CHAPTER ONE

INTRODUCTION

1.1 Background to the Study

With the increasing demand in electric power, numerous changes are continuously being introduced in the power system. Advanced technologies like Flexible Alternating Current Transmission (FACTS) devices are now being used for more utilisation and control of the existing transmission infrastructure. These FACTS devices offer flexible control of the voltage magnitude, phase angle and the line impedance. With their operation, power flow in the system can be easily redistributed and therefore transmission capacity is fully utilised. They also enhance power system performance by redirecting the power from congested path to the other path which is underutilised. Owning to their many economical and technical benefits, significant interest have been geared towards the technological development of FACTS controllers with several kinds of controllers been commissioned around the world.

The major functions of these FACTS controllers include regulation of power flow in prescribed transmission routes, securing loading of transmission lines nearer to their thermal limits, prevention of cascading outages by contributing to emergency control and damping of oscillations that can threaten security or limit the usable line capacity.

However, the numerous benefits of these FACTS devices notwithstanding, they adversely cause the mal-operation of pre-existing protective relays installed within the power system prior to their deployment. Since these devices will directly alter power system quantities on a compensated line, the conventional relay characteristics may not work properly in the presence of these FACTS devices.

Also the presence of these FACTS devices in the faulted loop introduces changes to the line parameters seen by the distance relay. The impact of FACTS devices would affect both the steady state and transient trajectory of the apparent impedance seen by distance relays due to the fast response time of FACTS controllers with respect to that of the protective devices. During system faults, high fault currents through the series capacitor cause voltage to rise across the series capacitor bank, which in turn causes overvoltage that may damage the compensation devices (Biswal, Pati & Pradhan 2013). Metal-oxide-varistor (MOV) devices, connected in parallel have been used to protect the series compensation against overvoltage during faults. The MOV-protected series compensation increases the complexity of fault analysis and device protection (Srivani & Vittal 2010), (Jiang, Annakkage & Gole 2006).

The type of FACTS device, the application for which it is applied and the location of the FACTS device in the power system have various impacts on the distance protection of the transmission line (Kazemi, Jamali, & Shateri 2008).

Hence the performance evaluation of distance protection scheme in the presence of FACTS controllers which affect the apparent calculations at relay is very essential so as to develop a new setting for zones for distance relay on a transmission line.

These FACTS devices introduce operational challenges that affect the performance of distance protection schemes. They affect the fault levels seen by protection relays which can alter the sensitivity of power system protection (Sivov, Abdelsalam & Makram 2015). The operating time of relays are affected due to topological changes in the power system transmission and distribution levels which results in changes in fault level or changes the fault path thereby affecting the coordination of protection (Khederzadeh & Sidhu, 2006). Also, increased utilisation of the transmission network in the presence of FACTS controllers can result in forceful system disturbances and this can affect the performance of system protection especially those relying on system frequency. During system faults, high fault currents through the series capacitor cause voltage to rise across the series capacitor bank, which in turn causes overvoltage that may damage the compensation device (Terzija et al. 2011), (Pradhan & Joos 2007). Metal-oxide-varistor (MOV) devices, connected in parallel, have been used to protect the series compensation against overvoltage during faults. The MOV-protected series compensation increases the complexity of fault analysis and distance protection

This dissertation explores the effects of the installation of FACTS devices on the Nigeria 330kV transmission line distance relays under various fault conditions and proposes an adaptive technique to improving the protection functionality of the power system relays.

1.2 Statement of the Problem

Since the restructuring of the Nigeria power system, many literature have proposed the adoption of various FACTS compensating devices in the Nigeria power system without articulating the effects of these devices. These FACTS devices create problems for conventional distance protection scheme. Distance protection scheme measures the apparent impedance of a particular network for which it provides protection. The apparent impedance seen by the relay is influenced by the uncertain variation of series compensation voltage by FACTS devices. The control characteristics of these devices, their location on the transmission line, fault resistance especially the higher ones make this problem more severe.

This dissertation reveals an adaptive approach of the distance protection scheme for the generation of trip boundaries during various fault conditions in the presence of the FACTS compensating devices placed in the Nigeria power system.

1.3 Aim and Objectives of the Study

The aim of this research is to implement an adaptive technique for adjusting the settings of distance protection relays in the presence of FACTS devices in the Nigeria transmission network.

The objectives of this research work include;

i. To determine the impact of FACTS placement on protection relay performance in the Nigeria 330kV transmission line.

ii. To develop a model for the analysis of the FACTS devices impact on the reach of distance protection zones under different operating modes and different fault conditions.

iii. Evaluate the effect of MOV protection of FACTS devices on the distance relays considering line distributed parameters in the Nigeria transmission network.

iv. To develop an adaptive protection relay setting for various fault levels in the Nigeria power system.

1.4 Scope of the Study

The Nigeria 330kV network incorporated with Thyristor Controlled Series Capacitor (TCSC) was modelled in the environment of MATLAB/Simulink. The FACTS device was installed on the transmission line between Ikeja West to Benin in the Nigeria transmission network and the system models under fault conditions were studied. Only the distance relays of mho (admittance) type were examined with their setting zones impedance in the presence of the compensating devices. The impedance calculation for faults conditions are based on symmetrical components of voltages and relay locations.

1.5 Justification of the Study

The use of advanced technology for the enhancement of available transmission capacity is imperative. But it comes with some challenges. The rationale for this dissertation is the need to articulate proactive measures aimed at ameliorating the effects of the placement of FACTS compensating devices on the Nigeria transmission network.

CHAPTER TWO

LITERATURE REVIEW

2.1 Theory of FACTS Devices on Transmission Lines

Flexible Alternating Current Transmission Systems (FACTS) are new technology developed in recent two decades, and these have been widely put in practice in the world. FACTS are defined by the IEEE as a power electronic-based system and other static equipment that have the ability to enhance controllability and increase power transfer capability. Nowadays, power producers and system operators all over the world are faced with increasing demands for bulk power transmission, low-cost power delivery and higher reliability, to some extent; such issues are being alleviated by the developing technology of FACTS. FACTS could be connected either in series or in shunt with the power system or even in a combined pattern to provide compensation for the power system (Hingorani & Gyugyi 1999), (Blackburn & Domin 2007). Variable series capacitors, phase shifters and unified power flow controllers was the most used FACTS devices can be utilized to change the power flow which result in many benefits like losses reduced, stability margin increased etc.

The IEEE defines FACTS as alternating current transmission system incorporating electronic-based and other static controllers to enhance controllability and increase power transfer capability.

2.1.1 Types of FACTS Controllers

A FACTS controller is defined as a power electronic-based system and other static equipment that provide control of one or more AC transmission parameters. FACTS devices can broadly be categorized as shunt, series, combined series and combined series shunt (Hingorani & Gyugyi 1999).

2.1.1.1 Series FACTS Controllers

These devices are connected in series with the lines to control the reactive and capacitive impedance there by controlling or damping various oscillations in a power system. The effect of these controllers is equivalent to injecting voltage phasor in series with the line to produce or absorb reactive power. Examples are Static Synchronous Series Compensator (SSSC), Thyristor controlled Series Capacitor (TCSC), Thyristor-Controlled Series Reactor (TCSR), Thyristor-Switched Series Capacitor (TSSC), Thyristor-Switched Series Reactor (TSSR). They can be effectively used to control current and power flow in the system and to damp system's oscillations. The series controller could be variable impedance such as capacitor, reactor or power electronics based variable source of main frequency, sub-synchronous and harmonic frequencies (or a combination) to serve the desired need.

2.1.1.2 Shunt FACTS Controllers

Shunt controllers inject current into the system at the point of connection. The reactive power injected can be varied by varying the phase of the current. The ultimate objective of applying reactive shunt compensation in a transmission system is to increase the transmittable power. This may be required to improve the steady-state transmission characteristics as well as the stability of the system. Shunt controllers are thus used for voltage regulation at the midpoint (or some intermediate) to segment the transmission line and at the end of the (radial) line to prevent voltage instability, as well as for dynamic voltage control to increase transient stability and damp power oscillations.The examples are Static Synchronous Compensator (STATCOM), Static Synchronous Generator (SSG), Static VAR Compensator (SVC).

2.1.1.3 Combined Series-Series FACTS Controllers

This controller may have two configurations consisting of series controllers in a coordinated manner in a transmission system with multi lines or an independent reactive power controller for each line of a multi-line system. An example of this type of controller is the Interline Power Flow Controller (IPFC), which helps in balancing both the real and reactive power flows on the lines.

2.1.1.4 Combined Series-Shunt FACTS Controllers

In this type of controllers there are two unified controllers, a shunt controller to inject current in to the system and a series controller to inject series voltage. Examples of such controllers are UPFC and Thyristor- Controlled Phase-Shifting Transformer (TCPST).

2.1.2 Applications of FACTS Devices

FACTS controllers or devices can be used in various power applications for its performance enhancement. These devices can be used in all three states namely steady state, transient state and post transient state of the power system (Anderson, 2012).

2.1.2.1 Steady State Applications

These applications include steady state voltage control, increase of thermal loading, post contingency voltage control, loop flow and power flow control. SVC and STATCOM are preferred for voltage control where as TCSC is used for loop control and power flow control. The other steady state applications are

a) **Congestion management:** Congestion can increase the price and may become an obstruction for the free electricity trade in the present deregulated environment. FACTS devices like TCSC, TCPAR and UPFC can help to reduce congestion and smoothen location marginal price

(LMP) by redirecting the power from congested path to other path which is underutilized.

b) **Available Transfer Capacity Improvement:** Available Transfer Capacity (ATP) is the basis for a power transaction between the buyer and seller in a deregulated market. A low value of ATC implies the inability of the path for further transaction and may hinder the free competition. TCSC, TCPAR and UPFC can help in ATC enhancement while allowing more power transaction.

c) **Reactive power and Voltage control:** SVC, STATCOM can be use for this purpose.

d) **Loading Margin Improvement:** Voltage collapse occurring at the maximum load capacity is the main cause of recent world wide black outs. The maximum transfer capability of a power system can be improved by using shunt compensators efficiently.

e) **Power flow and balancing control:** TCSC, SSSC, UPFC can be used to enable the load flow through parallel lines and there by efficient utilization of lines can be made possible (Dubey, Samataray & Panigrahi 2014).

2.1.2.2 Dynamic Applications

In these applications FACTS devices are used to enhance transient stability by providing fast and rapid response, oscillation damping dynamic control of voltage during contingencies to alleviate the system from voltage collapse and sub synchronous resonance mitigation. These devices are also used for inter connecting power systems for exchanging the power between the regions over a long distance.

2.1.3 Importance of Different Types of Controllers

Series-connected Controllers impact the driving voltage and hence the current and power flow directly. Therefore, if the purpose of the application is to control the current/power flow and damp oscillation, the series Controller for a given MVA is several times more powerful than the shunt controllers (Kavaseri & Srinivasan 2011).

The shunt on the other hand, is like a current source, which draws from or injects current into the line. The shunt Controller is therefore a good way to control voltage at and around the point of connection through injection of reactive current (leading or lagging), alone or a combination of active and reactive current for a more effective voltage control and damping of voltage oscillations.

This is not to say that the series Controller cannot be used to keep the line voltage within the specified range. After all, the voltage fluctuations are largely a consequence of the voltage drop in series impedances of lines, transformers, and generators. Therefore, adding or subtracting the FACTS Controller voltage in series (main frequency, sub synchronous or harmonic voltage) can be the most cost-effective way of improving the voltage profile. Nevertheless, a shunt controller is much more effective in maintaining a required voltage profile at a substation bus. One important advantage of the shunt controller is that it serves the bus node independently of the individual lines connected to the bus.

Series Controller solution may require, but not necessarily, a separate series Controller for several lines connected to the substation, particularly if the application calls for contingency outage of any one line. However, this should not be a decisive reason for choosing-a shunt-connected Controller, because the required MVA size of the series Controller is small compared to the shunt Controller, and, in any case, the shunt Controller does not provide control over the power flow in the lines.

On the other hand, series-connected Controllers have to be designed to ride through contingency and dynamic overloads, and ride through or bypass short circuit current. They can be protected by metal-oxide varistor (MOV) arresters or temporarily bypassed by solid-state devices when the fault current is too high, but they have to be rated to handle dynamic and contingency overload (Sarangi & Pradhan 2011), (Nayak, Pradhan & Bajpai 2015). This suggests that a combination of the series and shunt controllers can provide the best of both, that is, an effective power (current flow and line voltage control). For the combination of series and shunt controllers, the shunt controller can be a single unit serving in coordination with individual line controllers. This arrangement can provide additional benefits (reactive power flow control) with unified controllers.

FACTS controllers may be based on thyristor devices with no gate turn-off (only with gate turn-on), or with power devices with gate turn-off capability. Also, in general, as will be discussed in other chapters, the principal controllers with gate turn-off devices are based on the dc to ac converters, which can exchange active and/or reactive power with the ac system. When the exchange involves reactive power only, they are provided with a minimal storage on the dc side. However, if the generated ac voltage or current is required to deviate from 90 degrees with respect to the line current or voltage, respectively, the converter dc storage can be augmented beyond the minimum required for the converter operation as a source of reactive power only.

This can be done at the converter level to cater to short-term (a few tens of main frequency cycles) storage needs. In addition, another storage source such as a battery, superconducting magnet, or any other source of energy can be added in parallel through an electronic interface to replenish the converter's dc storage. Any of the converter-based, series, shunt, or combined shunt-series controllers can generally accommodate storage, such as capacitors, batteries, and superconducting magnets, which bring an added dimension to FACTS technology. The benefit of an added storage system (such as large dc capacitors, storage batteries, or superconducting magnets) to the controller is significant. A controller with storage is much more effective for controlling the system dynamics than the corresponding controller without the storage. This has to do with dynamic pumping of real power in or out of the system as against only influencing the transfer of real power within the system as in the case with controllers lacking storage. A converter-based controller can also be designed with high pulse order or with pulse width modulation to reduce the low order harmonic generation to a very low level. A converter can in fact be designed to generate the correct waveform in order to act as an active filter. It can also be controlled and operated in a way that it balances the unbalance voltages, involving transfer of energy between phases.

2.2 Faults in Transmission Lines

A transmission line fault occurs when the insulation between phases or between phases and ground fails. Because overhead transmission lines are exposed to the various weather conditions, abnormal or faults may likely arise. Several reasons and events in our daily lives can cause a fault to occur. However, the most common factors are well recognized and are usually classified into two classes based on the causing factors, natural factor and human factors.

2.2.1 Types of Faults in the Power System

Power system faults may be categorized as shunt faults and series faults. The most occurring type of shunt faults is the Single Line-to-ground faults (SLG) and which is one of the four types of shunt faults that occur more along the power lines. This type of fault occurs when one conductor falls to ground or contacts the neutral wire. It could also be the result of falling trees in a winter storm. The second most occurring type of shunt faults is the Line-to-Line fault (LL). It is the result of two conductors being short-circuited. As in the case of a large bird standing on one transmission line and touching the other, or if a tree branch fall on top of the two of the power lines. Third type of fault is the Double Line-to-Ground fault (DLG). This can be a result of a tree falling on two of the power lines, or other causes. The fourth and least occurring type of fault is the balanced three phase fault, which can occur by a contact between the three power lines in many different forms.

2.2.1.1 Symmetrical Faults in Transmission Line

This type of fault occurs when three phases of transmission line are shorted. The fault current in this type can be calculated from single-phase impedance because the system still balanced. The magnitude of fault current is the same for all three phases but with phase shift 120^0 (Fortescue, 1918).

i) Symmetrical Component

There are many types of unsymmetrical system in electrical power system network. The best way to deal with unsymmetrical system is using symmetrical components. The unbalanced voltages and currents in power system can replace them by three separate balanced Symmetrical Components. These vectors sets are described as the positive, negative and zero sequence.

(a) Positive-sequence components are represented as three phasors having same magnitude with ± 120 degrees phase angles and sequence abc, as shown in Figure 2.1 (a).

(b) Negative-sequence components are represented as three phasors having same magnitude with ±120 degrees phase angles and sequence acb, as shown in Figure 2.1 (b).

(c) Zero-sequence components are represented as three phasors having same magnitude with zero phase angles, as shown in Figure 2.1 (c).

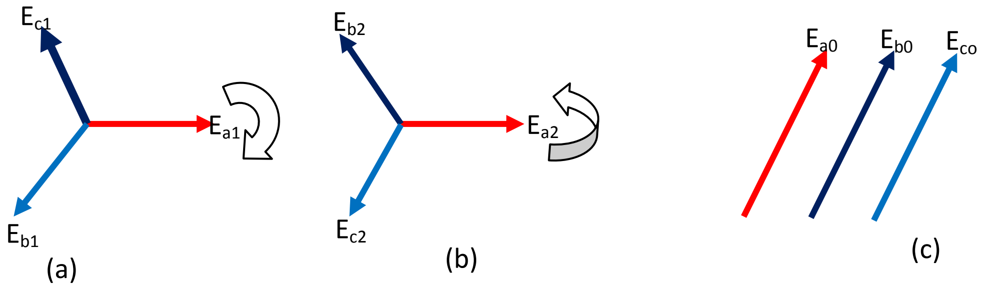

Fig 2.1 (a) Positive sequence component (b) Negative sequence component (c) Zero sequence component

The equations between phase and sequence voltage are given below (Blackburn & Sleva 2011).

$$\bar{E}_a = \bar{E}_1 + \bar{E}_2 + \bar{E}_0 \tag{2.1}$$

$$\bar{E}_b = a^2 E_1 + a\bar{E}_2 + \bar{E}_0 \tag{2.2}$$

$$\bar{E}_c = a\bar{E}_1 + a^2\bar{E}_2 + \bar{E}_0 \tag{2.3}$$

Or

$$\bar{E}_1 = \frac{1}{3}(\bar{E}_a + a\bar{E}_b + a^2\bar{E}_c) \tag{2.4}$$

$$\bar{E}_2 = \frac{1}{3}(\bar{E}_a + a^2\bar{E}_b + a\bar{E}_c) \tag{2.5}$$

$$\bar{E}_0 = \frac{1}{3}(\bar{E}_a + \bar{E}_b + \bar{E}_c) \tag{2.6}$$

Also the equations in a matrix format are given as

$$\begin{bmatrix} \bar{E}_a \\ \bar{E}_b \\ E_c \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \mathrm{x} \begin{bmatrix} \bar{\mathrm{E}}_0 \\ \bar{\mathrm{E}}_1 \\ \bar{\mathrm{E}}_2 \end{bmatrix} \tag{2.7}$$

$$\begin{bmatrix} \bar{E}_0 \\ \bar{E}_1 \\ E_2 \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \mathrm{x} \begin{bmatrix} \bar{\mathrm{E}}_\mathrm{a} \\ \bar{\mathrm{E}}_\mathrm{b} \\ \bar{\mathrm{E}}_\mathrm{c} \end{bmatrix} \tag{2.8}$$

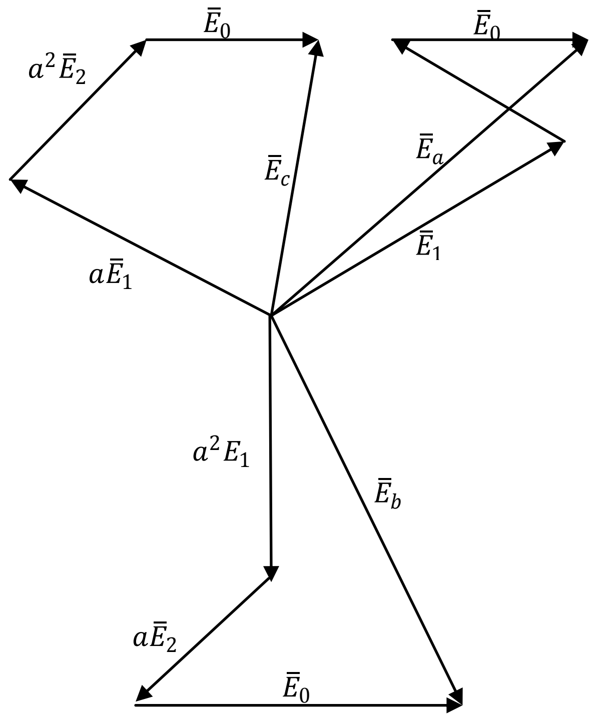

Figure 2.2: Resolution of a system of unbalanced vectors

Applying equation 2.7 and (2.8) for currents give

$$\begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} = \frac{1}{3}\begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \text{x} \begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} \tag{2.9}$$

$$\begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} = \frac{1}{3}\begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \text{x} \begin{bmatrix} I_a \\ I_b \\ c \end{bmatrix} \tag{2.10}$$

When,

$$a = 1 < 120^0 \tag{2.11}$$

$$a^2 = 1 < 240^0$$

$$a + a^2 + 1 = 0 \tag{2.12}$$

$$= \begin{vmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{vmatrix} \tag{2.13}$$

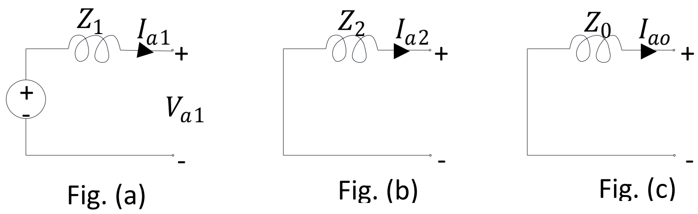

Figure 2.3: Sequence networks: (a) positive-sequence; (b) negative-sequence; (c) zero sequence (Blackburn & Sleva 2011).

From figure 2.3,

$$\bar{V}_{a1} = E_a - \bar{Z}_1\bar{I}_{a1} \tag{2.14}$$

$$\bar{V}_{a0} = 0 - \bar{Z}_0\bar{I}_{a0} \tag{2.15}$$

$$V_{a2} = 0 - \bar{Z}_2\bar{I}_{a2} \tag{2.16}$$

2.2.1.2 Unsymmetrical Fault in Transmission Line

Before fault happens in power system, it is considered as balanced system. In the order of frequency of occurrence, the types of fault that may occur in a transmission line are: single line-to-ground, line-to-line, double line-to-ground, and balanced three-phase fault. These types are called shunt fault because they occur between two points (phase and phase or phase and ground).

There are other types of fault called series fault such as one-conductor-open, and two-conductors-open (Jamali, Kazemi, & Shateri, 2008).

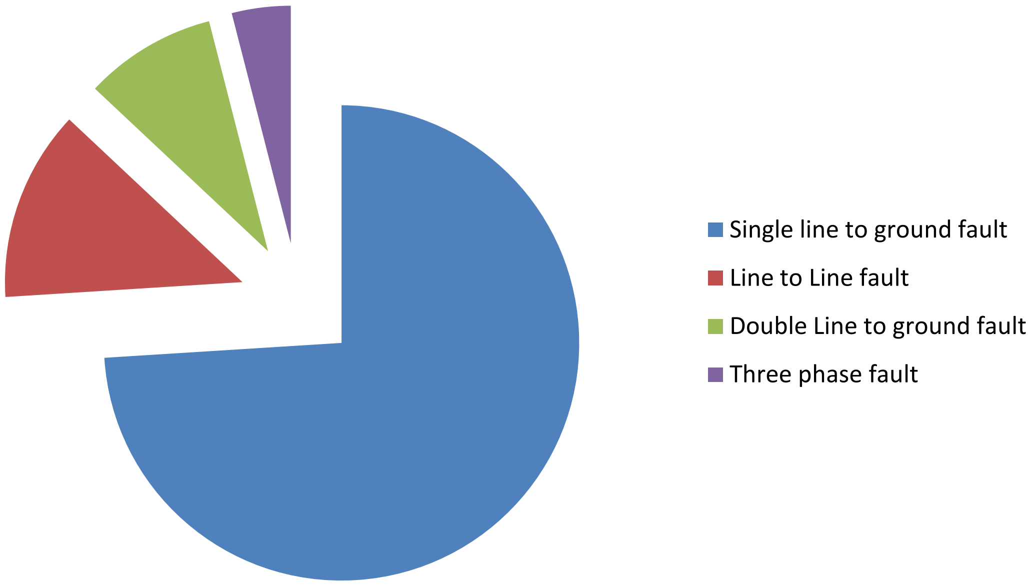

Figure 2.4: Different Fault Types

i. Single line-to-ground Fault

Figure 2.5 shows three-phase generator with a Single line-to-ground Fault at phase *a* through fault impedance.

