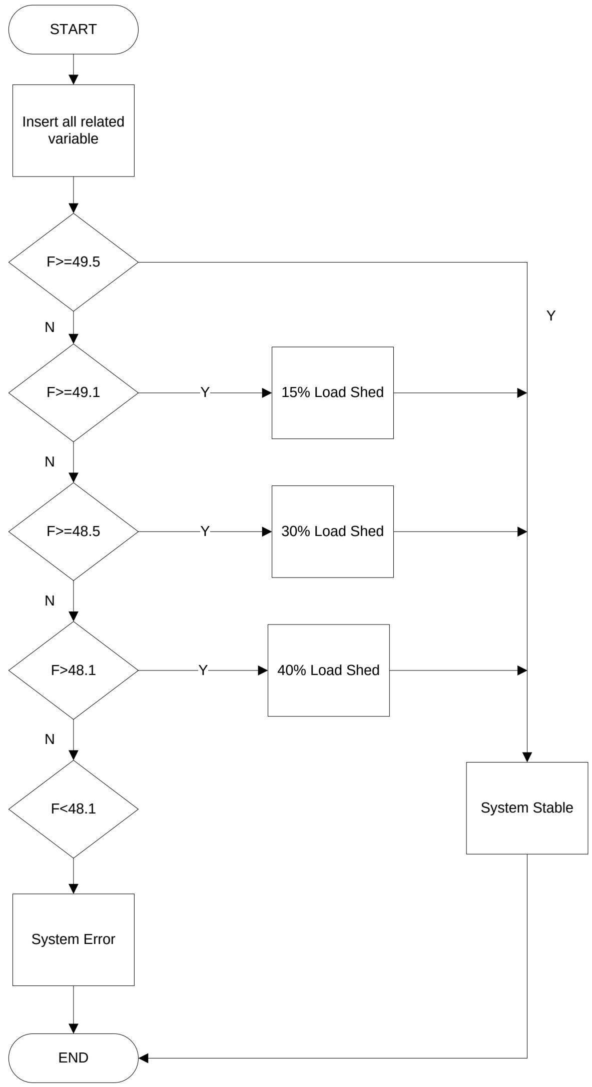


Figure 5.15 The process of underfrequency load shedding [27]

5.6.4. Adaptive Underfrequency Load Shedding

The method shown in Figure 5.9 disconnected the predefined load from the grid regardless of the frequency change rate and the amount of power shortage. To come up with this problem, the rate of frequency variations is used, but because frequency changes are too fast and severe, the integer is used (h_i). The time of load shedding determined based on this integer, and after this time is over, the predefined load is removed from the network[28][29].

$$h_i=\frac{1}{T}\int_{t_0}^{t+T}\left(f^{th}-f(t)\right)dt \tag{5.6}$$

To improve this method, the amount of chosen load is computed as below [27]:

$$LD=\frac{\frac{L}{1+L}-d(1-\frac{f}{f_0})}{1-d\left(1-\frac{f}{f_0}\right)} \tag{5.7}$$

Where *LD* is a total load which must be disconnected from the network, *f* is minimum allowed frequency value, f_0 is the nominal frequency, and L is the amount of overload in p.u. The constant d is defined by the type of disturbance considered between 0 and 6. The lower the value of d, the higher the amount of load shedding. To achieve a better result, other parameters are used, such as frequency changes, power, and voltage [30]. The frequency changes are directly related to power variations, obtained from the equations of synchronous machines:

$$\frac{2H_i}{f_n}\frac{df_i}{dt}=\Delta p_i \tag{5.8}$$

Where, f_n is the nominal frequency of the system, H_i is the inertia constant, f_i is the frequency in Hz and ΔP_i is the load generation imbalance in p.u.

In Ref. [30], the basic principle of load shedding is the value of frequency and voltage, and the amount of load to be removed from the system is obtained from the following equation:

$$S_i=\frac{\left(dV_i/dQ_i\right)}{\sum_{i=1}^{N} dV_i/dQ_i} \tag{5.9}$$

5.6.5. Underfrequency Load Shedding Consideration

In designing underfrequency load shedding schemes, some criteria should be considered. In the actual power systems, detecting the fault should be very fast. Also, the amount of load which should be removed in the underfrequency situation and the time of load shedding plays a critical role in underfrequency load shedding. Having studied the recorded data from an actual system, it would conclude that shedding too much load is better than shedding not enough. But shedding too much load also may result in inconvenience to customers. So, an index is needed, which is related to the magnitude of disturbance and can be used to define the amount of load that must be shaded from the power system. In this case, the initial slop of frequency decline can be used to determine the amount of disturbance computed by Equation 5.10.

$$m_0 = \frac{d\Delta\omega}{dt} \xrightarrow{t=0} = \frac{60P_{step}}{2H} \text{ Hz/S} \qquad (5.10)$$

5.6.6. Conventional Underfrequency Load Shedding Relays simulation

In the case of the underfrequency situation, power plants face failure, and without a quick reaction of the governor to restore the normal operating frequency, the protective frequency relays trip the generation units. The aim of under-over frequency load shedding relays is to prevent the tripping of generator units.

In the following simulation, there is an unbalance between the amount of load and generated power. The simulated relay compares the value of the system’s frequency with an allowed range-- which is predefined by the user, and in the case of detecting an under or overfrequency, the relay starts counting to make a delay before tripping. Actually, this delay used as a time integral of the duration of the error in the system. Whenever the output of time integration reaches the maximum value of the delay time, the relay trips the load. Figures 5.16 and 5.17 show the system diagram, and Figure 5.18 shows the frequency response of the system, respectively. As shown in Figure 5.18, the underfrequency relay trips the load at Bus B at 0.8 seconds, and there is a 0.6-second delay consider as an integral time.

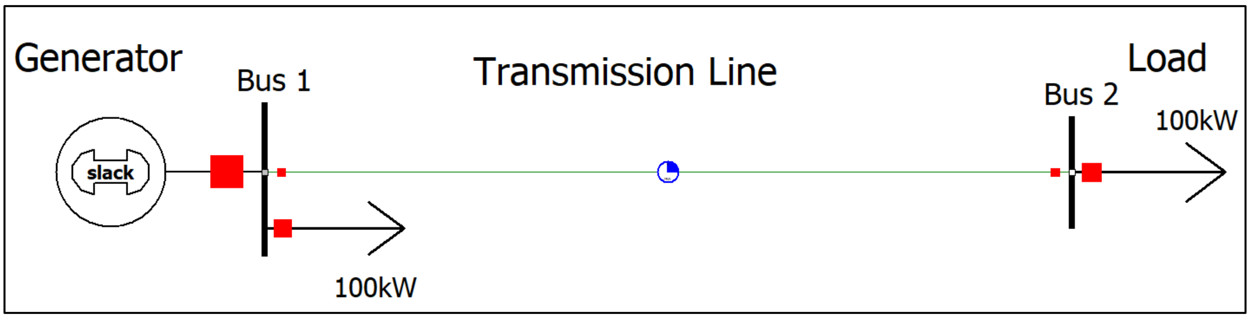


Figure 5.16 Oneline diagram of a two-bus power system

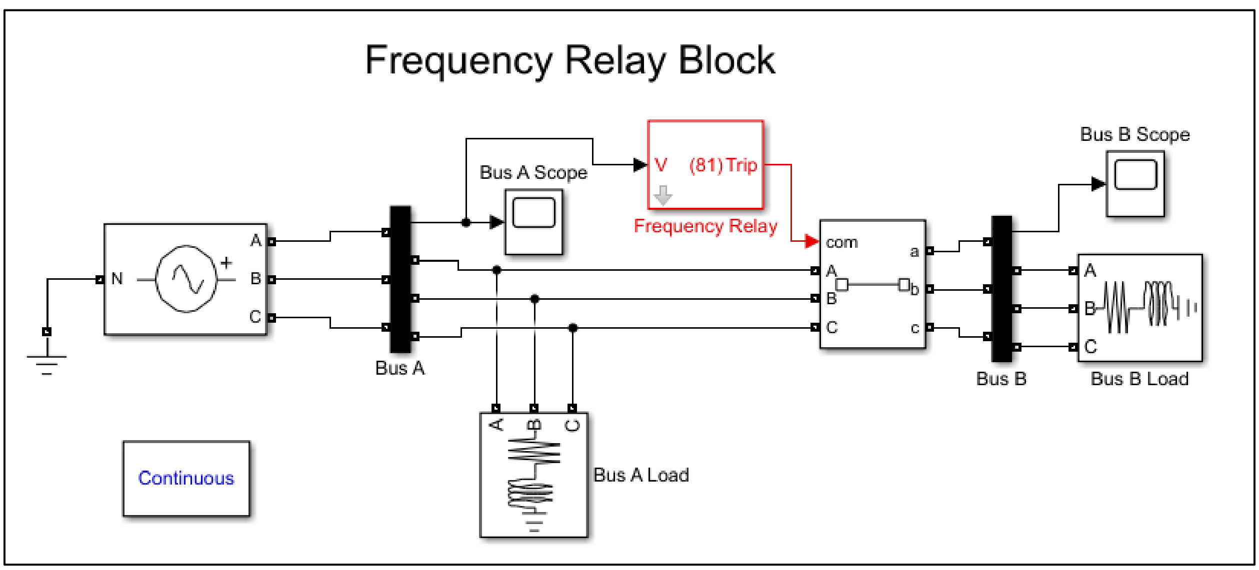


Figure 5.17 Simulated system block diagram

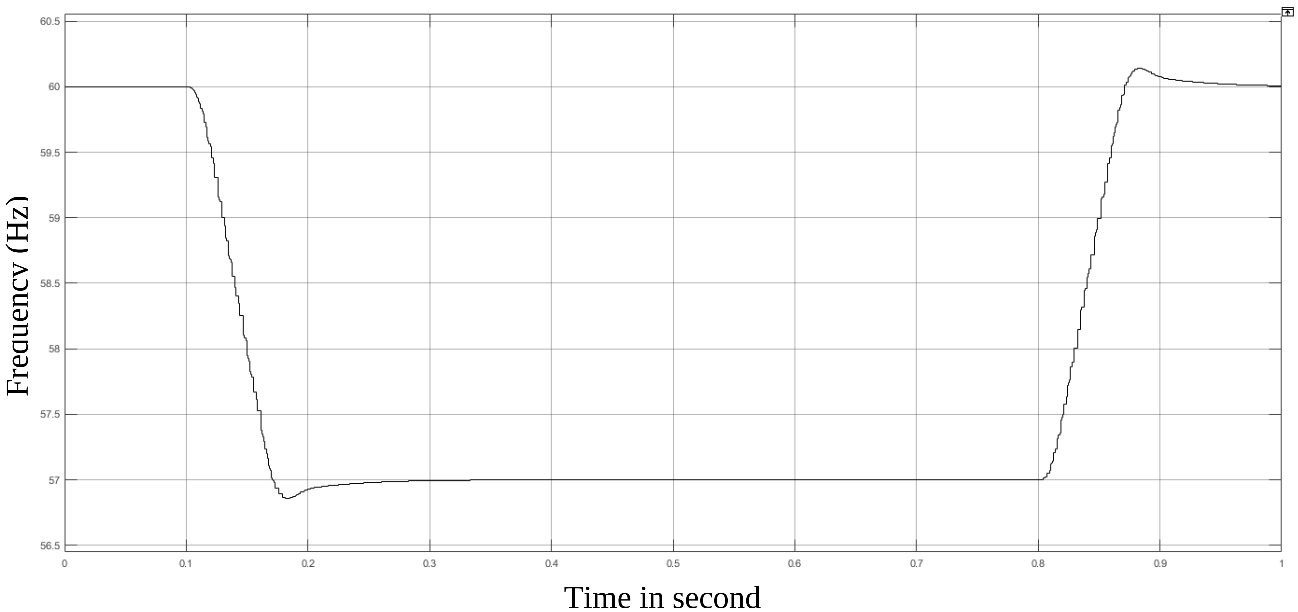


Figure 5.18. The frequency response of the power system

5.7. Conclusion

In this chapter, the concept of load curtailment (load shedding) is studied. Load shedding methods are classified based on some criteria, including the operation time, the structure of the methods consist of static and dynamic load shedding, and the techniques used in load curtailment. In addition, the different techniques used for conventional load shedding (undervoltage, underfrequency, and under current load shedding) is illustrated. Also, two under voltage load shedding relays using conventional method and adaptive techniques are modeled and simulated in Powerworld. Furthermore, the effect of the number of steps and time delay on UFLS is illustrated. From all the analyses and simulations, it is concluded that the number of steps in underfrequency load shedding has a very small effect on the output frequency after load shedding, while the amount of time delay in underfrequency load shedding affects the maximum deviation value of frequency and it can be concluded that at the greater time delay, the maximum deviation value increases. Finally, a conventional UFLS relay is proposed and simulated.

Chapter 6

Determining Significant Factors Affecting Power System Stability

6.1. Introduction

The concept of power system stability is defined as “The ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact” [31]. According to that quotation, an imbalanced system is considered an unstable system. Voltage and frequency are two of the main reasons for any instabilities in power systems. Depending on the type of instabilities, the proper stabilization schemes should be used. To prevent instability, compensation methods can be used, such as shunt compensation and series compensation. Shunt compensation methods, including a thyristor-switched capacitor, thyristor-controlled reactor, static var compensator, and static synchronous compensator, are used to regulate the voltage at busses while series compensation techniques are used to modify the line reactance. Fixed series capacitor, thyristor-protected series capacitor, static synchronous series compensator, unified power flow controller, interline power flow controller, and interphase power controller are the methods that can be used as series compensators [32].

6.2. Classification of Power System Stability

Modern power systems consist of several devices with different characteristics and responses, which can affect their dynamic response. In a power system, stability is defined as the equilibrium between opposing forces, but due to different network structures, system operating situations, and types of disturbances, different forms of instability can cause a condition of sustained imbalance. The classification shown in Figure 6.1 is based on the physical mechanism being the main driving force in the development of the associated instability, which includes the physical nature, the size of the disturbance and the devices, the processes, and the time span consideration.

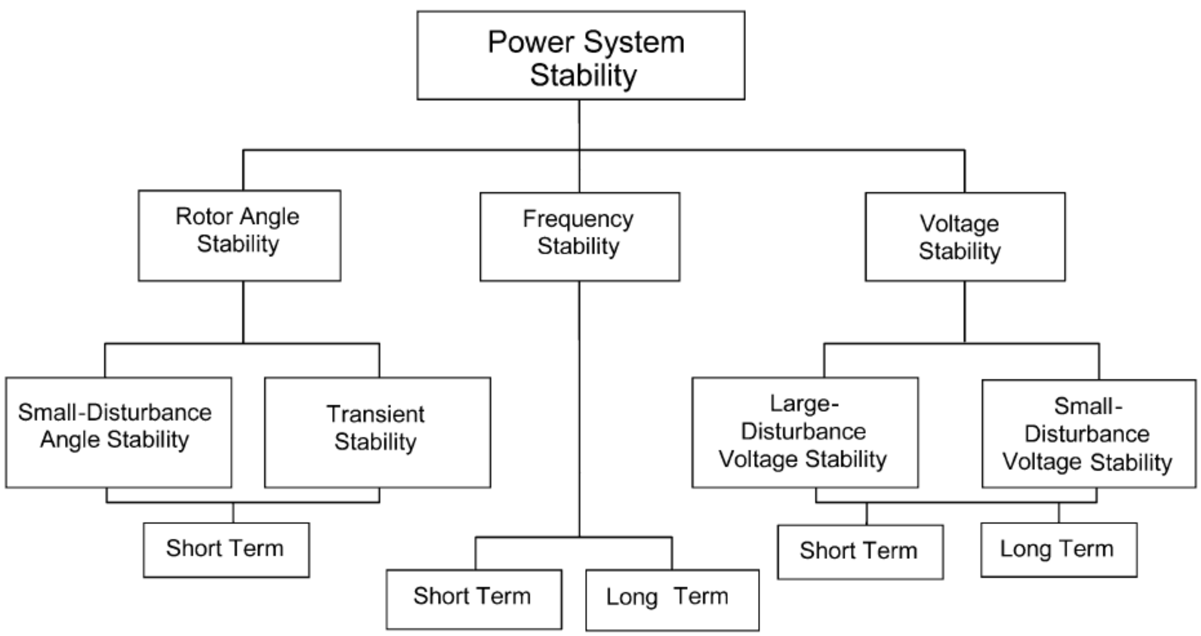


Figure 6.1 The classification of power system stability [31]

6.3. Rotor Angle Stability

In Ref. [31], rotor angle stability is defined as "The ability of synchronous machines of an interconnected power system to remain in synchronism after being subjected to a disturbance."