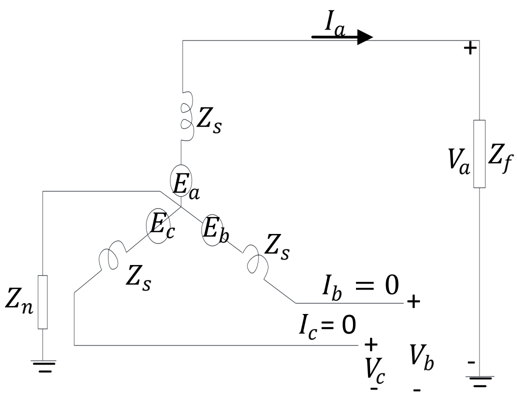

Figure 2.5: Single line-to-ground fault on phase a (Zellagui & Chaghi 2012).

$\bar{V}_{\boldsymbol{a}} = Z_f \bar{I}_a$ (2.17)

$\bar{I}_b = 0, \bar{I}_c = 0$ and $\bar{\mathrm{V}}_{\mathrm{a}} = 0$

From equation 2.9 and (2.12),

$$\bar{I}_1 = \bar{I}_2 = \bar{I}_0 = \frac{1}{3}\bar{I}_a \quad (2.18)$$

$$\bar{V}_a = \bar{V}_{a1} + \bar{V}_{a2} + \bar{V}_{a0} \quad (2.19)$$

Substitutin for $\bar{V}_{a1}, \bar{V}_{a2}$ and $\bar{\mathrm{V}}_{\mathrm{a0}}$ from $(2.14), (2.15)$and (2.16) and noting $\bar{\mathrm{I}}_1 = \bar{\mathrm{I}}_2 = \bar{\mathrm{I}}_0$,

$$V_a = E_a - \bar{I}_{a0}(\bar{Z}_1 + \bar{Z}_2 + \bar{Z}_0) \quad (2.20)$$

Substituting for $\bar{V}_a$ from (2.17) and $\bar{I}_a = 3I_0$,

$$3Z_f\bar{I}_{a0} = E_a - \bar{I}_{a0}(\bar{Z}_1 + \bar{Z}_2 + \bar{Z}_0) \quad (2.21)$$

Or

$$\bar{I}_a = \frac{E_a}{(Z_1 + Z_2 + Z_0 + Z_f)} \quad (2.22)$$

The fault current is

$$\bar{I}_a = 3\bar{I}_a = \frac{3E_a}{(\bar{Z}_1 + \bar{Z}_2 + \bar{Z}_0 + 3\bar{Z}_f)} \quad (2.23)$$

Representing equation 2.18 and (2.22) as a sequence series equivalent circuit as shown in figure 2.6.

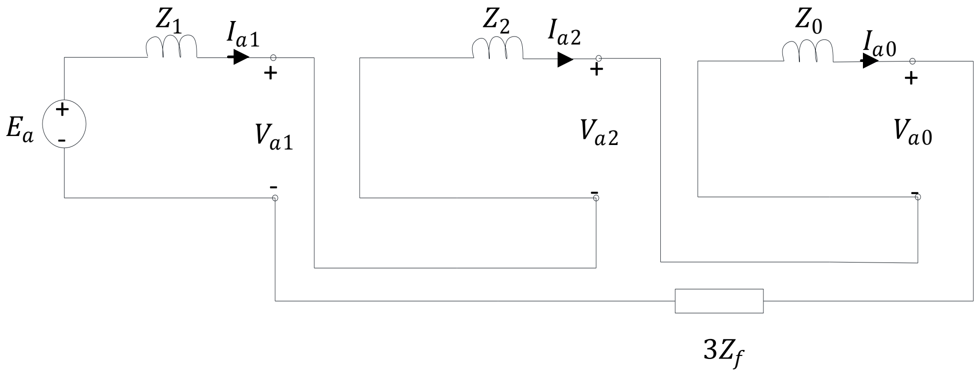

Figure 2.6: Sequence network connection for line to ground fault (Zellagui & Chaghi 2012).

ii. Line-to-Line Fault

Figure 2.7 shows three-phase generator with a line to tine fault between phases *b* and *c* through fault impedance.

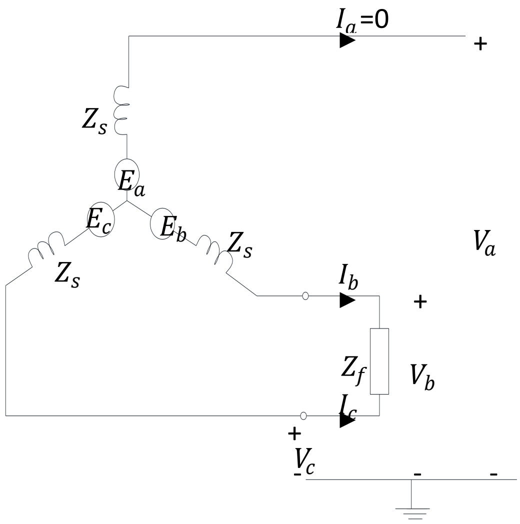

Figure 2.7: Line to line fault between phase *b* and *c* (Zellagui & Chaghi 2012).

$$\bar{I}_a = 0 \tag{2.25}$$

$$\bar{V}_b - \bar{V}_c = Z_f \bar{I}_b \qquad (2.26)$$

From equation 2.9 and (2.12),

$$\bar{I}_{a1} = -\bar{I}_{a2} \qquad (2.27)$$

$$\bar{I}_{a0} = 0 \qquad (2.28)$$

$$\bar{V}_b - \bar{V}_c = (a^2 - a)(\bar{V}_{a1} - \bar{V}_{a2}) = Z_f \bar{I}_b \qquad (2.29)$$

Substituting for $\bar{V}_{a1}$and $\bar{V}_{a2}$ from (2.14), (2.15), and (2.16) and noting $\bar{I}_{a1} = -\bar{I}_{a2}$,

$$(a^2 - a)[E_a - \bar{I}_{a1}(\bar{Z}_1 + \bar{Z}_2)] = Z_f \qquad (2.30)$$

$$[E_a - \bar{I}_{a1}(\bar{Z}_1 + \bar{Z}_2) = \bar{Z}_f \frac{3\bar{I}_{a1}}{(a^2-a)(a-a^2)} \qquad (2.31)$$

Where,

$$(a^2 - a)(a - a^2) = 3$$

$$[E_a - \bar{I}_{a1}(\bar{Z}_1 + \bar{Z}_2)] = Z_f \frac{3\bar{I}_{a1}}{(a^2 - a)(a - a^2)} \qquad (2.32)$$

$$\bar{I}_{a1} = \frac{E_a}{(\bar{Z}_1 + \bar{Z}_2 + Z_f)} \qquad (2.33)$$

The fault current

$$\bar{I}_b = -\bar{I}_c = (a^2 - a)\bar{I}_{a1} = -\sqrt{3}j\bar{I}_{a1} \qquad (2.34)$$

Equation 2.27 and (2.33) can be represented in an equivalent circuit as shown in figure 2.8

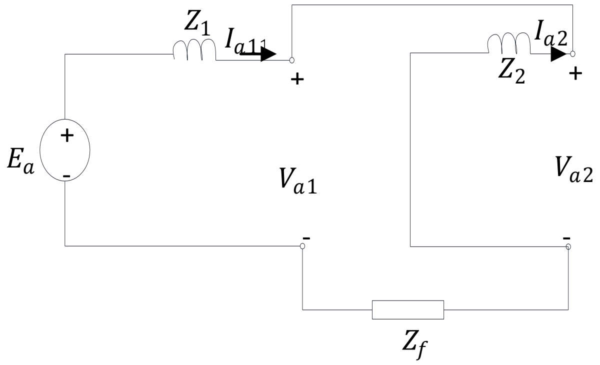

Figure 2.8: Sequence network connection for line to line (Zellagui & Chaghi 2012).

iii. Double Line-to-Ground Fault

Figure 2.9 shows three-phase generator with a line to tine fault between phases *b* and *c* through fault impedance to ground.

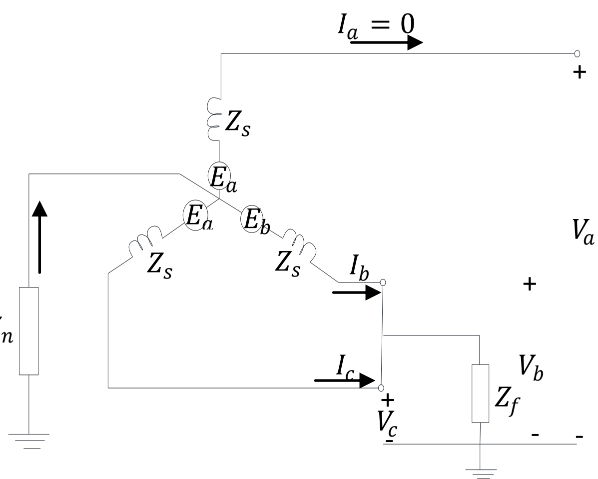

Figure 2.9: Double line-to-ground fault *bcg* (Zellagui & Chaghi 2012).

$$\bar{V}_b = \bar{V}_c = Z_f(\bar{I}_b + \bar{I}_c) \tag{2.35}$$

$$\bar{I}_a = \bar{I}_{a1} + \bar{I}_{a2} + \bar{I}_{a3} = 0 \tag{2.36}$$

$$\bar{V}_b = a^2\bar{V}_{a1} + a\bar{V}_{a2} + \bar{V}_{a0} \tag{2.37}$$

$$\bar{V}_c = a\bar{V}_{a1} + a^2\bar{V}_{a2} + \bar{V}_{a0} \tag{2.38}$$

$$\bar{V}_{a1} = \bar{V}_{a2} \tag{2.39}$$

Substituting for the symmetrical component of currents in (2.35),

$$\bar{V}_b = Z_f(a^2\bar{I}_{a1} + a\bar{I}_{a2} + \bar{I}_{a0} + a\bar{I}_{a1} + a^2\bar{I}_{a2} + \bar{I}_{a0}) = Z_f(2\bar{I}_{a0} - \bar{I}_{a1} - \bar{I}_{a2})$$

$$\bar{V}_b = 3Z_f \tag{2.40}$$

Substituting for $\bar{V}_b$ from (2.40) and $\bar{V}_{a2}$from (2.39) into (2.37),

$$3Z_f\bar{I}_{a0} = \bar{V}_{a0} + (a^2 + a)\bar{V}_{a1} = \bar{V}_{a0} - \bar{V}_{a1} \tag{2.41}$$

Substituting for the symmetrical component of voltages in (2.41),

$$\bar{I}_{a0} = \frac{E_a - Z_f\bar{I}_{a1}}{Z_a + 3Z_f} \tag{2.42}$$

Also, substituting for the symmetrical component of voltages in (2.39),

$$\bar{I}_{a2} = \frac{E_a - Z_f\bar{I}_{a1}}{\bar{Z}_2} \tag{2.43}$$

Substituting for$\bar{I}_{a0}$ and $\bar{I}_{a2}$ into (2.36) and solving for $\bar{I}_{a1}$,

$$\bar{I}_{a1} = \frac{E_a}{\bar{Z}_1 + \frac{\bar{Z}_2(\bar{Z}_0 + 3Z_f)}{\bar{Z}_2 + \bar{Z}_0 + 3Z_f}} \tag{2.44}$$

The fault current is

$$\bar{I}_f = \bar{I}_a + \bar{I}_c = 3\bar{I}_{ao} \tag{2.45}$$

Equations 2.42 and (2.44) can be represented in an equivalent circuit as shown in figure 2.10.

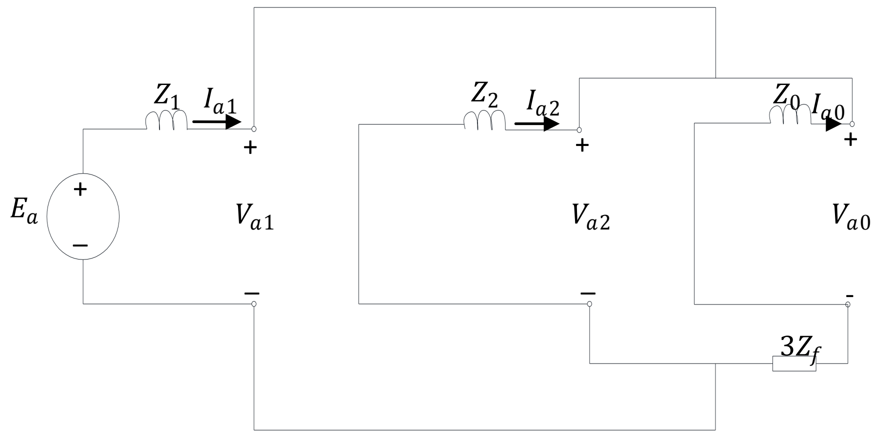

Figure 2.10: Sequence network connection for double line to ground *bcg* **(**Zellagui & Chaghi 2012).

2.3 Power System Protection Scheme

Faults in power system are inevitable due to external or internal causes, lightning may struck on the overhead lines causing insulation damage. A fault is technically defined as any abnormal change in one of the power system quantities such as current, voltage, or frequency. Fault current is the expression given to the current that flow in the circuit when load is shorted i.e. flow in a path other than the load. This current is usually very high and may exceed ten times the rated current of a piece of plant. Internal overvoltage due to switching or other power system phenomenon may also cause an over voltage which leads to deterioration of the insulation and faults. Power networks are usually protected by means of two main components, relays that sense the abnormal current or voltage and a circuit breaker that put a piece of plant out of tension. The transmission lines are the ones with highest probability for a fault to occur and thus more attentions have been focused on them. Transmission lines can be underground cables or overhead conductors and they have their own advantages and disadvantages. A fault not only impacts transmission lines but also other parts of the power grid such as generators, transformers, and of course loads (Singh, 2008). Therefore, appropriate protective relays and circuit breakers are employed to provide as much protection as possible for each section of the power system.

Protective Relays are devices that trip the circuit breaker when fault is detected. The inputs for these devices could be voltage, current, temperature, and frequency and protective relays make comparison with setting point to send tripping signal as the output. The fault is unavoidable problem in power system network and the customers demand higher levels of reliability, it is essential to increase the functionality of relays so as to reduce customer outages. Power system protection is the art and science of the application of devices that monitor the power line currents and voltages (relays) and generate signals to de-energize faulted sections of the power network by circuit breakers. The goal is to minimize damage to equipment that would be caused by system faults, if residues, and maintain the delivery of electrical energy to the consumers (Phadke & Thorp 2008). Many types of protective relays are used to protect power system equipments. They are classified according to their operating principles; over current relay senses the extra (more than set) current considered dangerous to a given equipment, differential relays compare in and out currents of a protected equipment, while impedance relays measure the impedance of the protected piece of plant.

a) Distance Protection of Transmission Line

The protection of transmission lines consists of main (or primary) and backup protection **(**in order to provide high power system reliability) which are worked in parallel. In the event of failure or non-availability of the primary protection some other means of ensuring that the fault is isolated must be provided. These secondary systems are referred to as ‘back-up protection. Remote back-up protection is provided by protection that detects an un-cleared primary system fault at a remote location and then issues a local trip command, e.g. the second or third zones of a distance relay. In both cases the main and back-up protection systems detect a fault simultaneously, operation of the back-up protection being delayed to ensure that the primary protection clears the fault if possible. Normally being unit protection, operation of the primary protection will be fast and will result in the minimum amount of the power system being disconnected. Operation of the back-up protection will be, of necessity, slower and will result in a greater proportion of the primary system being lost (Novosel et al. 2010).

Transmission lines in Nigeria operate at voltage levels from 66 kV to 330 kV. The level of voltage in transmission line is one of the most important factors considered in selecting the protective approaches to be used. Overcurrent protection of distribution radial feeders, distance protection of transmission lines, and differential protection of transmission lines are the most protective relay types in transmission lines.

Distance protection has been widely used for protecting transmission and sub transmission lines because of its simplicity, economy, suitability, and reliability. The basic principle of distance protection involves the division of the voltage at the relaying point by the measured current. The apparent impedance so calculated is compared with the reach point impedance. If the measured impedance is less than the reach point impedance, it is assumed that a fault exists on the line between the relay and the reach point. The calculated apparent impedance is compare with predetermined impedance is called reach of the relay. The apparent impedance is must larger than the impedance of reach of the relay during normal operation. However, if the fault occurs, the apparent impedance is less than the impedance reach so relay will send a trip signal to the breaker.

A distance relay is able to detect a fault in transmission line depends on the impedance of transmission line which is a function of length of transmission line or power system cable. The reach point in distance relay comes from the resistance and capacitance per kilometre which is known for specification of each conductor in transmission line. The change in determine impedance because the fact that current will increase and voltage decrease when fault occurs. Therefore, the impedance will decrease according to ohm's law (Z= V/I), and when distance relay compare this value with preset value, it will be able to detect the fault and its location. The distance relay can only detect fault for area between the reach points and relay location, so it's necessary to select the right reach point for distance relay on length transmission line (Tziouvaras, Alturve, Benmouyal & Roberts 2004).

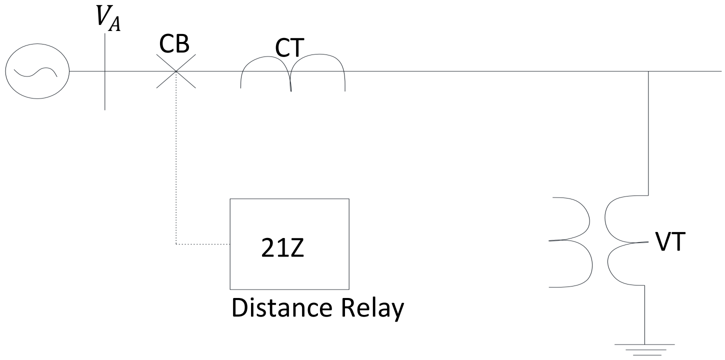

Figure 2.11: Basic distance protection scheme

In the figure 2.11, the distance relay takes the voltage and current from voltage transform (VT) and current transform (CT). Then, calculate the apparent impedance, and compare this value with setting value (reach point) to detect fault in transmission line.

(b) Overcurrent Protection of Distribution Feeders

Protection of distribution feeder in transmission line depends on the principle operation of overcurrent relay. The magnitude of fault current varies according to the fault position. The fault currents are the highest when fault occurs close to the source, and its value will decay when the distance between fault location and the source increases. The principle operation of overcurrent relay depends on the magnitudes of fault currents (Ernst et al. 1992). The following are the data required for a relay setting.

a) A one-line diagram of the power system includes the type and rating of the protection devices.

b) The impedances in ohms, per cent or per unit, of all power transformers, rotating machine and feeder circuits

c) The maximum and minimum values of short circuit values of the fault currents.

d) The maximum load current through protection devices.

e) The starting current and their times of induction motors.

f) The transformer inrush, thermal withstands and damage characteristics.

g) Decrement curves showing the rate of decay of the fault current supplied by the generators

h) Performance curves of the current transformers.

(c) Directional Relay for High-Voltage Transmission Line

Unlike the distance relay, the directional relay needs to receive information from both ends, and transfer the information using a communication channel. That because the effect of current in-feed in transmission line which leads to wrong decision for relay based on one end information.

Each relay has a forward overreaching (FO) and a backward reverse (BR) setting. The FO setting is selected so that the relay can sense the faults occurring in the forward direction, overlooking the region from the relay position toward the adjacent line terminal and beyond. The BR setting is selected so that the relay can sense the faults occurring in a backward direction, causing a reversal of power flow. If the relay R1 (At location A) has sensed the fault at location X1 in zone FO, which is behind the relay R2 (At location B) of the line, then the relay is blocked by relay R2 from operating. On the other hand, when relay R2 senses a fault at location X1 in a BR zone end, it can communicate to R1 not to trip by sending a blocking signal. If a fault occurs at a location between the two relays (as in location X2), the blocking signal will not be sent and both relays will operate simultaneously.

(d) Differential Relay of High-Voltage Transmission Line

This type of relay use to protect transmission lines when the high-voltage transmission lines are not sufficiently protected using the other types. Differential relay make the decision by comparing the measurements from two ends. It is provide 100% protection of transmission lines with minimal effect caused by the rest of system. For this reason, differential relay used to protect high-voltage transmission line that have a strategic importance or have difficult application such as series compensator or radial system configuration. It can be classified according to the type of the communication media and the type of the measurement compared. Metallic wire, leased telephone lines, microwave radio, and fiber-optic cables are most communication media used in differential relay (Terzija et al. 2011). The comparison inside the relay either phase comparison or both ends directly compared. It may convert the currents into square waves or composite waveform converted into binary to use for phase comparison. In case of both ends directly compared, it samples of each current transmitted to other or convert each current into sequence current and composite signals from both side. The material which use in communication channels and comparison methods make the differential relay more expensive than other type and that is considered as a disadvantage for this relay (Novosel et al. 2010).

2.3.1 Principal Characteristics of Protection System

For system protection to be effective, the following characteristics must be met (Zellagui & Chaghi 2012).

i. Reliability: assurance that the protection will perform correctly in presence of faults on electrical transmission and distribution line.

ii. Selectivity: maximum continuity of service with minimum system disconnection.

iii. Speed of operation: minimum fault duration and consequent equipment damage and system instability.

iv. Simplicity: minimum protective equipment and associated circuitry to achieve the protection objectives.

v. Economics: maximum protection at minimal total cost.

The protection schemes may be pilot aided scheme or non pilot aided scheme. The distance relays used in pilot aided scheme communicate between each other to determine where the fault occurs on the transmission line or not (Li, Lai, & David 2000). The relays in Non-pilot aided scheme do not communicate between each other and instead use delays and other forms of coordination to determine whether the fault is located on the transmission line or not. Under the Non-pilot aided scheme, two categories are available; the stepped distance and the Zone 1 extension.

For the stepped distance protection scheme, any fault that occurs in the mid point of the transmission line and therefore fits into the each relay Zone1 will be cleared by the relay located at the each ends of the line. If fault however is located at the end zone of each transmission line, which is also known as a closing fault, it will be cleared instantly by the relay near the fault but will not be cleared instantly by the relay at the far end of the transmission line because the fault does not fall in its Zone 1. The main reason to modify the stepped scheme with the pilot aided scheme is to speed up the time of clearing faults for faults that occur in the end zones of the transmission line. Pilot schemes speed up the time of clearing faults that occur in the end zones an inside the Zone 2 of the local relay by communicating the relay at the remote end of the line to determine if the fault is actually on the transmission line. Therefore all pilot aided schemes require that a communication channel be provided over this two relays. Over this communication channel, the two relays share information in regarding the general location of the fault allowing the clearing of fault on the transmission line to occur as fast as possible. The most common pilot aided scheme are: direct under reaching transfer trip (DUTT), permissive under reaching transfer trip (PUTT), permissive over-reaching transfer trip (POTT), hybrid permissive over reach transfer trip (Hybrid-POTT) and directional blocking scheme (DBS).

In a deregulated or decentralized market, in order to meet the power demand with limited right-of-way, utilities are trying for the optimum utilization of existing power assets. Incorporation of series compensation provides better utilization of the existing transmission line. Multi terminal lines are often used both at transmission and sub-transmission levels. Distance relay has under reach problem due to in feed issue with three terminal lines and overreach problem due to the presence of series compensation in a line. This may cause relay mal-operation and such action may lead to cascaded outage when the power system operates at a stressed condition. Communication assisted scheme like DUTT may be applied for protection of three terminal lines and has better performance than conventional distance relay using local information only. With increased in feed current, when the overlapping between Zone1 distance elements vanishes, fault in a section of three terminal lines remain undetected by DUTT scheme. Similarly in a series compensated line as the compensation level varies, distance relay seeks information on the compensation level present in the line for correct relay decision. To detect and clear fault with a high degree of selectivity and dependability the relay setting must be changed according to current operating condition of the power system. To improve the relay performance data from both ends of the line are applied. Conventional protection scheme which uses both end data for protection suffers with mal-operation for a high resistance fault.

Zone 3 element of distance relay takes decision based on local measurements. It encounters the problem of unwanted tripping during overload and is the main contributing reason of cascaded outage and subsequent blackout. In recent years, due to competitive environment and transmission line being operated close to their limits and Zone 3 maloperation are more prevalent as a result of load encroachment (Vournas, Nikolaidis, & Tassoulis 2006).

2.3.2 Protection System Components

Generally protection system consists of three main components which are protection devices (relay), instrument transformers (current transformers CTs and voltage transformers VTs) and circuit breakers.

(a) Current Transformers

They provide a current proportional to the current flowing through the primary circuit in order to perform energy metering or to analyze this current through a protection device. The secondary is connected to low impedance (used in practically short-circuited conditions). BS 3938 specifically defines current transformers designed for protection under the heading class X.

According to the British Standard, class X is defined by the rated secondary current, the minimum knee-point voltage, the maximum resistance of the secondary winding and the maximum magnetizing current at the rated knee-point voltage. Rated knee-point voltage (VK) at the rated frequency is the voltage value applied to the secondary terminals, which, when increased by 10%, causes a maximum increase of 50% in magnetizing current. While the maximum resistance of the secondary winding is the maximum resistance of this winding, corrected at 75°C or at the maximum operating temperature if this is greater. The maximum magnetizing current is the value of the magnetizing current at the rated knee-point voltage, or at a specified percentage of this current.

(b) Voltage Transformers

A voltage transformer is designed to give the secondary a voltage proportional to that applied to the primary. For a VT, the primary voltage/secondary voltage ratio is constant; the main types are the electromagnetic voltage transformer. Voltage transformers used for protection are in compliance with IEC 60044-2. The IEC accuracy classes are 3P and 6P. In practice, only class 3P is used, the accuracy class is guaranteed for the following values, voltages between 5% of the primary voltage and the maximum value of this voltage which is the product of the primary voltage and the rated voltage factor.

(c) Protection Devices (Relays)

One of the important equipments in the protection of power system is the protective relay. IEEE defined a relay as an electric device that is designed to interpret input conditions in a prescribed manner, and after specified conditions are met to respond to cause contact operation or similar abrupt changes in associated electric control circuits (Hingorani & Gyugyi 1999). Thus the main function of protective relays is to separate a faulty area by controlling the circuit breaker with the least interruption to give service. The relay are automatic devices used to detect and to measure abnormal conditions of electrical circuit, and closes its contact with the system. There are many types of relay can be used in protect transmission lines systems according to their characteristic, logic, actuating parameter and operation mechanism such as magnitude relay, instantaneous relay, differential relay, directional relay, and distance schemes (Gajbhiye, Gopi, & Soman 2008).

The main objective of protective relay is to detect any abnormal change in power system quantities such as voltage and current values and bring it back into operative conditions when possible. When Relay detects the Fault in protective zone, the relay sends signal to circuit breaker to clear and isolate the faulty section. The relays depend on current and voltage and relays cannot afford the high voltage and current, so we have to use current transformer (CT) and voltage transformer (VT) to reduce the magnitude of faulty current and voltage values to avoid damaging the relays. Currently available relays are small in size and high in accuracy and classified in four types. These are:

i. Electromechanical Relays.

This is the earliest relay invented which uses electrical and mechanical devices or a combination of both to switch the breaker. When the relay detects the fault, it forces mechanical contact using magnetic field to open circuit breaker. Galvanic isolation between inputs and outputs is a main advantage of this relay. There are different types of this relay such as attracted armature, moving coil, induction, thermal, motor operated, and mechanical (Jamali & Shateri 2010).

ii. Static Relays

When the first static relay was designed in 1960, it was based on electronic devices to perform the relay characteristic instead of coils and magnetic field. The first version was made by discreet devices such as transistors and diodes with resistors, capacitors and inductors. The advantages of this relay are: smaller size, more accurate, and is easier to change the characteristics of the relay.

iii. Digital Relays

Digital relay is an advanced relay that uses analog to digital conversion of all measured quantities. Also, it uses microprocessor to implement the protection algorithm. This process uses counting technique or Discrete Fourier Transforms (DFT) to implement the algorithm. The digital relay has hardware and software components. In addition, it can be used as a part with another type of relays by simply downloading the software to the RAM or EEPROM. It has the ability to function offline for testing purposes. Typically, the quantities used to detect faults are current, voltage, impedance, and phase of the protected transmission line. The disadvantage of this relay is that it takes a longer time to process when compared with static relays (Kazemi, Jamali, & Shatari 2008).

iv. Numerical Relays

Numerical relays are the advanced version of digital relay. They use one or more digital signal processors (DSP) optimized for real time signal processing, running the mathematical algorithms for the protection functions. This relay is made as lower cost and size of microprocessors, memory and input/output circuitry leads to a single item of hardware for a range of functions. Also, the process in this relay faster than digital relay because the Discreet Signal Processing can run in parallel (Ha & Zhang 2004).

(d) Circuit Breaker

The International Electrotechnical Commission (IEC) Standard, IEC 60947-2 defines a circuit breaker as “a mechanical switching device, capable of making, carrying and breaking currents under normal circuit conditions and also making, carrying for a specified time and breaking currents under specified abnormal circuit conditions such as those of short-circuit. The protective relay detects and evaluates the fault and determines when the circuit should be opened. The circuit breaker functions under control of the relay, to open the circuit when required. A closed circuit breaker has sufficient energy to open its contacts stored in one form or another (generally a charged spring). When a protective relay signals the circuit breaker to open the circuit, the stored energy is released causing the circuit breaker to open. Except in special cases where the protective relays are mounted on the breaker, the connection between the relay and circuit breaker is by hard wiring.

(e) Metal Oxide Varistors

The Metal Oxide Varistor scheme consists of a capacitor bank, metal-oxide-varistor bank, a triggered bypass air gap, a damping reactor, and a bypass switch as shown in Figure 2.14(a). The significant part of the protection system is the MOV device which has nonlinear voltage-current characteristics as shown in Figure 2.14(b). This figure shows that for the voltage across the MOV device below the overload voltage (threshold voltage, or protective voltage, V_{prot}) , the

MOV acts as an open circuit. For voltages above the V_{prot} the MOV acts as a resistor. The higher the overload voltage, the lower is the MOV resistance. MOV devices have nonlinear characteristic and are used for overvoltage surge protection. During high transient voltages, the MOV clamps the voltage to a safe level and dissipates the potentially destructive energy as heat, thus protecting the circuit element from overvoltage and preventing system from damage. The MOV consist of series and parallel arrangement of zinc-oxide disks to achieve the required protective voltage level and energy requirements. The series capacitor bank on each phase typically consists of a number of capacitor unit connected in a series –parallel arrangement to make up for the required voltage, current, and MVar rating.

The triggered air gap in the protection scheme is controlled to spark over in an event when the energy absorbed by MOV exceeds its nominal power rating. It is typically used as an intermediate bypass device since it is faster than the bypass circuit switch but not as instantaneous as the MOV. In the case of prolonged gap conduction (such as delayed fault clearing), the bypass switch automatically closes to limit the excess energy for both MOV and the triggered air gap. The damping reactor limits the magnitude of the capacitor discharge current during the spark over of the triggered gap or the bypass breaker switch.

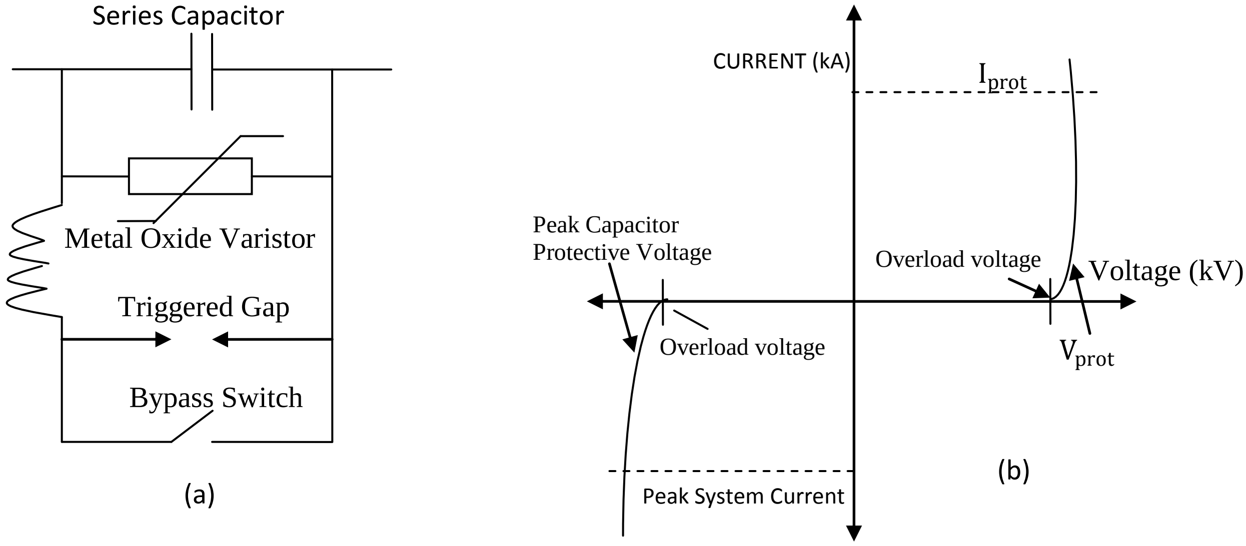

Figure 2.12 (a) MOV typical overvoltage protection scheme, and (b) V-I characteristics

During normal system operation, the equivalent impedance of the MOV connected in parallel with the capacitor is purely capacitive since the MOV does not conduct any current. During faults, the MOV action modifies the per phase line impedance.

2.3.3 Zones of Distance Protection

Protection is arranged in zone in order to limit the broadness of the power system which is disconnected when a fault occurs. The protection zones overlap around circuit breakers. The purpose is to make certain that no section of the system is left unprotected. Back-up protection is provided to ensure that the faulted element of the system is disconnected even if the primary protection fails to isolate the faulted element. Back-up protection can be provided locally or from a remote location. Local back-up protection is provided by equipment that is in addition to the equipment provided for primary protection whereas remote back-up protection is provided by equipment that is physically located at substations away from the location where equipment for primary (Eissa, 2005).

A distance relays will have instantaneous directional zone 1 protection and one or more time delayed zones. The tripping signal produced by zone 1 is instantaneous as it should not reach as far as the bus bar at the end of the first line so it is set to cover only 80-85 percent of the protected line. As for the other zones, they act as a back-up of the first zone making there is delay in seconds within those zones. The protection of each zone normally includes relays that can provide backup for the relay protecting the adjacent equipment (Zellagui & Chaghi 2012). The protection in each zone should overlap that in the adjacent zone; otherwise, a primary protection void would occur between the protection zones. This overlap is accomplished by the location of the CTs key sources of power system information for the relays.

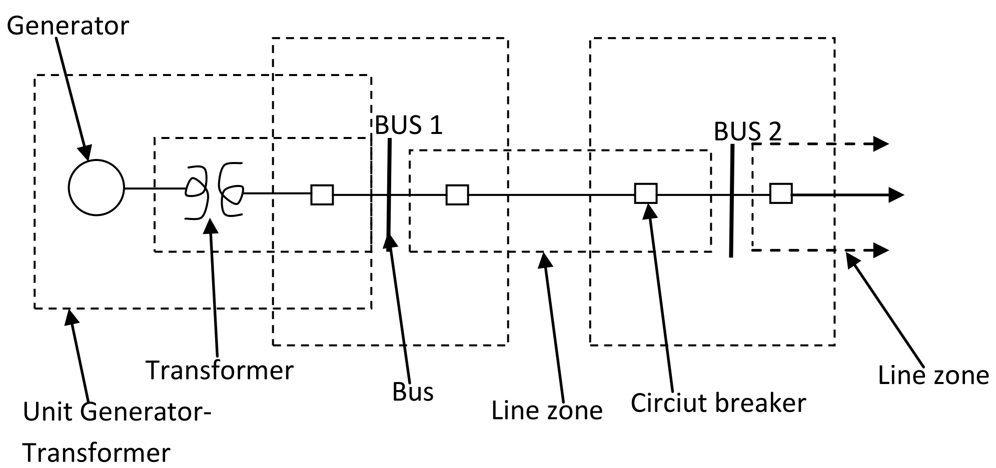

Figure 2.13: Protection system zones (Primary and Backup protection)

2.3.3.1 Setting Zones for MHO Distance Relays

Distance protection is so called because it is based on an electrical measure of the distance along a transmission line to a fault. The distance along the transmission line is directly proportional to the series electrical impedance of the transmission line. Impedance is defined as the ratio of voltage to current. Therefore, distance protection measures distance to a fault by means of a measured voltage to measured current ratio computation (Zigler, 2008), (Zellagui & Chaghi 2012).

The distance relay is used to detect and clear the power system from faults near the transmission line. It performs this type of protection by measuring the voltage and current and using this to calculate the impedance of the transmission line (Xu et al. 2007). When the measured impedance is less than the known impedance of the line, it indicates that the line is shorter than expected and indicating that the line is faulted but due to inherent inaccuracies of the current transformers (CT) and voltage transformers (VT), the impedance calculation made by the CTs and VTs may not guarantee to be accurate. Due to the inaccuracies of CTs and VTs, the relay may measure the fault as being on the transmission line it is protecting (Megahed, Moussa, & Bayoumy 2006). This will cause the relay to trip the circuit breaker and shut down the transmission line when it did not need to be. Because of these inaccuracies of CTs and VTs, distance zones of protection are not set to be on the boundaries of the transmission line. The zones of protection that are set to protect some parts of the transmission line for example, Zone 1 is set to be under-reaching (is set to only reach 80% of the total line. The zones set to cover more than its length of the transmission line is said to be overreaching (Zone 2 and Zone 3). Zones of protection are also set to protect in the forward direction or in the reverse direction. Zones set to protect in the forward direction are said to be looking into the line, while zones set to protect in the reverse direction are said to be looking out of the line. The philosophy of setting relay is three forward zones and one reverse zone to protect EHV transmission line between busbar A and B with total impedance Z_{AB} as shown in figure 2.13.

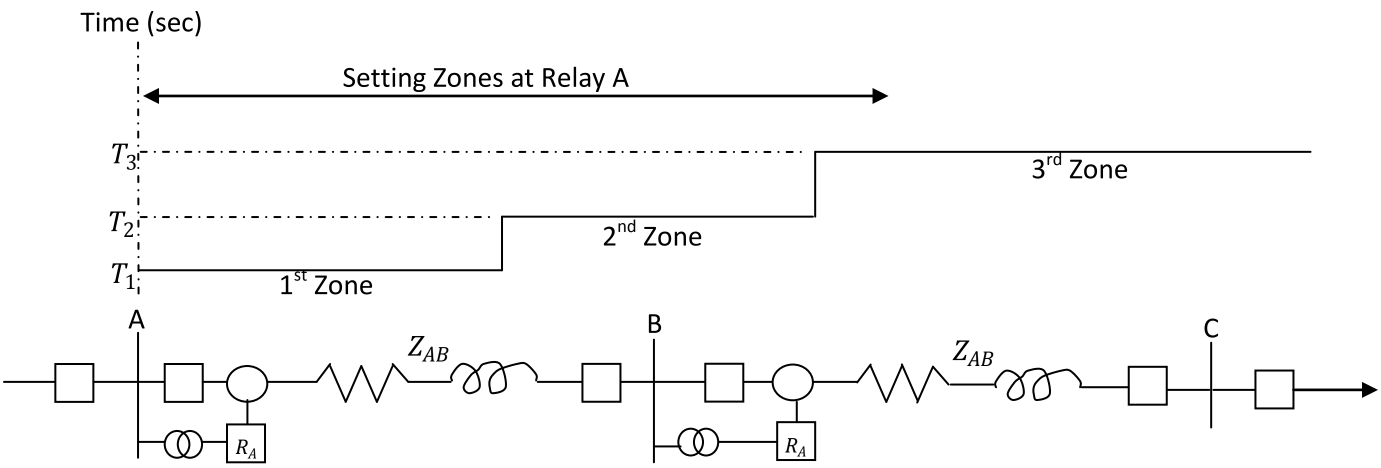

Figure 2.14: Zones of Protection

Distance relays are widely used in the protection of transmission lines. Such a relay is designed to operate only for faults occurring between the relay location and the selected reach point thus discrimination of faults that may occur in different line zones. Since the impedance of a transmission line is proportional to its length, distance relays have the capability of measuring the impedance of a line up to a predetermined point (the reach point). The basic principle of distance protection involves the division of the voltage at the relaying point by the measured current (Rockefeller et al.1988). The apparent impedance so calculated is compared with the reach point impedance. If the measured impedance is less than the reach point impedance, it is assumed that a fault exists on the line between the relay and the reach point.

A transmission line is normally divided into several protection zones, such as zone 1, zone 2and zone 3. The distance relay in location A is typically set to act as main protection for faults taking place within zone 1, and backup protection for faults occurring within zones 2 and 3. The reach of zone 1 is defined as 80% of the line between location A and location B, based on the impedance of the line. Zone 1 is not set to cover the full 100% of the line to prevent overreaching due to transient voltage or current measurement errors. The reach for zone 2 is typically set to 120% of the protected line. Zone 2 ensures full coverage of the protected line. Finally, the reach for zone 3 is typically set as 100% of the primary plus 120% of the adjacent line as a backup protection for the entire adjacent line. If the fault within the primary protection zone 1, the distance relay would instantaneously send a trip signal to open the circuit breaker. If a fault occurs within backup zone 2 or 3, the relay tripping signal would be delayed by some predefined number of cycles to give time for other protective system to respond. The relay would send a trip signal if the fault is still present after the delay.

2.4 Review of Related Literature

The presence of FACTS devices in the fault loop will make the voltage and current values at distance relay locations to be changed in both steady and transient state, and the impedance seen by distance relay will be affected. Many researchers have investigated the FACTS devices impact on performances of distance relays.

Sidhu et al. (2005) presented the effects of two types of shunt controller FACTS devices, namely the static synchronous shunt compensator and static VAR compensator. In this work, shunt controllers were presented as shunt reactance to calculate the transmission line impedance and artificial neural network was used for detecting and classifying the faults. Static VAR Compensators (SVC) and Static Synchronous Compensator (STATCOM) can cause under-reach and incorrect phase selection. Also, this work discussed the over-reach phenomena caused by employing STATCOM in weak systems only. The results showed that the distance relay is not the best relay in a mid-point STATCOM connected transmission line. In addition, STATCOM caused incorrect phase selection and increased the operation time of distance relay. In Hemasundar, Thakre, and Kale (2014), detailed modelling of distance relay and

STATCOM were presented using Power System Computer Aided Design (PSCAD/EMTDC). Different fault types and location are simulated with different operation mode of STATCOM. The simulation results showed the under-reach and over- reach problems resulted from injected reactive power to the system. The locations of STATCOM and distance relay have a significant effect on apparent impedance seen by protective relay.

Kazemi, Jamali, and Shateri (2008), discussed the distance relay mal-operation when applied to protected transmission line that has static synchronous series compensator (SSSC). Mathematical calculations for apparent impedance in presence of SSSC in transmission line under different fault types are studied. This work reported that SSSC injected voltage caused a variation in the values of measured impedance. The result of the report was justifiable if compared to the works in Khederzadeh, Ghorbani, and Salemnia (2009), where detailed model of SSSC and its control were presented. Analytical study based on voltages and currents symmetrical components for single phase to ground fault to show the impact of SSSC on distance relay performance was investigated. The simulation results showed that the error in apparent resistance increased in capacitive mode more than in inductive mode and the apparent reactance error increased in inductive mode more than in the capacitive mode. The apparent resistance and reactance increase in presence SSSC and the impact of SSSC is smaller for farther A-G faults.

New equivalent symmetrical components of a 48-pulse SSSC and apparent impedance calculations for phase to ground and phase to phase fault were presented in Shojaei and Madani, 2010. The simulation results showed the apparent resistance and reactance values were increased in both capacitive and inductive compensation mode due to the effect of coupling transformer leakage impedance.

Khederzadeh and Ghorbani (2012), presented the impact of voltage sourced controller (VSC) -Based multiline FACTS controller on performances of distance relay. Single phase to ground and phase to phase fault with multiline FACTS controller are studied analytically. The simulation results showed the distance relay mal-operate when power flow controlled in the system using multiple line FACTS controller such as generalized unified power-flow controller (GUPFC). A comparison between apparent impedance for uncompensated and compensated line with Unified Power flow Controller (UPFC) based on new pi-model is presented. Detailed modelling of UPFC during power swing condition and impact of different.

In Mrehel (2013), new setting rule of the zones of distance relay to mitigate STATCOM effects when it is connected in a mid-point was discussed. The suggested setting rules are based on the simulation results to mitigate the error in impedance measurement. Different setting rules for under-reach and over-reach are proposed in this work. Also impedance relay based on digital distance relay algorithm using MATLAB/SIMULINK environment and a mathematical model of STATCOM was presented in Dash, Pradhan, & Panda (2001). The analytical and simulation results showed the impact of STATCOM on distance relay for single line to ground fault. According to this work, the distance relay will not operate because the impedance trajectory shown the fault out of protected area and are presented using Power System Computer Aided Design (PSCAD/EMTDC). Different fault types and location are simulated with different operation mode of STATCOM. The simulation results showed the under-reach and over- reach problems resulted from injected reactive power to the system. The locations of STATCOM and distance relay have a significant effect on apparent impedance seen by protective relay.

Numerous research works have proposed for the adoption of FACTS devices in the Nigeria transmission network owing to the benefits of these devices, but only a handful have actually examined the effects of these devices on distance relay tripping characteristics. Yusuf & Nwohu (2015) investigated the effects of Unified Power Flow Controller (UPFC) on distance relay in Nigeria 330kv (North Central) Network. The case system modelled in the environment of Power System Computer Aided Design (PSCAD) deduced by simulation analysis that the presence of UPFC in a faulted transmission loop, protected by distance relay greatly affects the trip boundaries of the distance relay by setting it to either over reaching or an under reaching state. However, this method was only applied to a medium length line of just about 120km thereby neglecting the effect of distributed parameters. The effects of protective MOV operation during fault conditions were also not considered. No solution was proffered to mitigating these effects in the Nigeria power system.

For series compensated lines protected by MOV, several adaptive distance relaying methods have been proposed to correct the relay operation during fault conditions. In Bhalja & Maheshwari (2008), the method used phasor-measurement units (PMUs) at both ends of the line with a dedicated communication channel to compute the compensation level during a fault and adapt relay setting accordingly. The compensation level was determined by subtracting the measured impedance between PMUs from a known line impedance without series compensation. This method considered both cases with the capacitor placed at the end and in the middle of a transmission line. However, for the second case, the method's approach did not address overreaching issues for faults occurring between the relay location and the series capacitor. Also, this method used a medium length transmission line model and neglected the effects of the distributed parameters.

In Zhou et al. (2006), the simulation results of employing UPFC on distance protection was analyzed. This work investigated only the effects of fault location and voltage magnitude of the shunt part of the UPFC but the influence of the load angle variation on the impedance seen by the relay was not considered. The impact of the following factors for a double circuit transmission line were studied in Jamali et al. (2009); fault location, phase angle, voltage magnitude and ground fault resistance. Whereas the loading conditions were kept constant and there was no solutions proposed to solving the identified effects. In Chauhan, Tripathy & Maheshwari (2014), the errors in the estimation of impedance seen by mho relay due to the presence of UPFC in the transmission line was studied. These errors occur due to rapid change in the compensation parameters such as shunt reactive current and series voltage injection into the transmission line. The study presented the cause of under reach /overreach of Mho relay due to error in impedance calculation that lead to mal-operation of the relay for faults like single line to ground fault specifically. The effect of fault location and fault resistance were investigated. The performance of quadrilateral characteristics relay under fault conditions was also evaluated. The study suggested the supremacy of quadrilateral relay over Mho relay during high resistance fault on UPFC compensated transmission lines. The need for adaptive relaying scheme for FACTS compensated transmission line was recommended.

The application of Modified Optimization (MPSO) technique for optimal settings zones for Mho distance relay protected 400kV single transmission line of Eastern Algerian Transmission network compensated by TCSC connected at midpoint was studied in Zellagui & Chaghi (2013). The effect of TCSC insertion on the total impedance of a protected line with respect to injected variable reactance value (X_{TCSC}) in capacitive and inductive boost mode depending on the firing angle was considered. This work compared the performance of the proposed Modified Particle Swarm Optimisation (MPSO) method with an analytical method. The findings demonstrated the outstanding performance of the proposed MPSO over analytical method in terms of computation speed, rate of convergence and feasibility.

According to Benmouyal & Mahseredjian (2001), the equivalent MOV/capacitor per phase impedances were used to compute the new sequence impedances of the transmission line impedance matrix. This method ultimately set the trip boundaries of a quadrilateral-type distance relay. The adaptive distance relaying method, however, works only for the case where the series capacitor placed at the line terminal directly following the distance relay. If the capacitor was placed elsewhere in the line, the method would risk significant overreaching/underreaching issues. This method was also developed for a medium length transmission line neglecting the line's distributed parameters.