Rotor angle stability is associated with the capacity of each generator to maintains or restores the equilibrium between the electromechanical torque and the mechanical torque.

The definition of rotor angle instability is the loss of synchronism of a generator with the other generators due to increasing angular swings. In a normal situation, the amount of mechanical torque as an input and the amount of electromagnetic torque as an output of each generator is the same, and there is no change in the speed of the generators. Any disturbance in the system causes the rotor of the machines to accelerate or decelerate. Following an angular speed difference, part of the load is transferred from the slower machines to the faster ones. The rotor angle instability increases in angular separation results and decreases power transfers. In this case, if the system cannot absorb the kinetic energy based on these rotor speed differences, it will be unstable. The two components which can resolve the change in electromagnetic torque of a synchronous machine are: synchronizing torque component, in phase with rotor angle deviation, and damping torque component, in phase with the speed deviation.

Rotor angle stability has two stability issues:

- Small signal stability
- Transient stability

6.3.1. Small signal stability

As the authors in Ref. [31] stated, “Small-disturbance (or small-signal) rotor angle stability is concerned with the ability of the power system to maintain synchronism under small disturbances.” When using a linear model of the system for studying stability issues, the disturbance is considered very small. A small disturbance might be the result of a change in loads, a change in set-point voltage of the voltage regulator, weakly coupled static var compensator (SVC), or high voltage DC converters (HVDC).

6.3.2. Large-disturbance rotor angle stability (Transient stability)

In Ref. [31], transient stability is defined as "It is the ability of power system to maintain synchronism within the machines after high transient disturbance such as short circuit on transmission line." The initial operating state of the system and the severity of the contingency occurred in the system are major causes of rotor angle large deviation[33].

Due to the type of study, the time interval to analyze transient stability varies. Usually, 3-5 seconds after the contingency event is studied to understand the basic transient nature of the system. To comprehend the behavior of the system elements, including automatic voltage regulators and turbine governors, the study time can extend up to 30 seconds.

6.4. Transient Stability

As mentioned in the previous section, transient stability is considered the ability of the power system to reside in a balanced state when facing severe disturbances such as faults on transmission elements, loss of loads, loss of generators, or loss of system components such as transformers or transmission lines.

To examine transient stability, studying the plot of the generator rotor angle (δ) versus time (swing curve) can be useful. Usually, the system will be stable if the first and second swing curve both oscillate around a new equilibrium point. Figure 6.2 shows the swing curves for a generator facing a disturbance. In trace (a), it presents how the rotor angle recovers after a generator is subjected to a particular fault and becomes transiently stable, while in trace (b), the angle increases aperiodically and deems the trace transiently unstable.

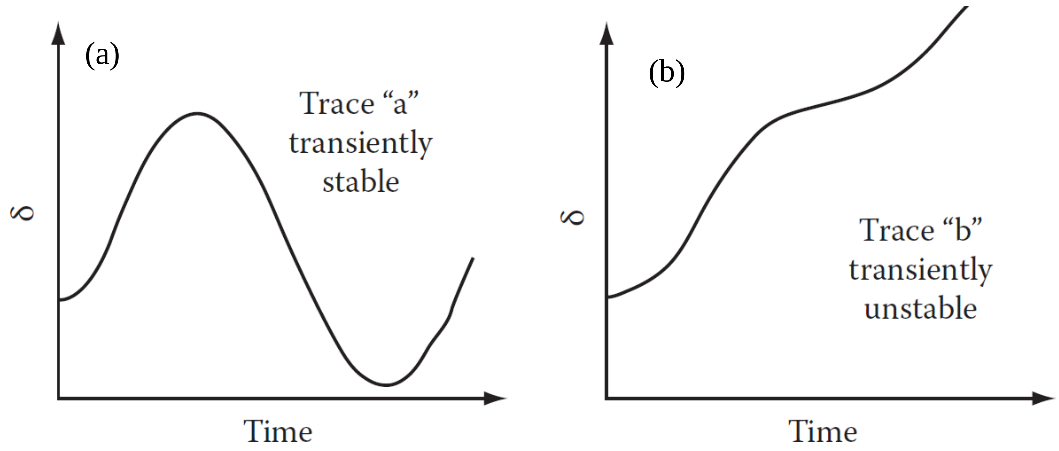


Figure 6.2 Trajectory of generator rotor angle through time [34]

6.4.1. Concept of Transient Stability

Studying the power angle relationship and the swing equation is essential to understand the concept of transient stability.

A single machine infinite bus system (SMIB) with two transmission lines, as shown in Figure 6.3, illustrates the power angle relationship.

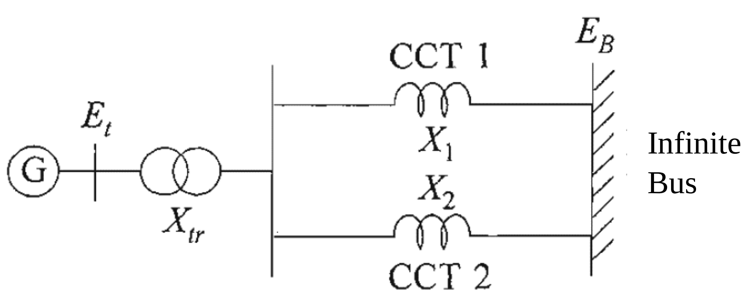


Figure 6.3 SMIB system with two transmission lines [33]

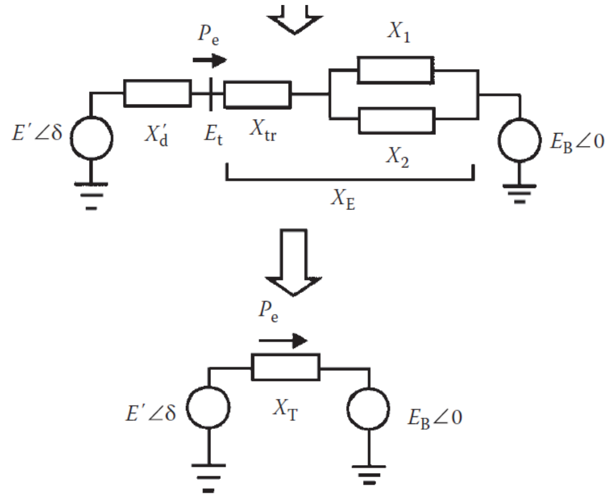


Figure 6.4 Reduced equivalent circuit of SMIB system [34]

To reduce the order of the equivalent circuits, the stator resistance can be neglected. Equation 6.1 shows the relationship between the electrical power of the generator (P_e) and the rotor angle of the machine (δ).

$$P_e = \frac{E'}{X_T}\sin\delta = p_{max}\sin\delta \qquad (6.1)$$

Where δ is the angle between transient voltages E' and E_B and

$$p_{max} = \frac{E' E_B}{X_T} \qquad (6.2)$$

Equation 6.2 is plotted for normal and out of service situation, as shown in Figure 6.5. By increasing Thevenin Impedance between the generator and infinite bus (X_T), the power output decreases due to loss of transmission line [33].

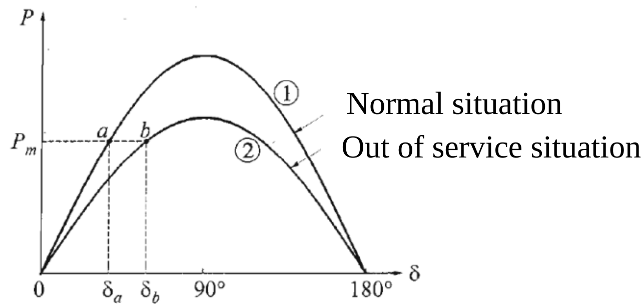
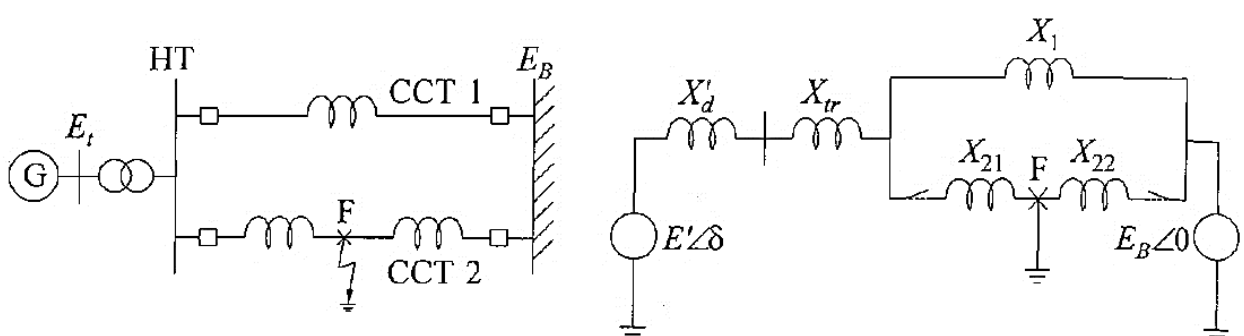


Figure 6.5 Power angle relation plot for SMIB system [33]

Figure 6.5 shows the power angle curve, which is used to evaluate the transient stability of SMIB. The method which examines the transient stability based on the power angle curve is called the Equal area criterion. The Equal area criterion is a direct method used to determine stability without solving the swing equation and is applicable for SMIB or two machines [5].

In the Equal area criterion method, a graphical interpretation of energy stored in a machine is used to determine the stability of the machine after facing a disturbance.

Figure 6.6 shows that the SMIB was initially operating in the steady-state condition when a permanent three-phase-to-ground bolted short circuit (F) occurs in the second transition line.



(a) Single line diagram (b) Equivalent Circuit

Figure 6.6 Bolted 3 phase fault in SMIB system [33]

Figure 6.7 shows the power angle curve for pre-fault, during the fault, and post-fault condition. The pre-fault condition illustrates the initial state of SMIB. The operating point moves from the pre-fault state (a) to an operating point on the during fault curve (b) after the SMIB is subjected to the fault. In this situation, the machine accelerates because the output power is smaller than the input power. The operating point moves on the persisting-fault condition curve and reaches the operating point (c) when the fault is cleared, followed by an increase in load angle. During this period, the kinetic energy is gained by the synchronous machine. Then, the operating point jumps to point (d) on the post-fault power-angle curve and continues to operation point (e) because of its inertia and jumps back to the operating point (d), which means the kinetic energy is giving back to the system. So, to have a stable condition, the area A_1, which represents energy gained, should be equal to area $A_{2,}$ which represents energy loss. If the fault clearing action is not fast enough, area A_2 cannot be equal to area $A_{1,}$ and the machine will go out of synchronism.

The maximum fault clearing time that allows the system to recover and continues to be stable is called critical clearing time, and the corresponding load angle is called the critical clearing angle.

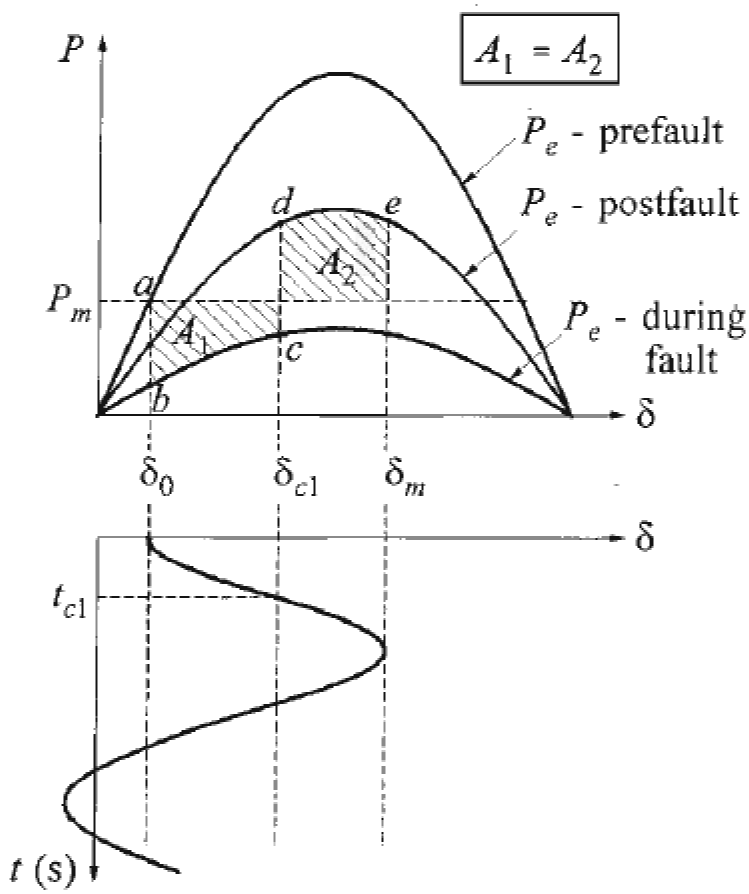


Figure 6.7 Power angle relation plot of SMIB (Stable) [33]

Figure 6.7 represents a stable condition where the rotor angle oscillates and moves to a steady-state, while Figure 6.8 represents an unstable condition where the rotor angle continues increasing.

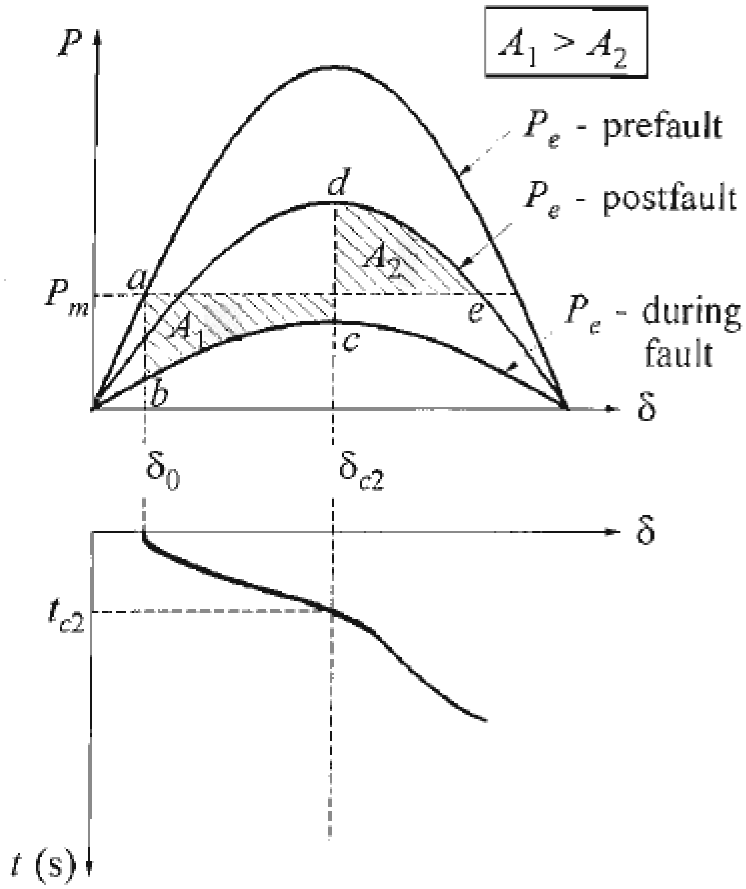


Figure 6.8 Power angle relation plot of SMIB (Unstable)[33]

To calculate the energy stored or lost in area A_1 and A_2, which determines the stability of the system using equal area criterion, the swing equation should be used. The swing equation is used to identify the dynamic behavior of a generator subjected to a network disturbance. The swing equation is derived based on Newton's second law, in regards to the power system quantities [2]. In terms of the concept of a power system, the swing equation is defined as "The electromechanical equation which relates the rotor angle to the stator rotating magnetic field as a function of time" [33]. Equation 6.3 illustrates the swing equation.

$$\frac{2H}{\omega_0}\frac{d^2}{dt^2}=P_m-P_{max}\sin\delta \qquad (6.3)$$

Where,

P_m = Generator mechanical power input, in pu

P_{max} = maximum generator power output, in pu

H = inertia constant, in MW. s/MVA

δ = rotor angle, in electrical radians

To determine the stability of a system, the swing equation should be solved and results in the load angle variation over time. To solve the swing equation, numerical integration methods should be used because the swing equation is a nonlinear algebraic equation. Point by point method is used to solve the swing equation by calculating the rotor angle deviation change through a small-time step.

6.4.2. Illustration Using an Example

In this section, the swing equation for a SMIB problem is solved by using the point by point method in MATLAB for 0.5 seconds while the fault cleared at 0.1 seconds. The SMIB system, which is shown in Figure 6.3, a 50 MVA Generator supplying 50 MW with inertia constant 'H' = 2.7 MJ/MVA at rated Speed with Et = 1.05 pu, Eb= 1 pu, and X1 = X2 = 0.4 pu at generator MVA.

In Figure 6.9, the pre-fault, persisting fault, and post-fault power curves are shown, and the swing curve plots for the unstable and stable cases are shown in Figures 6.10 and 6.11, respectively.

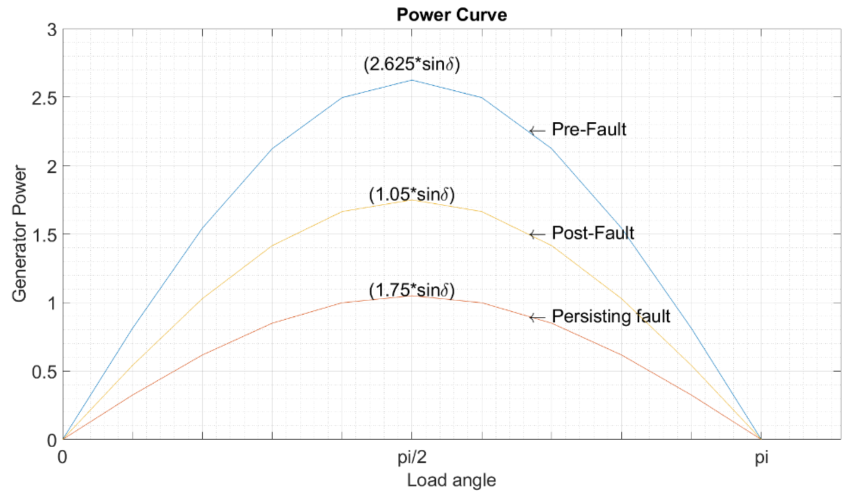


Figure 6.9 Power angle relation plot of the SMIB system example

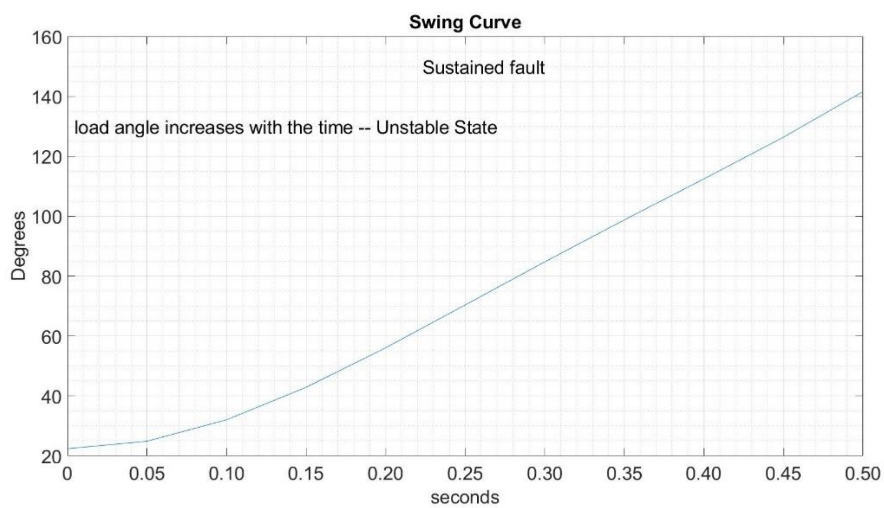


Figure 6.10 The plot of the Swing equation for a sustained fault (Unstable)

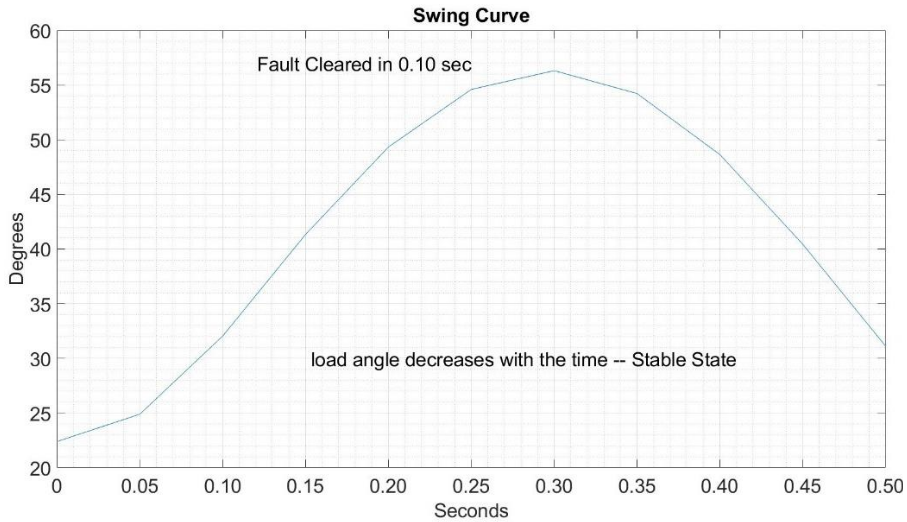


Figure 6.11 The plot of the swing equation for the fault cleared at 0.1 seconds (Stable)

The equal-area criterion can be used only for one machine and an infinite bus or two machines because of its complexity. Instead, numerical integration techniques are applicable for multimachine stability problems by solving the swing equations for each machine. In this way, many numerical integration techniques can be employed, such as Euler's method, Runge-Kutta, Picard's method, and Milne's predictor-corrector method [5].

6.4.3. Significant Factors Affecting Transient Stability

The behavior of the power system elements is very important because those devices affect the power flows throughout the system consist of the actions of the generator excitation systems, speed governors, Static Var Compensators (SVCs), and HVDC converters when subjected to a disturbance. To study the power system transient behavior, computer stability programs are used to solve the differential equations of the entire system. The system's transient behavior, when confronted by a large disturbance, is significantly affected by the amount of power transfer in the faulty line, the circuit breaker speed, and reclosing operation. To illustrate the effect of those factors, a standard IEEE 9-bus system is used. Figure 6.12 shows the oneline diagram of the system.

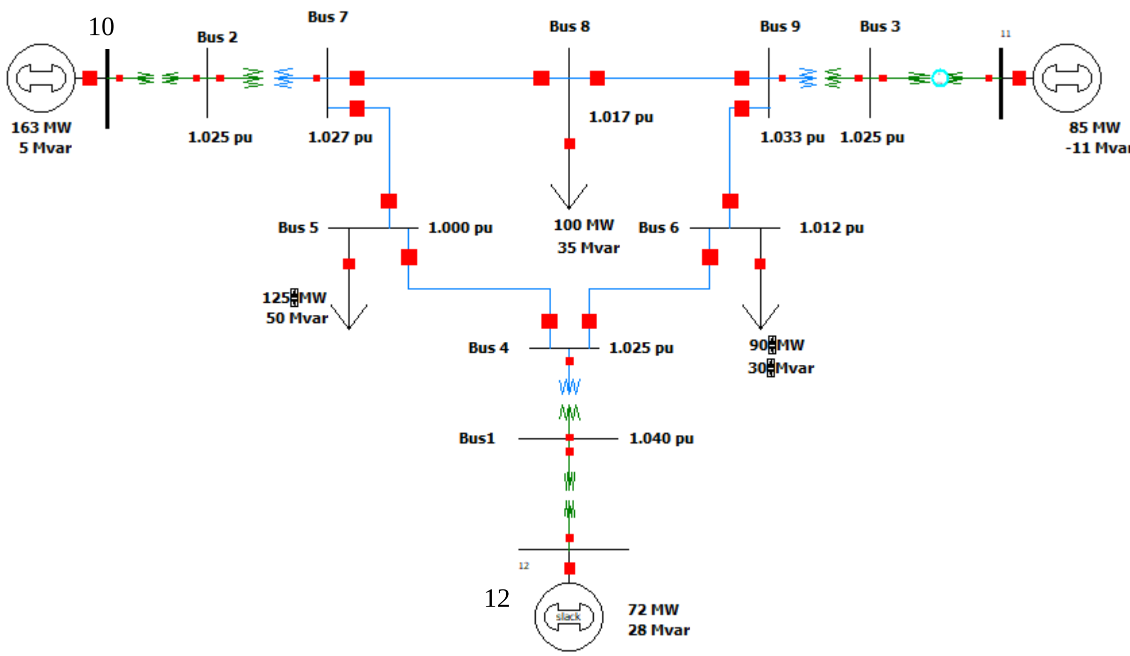


Figure 6.12 Standard IEEE 9-bus oneline diagram

6.4.4. Effect of Power Transfer

To illustrate the effect of power transfer's amount on the transient behavior of the system, different amounts of load are applied to Bus 5. The dynamic performance of the system is presented in Figures 6.13 to 6.15 for generators #10, #11, and #12, respectively. In this way, a 3phse solid fault is applied to the line between bus #5 and #7 at t=1s, and the line will be open in the next four cycles (t=1.08s). The applied fault causes an acceleration of the shafts of all generators. As shown in the figures, by increasing the pre-fault transfer level, the angular separation and its rate of change increases as well. Also, it is obvious that the power transfer capability of the system has a limitation that can be determined by stability. In this case, the 375 MW level of load overrode the limit and made the system unstable [2].

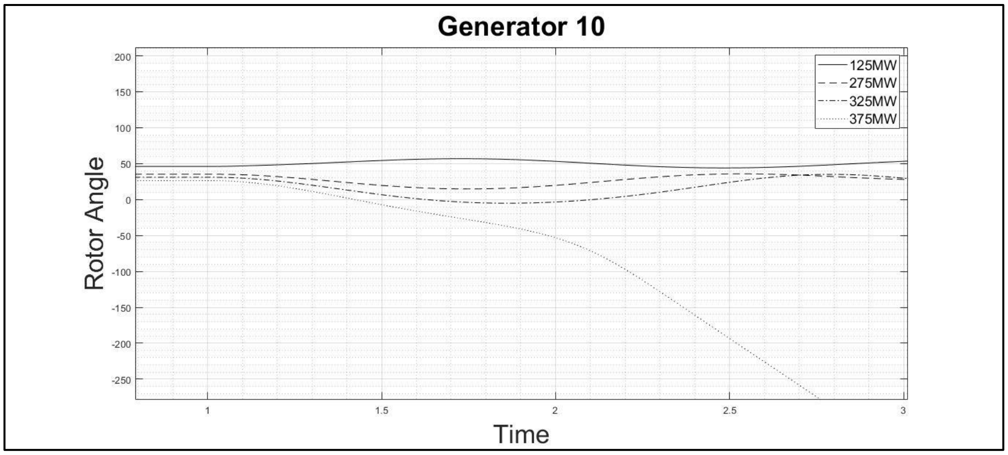


Figure 6.13 Rotor angle of the generator 10

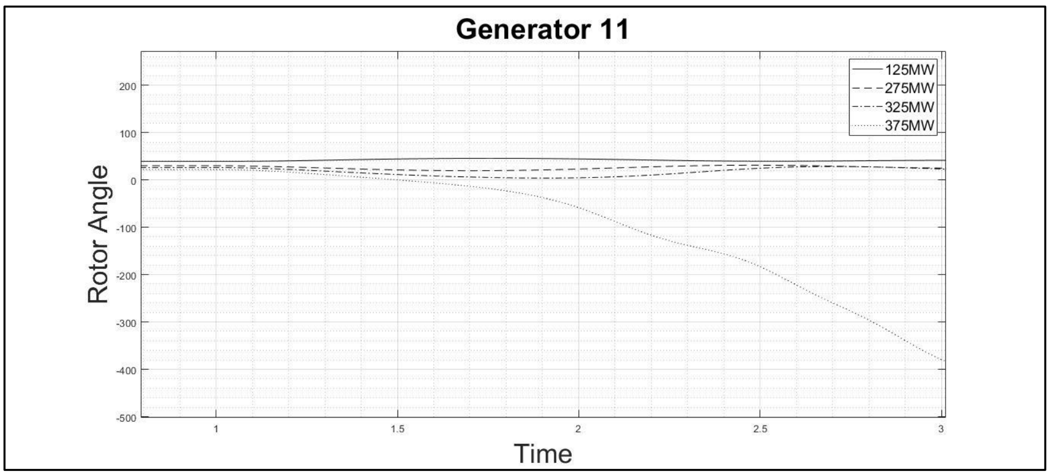


Figure 6.14 Rotor angle of the generator 11

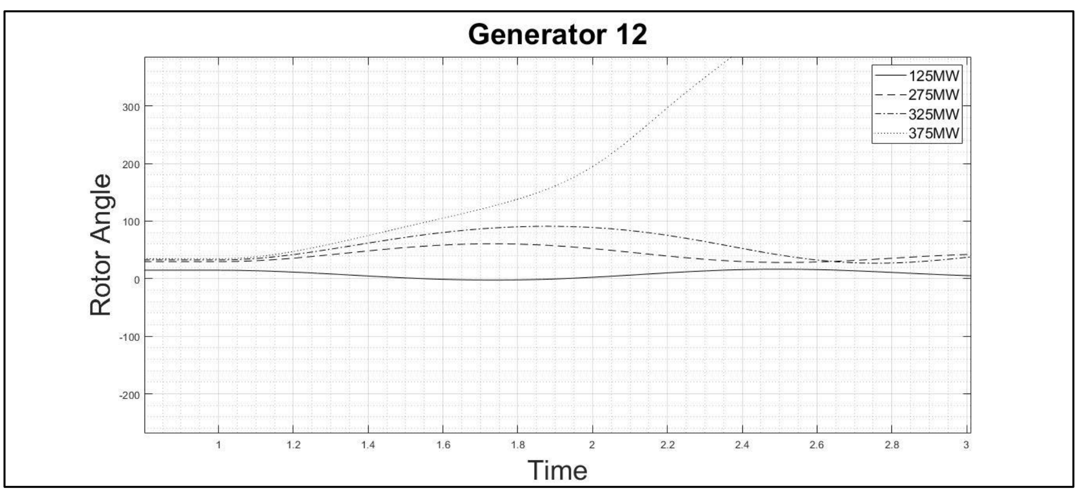


Figure 6.15 Rotor angle of the generator 12

6.4.5. Transient Stability Enhancement Through Fast Fault Clearing

To examine the effect of circuit breaker speed, a 3-phase solid fault is applied to bus #8 at t=1.0s and will be cleared at a different time (t=1.1s, 1.3s, 1.5s, and 1.6s). The dynamic performance of the system is presented in Figures 6.16 to 6.18 for generators #10, #11, and #12, respectively.