Jyoti & Reshmita (2017) presented an adaptive zone selection algorithm for the transmission line with mid-point connected STATCOM. The impact of STATCOM on distance protection was investigated for different fault types, fault resistances and load angles. The system elements and STATCOM controller were modelled using PSCAD/EMTDC. This work proposes a new adaptive zone selection algorithm based on the calculation of compensating impedance. The compensating impedance was calculated depending upon the current injected or absorbed by the STATCOM. This method concluded that the proposed adaptive technique was effective for accurate zone tripping thereby mitigating both the under reach and overreach effects of STATCOM. According to Kumar, Chowdary and Babu (2013), Artificial Neural Network can be used to test for the effects of series compensated transmission line on distance protection under various fault conditions. The result indicated that the presence of a series compensator TCSC changes the impedance measured by the relay used by the protection system which causes mal-operation of protective and also shows wrong distance measurement. This mal-operation was avoided by ANN training by back propagation algorithm. The ANN based relay gives promising results for tripping conditions and also the correct distance where the fault has occurred compared to the conventional relay in the presence of TCSC.

Song, Johns and Xuan (2006), used the classification technique based on Artificial Neural Network (ANN) examine the effect of series compensation on distance relay used to protect transmission line. However the method involves a lot of empirical risk minimization and suffers from drawbacks. The performance of the classification schemes have not been investigated over extensive test cases and the compensation level was kept constant. Also the classification scheme based on wavelet transformation was suggested in

Megahed, Monem and Bayoumy (2006); the proposed technique was validated only for limited cases and involved a lot of assumptions especially on the compensation level.

In Dash, Pradhan, & Panda (2001), the presented method attempted to adapt relay reach setting to different cases of line percent compensation. This method made a number of assumptions including the information about the presence or absence of the capacitor and the amount of compensation provided to the relay a priori. However, the effects of MOV action on the equivalent MOV/capacitor impedance were neglected. Also the method was applied for a series capacitor at a terminal of a medium length transmission line.

In this dissertation, a detailed modelling of distance relay is presented and the proposed model was verified under a variety of fault types and fault locations. The impact of series FACTS controller (TCSC) on the performances of distance relay was analytically investigated. Also considered are the distributed parameters of a long transmission line with series compensation that would result in underreach or overreach operation. An adaptive setting method for a distance relay of a long transmission compensated line considering distributed line parameters and MOV operation are presented for different fault types.

2.5 Summary of the Review of Related Literature

Related literature has discussed the effects of FACTS devices on the zones settings of protective relays. Yusuf & Nwohu (2015) studied the effects of Unified Power Flow Controller (UPFC) on distance relay in the Nigeria 330kV (North Central) network. This work concluded that the UPFC during fault conditions greatly impact on the trip boundaries of distance protection relays. However, the effects of distributed parameters were neglected as the method was only applied to a medium length line of just about 120km. The presence of protective MOV operation during high fault conditions was not considered and he work did not proffer any solution to these identified effects of UPFC in the Nigeria power system. Dash, Pradhan, & Panda (2001) analysed the effects of series compensation on distance protection relay and presented a method using differential relays in adapting relay reach setting. This method neglected the effects of MOV action on the equivalent MOV/FACTS impedance and made assumpt ion about the presence or absence of FACTS and the amount of compensation provided to the relay. Also the method was applied only on a medium length line neglecting distributed parameters.

In Kazemi, Jamali, and Shateri (2008), the mal-operation of distance relay in the presence of series synchronous compensator using voltage and current symmetrical components was evaluated. However, this method did not consider the action of MOV protection on the SSSC during fault conditions and distributed parameters of the transmission line were neglected. Solutions were not provided to alleviate the identified problems in the work.

With increasing research works proposing for FACTS devices to be incorporated into the Nigeria power system, the cumulative effect of these devices with MOV operation during fault conditions have not been hitherto articulated. This dissertation tends to bridge these identified gaps and particularly develop an adaptive algorithm that will adjust the distance relay settings during fault condition in the presence of FACTS device, considering MOV operation and distributed parameters in the Nigeria 330kV transmission system

CHAPTER THREE

MATERIALS AND METHOD

In this dissertation, the apparent impedance of the different system operating conditions in the Nigeria 330kV transmission network was developed based on symmetrical components of voltage and current at the relay location. Since the apparent impedance seen by the distance relay should be equal to the actual impedance of the transmission line, it was calculated by dividing the voltage and current at the relay location. Computing of the impedance according to faults type was used to model the distance relay and comparing the measured impedance with impedance setting values for each zone allowed for a fault or no faults to be declared. The distance relay mathematical model was used for the activation of a tripping signal which was transmitted to the suitable circuit breaker to isolate the faulty zone from the rest of the system or network.

The Ikeja West to Benin transmission line, a 280km long line in Nigeria 330kV transmission network was developed in MATLAB/Simulink. The Simulink model of the Thyristor Controlled Series Capacitor (TCSC) was simulated in the Nigeria power system so as to show the impact of this compensation device on the performance of distance relays on the transmission line. Various levels of compensation for the line were studied to show the influence of TCSC placed at different locations on the performance of distance relays.

The relay zone settings of the distance relays are calculated from the values of the positive sequence resistance and reactance in the transmission line. The case system is modified to include MOV-protected TCSC on one of the longest transmission line in the Nigeria network, Benin to IkejaWest (280km, 330kV). The system was simulated for different fault types and locations. An adaptive relay protective system approach was proposed that has the ability to change the setting rule of the zones according to the effects of the TCSC on the power system quantities so as to assure accurate relay operation.

3.1 The TCSC Modelling

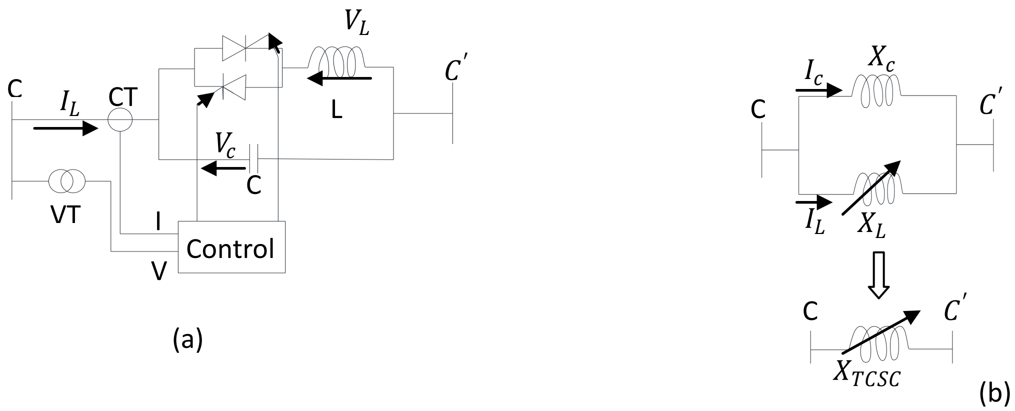

Figure 3.1: Transmission Line with TCSC System
a) System Configuration (b) Apparent Reactance

The TCSC is a series FACTS compensator which consist of a capacitance (C) connected in parallel with an inductance (L) controlled by a valve mounted in anti-parallel conventional thyristors T_1 and T_2 and controlled by an extinction angle (α) varied between 90^0 and 180^0. This compensator can be modelled as a variable reactance (X_{TCSC}) as shows in Figure 3.1(b) and the apparent reactance of the TCSC injected on transmission line is defined by (3.1) and (3.5).

$$X_{TCSC} = X_{L(\alpha)} // X_C = \frac{X_{L(\alpha)} X_C}{X_{L(\alpha)} + X_C} \tag{3.1}$$

The reactance of the variable inductance $X_{L(\alpha)}$ controlled by the thyristor is defined by equation 3.2 (Sidhu & Khederzadeh 2005).

$$X_{L(\alpha)} = X_L \left[\frac{\pi}{\pi - 2\alpha - \sin(2\alpha)}\right] \tag{3.2}$$

Where $X_L = \omega \mathrm{L}$ (3.3)

The capacitance is defined by

$$X_c = \frac{1}{\omega C} \tag{3.4}$$

α is the delay angle from the crest of the capacitor voltage.

From (3.2) and (3.4), the final equation 3.1 becomes

$$X_{TCSC(\alpha)} = \left[\frac{\omega L . \left[\frac{\pi}{\pi - 2\alpha - \sin 2\alpha}\right] . \frac{1}{\omega C}}{\omega L \left[\frac{\pi}{\pi - 2\alpha - \sin(2\alpha)}\right] + \frac{1}{\omega C}}\right]$$

Or

$$X_{TCSC(\alpha)} = \frac{X_C X_L \left[\frac{\pi}{\pi - 2\alpha - \sin(2\alpha)}\right]}{X_c + X_L \left[\frac{\pi}{\pi - 2\alpha - \sin(2\alpha)}\right]} \tag{3.5}$$

The active power (P) and reactive power (Q) on transmission line with TCSC are defined by (3.6) and (3.7).

$$P(\delta) = \frac{V_A . V_B}{Z_{AB} + X_{TCSC(\alpha)}} \sin\delta \tag{3.6}$$

$$Q(\delta) = \frac{V_B^2}{Z_{AB} + X_{TCSR}} - \frac{V_A V_B}{Z_{AB} + X_{TCSC}} \cos\delta \tag{3.7}$$

3.2 Fault Calculations on the Transmission Line in the Presence of TCSC

For a single line to ground fault in the presence of TCSC, the method of symmetrical components are used to analyze the unbalanced fault currents. With the TCSC inserted on the midline and subjected to a single line to ground fault F at phase A which occurs at a fault location represented by n_F in the presence of a fault resistance, R_F. Fault location (n_F) is equal to zero if the fault occurs at bus-bar A and it is 100% if it occurs at bus-bar B. The generator internal impedance denoted by Z_S is ignored due to its small magnitude when compared with the impedance of the line. Basic equations for this type of fault at phase A are given by (Mathur & Varma 2002) and (Sidhu & Khederzadeh 2005).

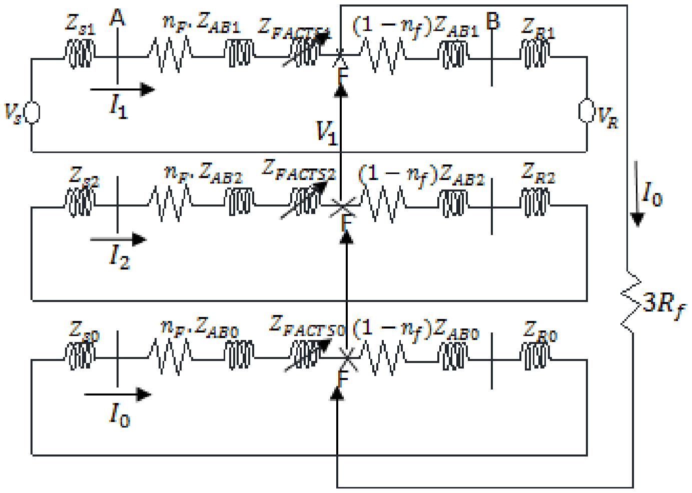

Figure 3.2: Interconnection of sequence network for a single line to ground

The boundary conditions for a single line to ground fault are:

$$I_B = I_C = 0 \tag{3.8}$$

$$V_A = 0 \tag{3.9}$$

The symmetrical component of line currents are given by

$$\begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} = \frac{1}{3}\begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix}\begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix} \tag{3.10}$$

From (3.8) and (3.10) the current symmetrical components take the following form

$$I_0 = I_1 = I_2 = \frac{I_A}{3} \tag{3.11}$$

Similarly, the voltage symmetrical components are given by

$$\begin{bmatrix} V_0 \\ V_1 \\ V_2 \end{bmatrix} = \frac{1}{3}\begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix}\begin{bmatrix} V_A \\ V_B \\ V_C \end{bmatrix} \tag{3.12}$$

Also, the symmetrical component of impedances are given by

$$\begin{bmatrix} Z_0 \\ Z_1 \\ Z_2 \end{bmatrix} = \frac{1}{3}\begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix}\begin{bmatrix} Z_A \\ Z_B \\ Z_C \end{bmatrix} \tag{3.13}$$

Hence, the symmetrical components of the transmission line impedance Z_{AB} and the apparent reactive impedance of the TCSC device Z_{TCSC} are defined according to (3.13) as follows:

$$Z_{AB} = Z_{AB0} + Z_{AB1} + Z_{AB2} \tag{3.14}$$

$$Z_{TCSC} = Z_{TCSC0} + Z_{TCSC1} + Z_{TCSC2} \tag{3.15}$$

From figure 3.2, $V_1, V_0\ and\ V_2$ have the following form as the sequence network equations:

$$V_1 = V_s - \left(n_f . Z_{AB1} \pm Z_{TCSC1}\right) I_1 \tag{3.16}$$

$$V_2 = -\left(n_f . Z_{AB2} \pm Z_{TCSC2}\right) I_2 \tag{3.17}$$

$$V_0 = -\left(n_f . Z_{AB0} \pm Z_{TCSC0}\right) I_0 \tag{3.18}$$

But (3.9) can be written in terms of symmetrical components as $V_A = V_1 + V_2 + V_0 = 0$ and $V_A = R_f I_A$.

Substituting by the above (3.16), (3.17) and (3.18) in equation 3.12 using (3.10) yields;

$$V_s = \frac{I_A}{3}\left(n_f . Z_{AB} \pm Z_{TCSC} + 3. R_f\right) \tag{3.19}$$

From (3.19), the amount of phase A in the presence of a TCSC device is given by

$$I_A = \frac{3V_s}{(n_f . Z_{AB} \pm Z_{TCSC} + 3R_f)} \tag{3.20}$$

From (3.10) and (3.20), the current symmetrical components in the presence of TCSC take the following form

$$I_0 = I_1 = I_2 = \frac{I_A}{3} = \frac{V_S}{(n_f . Z_{AB} \pm Z_{TCSC} + 3R_f)} \tag{3.21}$$

Substituting by I_1 from (3.21) into (3.16) using (3.14) and (3.15), the direct voltage components takes the following form.

$$V_1 = \frac{V_s[n_f(Z_{AB0} + Z_{AB2}) \pm (Z_{TCSC0} + Z_{TCSC2}) + 3R_f}{(n_f Z_{AB} \pm Z_{TCSC} + 3R_f)} \tag{3.22}$$

Similarly, using (3.17) and (3.21), the inverse voltage component becomes

$$V_2 = -\frac{V_s . [n_f . Z_{AB2} \pm Z_{TCSC2}]}{(n_f Z_{AB} \pm Z_{TCSC} + 3. R_f)} \tag{3.23}$$

Using (3.18) and (3.21), the zero sequence component of the voltage becomes

$$V_0 = \frac{-V_s.[n_f.Z_{AB0} \pm Z_{TCSC0}]}{(n_f.Z_{AB} \pm Z_{TCSC} + 3R_f)} \tag{3.24}$$

In order to obtain the phase voltage at the fault point in the presence of FACTS device and fault resistance, the following equation is used:

$$\begin{bmatrix} V_A \\ V_B \\ V_C \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} . \begin{bmatrix} V_0 \\ V_1 \\ V_2 \end{bmatrix} \tag{3.25}$$

Substituting by (3.22), (3.23) and (3.24) into (3.25) yields

$$V_A = \frac{3R_f V_s}{n_f.Z_{AB} \pm Z_{TCSC} + 3R_f} \tag{3.26}$$

$$V_B = \frac{V_s.\left[(a^2 - a)Z_2' + (a^2 - 1)Z_0' + 3a^2.R_f\right]}{(n_f.Z_{AB} \pm Z_{TCSC} + 3R_f)} \tag{3.27}$$

$$V_C = \frac{V_s.\left[(a - a^2)Z_2' + (a - 1)Z_0' + 3a^2.R_f\right]}{(n_f.Z_{AB} \pm Z_{TCSC} + 3R_f)} \tag{3.28}$$

The coefficient Z_2' and Z_0' are defined as follows

$$Z_2' = n_f Z_{AB2} \pm Z_{TCSC2} \tag{3.29}$$

$$Z_0' = n_f Z_{AB0} \pm Z_{TCSC0} \tag{3.30}$$

Hence the fault calculation in the discussed case is shown to be related to the TCSC device impedance Z_{TCSC}, system operation mode, fault condition presented in fault location n_f and fault resistance R_f.

3.3 Modelling Distance Relay Requirements

In this dissertation, the MATLAB/Simulink tools are used to model and simulate the distance protective relay. The libraries content of MATLAB/Simulink include almost all power system requirements such as three phase sources, transformers, transmission lines, three phase load. In addition, it has many other items which help to implement digital relay protection such as voltage transformer (VT), current transformer (CT), current measurements and three phase fault maker. Logical components, signal processing libraries, Analog to Digital converter, Filters, phasor estimation, which are provided by Simulink toolbox were used to model the digital relay.

Measurement of the voltage and current for each phase ($V_a, V_b, V_c, I_a, I_b I_c$) at the relay location and computing of impedance according to fault type used was used to model the distance relay. Comparing the measured impedance with impedance setting values for each zone allows for a fault or no fault to be declared. The distance relay model also allows for an activation of a tripping signal which is transmitted to the suitable circuit breaker to isolate the faulty zone from the rest of the system or network. Each subsystem is established separately and they are connected together to compose the larger transmission system. This feature is used to test each subsystem individually and thus simulations of the larger system can be more forward. The subsystems proposed are base on the main functions of a typical distance relay. These are:

1. Fault detection and classification
2. Apparent impedance measurement
3. Zone detection
4. Tripping signal

3.3.1 Fault Detection and Classification

Designing fault detection and classification is very important in distance relay to avoid unnecessary tripping of circuit breakers. Appropriate selection for fault type will minimize errors such as in cases where a tripping of three phase results when only one phase clearance is required. Also, it is necessary to calculate the apparent impedance because every type of fault has its own impedance algorithm.

The following steps were used in the design of a subsystem:

1. Measuring the current for each phase at relay location using Three-phase V-I measurement block.

2. Comparing the fault current with pre-fault current for phase using If and If action subsystems. The output of the comparator will be one at the time that the current exceeds the pre-fault current (reference current).

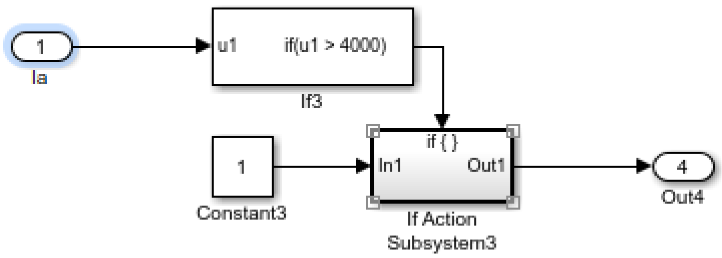

Figure 3.3: Fault comparator structure

3. Classifying the fault type using logical components based method since the output of comparator is binary. Then, the type of fault can be found by resolving input data by using Karnaugh-Map or other technique. Table 3.1 shows the possible inputs and desired outputs (fault types) cases.

Table 3.1: Inputs and Outputs for Fault Detection and Classification Subsystem

I_a	I_b	I_c	I_G	AG	BG	CG	ABG	AB	BCG	BC	ACG	AC	ABCG	ABC
0	0	1	1	0	0	1	0	0	0	0	0	0	0	0
0	1	0	1	0	1	0	0	0	0	0	0	0	0	0
0	1	1	1	0	0	0	0	0	1	0	0	0	0	0
0	1	1	0	0	0	0	0	0	0	1	0	0	0	0
1	0	0	1	1	0	0	0	0	0	0	0	0	0	0
1	0	1	1	0	0	0	0	0	0	0	1	0	0	0
1	0	1	0	0	0	0	0	0	0	0	0	1	0	0
1	1	0	1	0	0	0	1	0	0	0	0	0	0	0
1	1	0	0	0	0	0	0	1	0	0	0	0	0	0
1	1	1	1	0	0	0	0	0	0	0	0	0	1	0
1	1	1	0	0	0	0	0	0	0	0	0	0	0	1

This fault detection and classification can be implemented using logical components in Simulink as shown in figure 3.4 for a single line to ground fault. All other fault types are also implemented and results are summarized in Table 3.2

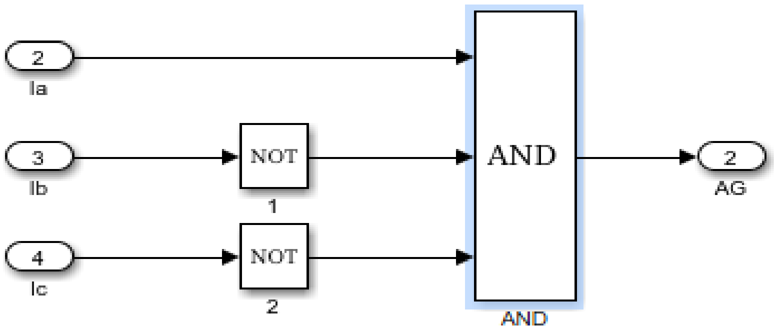

Figure 3.4: Fault detection and classification block for AG fault using logical components

Table 3.2: Fault Classification Based on Digital Components

Types of Fault	Digital input signals
AG	I_a AND (NOT I_b) AND (NOT I_c) AND I_G
BG	(NOT I_a) AND I_b AND (NOT I_c) AND I_G
CG	(NOT I_a) AND (NOT I_b) AND I_c AND I_G
AB	I_a AND I_b AND (NOT I_c) AND (NOT I_G)
ABG	I_a AND I_b AND (NOT I_c) AND I_G
AC	I_a AND (NOT I_b) AND I_c AND (NOT I_G)
ACG	I_a AND (NOT I_b) AND I_c AND I_G
BC	(NOT I_a) AND I_b AND I_c AND (NOT I_G)
BCG	(NOT I_a) AND I_b AND I_c AND I_G
ABC	I_a AND I_b AND I_c AND (NOT I_G)
ABCG	I_a AND I_b AND I_c AND I_G

Figure 3.5 shows the fault detection and classification subsystem. The inputs of this system are phase currents and the outputs are the signals which will determine which impedance algorithm for the apparent impedance calculation for each type of possible fault.