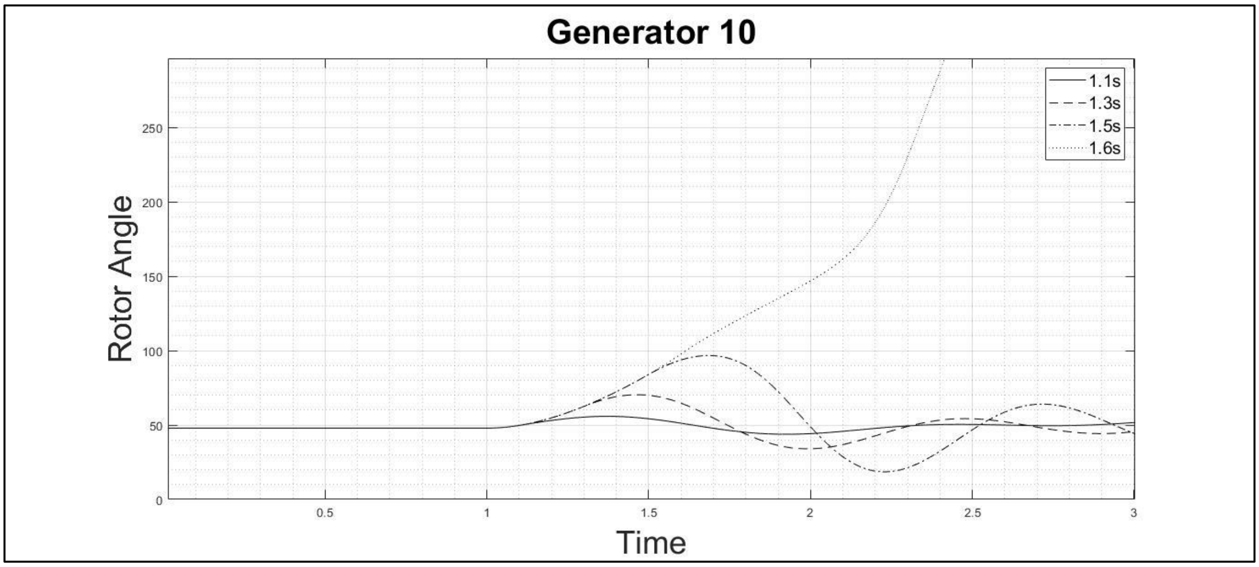


Figure 6.16 Rotor angle of the generator 10

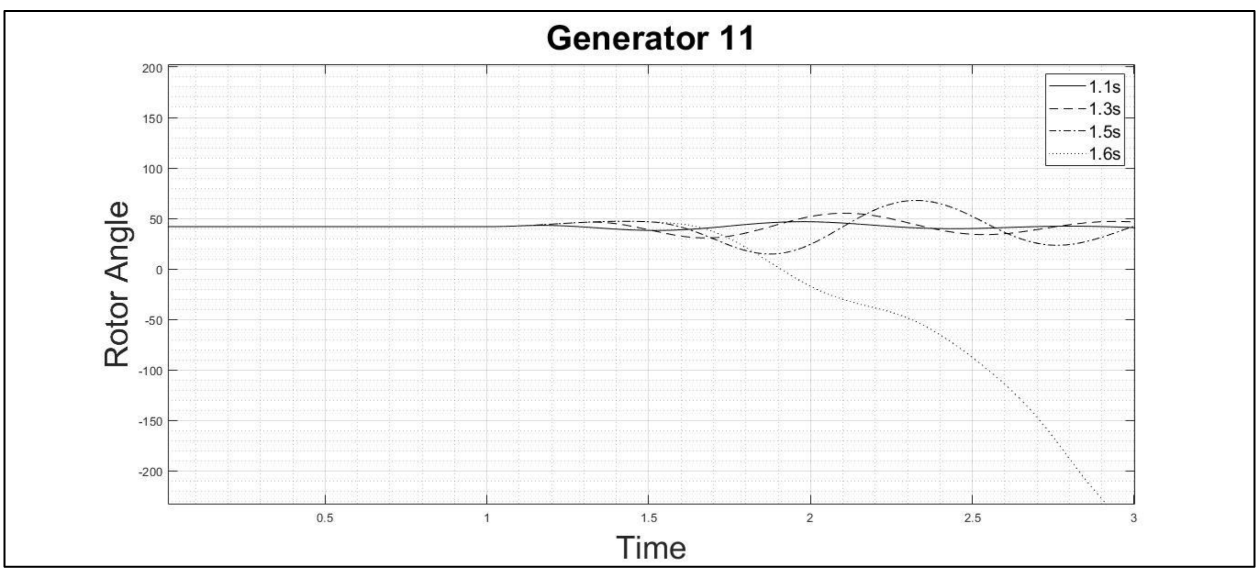


Figure 6.17 Rotor angle of the generator 11

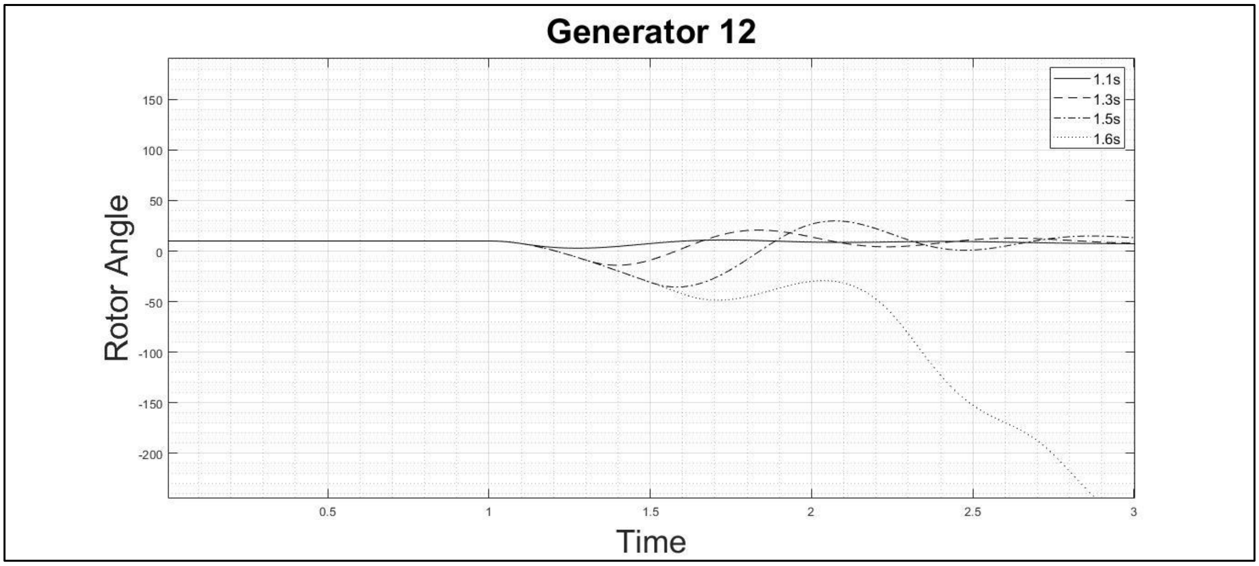


Figure 6.18 Rotor angle of the generator 12

With clearing time 1.1s, 1.3s, and 1.5s, generators are stable and remain in synchronism. However, Generator 10 angle increases dramatically at clearing time 1.5s while other generator angles change monastically. The reason is that Generator 10 transfers more power to bus#8 rather than the other generator.

As shown in the figures, all the generators become unstable for clearing time 1.6s. So, it can be concluded that at the greater breaker delay time, the stability of the generator is lost. This illustrates that breaker clearing time is an important factor in maintaining stability.

6.4.6. Effect of Reclosing

Reclosing is a method that sometimes used after fault detection and clearing. Automatic reclosing can improve transient stability if the fault is not permanent and can be cleared by tripping and immediately reclosing the faulted line. The effect of reclosing on power system stability will be discussed in chapter 7 of this thesis.

6.4.7. Other Factors affecting Transient Stability

The studies on previous sections have some important implications, which is that the transient stability of a generator associates with some other factors, including fault location, type of the fault, the inertia of the generator, and the internal voltage magnitude of the generator which is a function of field excitation.

6.4.7.1. Effect of Fault's Location

To analyze the effect of the fault's location, the IEEE 39-bus system is modeled in PowerWorld simulator v.20 to simulate classical transient stability. The IEEE 39-bus system is widely used as a test system template to simulate power system stability problems. The IEEE 39-bus system analyzed in this section is commonly known as "the 10-machine New-England Power System." [35]. Figure 6.19 shows the oneline diagram of this circuit. The system characteristic is given in Appendix B.

In the test system, a balanced 3 phase fault occurred at bus 22. The fault was applied at t=1 s (60 Cycle), and the critical clearing time was estimated as 66 cycles (1.1 s). Figure 6.20 shows the active power output of generators 35, 36, and 39. The level of active power for generator #39 changes extremely. Figure 6.21 shows the relative angle plot of generators #35, #36, and #39. The maximum swing angle of generators #35 and #36 is 85° and 95°, respectively. Bus #22 is confronted by a 3-phase solid fault at t=1.0s causes a rapid change in all generator's rotor angles except Gen#39. Also, the generator at bus #30 quickly became stable, mainly because of the fact that it is far from the fault location compared to the other machines.

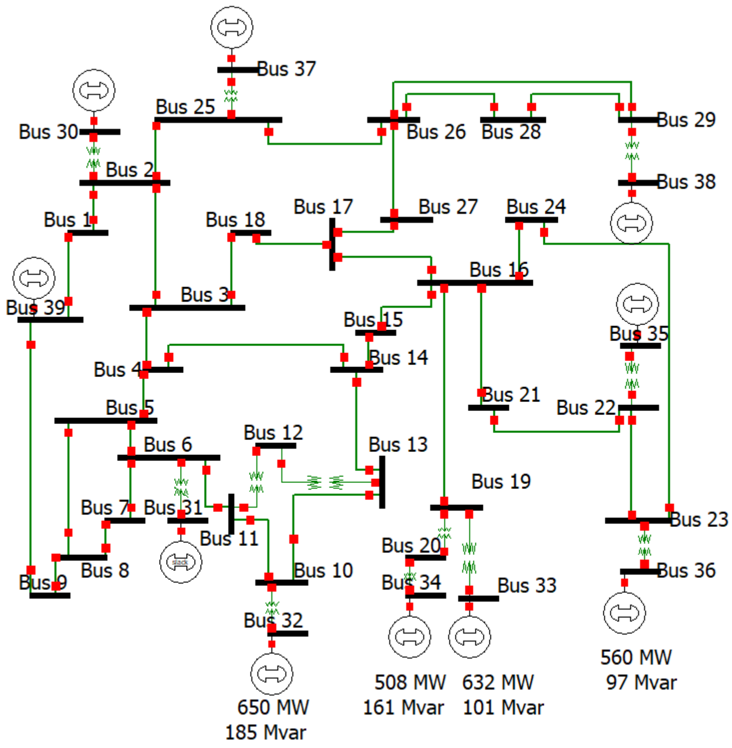


Figure 6.19 Oneline diagram of the IEEE 10-Generator 39-Bus New England Test System

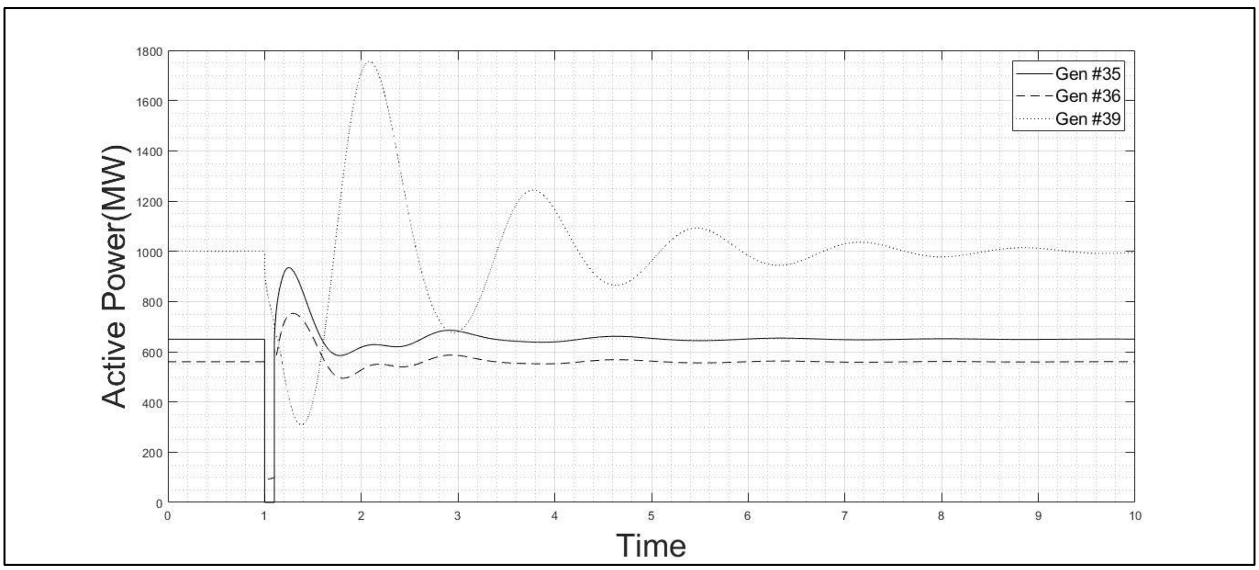


Figure 6.20 Output active power of generators

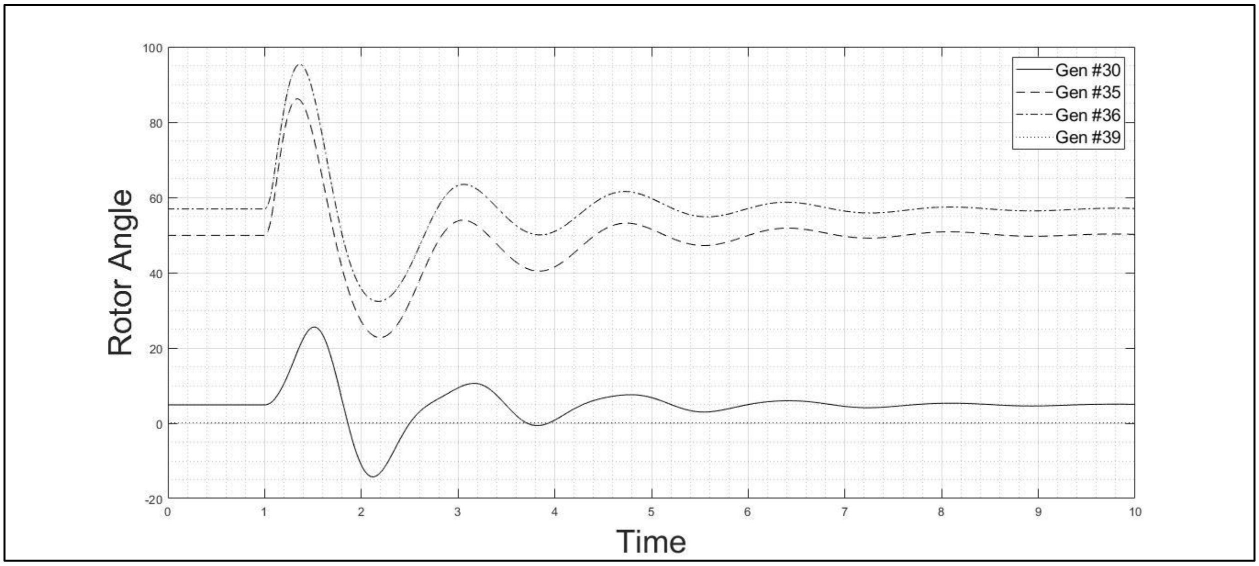


Figure 6.21 Rotor angle of the generators

6.5. Conclusion

In this chapter, the concept of power system stability is categorized and explained. Also, the concept of transient stability is studied for first swing rather than multi-swing by using a single machine infinite bus system (SMIB) with two transmission lines. Also, the power angle relationship equation is constructed, and their graphs are plotted for normal and out of service situation. Finally, an IEEE 9-bus was also modeled in MATLAB/Simulink environment to simulate classical transient stability, and the absolute angle of all generators and Relative angle plots of all generators are plotted.

Chapter 7

Using Autoreclosing Relays to Enhance Power System Stability

7.1. Introduction

In this chapter, the concept of autoreclosing and the methods which are used in autoreclosing relays are discussed. In Section 7.2, its advantages and importance investigated. In Section 7.3, the considerations needed before designing an autoreclosing scheme for a power system are explained. In Section 7.4, the functionality of a simple autorecloser scheme is studied. In Section 7.5, the basics of an autorecloser are investigated, followed by the modeling of autorecloser relays. In Section 7.7, an autorecloser relay is modeled and simulated for a one generator power system with two lines. In Section 7.8 and 7.9, two types of faults are applied to the model, and the results of the simulation will be shown. Finally, in Section 7.10, the concept of optimal Reclosing Time will be discussed.

7.2. Automatic Reclosing

Automatic reclosing is a very effective scheme to improve the stability of the power system. This method is identified as a quick control scheme that is used to restore the system to a normal situation after clearing the faults. The faults are cleared by breakers, and the steps of autoreclosing should take place a short time after the breaker trips. The time between breaker tripping and autoreclosing is identified as an outage time, which should be sufficient for fault clearing. This duration is very important in order for successful reclosing and should be at least 10-30 cycles [1].

7.3. The Importance of Autoreclosing

One of the most important characteristics considered in power system stability is the synchronous operation of all generating units. In a stable power system, just after a disturbance, these generation units want to oscillate and settle to a new steady-state operating situation. There, the steady-state condition is defined as a situation where all the generation units oscillate at the same speed and have the same frequency; however, there is no need to have the same phase angle in the steady-state condition. In this case, exchanging synchronizing power is a capability of the generators, which is required to maintain the power system stability and positively dampen the oscillation. After the occurrence of a fault in the system, such as a line or branch removal, all generators will give a new voltage angle value due to the new power system situation. The generators should be able to change their output power to achieve the new required balance.

Some disturbances and faults, regardless of their duration, either permanent or temporary, will not make the system unstable. These types of faults usually occur at lines that are not essential to maintaining an important patch for the flow of synchronizing power between the machines. Although adding a reclosing scheme to these circuits can help the system to restore the normal conditions without unnecessary delay, but it is not needed for stability [1].

Autoreclosing is required in important lines such as tie lines, which are connected to the important generators. The reason is that generators might become unstable in power systems without autoreclosing schemes (except for those situations where the system is restored to a normal condition in a short time, often a few cycles). Essentially, many high voltage lines of the bulk power systems armed with autoreclosing to maintain stability following a disturbance [1].

7.3.1. Illustration Using an Example

To show the effect of using an autorecloser relay in a power system, the IEEE 9-bus is modeled in PowerWorld, as shown in Figure 7.1. The time sequence of the simulations is (1) a transient balanced 3Phase fault occurs at the line between bus 5 and 7 at t = 0.1 seconds, (2) the circuit breakers are opened at both ends at t = 0.2 seconds and closed at t = 0.4. Figure 7.2 shows the results (Rotor speed of Generator #10) for two cases, with and without using an autoreclosing relay.

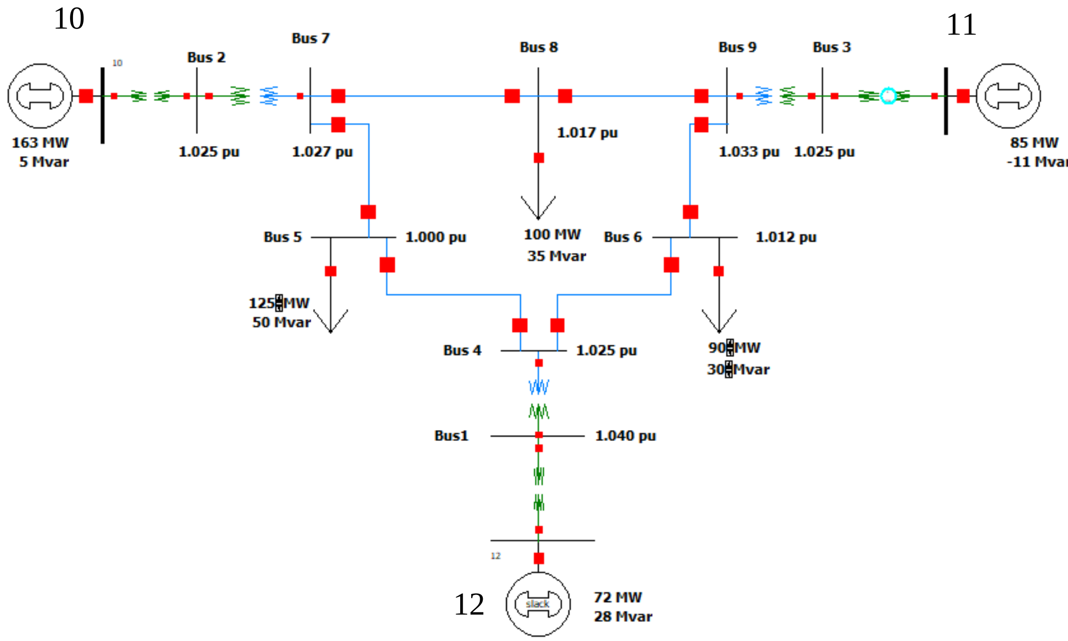


Figure 7.1 IEEE 9-Bus power system

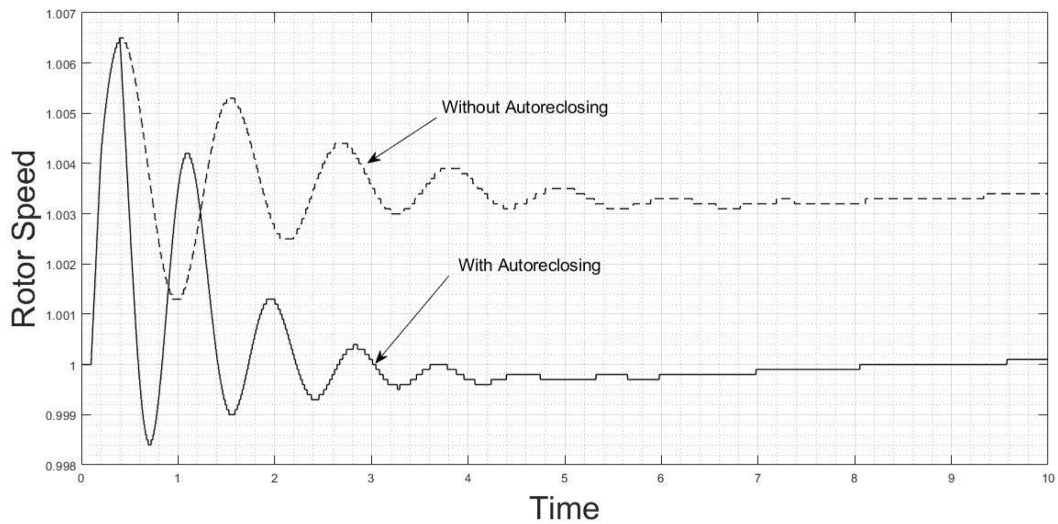


Figure 7.2 Rotor speed of Generator 10

7.4. Autoreclosing Design consideration

To design the autoreclosing system, several critical parameters such as line voltage level and fault type (related to disturbance consideration), and also, the number of reclosing should be considered before installing the autoreclosing system [1].

7.4.1. Voltage Level

The voltage level specified the necessity of the autoreclosing system. In other words, the voltage level determined that using autoreclosing is essential for the system, or it can be helpful to maintain system stability without additional delay or even if there is no need for an autoreclosing system.

The circuits with lower voltage levels, up to 34.5 kV, are often used for distribution for a limited number of users. Using autorecloser at this level might be useful in order to decrease the outage time for the customers. However, autoreclosing methods at this level of voltage do not enhance stability since these circuits either do not have a generation unit or a small generator.

At the circuits with a subtransmission voltage level, using autoreclosing would help the power system maintain a normal condition without additional delay. Autoreclosing at this voltage level is used at tie lines or in parallel with a higher voltage tie lines.

Autoreclosing methods are often used at EHV[1] lines. At the high voltage level, the faults are tripped and clear in a short time (a few cycles), and timed reclosing schemes may have a great functionality [1].

7.4.2. Fault Types

To design an autoreclosing system, the type of fault should be considered. The type of faults based on the duration of the fault and also the cause of the fault can be classified into three groups, as shown in Table 7.1.

Table 7.1 The classification of fault types

Type of the faults	Cause of the faults	Duration
Transient faults	Lighting Swinging wires Temporary contact with foreign objects (trees or blowing debris)	Quickly cleared by switching the line
Semipermanent faults	Contact with tree branches due to storms	Might clear themselves if left to burn for a short time
Permanent faults	Damage to the underground Cable faults, broken conductor	The faults do not clear themselves but must be repaired

[1] Extra High Voltage

EHV lines experience more transient faults, while subtransmission lines and distribution lines have more semipermanent faults. Although stability is not considered the main problem for distribution lines, to enhance the service to the end loads, reclosing should be used [1].

7.4.3. Number of Reclosures

The number of reclosures varies depending on the voltage level. At the EHV voltage level, a single reclosure is used. The advantage of using a single reclosure is that it is easily justified. At the subtransmission voltage level, usually, two or three reclosures are used, and most of them are installed on the tie lines. However, at the distribution level, multiple reclosures are used [1].

7.5. Operation of Autoreclosing Scheme

In a real power system subjected to a transient fault, the trip coil of the circuit breaker will be energized after the Operation Time to remove the faulted section from the system. Operation Time here is dedicated as the time from the energizing of the trip coil until the fault arc disappears. The breaker contact will then be opened, after a while, which is called Opening Time. After the full opening of the breakers, the autoreclosing timer starts counting, and after a predefined time, identified as Dead Time, the reclosing command will be sent to the breakers. Figure 7.3 shows the operating sequence of a single-shot autoreclosing scheme for a transient fault. Arcing Time is defined as, “The time interval between the instant of the first initiation of the arc and the instant of final arc extinction in all poles” [2]. Also, Closing Time is dedicated to the duration between the instant of the closing operation’s initiation until the circuit breaker is fully closed (metallic continuity is established in all poles). The total duration of Opening Time and Arcing Time is also called Operating Time (Protection).

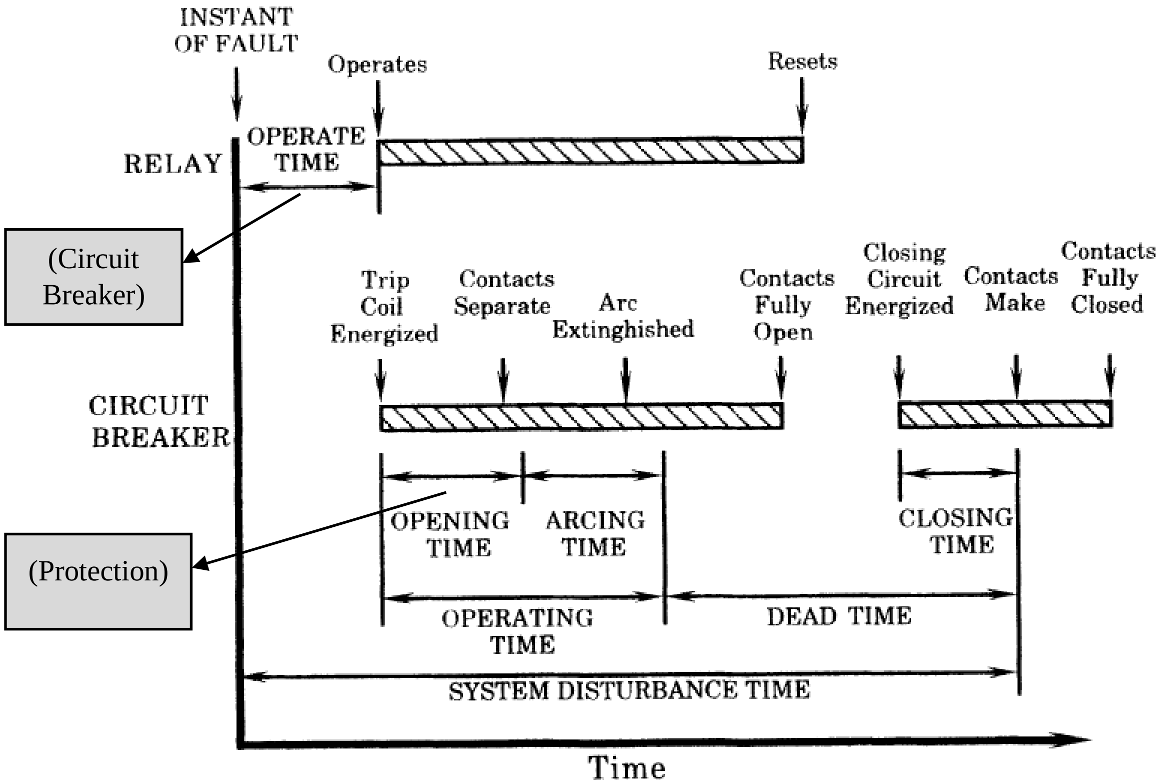


Figure 7.3 Single-shot autoreclose operation for a transient fault [1]

7.6. Reclosing Relays

Since most of the faults in the power system are transient, it is not a good idea to break the power circuit and to interrupt the power system by protective relays. So, an autorecloser device can be useful for this situation.

An autorecloser can be considered as a circuit breaker and operates based on a control method that sends a reclosing command to the breaker after opening it due to the fault detection. Since more than 80% of the faults are self-clearing in their nature, power outage time can be reduced if the reclosing function is automated and carefully planned [36].

7.6.1. Autorecloser Principle Function

The autoreclosing sequence starts just after the circuit breaker operates due to a fault in the system. When the circuit breaker detects a fault and breaks the circuit, the recloser recloses the breaker after a predefined time interval (usually 1/3 of a second), which is called First Shot. In the case that the fault does not disappear, the breaker opens again, and after a preset interval of time (usually 15 seconds), the recloser performs for the second time or Second Shot. If the fault persists, the breaker trips. The recloser operates for the last and third time, the Third Shot, after a preset time interval (usually 45 seconds). If the fault is still there, the breaker trips and will be locked. It will need manual resetting to continue operating. Figure 7.4 shows the sequence of the autorecloser function [36].

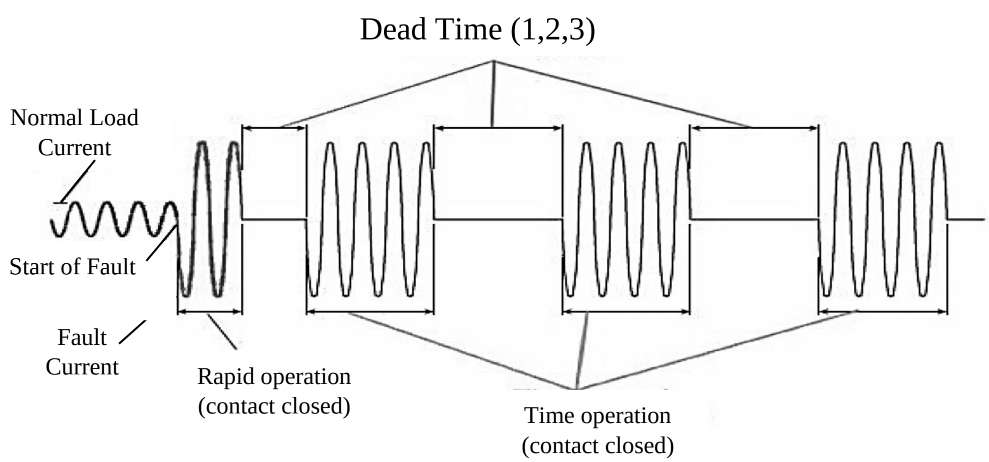


Figure 7.4 Typical sequence for Auto-recloser [36]

There are three important parameters for every recloser, Dead Time, Reclaim Time, and Number of Shots [36][37].

7.6.1.1. Dead Time

As mentioned in section 7.5, it is the preset time interval between the instant of the breakers' full opening and the next shot of the recloser operation.

7.6.1.2. Reclaim time

Reclaim time is a period of time just after the breaker closes and remains closed (which means that the fault was not permanent) until the timer reaches its maximum value. The recloser relays will initiate a new reclosing sequence.

7.6.1.3. Number of shots

The number of shots identifies the number of attempts of a reclosing relay to close the breaker after the fault. Usually, this number is set to three times.

7.7. The Model of an Auto-reclose Relay

It is very difficult to model protection schemes using software because, generally, protection schemes are sophisticated, and also there are no specific protection relay models or toolboxes in most software such as MATLAB Simulink. However, there are some software that have a built-in model for protection relays, but they are very expensive. In this section, an autoreclose protection scheme is modeled using MATLAB Simulink software.

7.7.1. Modeling Consideration

To model an autoreclosing system, several criteria should be considered, such as the type of fault, the zone where the fault occurred, the method of overcurrent detection, the number of reclosing attempts, and the number of poles in autoreclosing. To reduce the complexity of the model, several assumptions might be considered during the modeling process.

7.7.1.1. Fault Type

The fault types were previously discussed in section 7.4.2 and also in Table 7.1. In addition, the fault can also be a single line to ground, a line to line, or a combination of them.

7.7.1.2. Overcurrent Detection Relay

To detect an overcurrent in a power system network, the main protection relay is used, which is usually a distance transmission line protector or current differential relays.

7.7.1.3. Fault Inside a Range of Protected Line

Autoreclose relays usually do not operate for the faults outside the protected line, and the reclosing scheme is blocked in that area.

7.7.1.4. Auto-reclosing Poles

Based on the voltage level, an autorecloser trips poles individually or trips all three-phase lines at the same time. At Lower transmission voltage level, autorecloser trip all phases, but for higher transmission voltage level, each phase has its own breaker and can be tripped or reclosed independently.

7.7.1.5. Synchronization Checking

One of the critical inputs for autoreclosing relays is the status of the line ‘s synchronization and the busbar. So, it is very important to check the synchronization status before sending the autoreclosing command.

7.8. Modeling and Simulation

In this section, a single shot autoreclosing relay is modeled using MATLAB Simulink environment. A power system with one generator unit and two parallel lines is used as a test system. To model a transient fault, an arc is simulated with an ARC model block. To reduce complexity, some limitation is applied to the model.