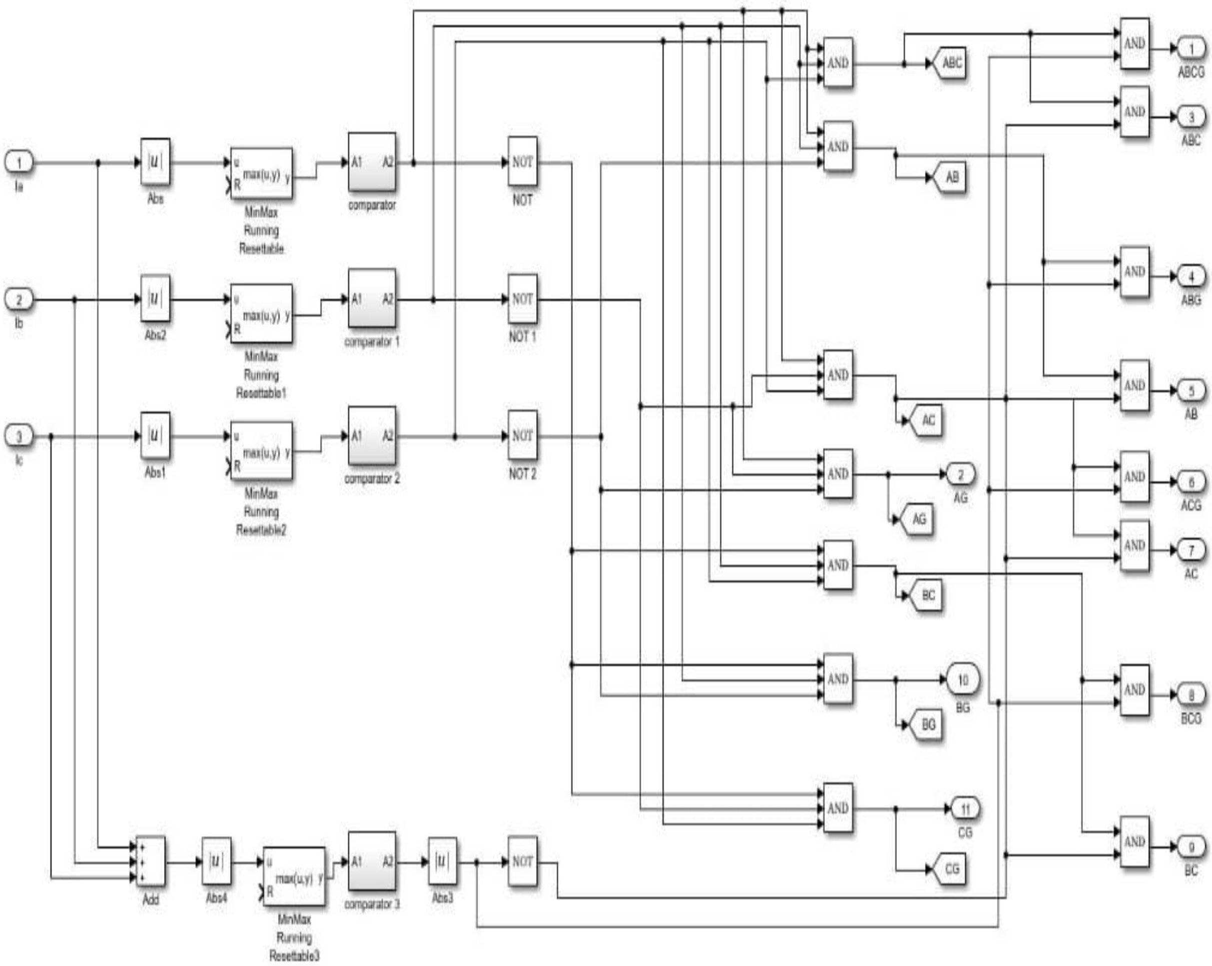

Figure 3.5: Fault detection and classification block

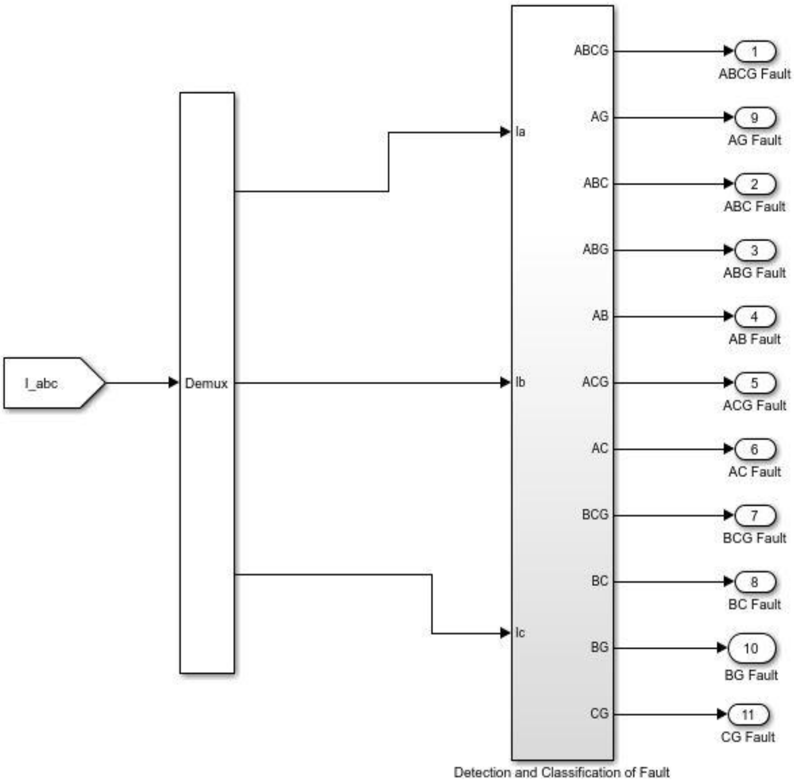

Figure 3.6: Overall fault detection and classification

3.3.2 Apparent Impedance Measurement

Apparent impedance measurement block includes all impedance algorithms to calculate the apparent impedance by measurement of the voltages and currents at the relay location. The output signals from the fault detection and classification block select which impedance algorithm must be used. The apparent impedance algorithm for various types of faults is shown in Table 3.3.

Table 3.3: Fault impedance Calculation on Different Faults

Fault Type	Algorithm
AG	$V_{an}/(I_a+KI_o)$
BG	$V_{bn}/(I_b + KI_o)$
CG	$V_{cn}/(I_c + KI_o)$
AB/ABG	$(V_{an} - V_{bn})/(I_a - I_b)$
AC/ACG	$(V_{an} - V_{cn})/(I_a - I_c)$
BC/BCG	$(V_{bn} - V_{cn})/(I_b - I_c)$
ABC/ABCG	(V_{an}/I_a) OR (V_{bn}/I_b) OR $(V_{cn}/(I_c)$

Where:

A, B, C indicates faulty phase, G indicate Ground

I_a, I_b, I_c indicates current phase.

V_{an}, V_{bn}, V_{cn} indicate voltage phases.

$K = {(Z_0 - Z_1)}/{3Z_1}$, residual compensation factor.

$I_0 = {(I_a + I_b + I_c)}/{3}$, zero sequence current

Z_0, Z_1, Zero sequence impedance, positive sequence impedance

Apparent impedance measurement block receives the voltage and currents in discrete form from V-I measurement and process these inputs to get the magnitude and phase angle for each input which are required to calculate the apparent impedance.

The processes in this block are;

1. Extract the input vector into three separate signals using DEMUX block.
2. Convert the complex input signal into magnitude and phase angle.
3. Use the impedance algorithm.
4. Convert the calculated impedance from magnitude and angle into (transmission line resistance) and imaginary (transmission line reactance).
5. Send the output to workspace to use them for drawing the impedance trajectory.

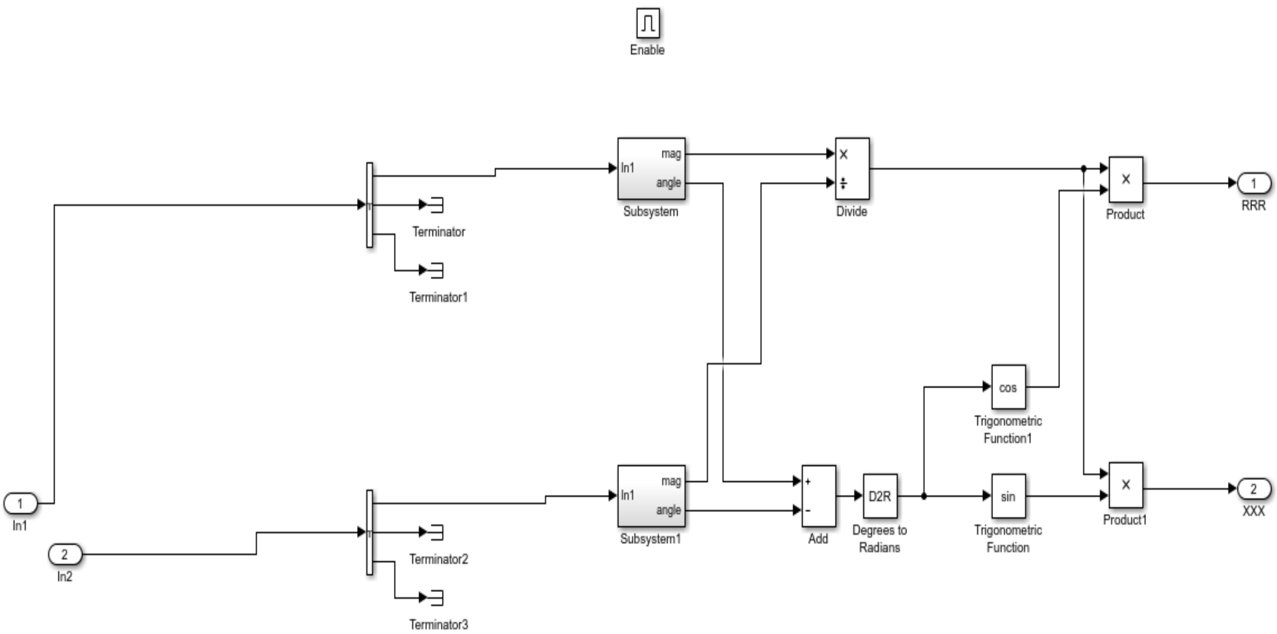

Figure 3.7: Apparent impedance model for three-phase fault

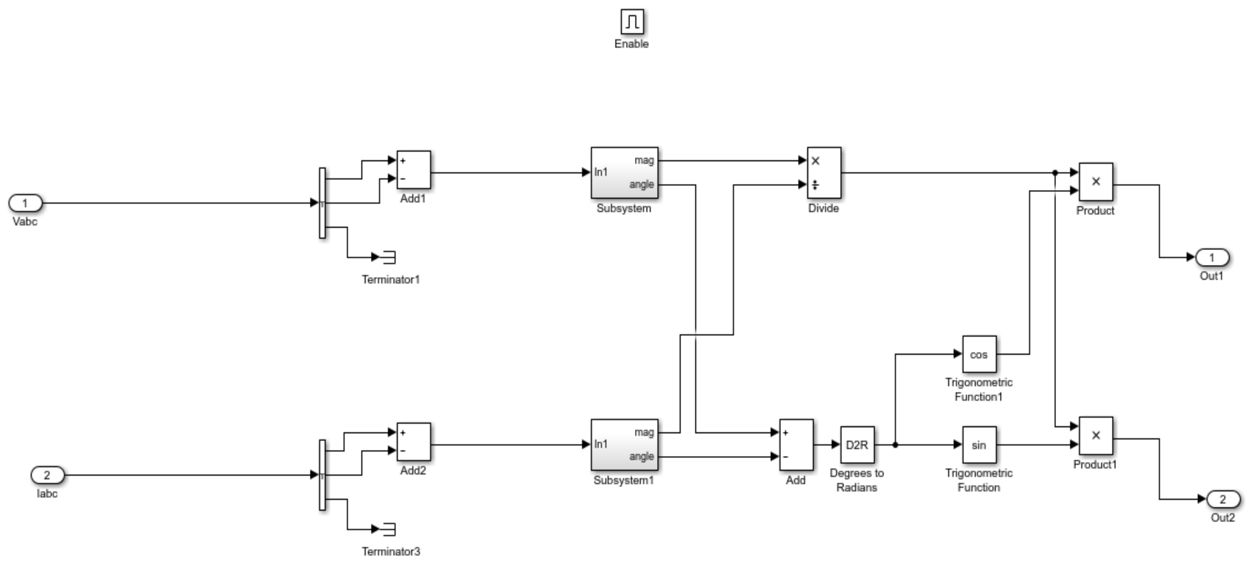

Figure 3.8: Apparent impedance model for line – line fault (between phase A and B)

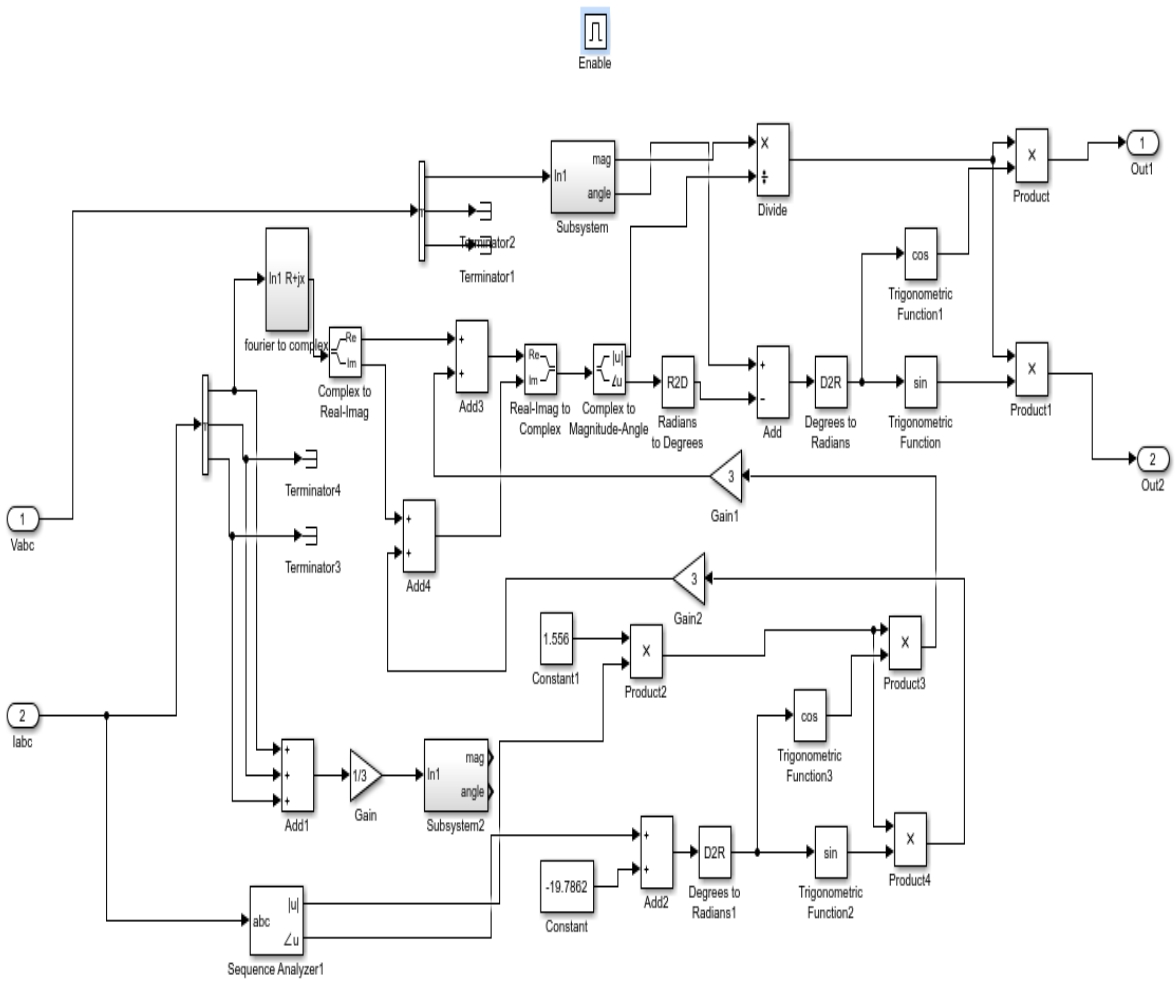

Figure 3.9: Apparent impedance model for SLG (at phase A)

Figure (3.7), (3.8), and (3.9) show the apparent impedance measurement subsystem for three-phase, line to line fault and single line to ground fault respectively. These blocks are built by using the enable subsystem block, which works when it receives an enabling signal. Figure 3.10 shows the overall apparent impedance block.

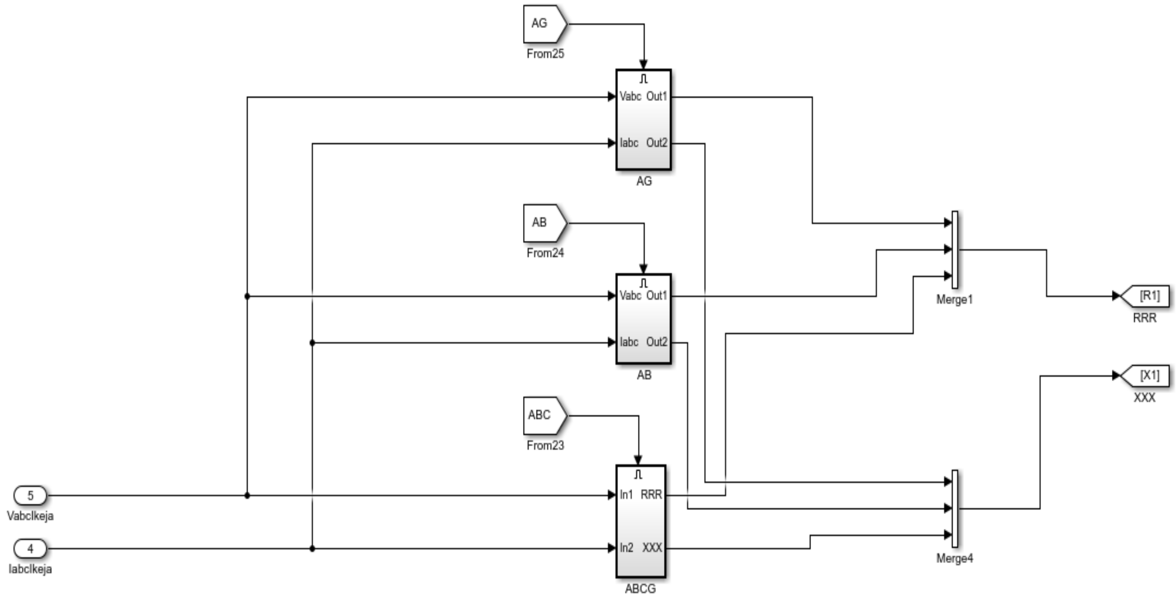

Figure 3.10(a): Overall apparent impedance measurement subsystem at Ikeja West

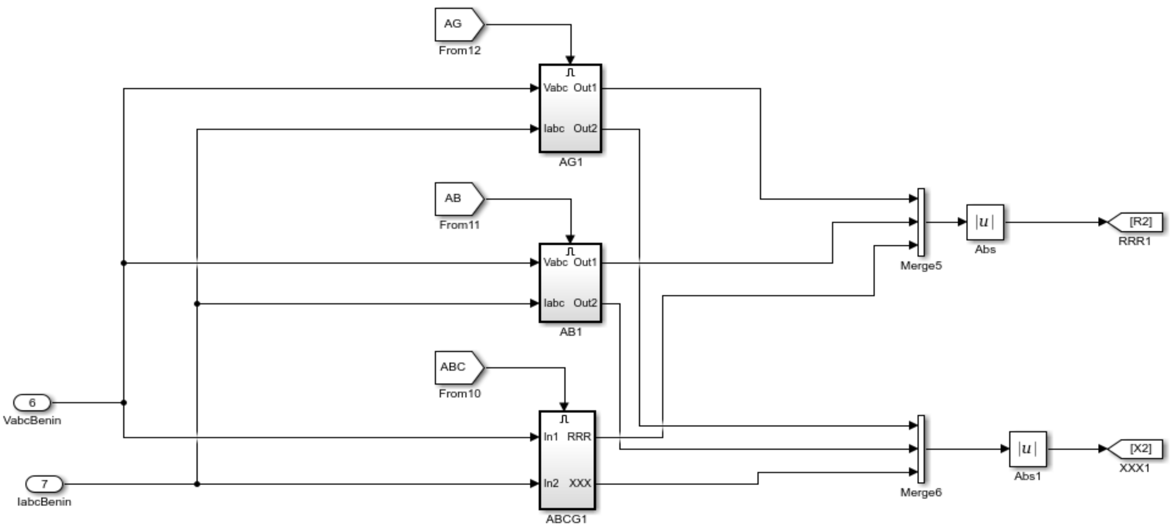

Figure 3.10(b): Overall apparent impedance measurement subsystem at Benin

3.3.3 Zone Detection

According to the principle of operation of distance relay, the transmission line is divided into several zones. Practical distance relay has three zones, but can be divided into four zones on the transmission line. If the distance relay indicates the fault in zone 1, the distance relay will send a tripping signal into the circuit breaker immediately, while there is a time delay if the fault is in zone 2 or zone 3. Many other factors determine the selection of the zones and the tripping delay such as power system configuration and coordination of the distance relay with other protected relay.

Figure 3.11 shows the zone detection subsystem produced using Simulink. The received the input signal from apparent impedance measurement block and the output is the number of zones.

Table 3.4: Setting Point of Three Zones Distance Relay

Zones	**Setting Point**
Zone 1	Cover 80% to 85% of the protected line
Zone 2	120% of the protected line
Zone 3	220% of the protected line

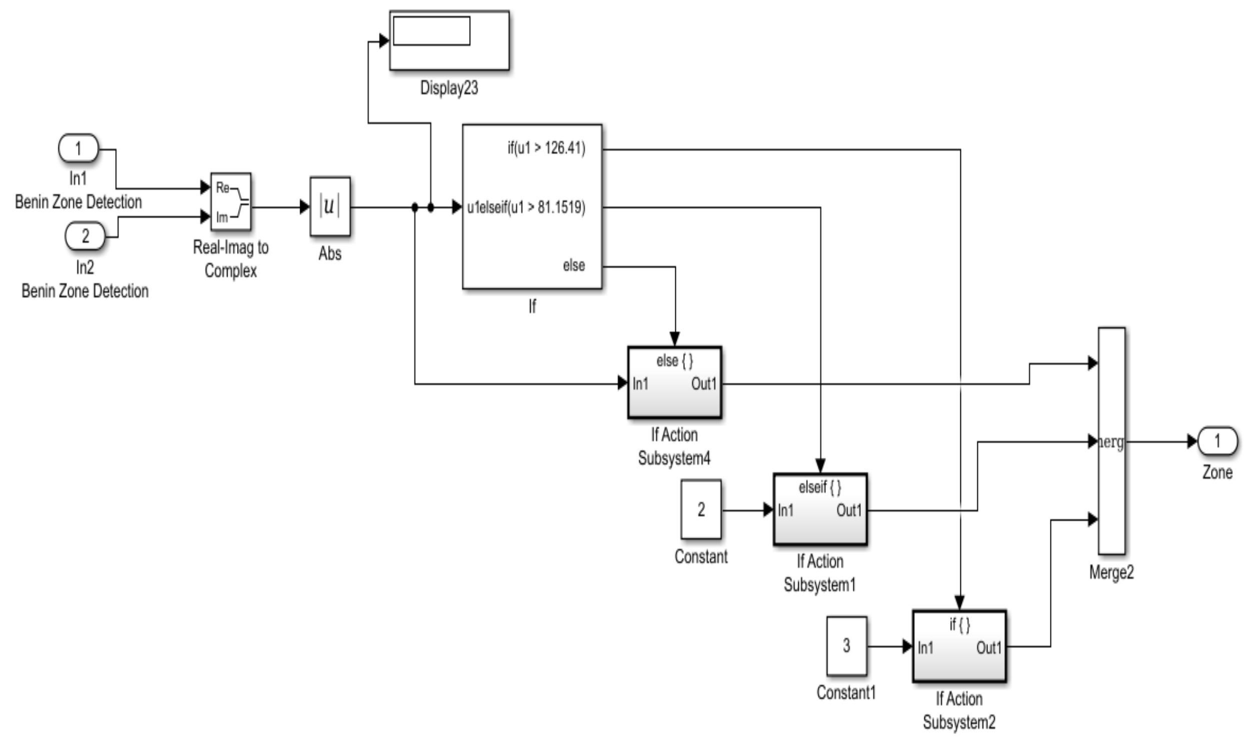

Figure 3.11(a): Zone detection subsystem at Benin

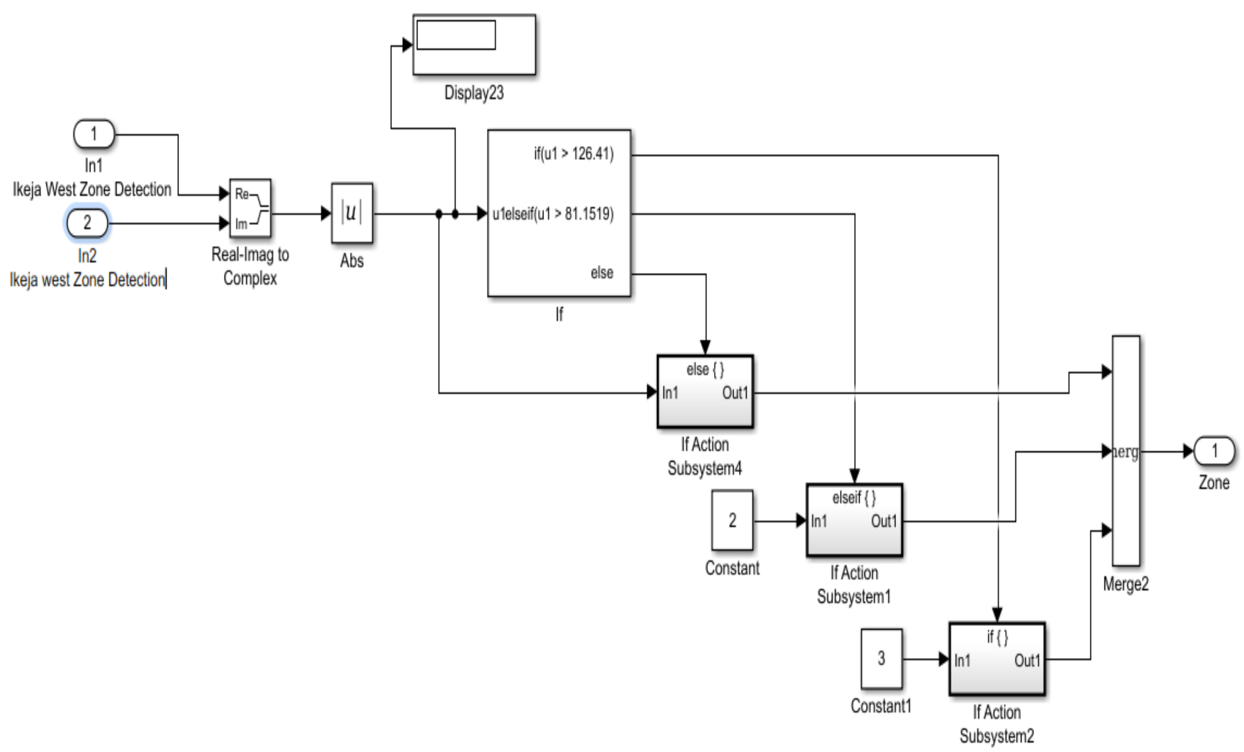

Figure 3.11(b): Zone detection subsystem at Ikeja West

3.3.4 Tripping Signal

This subsystem received the number of zones from the zone detection system and the operation in this subsystem is delaying the tripping signal as shown in figure 3.12

Table 3.5: The Typical Time Delay for Three Zones Distance Relay

Zones	Time Delay
Zone 1	0ms (instantaneous)
Zone 2	250ms
Zone 3	800ms

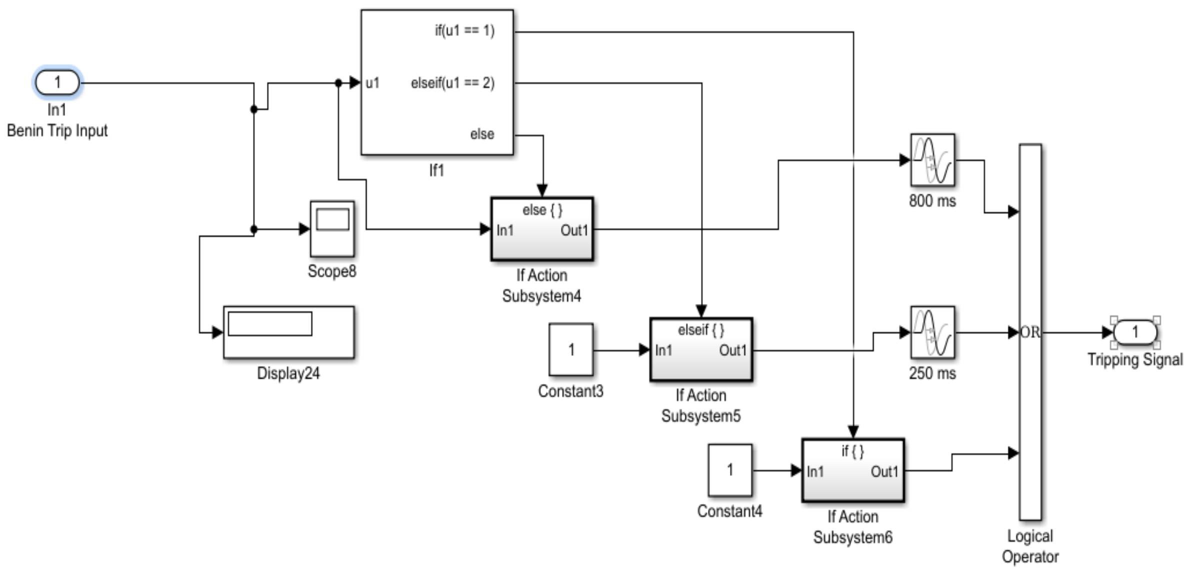

Figure 3.12(a): Model for tripping signal subsystem at Benin

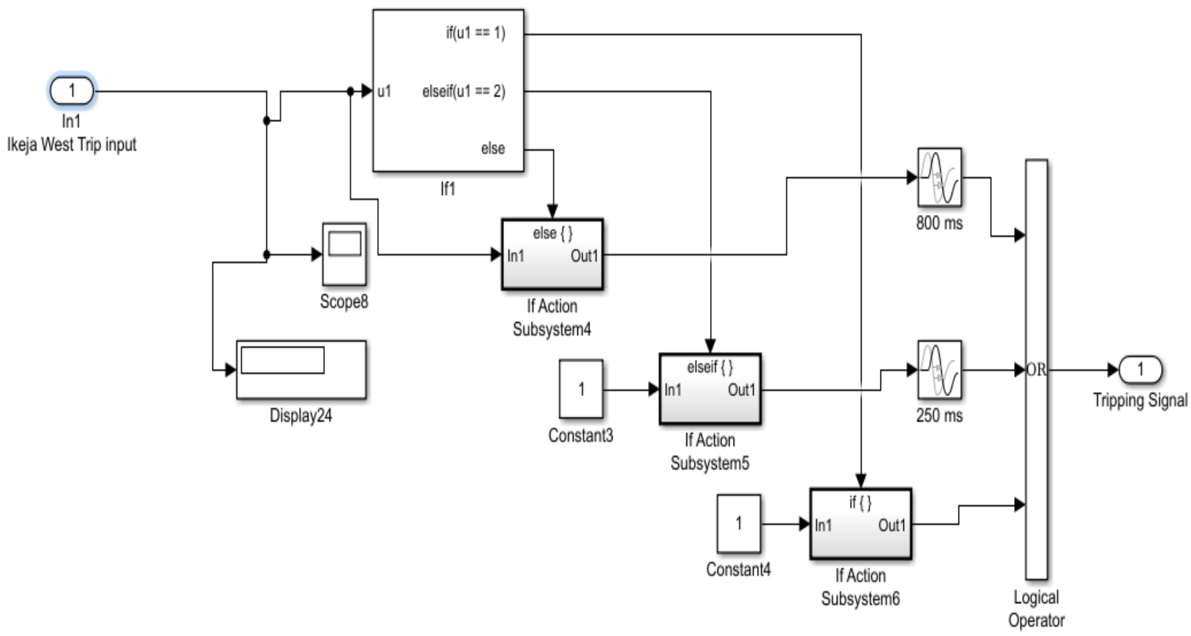

Figure 3.12(b): Model for tripping signal subsystem at Ikeja West

3.4 The Complete Distance Relay Model

Figure 3.13 shows the whole modelling of distance relay block built by Simulink. The input of the distance relay are phase voltages and currents, and the outputs are fault types indicators, zone indicator, the values of transmission line resistance and reactance to use for impedance trajectory and tripping signal.

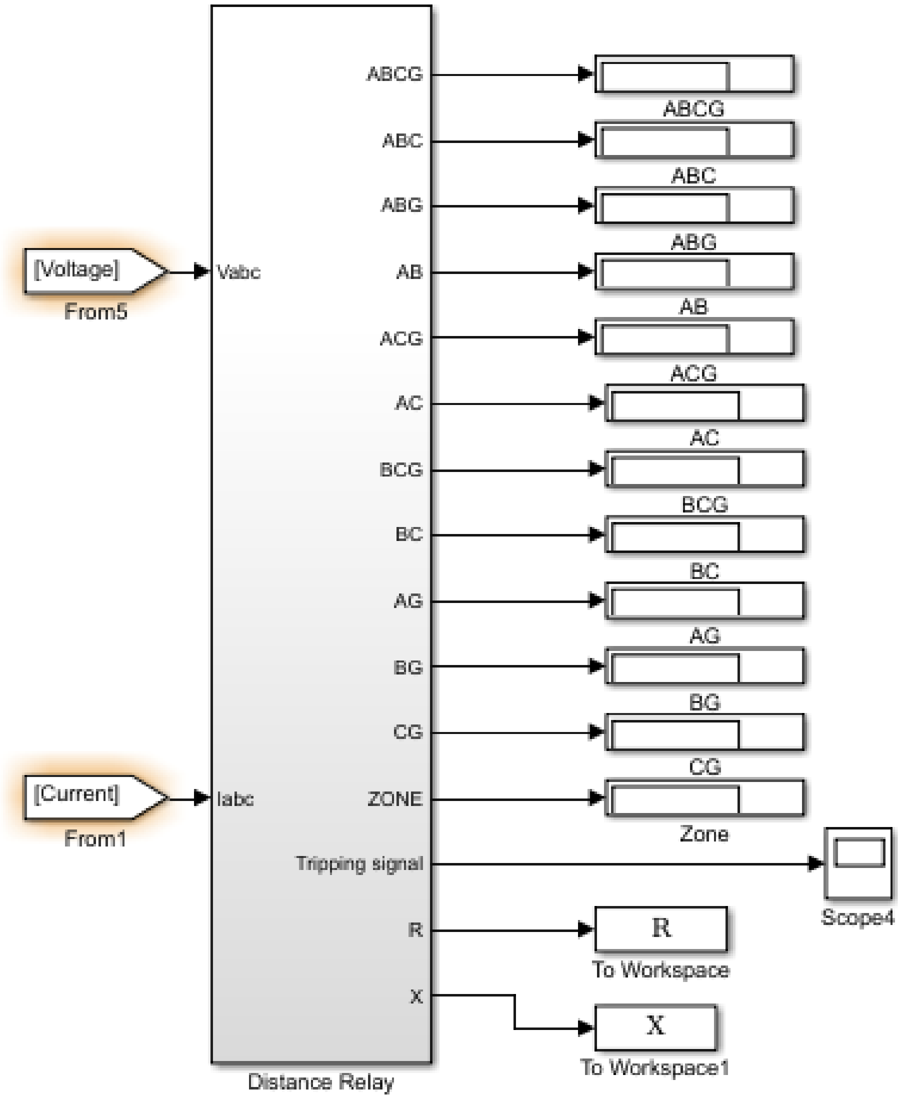

Figure 3.13: Distance relay Simulink model showing the inputs (currents and voltages), and the outputs (fault types, tripping signal and transmission line resistance and reactance)

3.5 Distance Relay Operation Flow Chart

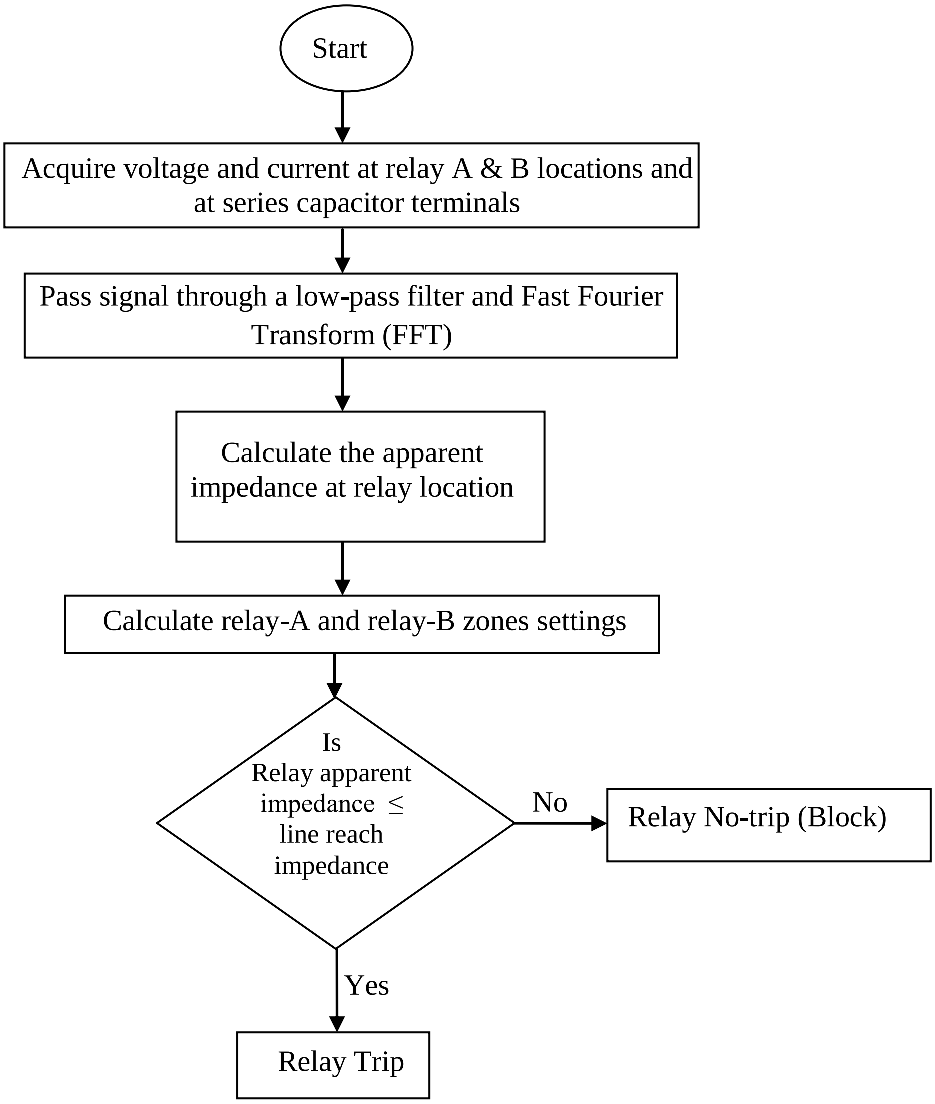

Figure 3.14: Flow chart of the conventional distance relay

3.6 Modeling of Distributed Parameter-Based Relay

For long transmission lines (typically longer than 250km), the distributed parameters have been considered to avoid serious distance relay underreaching or overreaching (Su, Wang, Gong & Xu 2007), (Jagdale & Validya 2013). The apparent impedance of relay considering parameters is given by

$$Z_{app} = Z_{c1} * \tanh(\gamma_1 * x) \tag{3.79}$$

Where: $Z_{c1} = \sqrt{\frac{Z_{T1}}{Y_{T1}}}$, $\gamma_1 = \sqrt{Z_{T1} * Y_{T1}}$, $Z_{T1} = R_{T1} + j\omega L_1$,

$and\ Y_{T1} = G_{T1} + j\omega C_{T1}$

Note that x in equation 3.79 is the distance between the relay and the fault location, $R_{T1}\ and\ L_{T1}$ are distributed resistance and inductance respectively, whereas, $G_{T1}\ and\ C_{T1}$ are distributed conductance and distributed capacitance respectively. The subscript 1 indicates positive sequence.

Since the relationship of the apparent impedance in equation 3.79 is consistent with the fault location *x*, the expression in equation 3.80 is used to set protection zones of distance relay by replacing *x* with L_{set} as

$$Z_{set} = z_{c1} * \tanh(\gamma_1 * L_{set}) \tag{3.80}$$

For zone 1, L_{set} = 0.8 x length of the protected line. For zone 2, $L_{set\,2}$ = 1.2 x length of the protected line.

3.6.1 Apparent Impedance Trajectory

For a case of SLG fault the apparent impedance trajectory is expressed as

$$Z_A = \frac{V_A}{(I_A + k_0 + I_0)} = z_{c1} * \tanh(\gamma_1 * x) \tag{3.81}$$

where k_0 is the zero sequence current compensation factor expressed as,

$$k_0 = \frac{1}{(z_{c1}\sinh(\gamma_1 x))}(z_{c0}\sinh(\gamma_1 x) - z_{c1}\sinh(\gamma_1 x) + Z_0(\cosh(\gamma_0 x) - \cosh(\gamma_1 x)) \tag{3.82}$$

Where: $z_{c0} = \sqrt{\frac{Z_{T0}}{\gamma_{T0}}}$, $\gamma_0 = \sqrt{Z_{T0} * Y_{T0}}$, $Z_{T0} = R_{T0} + j\omega L_{T0}$, and $Y_{T0} = G_{T0} + j\omega C_{T0}$.

The zero-sequence impedance of the equivalent system behind the relay is $Z_0 = {}^{-V_0}/_{I_0}$. The k_0 factor can be implemented by specifying the fault at *x*. R_{T0} *and* L_{T0} are distributed resistance and inductance respectively. G_{T0} and C_{T0} are distributed conductance and distributed capacitance, respectively. The subscript 0 indicates zero sequence.

3.7 The Nigeria Power System

The Nigeria 330kV electric power transmission network was used for this dissertation. It has 41- buses and 12 scheduled power generating station. Figure 3.15 shows the line diagram of the case power system. The system was simulated with MATLAB/Simulink and the Simpower tool was used to develop the models of the distance relay. Each subsystem was established and modelled separately, then connected together to compose the larger power transmission system. The subsystems used were based on the main function of a typical digital distance relay. These include: Fault detection and classification subsystem, apparent impedance measurement, zone detection and tripping signal subsystem.

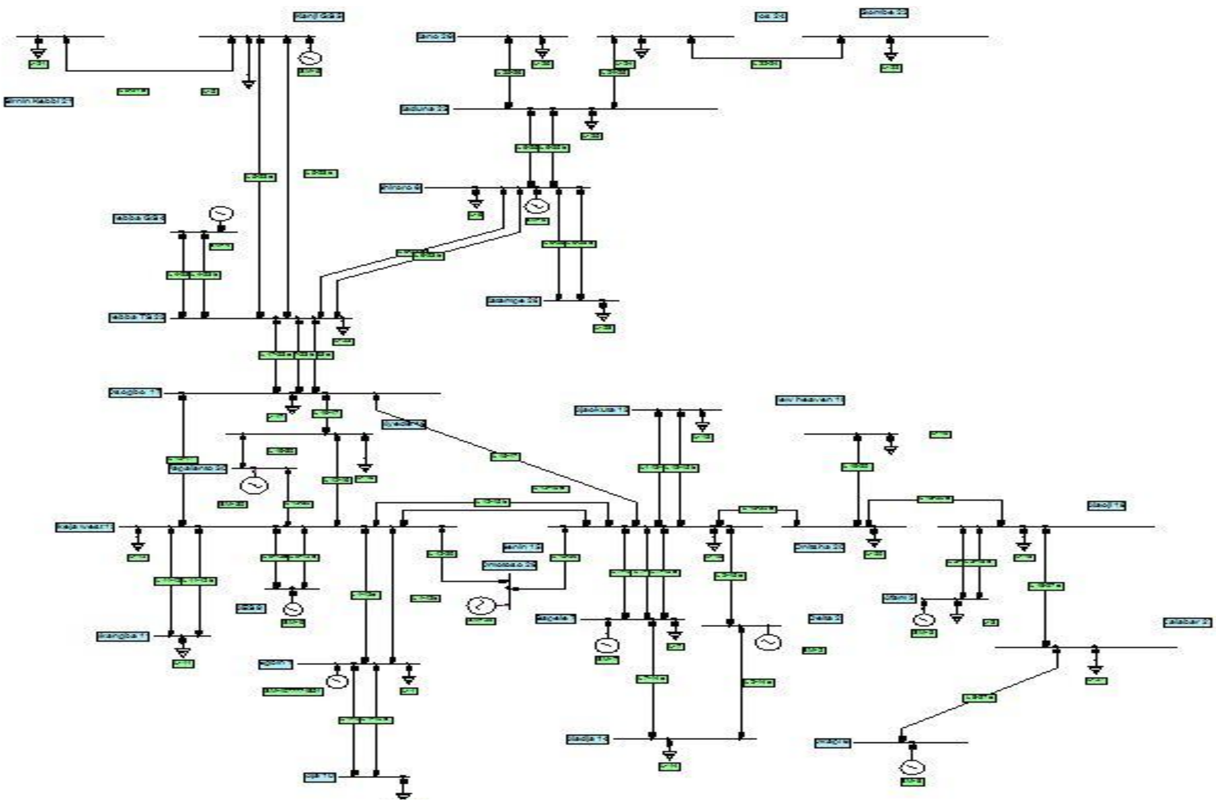

Figure 3.15: The Nigeria Power System (Also available in Appendix 7)

The Mho characteristics of the distance relay was obtained using MATLAB m-file. This enhances the understanding of the distance relay behaviour. To obtain the shape of mho characteristics, calculations of the setting impedance for each zone has to be performed first, and then attaching the corresponding results in a specific code in M-file MATLAB, which draws the shape of each zone of Mho relay characteristic, as presented in figure 3.16.

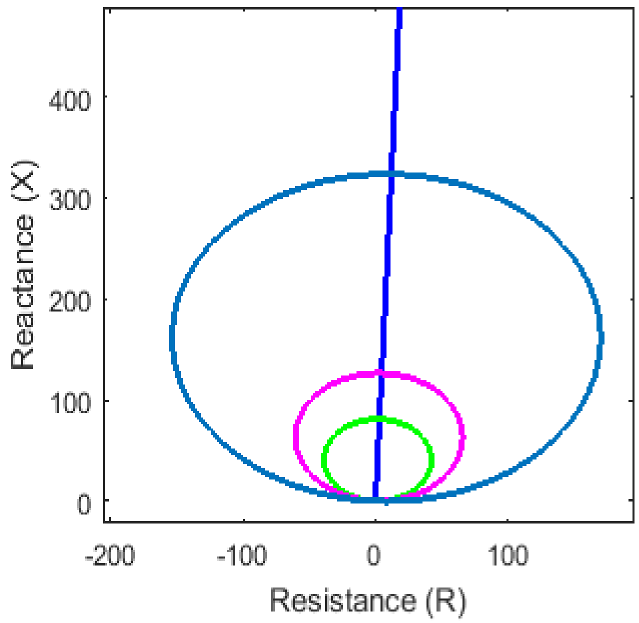

Figure 3.16: Mho Characteristics of distance relay

The case power system data was taken from Transmission Company of Nigeria (TCN), 2015 given in Tables A1-A6 of the Appendix 1. One of the longest transmission lines with a length of 280km and 330kv from Ikeja West to Benin was modified to include a FACTS device Thyristor Controlled Series Capacitor which is protected by a Metal-Oxide-Varistor (MOV) for this dissertation as shown in Figure 3.17.

3.8 Distance Relay Settings Adjustment Method

To mitigate the effects of TCSC placement and the cumulative action of the protective MOV to the distance relaying scheme, this dissertation developed an adaptive setting of the distance relay. In this method, the relay setting is adjusted whenever the TCSC finds itself within a fault loop.

Figure 3.17 shows the schematic diagram, while Figure 3.20 shows the flow chart of the distance relay adaptive setting algorithm for mitigating the effects FACTS compensation and MOV protection as developed in this dissertation. In Figure 3.17, relay A and relay B are located at each terminal of the line where local bus voltages and currents are measured and serve as inputs to the relays. Additional current measurement and voltage measurements are required at both terminals of the series capacitor. Also, a dedicated communication channel is required between relay A, series capacitor, and relay B. The flowchart in figure 3.20 summarizes the developed algorithm for adaptive setting of distance mho relay with MOV-protected series FACTS device.

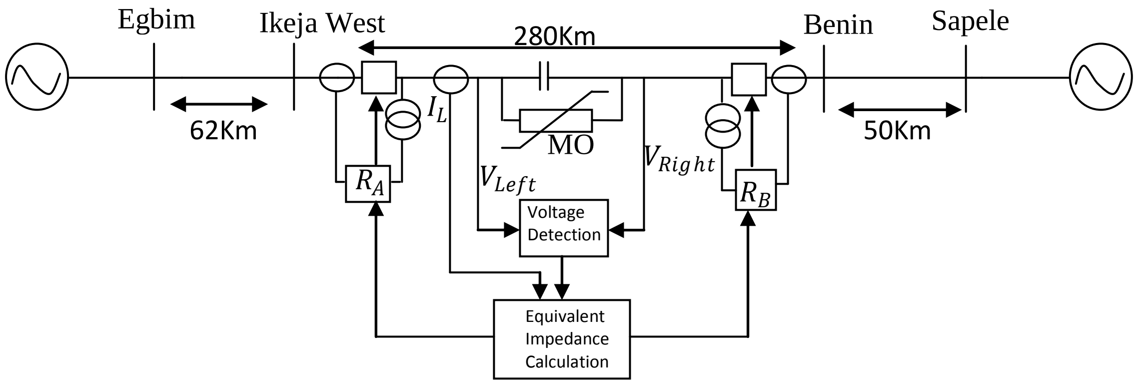

Figure 3.17: Schematic diagram of the developed adaptive setting of mho relay for series compensation on the Ikeja West to Benin Transmission line

The distance relays A and B are initially set for an uncompensated line with zones 1 and 2 reach settings. Voltages and currents are measured at the relay locations A and B. Each measured signal is passed through a low-pass filter and an FFT to obtain magnitude and phase of the signal's fundamental component. The resulting three phase voltages and currents are passed through the relay's fault detection algorithm. The apparent trajectory impedance is calculated as described in section 3.6. From the measured signals at the series capacitor location, the per phase equivalent impedance is calculated for the parallel

connection of MOV and capacitor as given in (3.83).

$$Z_{MOV/TCSC} = {(V_{Left} - V_{Right})}/{I_L} \tag{3.83}$$

where V_{left} and V_{Right} are the series capacitor terminal phase voltages, and I_L is the line current at the capacitor location. The fault location with respect to the capacitor bank can be determined through either directional relay, the direction of active power flow, or other directional discrimination methods. For a fault on the left side of the capacitor bank, the calculated equivalent impedance ZMOV/TCSC is seen by relay B to adjust the settings of the relay, but a value of zero is seen by relay A since the impedance between the relay and the fault will include only line impedance with no compensation. Similarly, for a fault on the right side of the capacitor bank the calculated impedance ZMOV/TCSC is seen by relay A, but a value of zero is seen by relay B. Once the relay's setting is adjusted the relay makes a decision based on the zone coordination described in sections 3.6 and 3.7.