7.8.1. Model Description

The power system has two 735 kV parallel lines, 200 km long, transmitting 3000 MW of power from a generation plant (12 generators of 350 MVA) to an equivalent network having a short circuit level of 20 GVA. To simulate the generation plant, a simplified synchronous machine (sub-transient reactance of 0.22 pu) is used. A transmission network with 13.8 kV/ 735 kV and a Y-Δ transformer is used to connect the machine. To model the transmission line, a distributed parameter line with positive- and zero-sequence components R, L, C /km is assumed in positive- and zero-sequence components. Two shunt reactors of 200 Mvars each, connected at line ends as shunt compensation. The modeled power system consists of two substations, local and remote, in which the autoreclose relay is normally connected to both of them. Figure 7.5 shows the oneline diagram of the tested power system.

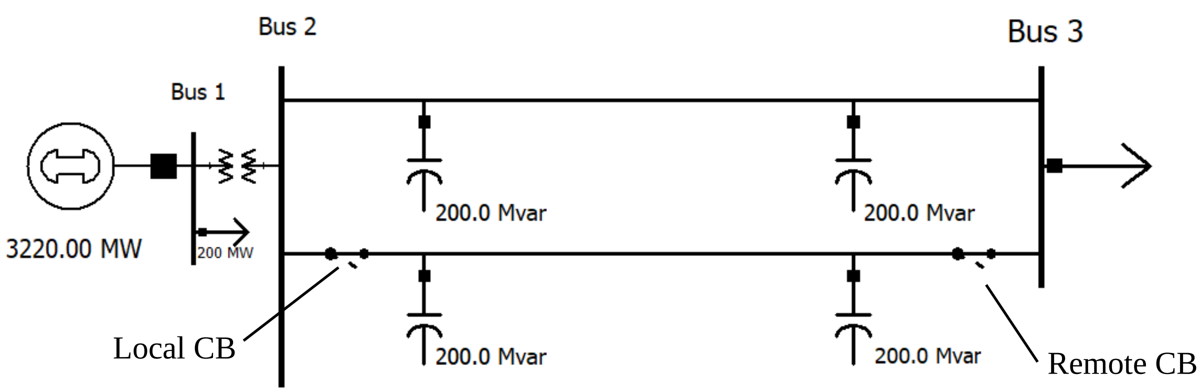


Figure 7.5 Oneline diagram of the modeled system

The parameters and settings used in the model and simulation are shown in Table 7.2. The parameters are used for modeling the local and remote substations, three-phase transmission line, and three-phase faults.

Table 7.2 Modelling Parameters and Relay Setting

Source parameters	**Values**
Phase to phase voltage	735 *1.01317 kV
Frequency	60 Hz
3Phase short circuit level	20GVA
X/R ratio	10
Transmission Line Parameters	**Values**
Positive sequence resistance	0.01165 (Ohms/km)
Zero sequence resistance	0.2676 (Ohms/km)
Positive sequence inductance	0.8679e-3 (H/km)
Zero sequence inductance	3.008e-3 (H/km)
Line length	200 km

7.8.2. Definite Time Overcurrent Relay

To protect the transmission line, and detect the fault (Overcurrent), two definite time overcurrent relays are developed and used in this simulation with the same settings. The overcurrent relays are connected to circuit breakers in both local and remote substations to send the trip signal and also to start auto-reclosing operation after a preset delay time. Figure 7.6 shows the subsystem for definite time overcurrent relay. The setting which is used for the overcurrent relay is shown in Table 7.3.

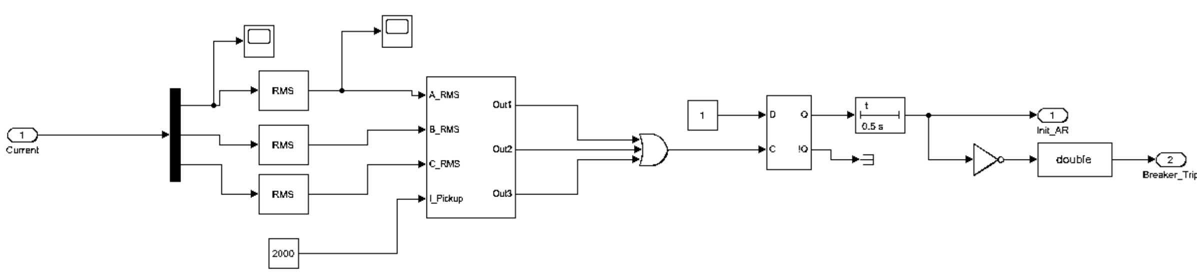


Figure 7.6 Definite time over-current relay subsystem

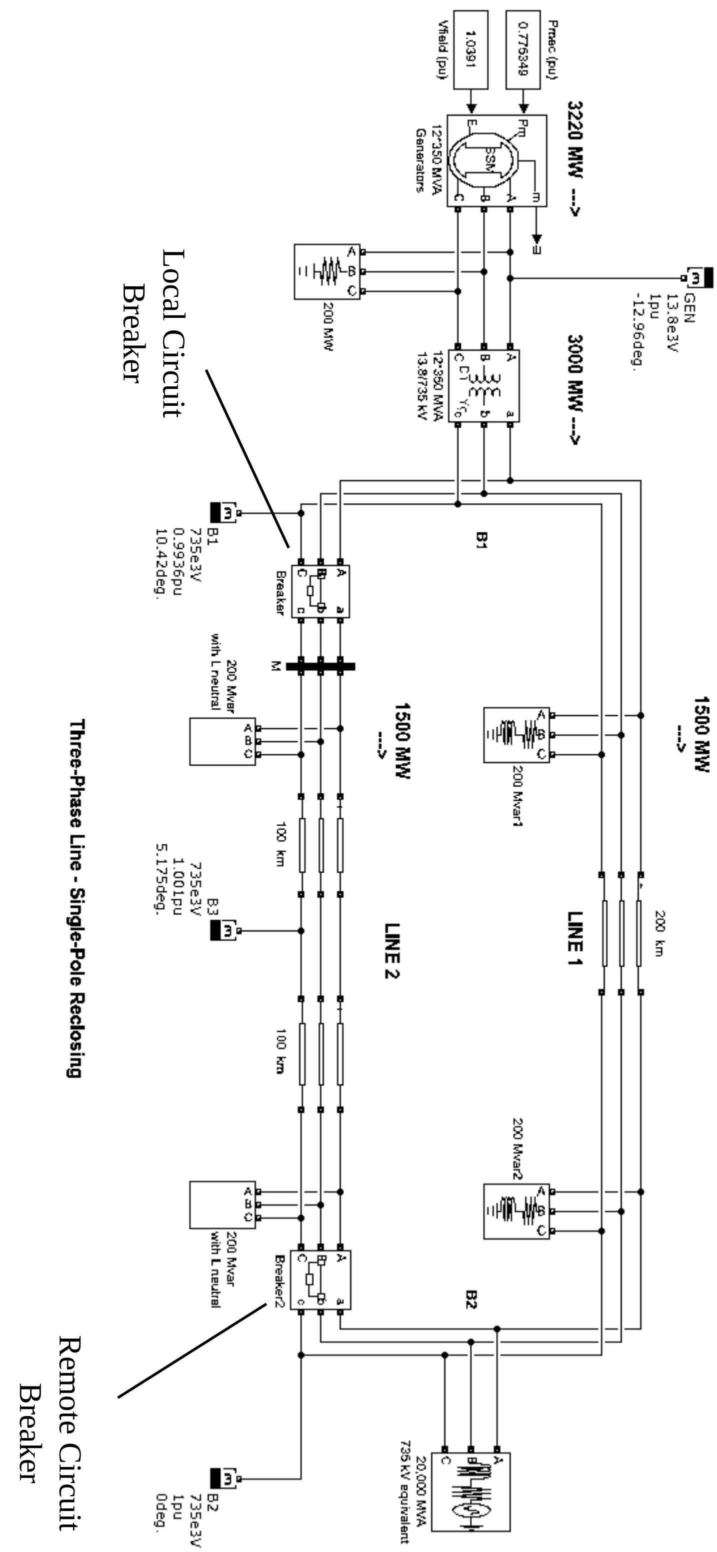


Figure 7.7 Substations, transmission line, and load in MATLAB Simulink

The definite time overcurrent relays compare the rms value of fault current with pickup current, which is predefined in the relays. The overcurrent relays operate when fault current is more than pickup current, and after the preset delay time, send two signals to related initiate/start auto-reclose relay and signal to trip the circuit breaker.

Table 7.3 Overcurrent relay setting

Over-current Relay Setting	**Values**
Rated Current	1190 A
Pick up current (I_{pickup})	2000 A
Operation time	0.5 s

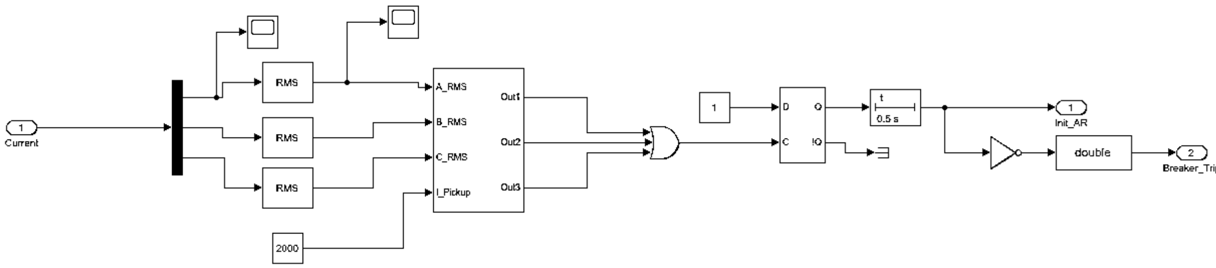


Figure 7.8 Definite time over-current relay subsystem

7.8.3. Autorecloser Relay

Figure 7.9 shows the auto-reclose relay subsystem. There are four inputs for the autorecloser subsystem, including circuit breaker status, the circuit breaker in ready condition, and synchronization status. The autorecloser relay operates after receiving auto-reclose initiation/start signal from overcurrent relay (To simplify the modeling process, the other inputs have a true value). After relay initiation, dead time will be started, and the autoreclosing signal will be sent to the circuit breaker when the timer reaches its preset maximum value. Table 7.4 shows the autorecloser relay setting.

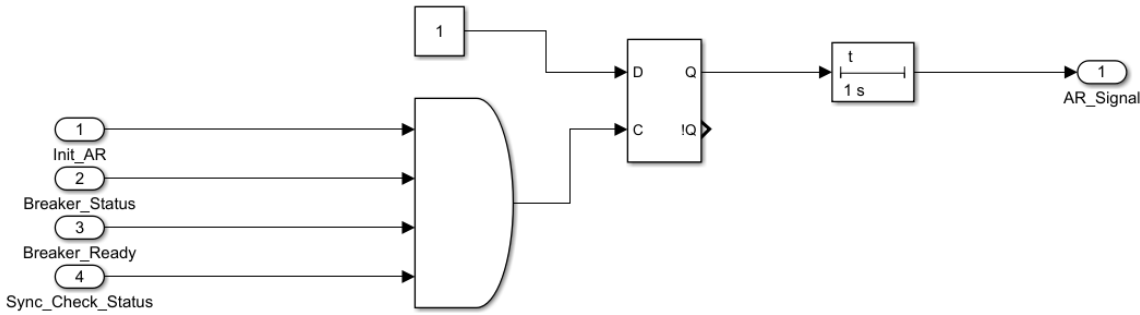


Figure 7.9 Auto-reclose relay subsystem

Table 7.4 Autorecloser relay setting

Auto-reclose Relay Setting Values	**Values**
Local dead time (strong point)	1.5 s
Remote dead time (weak point)	1.0 s

7.8.4. Fault and Line Switching

In this simulation, Line 2 is subjected to a phase-to-ground fault that is applied in the middle of it at phase “A” inside the zone of protection line without any blocking feature. So, line 2 is divided into two 100 km parts. The fault is modeled with fault block through MATLAB Simulink.

Following the fault detection by an overcurrent relay, an opening command will be sent to circuit breakers, which will disconnect line 2 from both end sides. After the predefined opening time, which is called “Dead Time,” the reclose command will be sent to both CBs by autorecloser relays. Deadtime is used to ensure that the transient fault is distinguished, and for the weak points of the network (Remote area), the dead time is slightly longer. To simplify the model, a definite time overcurrent relay is used. The functionality of an overcurrent relay was discussed in chapter 3 of this thesis.

7.8.5. Checking the Synchronization Status

To reduce the complexity, the requirements of synchronization include the values of voltage magnitude difference, voltage phase angle difference, frequency deviation range, and phase rotation are considered as a true value.

7.9. Simulation Results

The results of the autoreclose scheme in the case of occurrence of a single line to Earth transient fault through line 2 are investigated in this section. The fault is applied at 4/60 s and remains to 7/60 s in the middle of line 2 (at 200km). Figures 7.10 and 7.11 show the current (phase and rms form) of line 2. Also, Figures 7.12 presents the voltage (phase and rms form) of line 2. Figure 7.13 shows fault current in phase form and rms form, respectively.

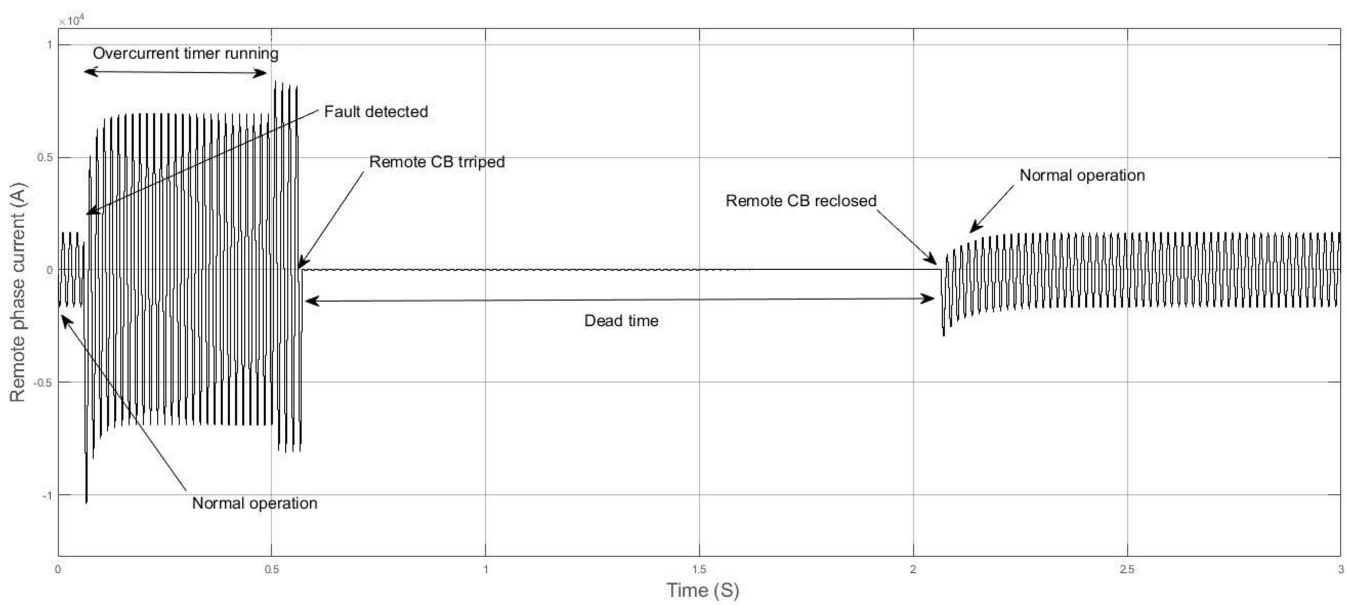


Figure 7.10 Line 2 phase current

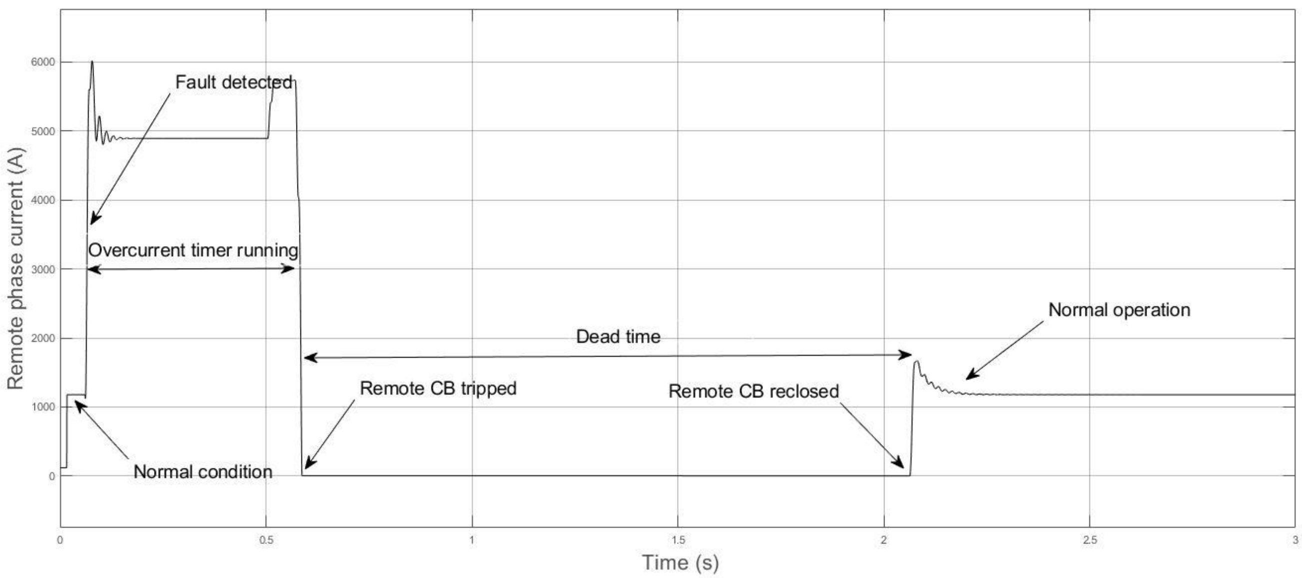


Figure 7.11 Line 2 rms current

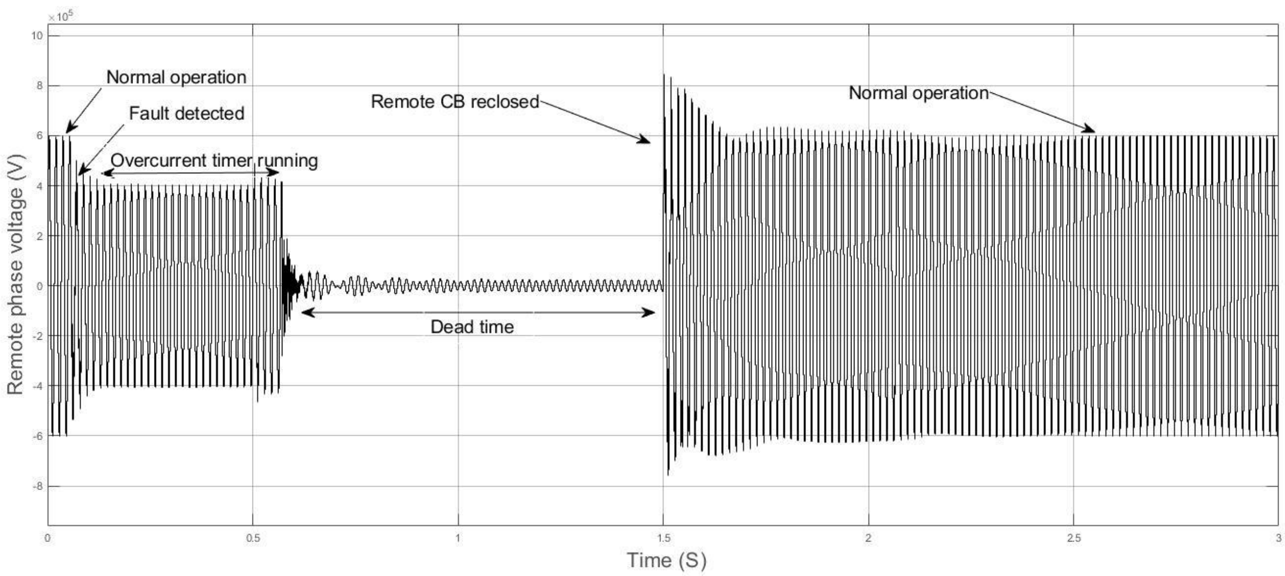


Figure 7.12 Line 2 phase voltage(V)

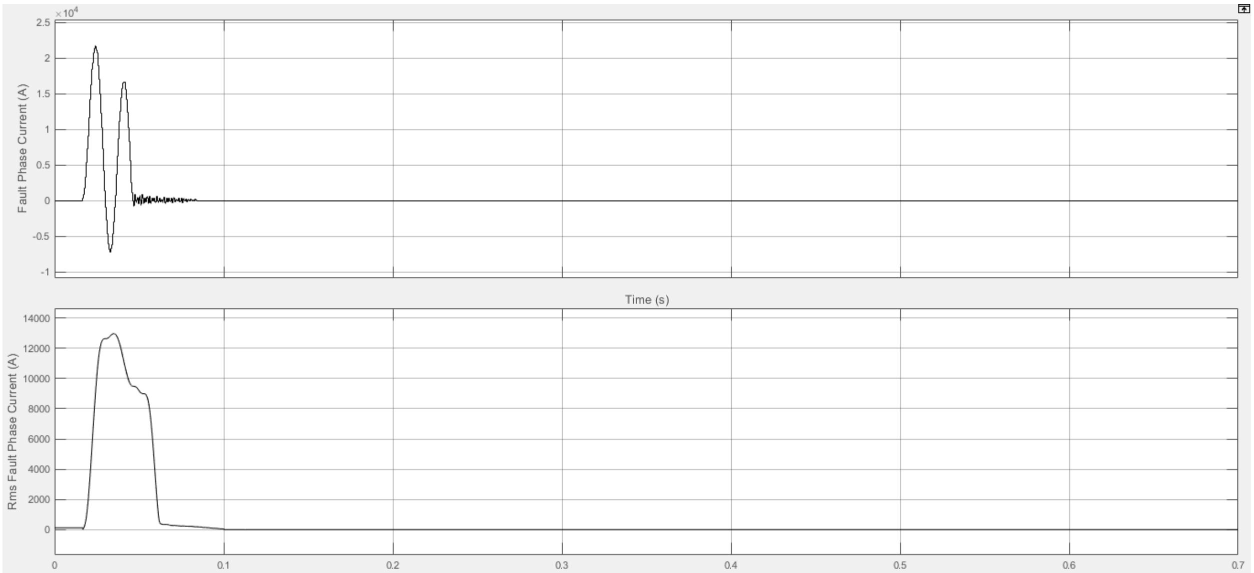


Figure 7.13 Fault current (phase and Rms)

As figures showed, the fault was initiate at 4/60 and detected by overcurrent relays, which compared the input current by pickup current value (I_{pickup} = 2000 A). As soon as the input current's value of the overcurrent relay became higher than I_{pickup}, the timer of the overcurrent relay started. The trip command sent after a predefined time (0.5 seconds in this model). During the fault and before breaker tripping, the current value increased sharply while the voltage value dropped. After the trip command sent to the breaker, the current and the voltage of the line 2 became 0 at the same time and also a command sent to the autoreclose section to initiating the autoreclosing process. That command caused a predefined timer at the autoreclosing section starts, and after a predetermined time value (1 second for local and 1.5 seconds for remote), the close command issued by autorecloser relays to breakers. The voltage value of line 2 after reclosing is a bit higher than the normal value, but it decreased to a normal value slightly.

To have a successful autoreclosing, all constrain of breaker should be met as follows [38]:

- Breakers should be fully open

- The closing coil should be ready
- Initiate/start signal from over-current relay should be received

in this model, all these requirements assumed to be in true status.

7.10. Arc Model

To model an arc, a fixed or non-linear resistance $R = f(I_{arc\_rms})$ is used. When the rms current of the arc goes below a threshold value (typically 50 A), it will eliminate. The mean arc resistance, which is used in this model, is considered as an exponential function of the rms current. Following the decrease of the rms arc current, the mean arc resistance increases, and that causes the arc current to become lower than the threshold value faster. The arc block parameter is shown in Figure 7.14. The fault is occurred using a control pulse applied on input 'Fault_init' and will be switched off when the arc rms current value goes under the 50 A.

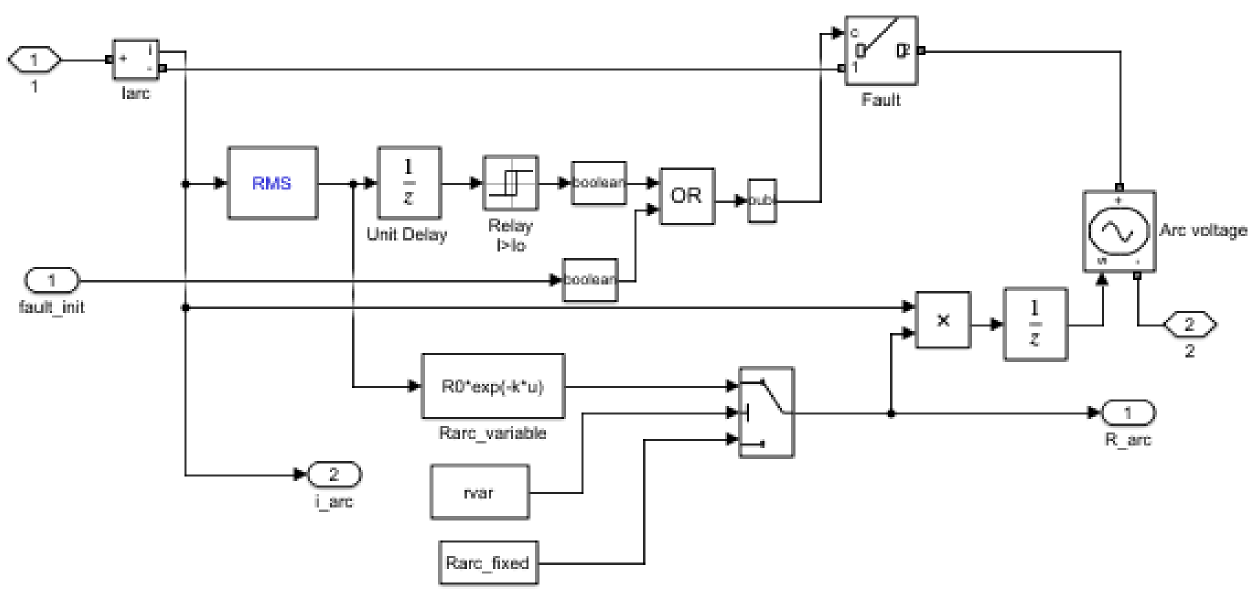


Figure 7.14 The Arc Model [39]

The result of applying an arc as a fault is shown in Figure 7.15. The fault is applied at t = 1 cycle. The first graph shows the resistance of the arc model, which is followed by the graphs of arc current, voltage, and current of Line 2 and also the autoreclosing command respectfully.

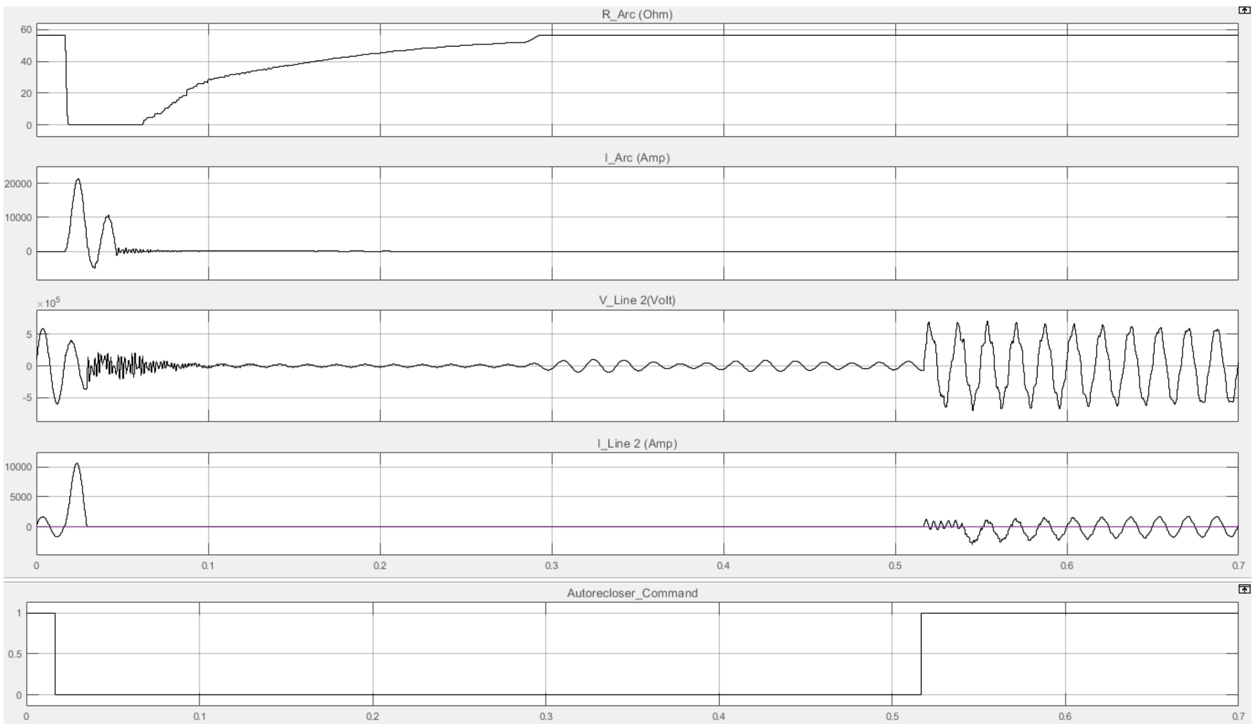


Figure 7.15 The result of arc and autoreclosing simulation

7.11. Optimal Reclosing Time

Autoreclosing methods are widely used in high voltage transmission lines. The autoreclosing schemes enhance transient power system stability by restoring the system to the normal situation just after a short time of the fault. This time plays a critical role in improving the power system stability since, in the case of unsuccessful reclosing, the power system confronts an unstable state. Currently, the regular auto-reclosing methods use a constant predetermined value, and the breakers reclose the line after this time. However, this fixed time is not efficient since the transient stability is dependent on the generator state, and the reclosing time must be changed in regard to each situation. So Optimal Reclosing Time (ORT) can be useful to have an efficient and successful or safe and unsuccessful reclosing. Here, the safe and unsuccessful reclosing is defined as a situation where the system disturbance has no effect after reclosing operation.

7.11.1. Need for ORT

The stability of the system can be affected by conventional autoreclosing since the stability is dependent on the generator states at the time of reclosing. Normally, in a real power system, the breaker trips because of the fault, and then the recloser relay closes the circuit after a fixed time. The time interval between the breaker trip and reclosing command is used to ensure that the arc is deionized. Reclosing after a fixed time may lead to reclose the breaker before arc extinction in a transient fault or reclose the breaker when there is a permanent fault in the system. In both cases, the reclosing may cause instability, as discussed in the previous section, or at least it does not enhance stability. So, the breakers should be reclosed at a time that has no effect on the system. This time can be evaluated by some ORCT methods that will be discussed in the next section.

7.11.2. Illustration Using an Example

To investigate the effect of the reclosing time, three different reclosing times are applied to the standard IEEE 9-bus system separately. Figure 7.16 presents the rotor speed of the generator #10 confronted by a fault at t=0.1s. The fault is a three-line to ground (3LG) and occurs near the generator at the bus #5. Following the fault, the breakers at two side of the bus #5 are opened at t=0.2 s to clear the fault. In Figure 7.16, the results are shown for cases: reclosing at 0.5 s, reclosing at 7.0 s, and also reclosing at 0.9 s. The oneline diagram of the IEEE 9-bus is shown in Figure 7.17.