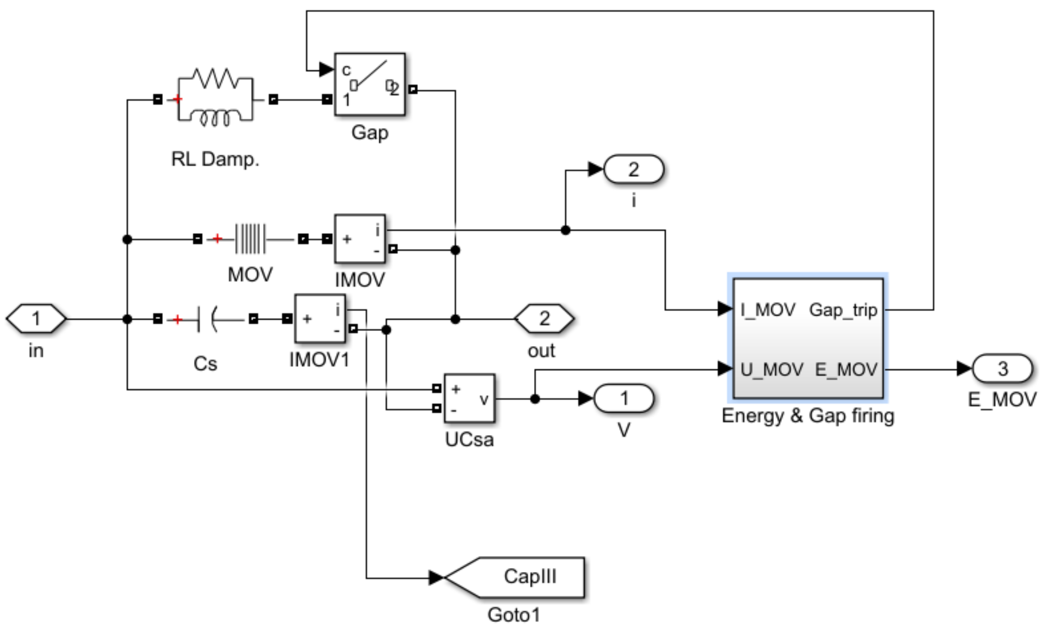

Figure 3.18: Simulink Model for MOV protection implementation

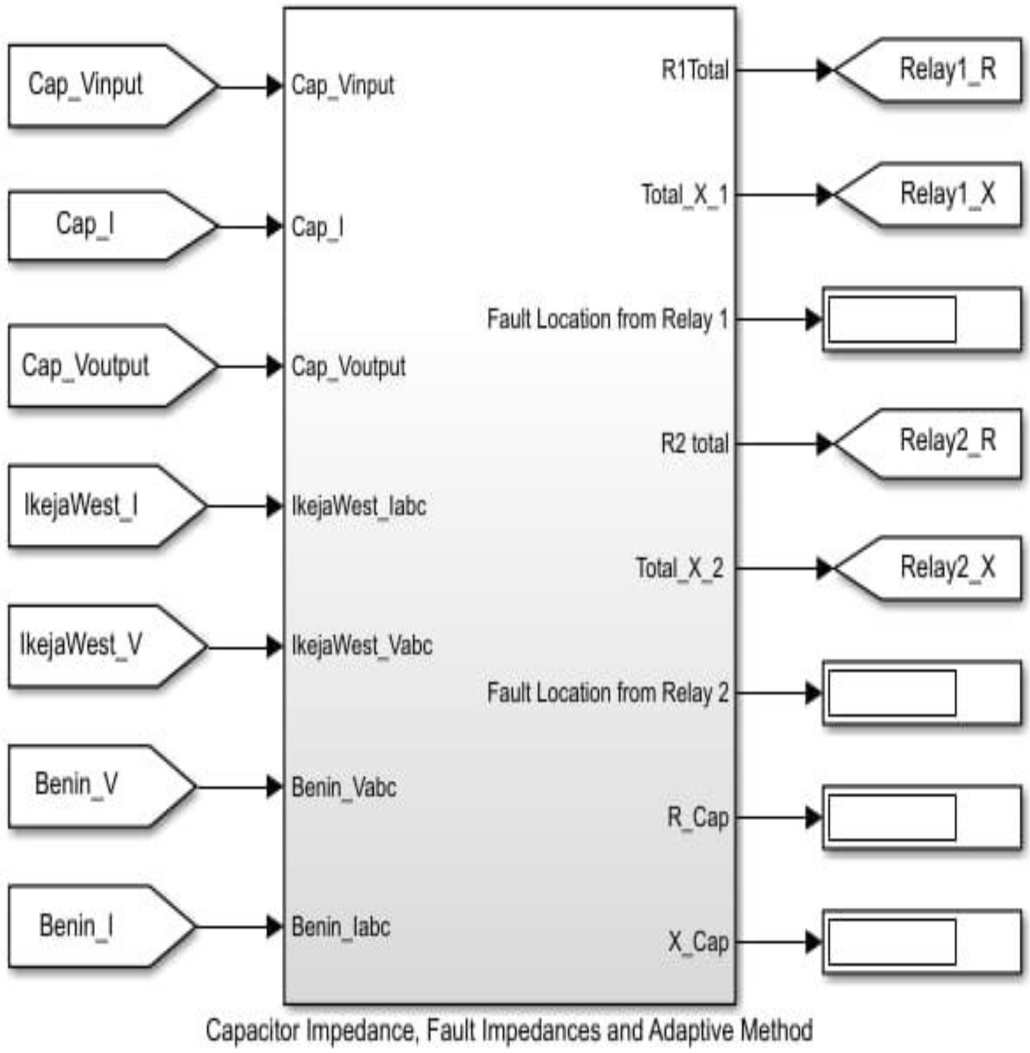

Figure 3.19: Proposed Adaptive Relay Setting Simulink Model. (Subsystems available in Appendix 9)

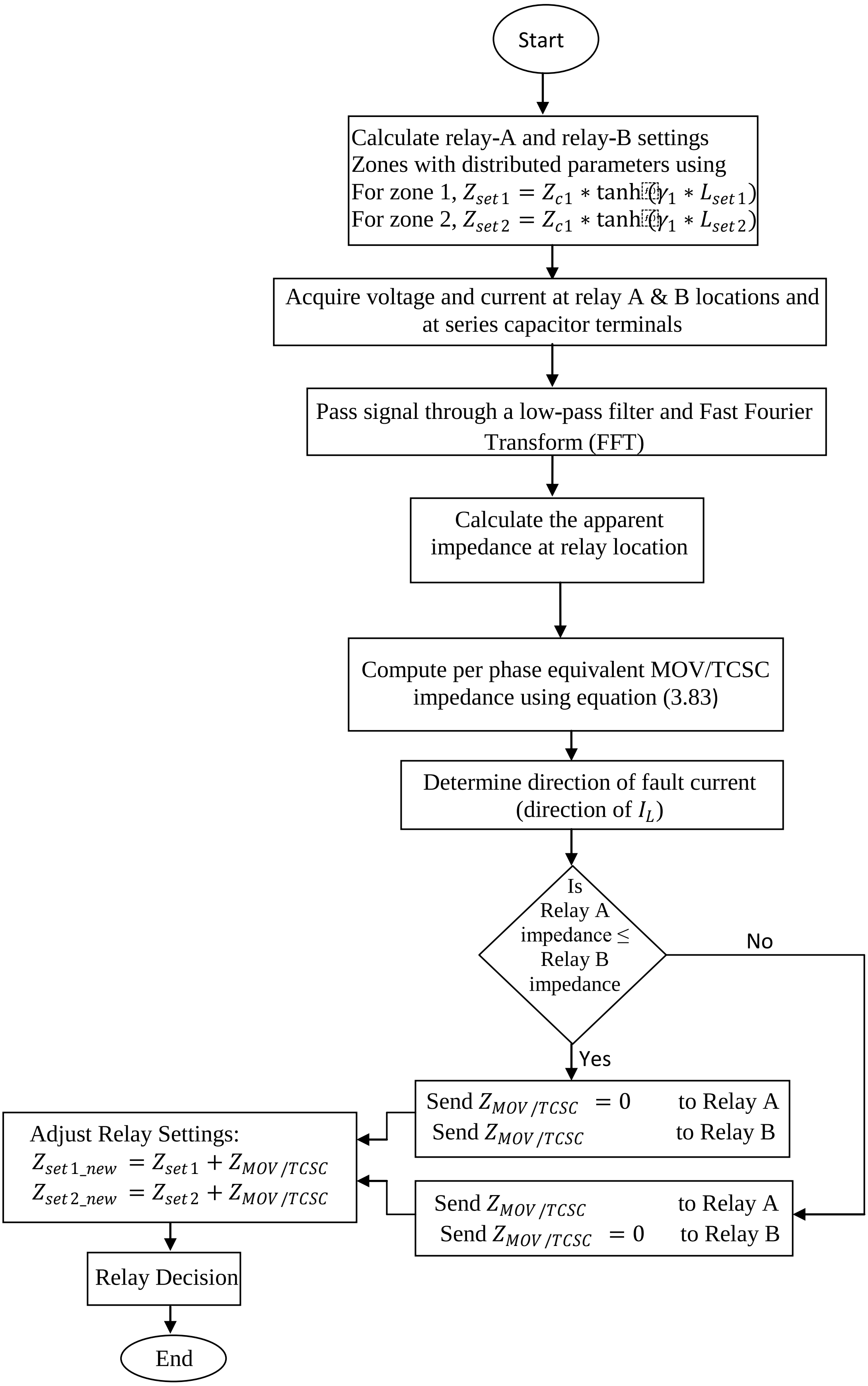

Figure 3.20: Flow chart of the proposed adaptive settings algorithm of mho relay for series compensation with MOV protection

CHAPTER FOUR

RESULTS AND DISCUSSION

The Nigeria power system was first simulated without FACTS devices for a single line to ground fault (SLG), line to line fault (L-L) and three phase fault on the transmission line from Ikeja West to Benin (280km, 330kV) at 50km, 100km and 250km. The Mho characteristics showing the distance relay protection zones are shown in figures 4.1 – 4.18. When TCSC was placed at the 140km point on the transmission line as shown in figure 3.17, faults were then simulated at 50km, 100km and 250km. This is to observe the effect of the FACTS series compensating device on the distance relays with respect to the fault loop on the line as shown in figures 4.19 – 4.36. For MOV-protected FACTS device, the faults were simulated at various locations considering the distributed parameters of the long transmission line in the model simulations. The Mho characteristics depicting the effects of MOV protection of TCSC on the distance relays are shown in figures 4.37 – 4.54.

4.1 A Case Study of Different Fault types without FACTS compensation

The simulations using Matlab/Simulink to show the Mho characteristics of the two relays R_A and R_B. Figures 4.1 to 4.18 show the case where the transmission line is simulated under different fault conditions without FACTS device.