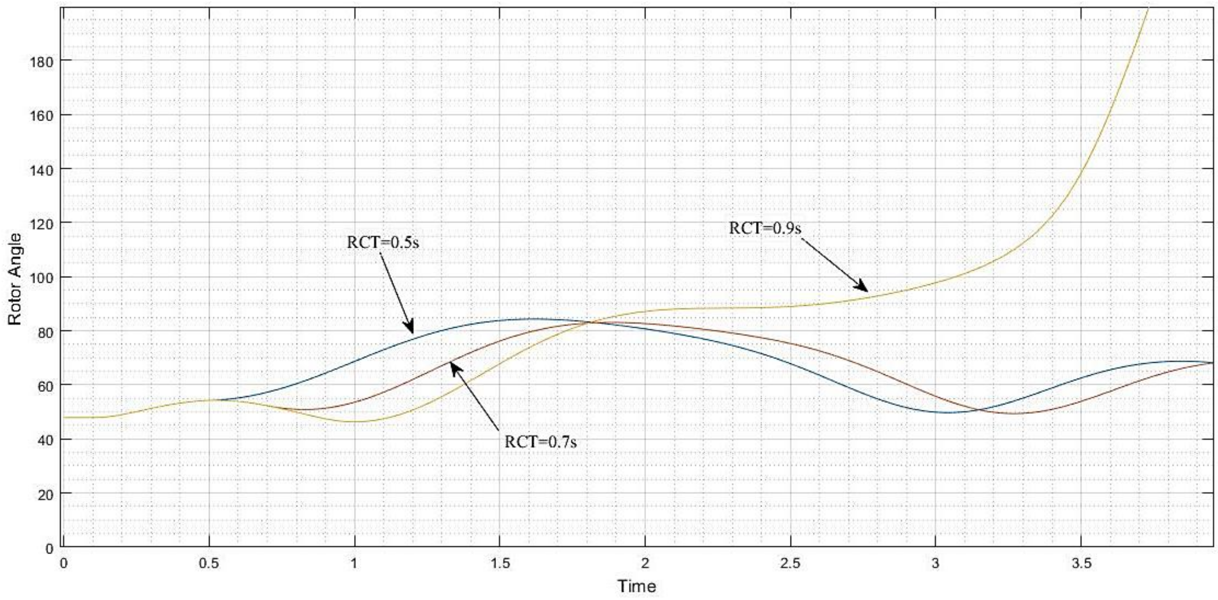


Figure 7.16 Rotor speed responses in each case of reclosing time

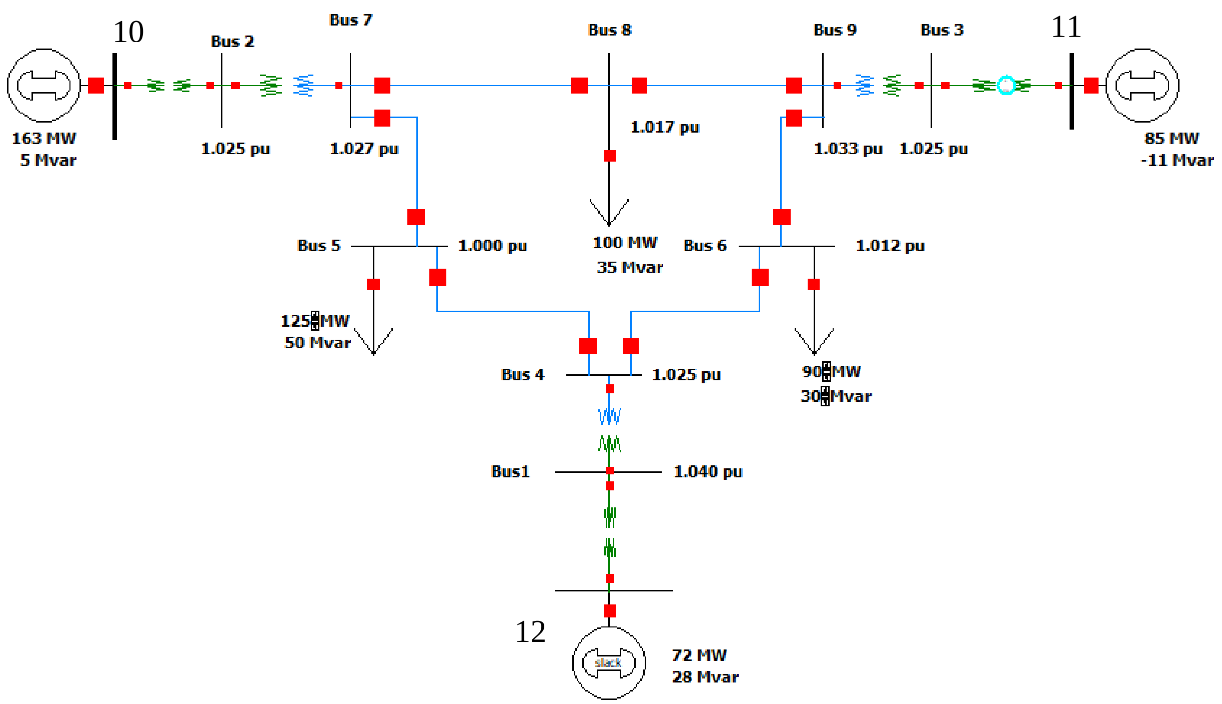


Figure 7.17 IEEE 9-Bus power system

7.11.3. Optimal Reclosing Time Methods

To evaluate the Optimal Reclosing Time (ORCT), several methods have been investigated and proposed. These methods can be divided into online and offline methods [40]. The offline applications need several simulation analyses, and also, in the case of a multimachine power system, most of the online methods cannot be used. The author in Paper [40] investigated an online method to determine the ORCT for a multimachine power system by using the kinetic energy of each generator.

7.11.3.1. Conventional Optimal Reclosing Method

In conventional reclosing relays, Deionization Time can be used to reclose relays after the fault. Deionization Time is defined as enough time required for the gas, which is the result of the fault, to disperse. This time is not constant and varies due to the voltage, the conductor spacing, the magnitude of fault current, and the weather conditions [37]. The Deionization Time is also called the "minimum dead time," which is the most optimistic estimate of the time the fault should disappear completely before trying for a reclosure [2]. The reclosing time in conventional reclosing relays is calculated based on.

$$T_R = 10.5 + \frac{kv}{34.5} \text{ (cycles)} \qquad (7.1)$$

Where kv is the line voltage. Equation 7.1 is just dependent on the line voltage and can consider as a fixed value. This time interval is not actual and may cause instability or closes the breaker before fault extinction.

7.11.3.2. Calculated ORCT by using the kinetic energy of synchronous generators

This online method is used to determine the ORCT for a multimachine power system using the total kinetic energy of generators. Due to this method, reclosing should be occurred at a time where the kinetic energy of a generator is minimum [40]. Figure 7.18 shows the kinetic energy of a synchronic generator and the points where kinetic energy is minimum represented by $ORCT_1$ and $ORCT_2$. However, it should be noted that the reclosing must take step after the deionization time (T_R< reclosing time).

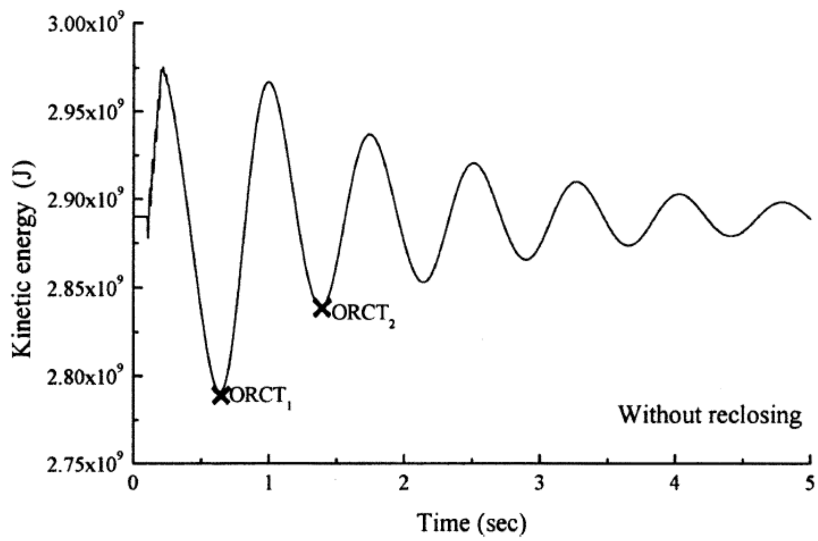


Figure 7.18 Kinetic energy of a synchronous generator subjected to a permanent fault [40]

The kinetic energy of a generator is calculated by Equation 7.2.

$$w=\frac{1}{2}J\omega_m^2 \quad (J) \tag{7.2}$$

Where J is the moment of inertia in kgm^2 and ω_m is the rotor angular velocity in mechanical rad/sec [40]. The total kinetic energy for a system is calculated by knowing the rotor speed of each generator expressed as Equation 7.3.

$$w_{total}=\sum_{i=1}^{N} w_i \tag{7.3}$$

Where N is the total number of generators in the system, and w_i represents the kinetic energy in joule for a generator i. w_i is calculated from Equation 7.4.

$$w_i = \frac{1}{2} j_i \omega_{mi}{}^2 \ (J) \tag{7.4}$$

Eventually, the stability of a whole power system is identified by the stability index w_c, which is calculated by Equation7.5.

$$w_c(s) = \int_0^T \frac{\left| \frac{d}{dt} w_{total} \right| dt}{\text{system}} \text{base power} \tag{7.5}$$

where T is the simulation time, and w_c is the cumulative absolute value of the kinetic energy change divided by the system base power.

The amount of w_c can vary depending on the reclosing time. From Equation 7.5, it can be concluded that the smaller value of w_c means the system is more stable [40].

7.11.3.3. Other Optimal Reclosing Method

Recently, numerous techniques were presented for identifying the OPRT. In Ref. [41], an adaptive optimal reclosure technique on the basis of a fault transient identification technique and an optimal reclosure timing technique was presented. The proposed method is able to estimate the transient energy of the power system and defines an optimal reclosing time for minimizing power system oscillation. In [42], an integrated auto reclosure scheme that mixes the functional benefits of adaptive and optimal reclosure scheme has been presented. In that technique, an optimal reclosure timing unit determines an optimal reclosing time for minimizing power system oscillation based on evaluating the load angle of the generator. In [43], the optimal reclosing time is evaluated from the total load angles of the DGs. In this method, the instant when the total load angles oscillation of the generators without reclosing operation become the minimum, is considered as optimum reclosing time.

7.12. Conclusion

In this chapter, the concept of autoreclosing is discussed, and the consideration for designing an autoreclosing system has been studied. Also, a model for an autoreclosing system is proposed and simulated using MATLAB Simulink. The results showed that the autoreclosing scheme could be very useful to enhance power system stability, especially in high voltage lines. However, the result of applying different autoreclosing time in the IEEE 9-bus standard system showed that the time of the reclosing might cause an unsuccessful reclosing or even cause instability. In total, the time of reclosing plays a critical role in power system stability. Finally, the methods of calculating the optimal reclosing time (OPT) has been studied in section 7.11.

Chapter 8

Conclusion and Future Work

The main goal of this thesis is to present the general concepts and classifications of power system protection schemes and power system performance enhancement using protective relays. Various methods of protection are applied to the power system equipment with the help of protective relays, which are used to prevent damages to power equipment, protect networks during a fault, and improve the power system performance.

8.1. Summary of the Research and Contribution of the Thesis

The main contribution of this research can be summarized as follows:

- The basic concept of protective relaying problems and the importance of using relays to protect power systems are studied in detail.
- Various type of protective relays, the hardware, and construction of them include analog and digital relay, and also, the equipment which is required to work with the relays has been discussed.
- The generator frequency hazardous situation and the parameters affect the frequency of the generator have been studied.
- The system frequency response model of a reheat generator has been discussed and used to investigate the factors which affect the system frequency response, such as the initial rate of frequency decline, maximum frequency deviation, and the final frequency value.

- The factors which significantly influence the system frequency response, including the initial rate of frequency decline, maximum frequency deviation, and the final frequency value, and also the interaction between these factors have been determined using the factorial design method.
- A novel method to model the power system frequency response and also to determine the significant factors influencing the power system frequency response is presented. In this way, the Box- Behnken design method is used as a statistical method to find the relationship between some factors that can affect the maximum rate of change of slope at t=0, and the time at which the slop is zero (t_z).
- To validate the proposed method, different level of input factors is applied to the system while the other parameters are constant. From the result, it can be concluded that the actual equations of the responses are very close to the actual system, and they can be used to model the system's frequency behavior.
- The load shedding methods have been studied and classified due to their characteristics. Also, Different load shedding relays, including under voltage load shedding relay and under frequency load shedding relay based on conventional methods and adaptive techniques are modeled and simulated using MATLAB Simulink environment and PowerWorld.
- The concept of transient stability is studied for first swing rather than multi-swing by using a single machine infinite bus system (SMIB) with two transmission lines.
- Using an IEEE 9-bus, it is shown that the amount of transferred power, circuit breaker speed, fast fault clearing, and reclosing are significant factors affecting transient stability.

- The concept of autoreclosing is discussed, and the consideration for designing an autoreclosing system has been studied. A model for an autoreclosing system is proposed and simulated using MATLAB Simulink to show that the autoreclosing scheme can be very useful to enhance power system stability.

8.2. Recommendations of Future Work

Some of the potential research areas for improving the performance of the protective relays in the future are presented in this section as follow:

- The factorial design method can be applied to an actual power system that helps to achieve an accurate model of a specific power system dynamic behavior and can be used to optimize load shedding.
- Using a computational intelligence-based adaptive control algorithm for load shedding can be studied in future research to optimize the amount and time of load curtailment.
- Using a combination of current, voltage, and frequency for load shedding in the case of a fault in a power system can be studied to improve the reclosing operation of the protective relays.
- In this study, to simplify the modeling process of an autorecloser relay, the proposed model has been developed with some limitations. The following areas could be considered for future work in design a multi-shot auto recloser relay that checks the synchronization status.

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Appendix A

The 27 experiments which are used in the Design of Expert are presented in Table A.1.

Table A.1 The distribution of the factor's levels for each run and related response

STD	RUN	Pstep (P.U)	R (P.U)	H (P.U)	TR (P.U)	dw/dt (P.U)	Tz (s)
10	1	-0.1	0.08	4	4	-0.0125	2.5779
22	2	-0.2	0.1	4	4	-0.025	2.9787
12	3	-0.1	0.08	4	6	-0.0125	2.9497
1	4	-0.3	0.06	4	5	-0.0375	2.2822
5	5	-0.2	0.08	3	4	-0.0333	2.0994
16	6	-0.2	0.1	5	5	-0.02	3.7275
11	7	-0.3	0.08	4	6	-0.0375	2.8915
2	8	-0.1	0.06	4	5	-0.0125	2.3308
3	9	-0.3	0.1	4	5	-0.0375	3.1504
27	10	-0.2	0.08	4	5	-0.025	2.7798
18	11	-0.1	0.08	3	5	-0.0167	2.2769
14	12	-0.2	0.1	3	5	-0.0333	2.6324
20	13	-0.1	0.08	5	5	-0.01	3.2586
9	14	-0.3	0.08	4	4	-0.0375	2.5639
6	15	-0.2	0.08	5	4	-0.02	3.0158
25	16	-0.2	0.08	4	5	-0.025	2.7798
21	17	-0.2	0.06	4	4	-0.025	2.1499
15	18	-0.2	0.06	5	5	-0.02	2.7015
17	19	-0.3	0.08	3	5	-0.05	2.2905
23	20	-0.2	0.06	4	6	-0.025	2.4471
7	21	-0.2	0.08	3	6	-0.0333	2.3921
19	22	-0.3	0.08	5	5	-0.03	3.259
4	23	-0.1	0.1	4	5	-0.0125	3.2044
26	24	-0.2	0.08	4	5	-0.025	2.7798
8	25	-0.2	0.08	5	6	-0.02	3.3923
13	26	-0.2	0.06	3	5	-0.0333	1.8991
24	27	-0.2	0.1	4	6	-0.025	3.3397

Appendix B
Presentation During MENG Program

Conference papers

R.Hesaraki, T. Iqbal, “Complete a Thermal Modeling and Analysis of a House in Iran and Design a PV System” *In Twenty-Seventh Annual Newfoundland Electrical and Computer Engineering Conference (NECEC),* Nov. 2018, IEEE.

R.Hesaraki, B. Jeyasurya, “Determination of Significant Factors Influencing the Power System Frequency Response Using Factorial Design Method” *In Twenty-Eight Annual Newfoundland Electrical and Computer Engineering Conference (NECEC)*, Nov. 2019, IEEE.

Posters

R.Hesaraki, B. Jeyasurya, “Design of Intelligent Algorithm for Current Load Shedding Relay based on transformer overloads” in Annual Research Posters Memorial University, Mar. 2019.