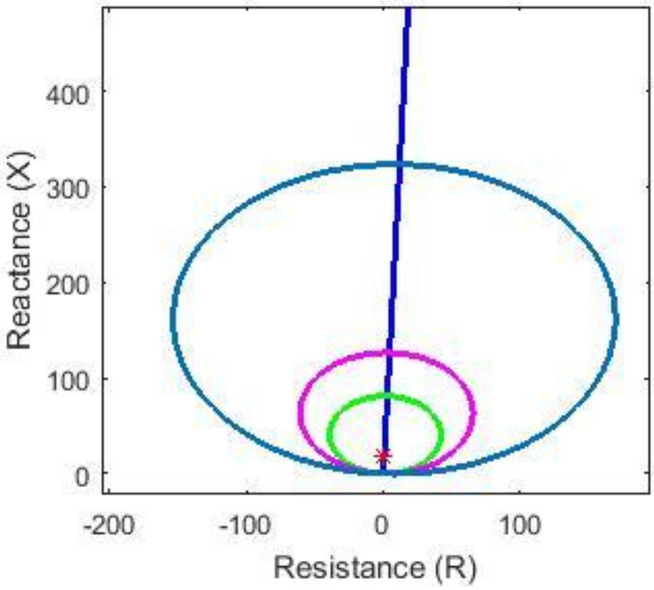

Figure 4.1: Mho characteristics of Relay A for 3phase fault at 50km

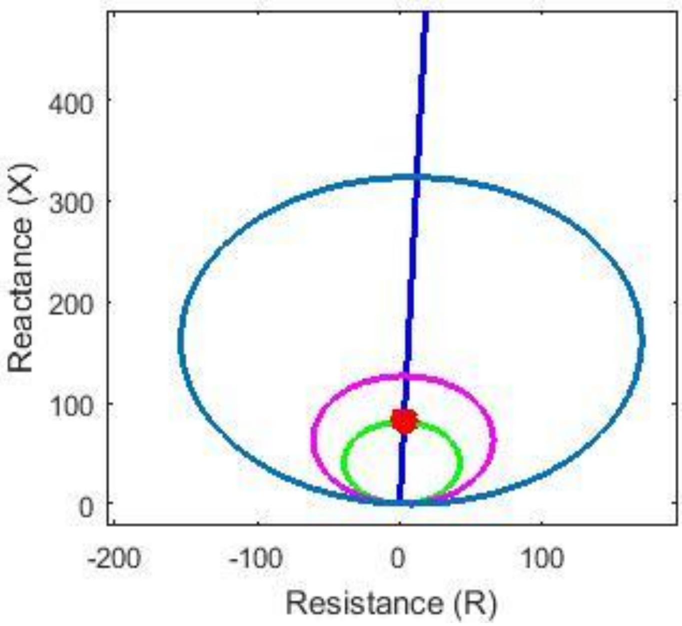

Figure 4.2: Mho characteristics of Relay B for 3phase fault at 50km

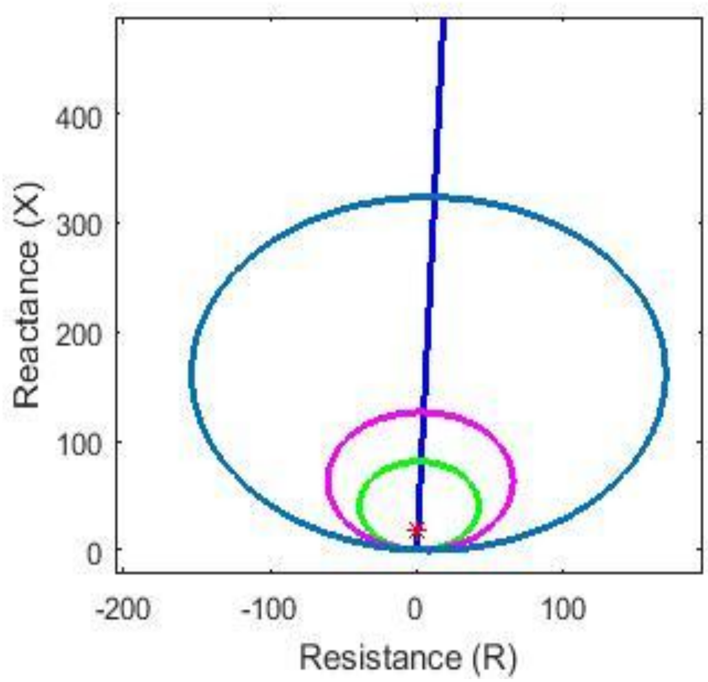

Figure 4.3: Mho characteristics of Relay A for Line to Line fault at 50km

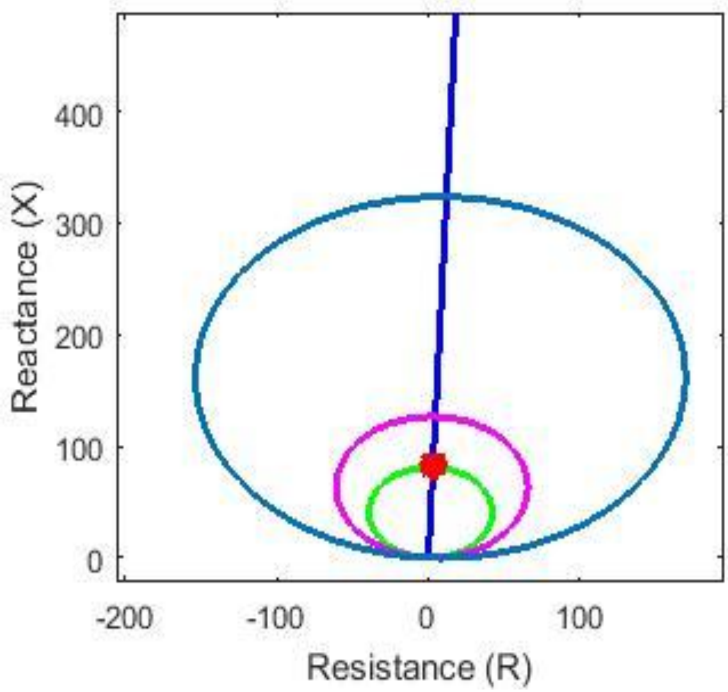

Figure 4.4: Mho characteristics of Relay B for Line to Line fault at 50km

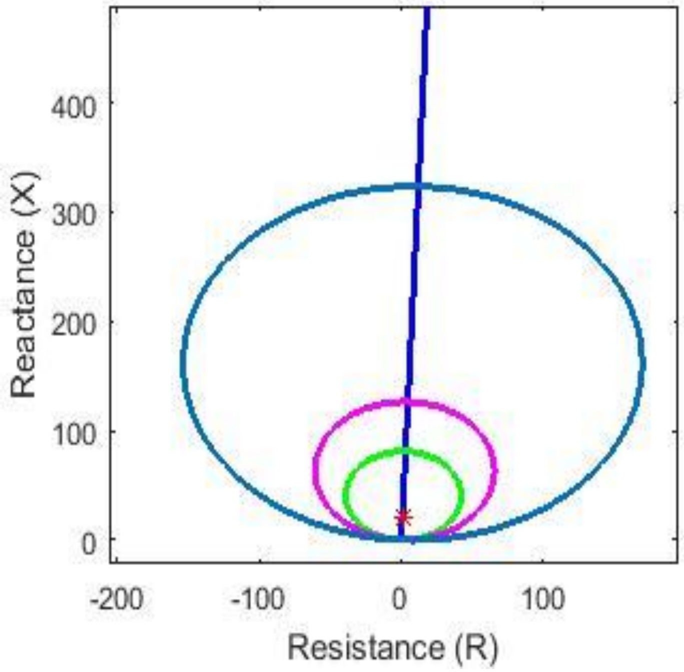

Figure 4.5: Mho characteristics of Relay A for Line to Ground fault at 50km

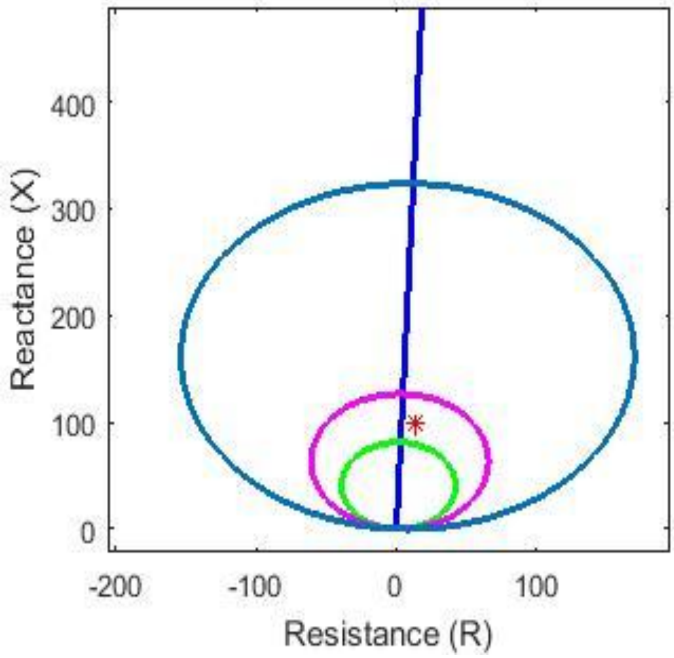

Figure 4.6: Mho characteristics of Relay B for Line to Ground fault at 50km

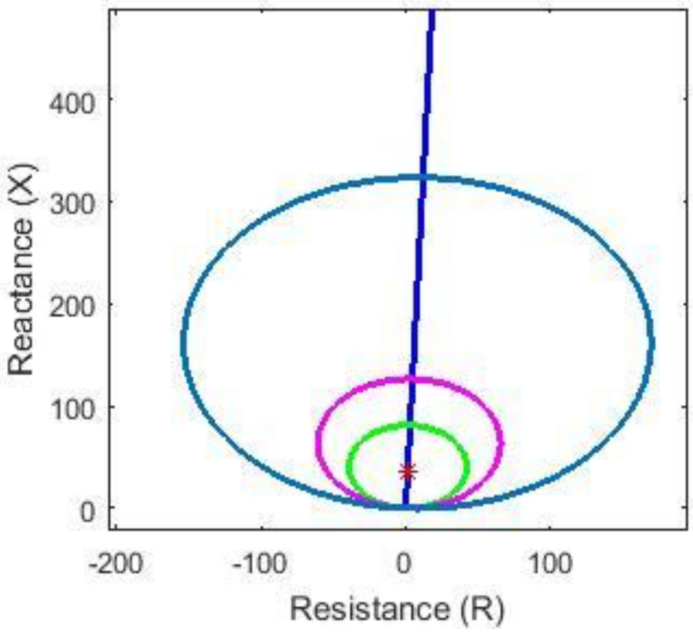

Figure 4.7: Mho characteristics of Relay A for 3 Phase fault at 100km

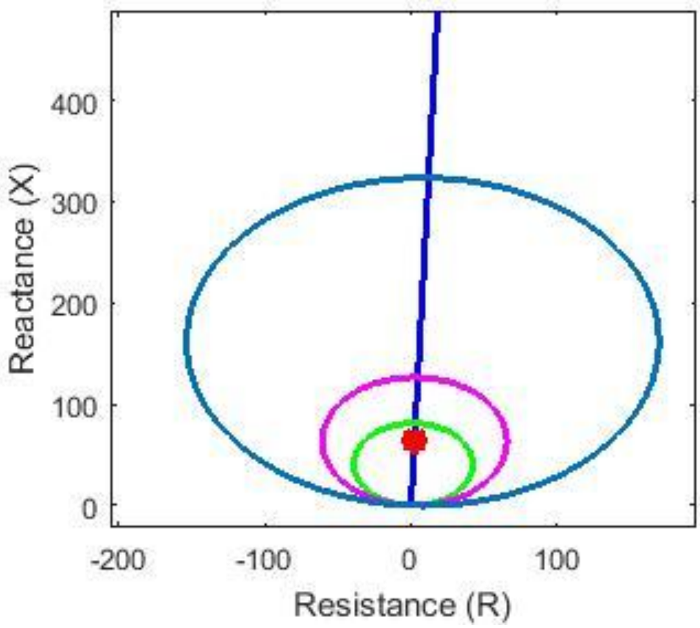

Figure 4.8: Mho characteristics of Relay B for 3 Phase fault at 100km

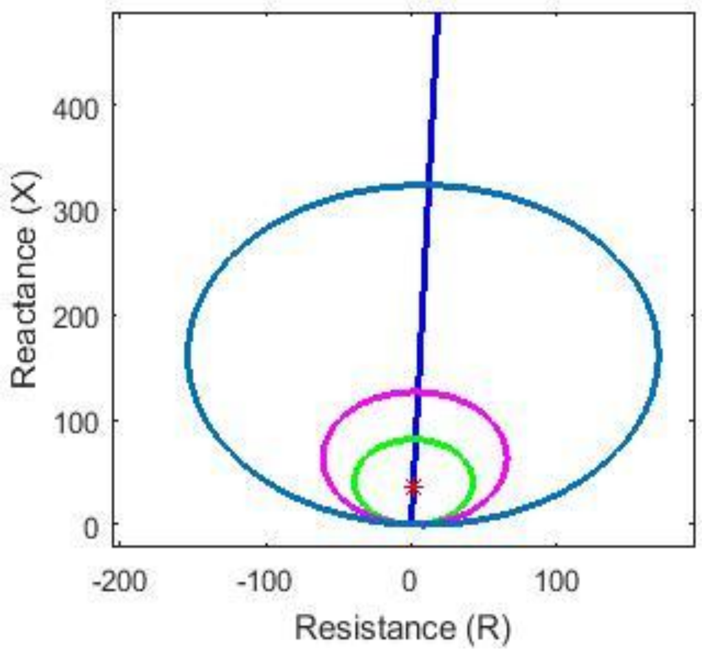

Figure 4.9: Mho characteristics of Relay A for Line to Line fault at 100km

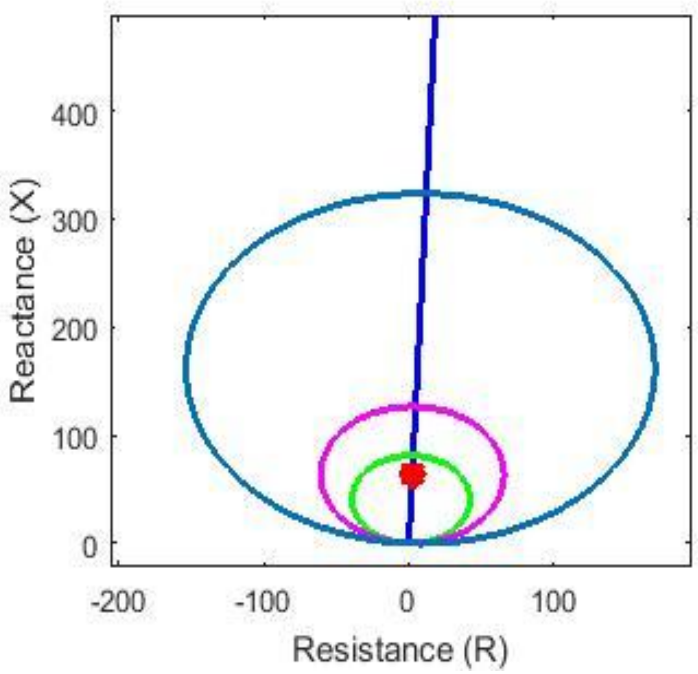

Figure 4.10: Mho characteristics of Relay B for Line to Line fault at 100km

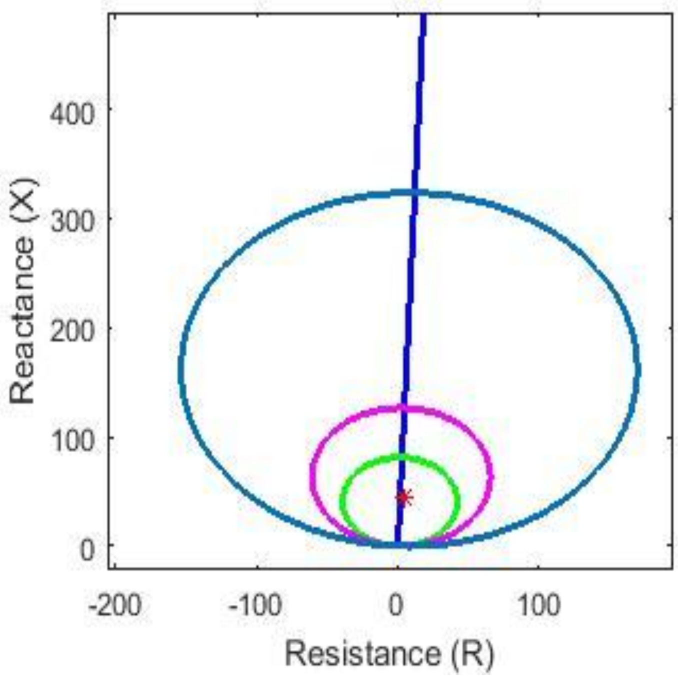

Figure 4.11: Mho characteristics of Relay A for Line to Ground fault at 100km

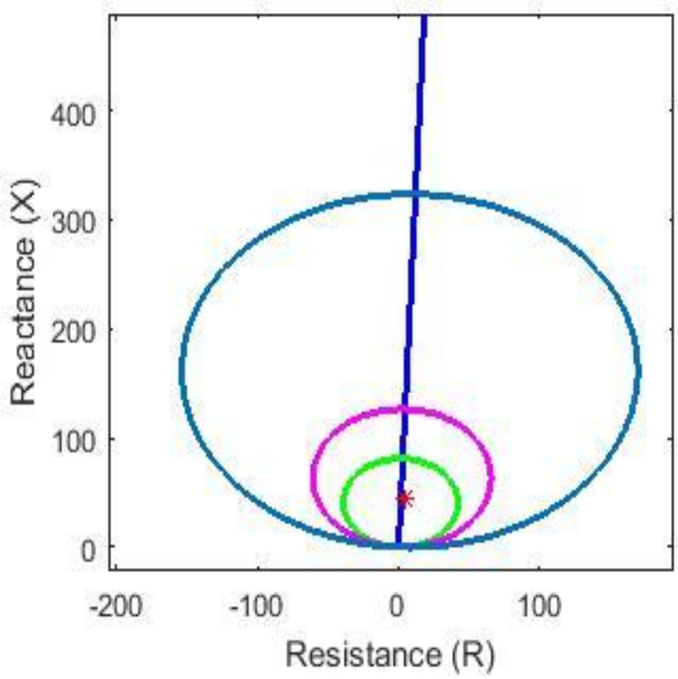

Figure 4.12: Mho characteristics of Relay B for Line to Ground fault at 100km

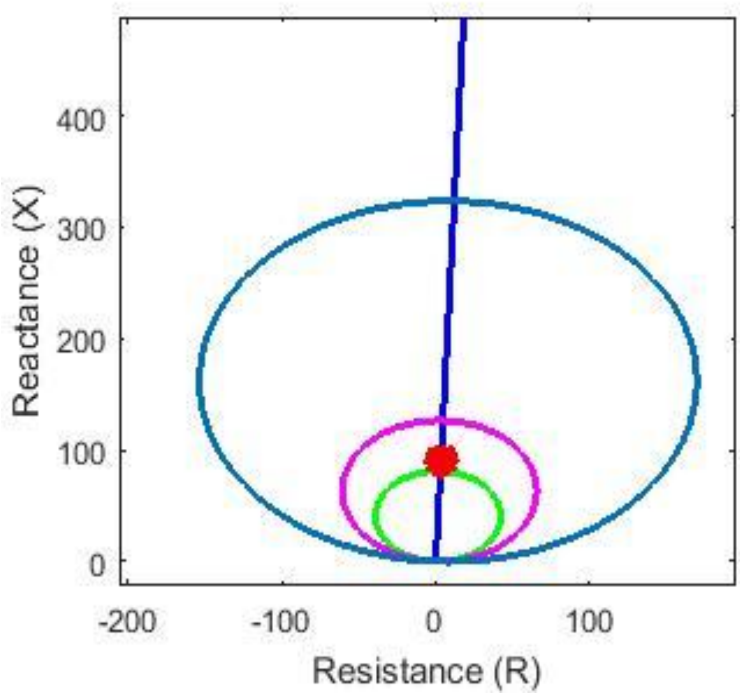

Figure 4.13: Mho characteristics of Relay A for 3 Phase fault at 250km

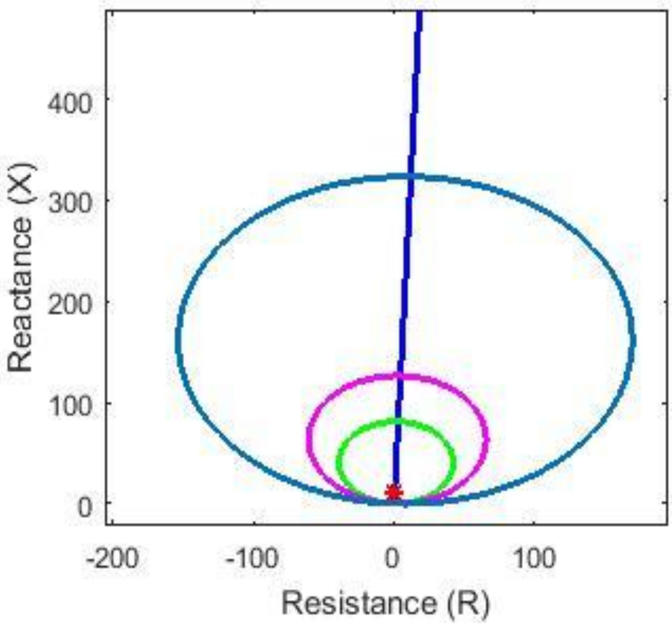

Figure 4.14: Mho characteristics of Relay B for 3 Phase fault at 250km

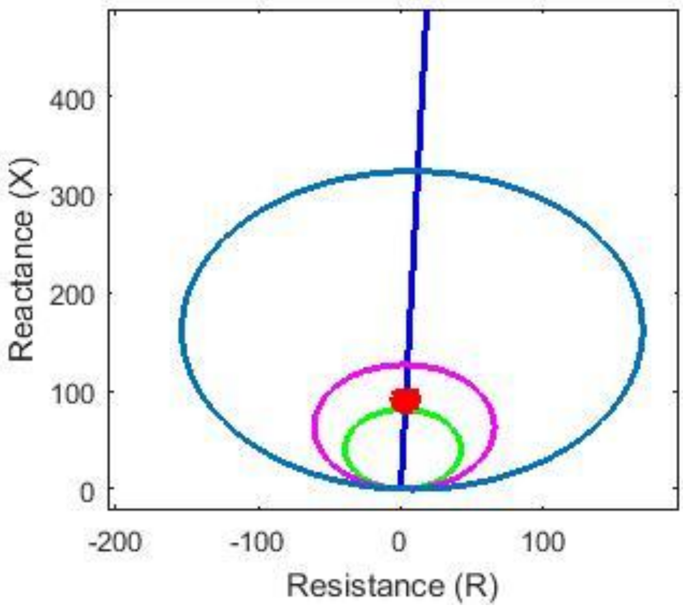

Figure 4.15: Mho characteristics of Relay A for Line to Line fault at 250km

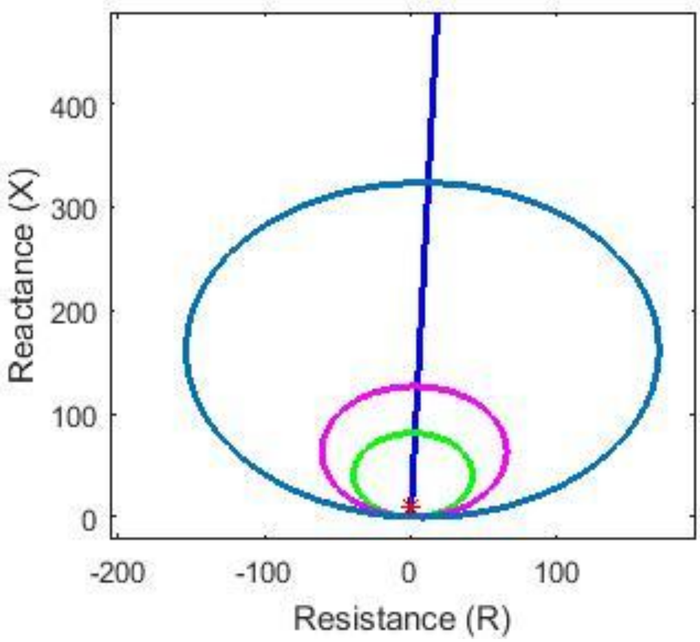

Figure 4.16: Mho characteristics of Relay B for Line to Line fault at 250km

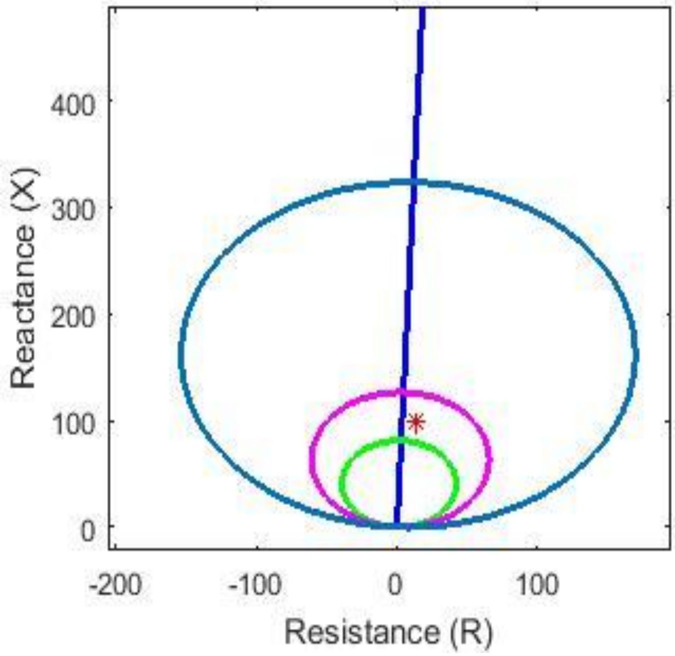

Figure 4.17: Mho characteristics of Relay A for Line to Ground fault at 250km

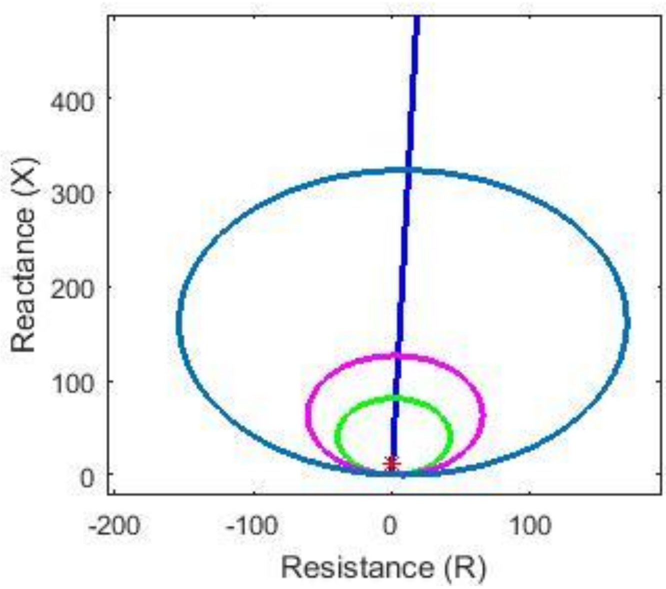

Figure 4.18: Mho characteristics of Relay B for Line to Ground fault at 250km

In the base case, simulation of the Ikeja West to Benin transmission line (280km, 330kV) without FACTS device was done. It can be seen from figures 4.1 – 4.18 that the distance relays operated accurately and correctly in accordance to the relay zones coordination. Figure 4.1 – figure 4.2 show the occasions of three phase faults, figure 4.3 – figure 4.4 show line to line (L – L) faults and figure 4.5 – 4.6 show single line to ground (SLG) faults. Each of these fault types were simulated on 50km, 100km and 250km of the case transmission line. The Mho relay characteristics trajectories showed that the faults were seen by distance relay A and distance relay B in the correct respective zones of protection on the 280km case transmission line. For faults at 50km, relay A tripped in its zone 1 whereas relay B tripped the same fault in its zone 2, for a 100km fault relay A and relay B overlapped and tripped the fault in zone 1 while for 250km fault relay A tripped the fault in zone 2 whereas relay B tripped the fault in its primary protection zone 1. This depicts correct relay zone coordination operations. It was also observed from the simulations that for the single line to ground faults, the fault appeared just outside the operating mho circle. This is because the single line to ground faults particularly provides problems to the distance relay because the arc often contains considerable amount of resistance thereby reducing the phase angle of the measured impedance. It also increases the magnitude of the impedance as compared to other fault conditions.

Therefore, this base case verifies that the Mho distance relay accurately measures the apparent impedance and fault location on the transmission line without series compensation.

Table 4.1: Relay A and Relay B fault location without TCSC

Length(km)	Fault Type	$\mathbf{R_A}$	$\mathbf{X_A}$	$\mathbf{R_B}$	$\mathbf{X_B}$	$\mathbf{L_A}$	$\mathbf{L_B}$
50km	LG L – L 3Ph	0.5387 0.641 0.642	14.96 17.62 17.64	0.6488 6.613 3.182	52.71 61.14 84.18	52.47 50.03 50.13	227.50 229.47 228.89
100km	LG L – L 3Ph	1.201 1.288 1.289	29.65 35.4 35.4	1.478 2.444 2.4442	37.85 65.22 65.23	83.97 100.1 100.1	106.9 181.9 181.9
250km	LG L – L 3Ph	0.2155 3.291 3.363	58.34 49.08 49.08	0.3063 0.3839 0.3842	9.014 10.57 10.57	259.05 250.17 250.21	30.11 29.15 29.59

4.2 A Case of Different Fault Types with 20% TCSC compensation

So as to ascertain the effect of FACTS devices on the zones of protection of distance relays in the Benin to Ikeja West transmission line, a series compensation device TCSC was placed at the middle the line. The Mho characteristics of the relays in the presence of TCSC with various faults are shown in figure 4.19 – Figure 4.36.

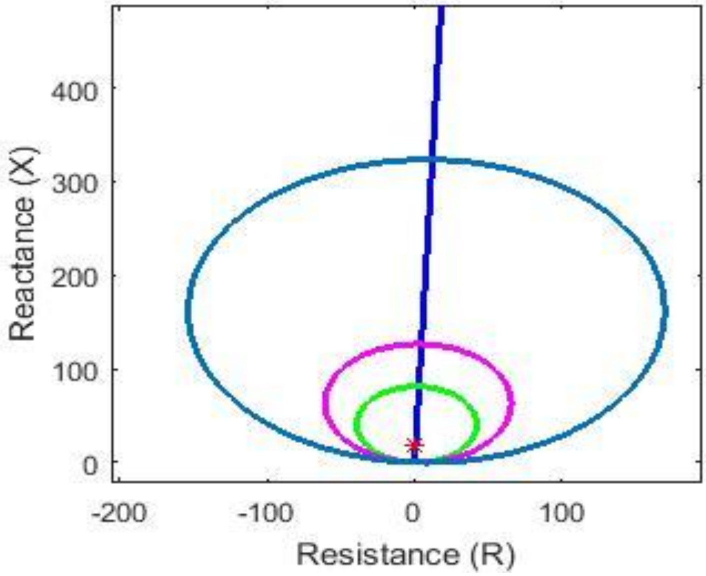

Figure 4.19: Mho characteristics of Relay A for 3 Phase fault at 50km in the presence TCSC.

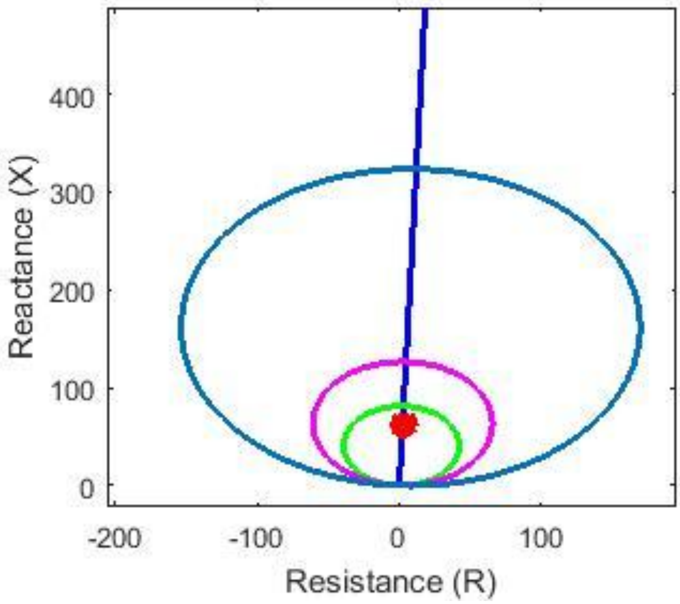

Figure 4.20: Mho characteristics of Relay B for 3 Phase fault at 50km in the presence TCSC.

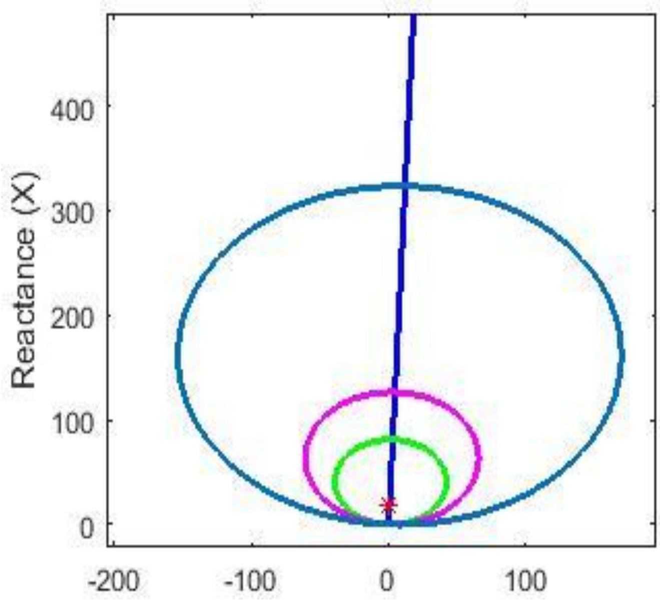

Figure 4.21: Mho characteristics of Relay A for Line to Line fault at 50Km in the presence TCSC.

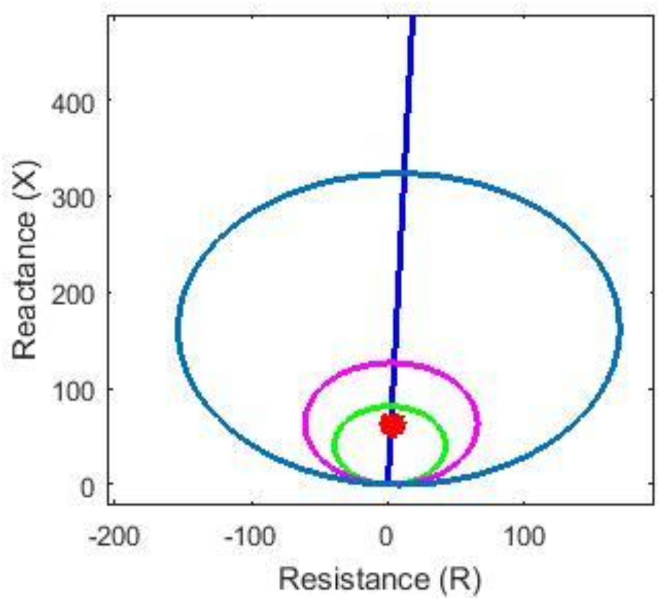

Figure 4.22: Mho characteristics of Relay B for Line to Line fault at 50km in the presence TCSC.

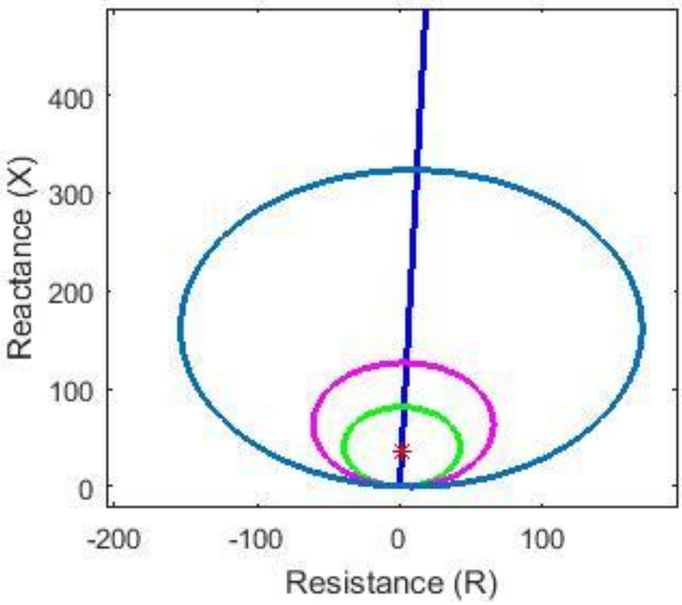

Figure 4.23: Mho characteristics of Relay A for Line to Ground fault at 50km in the presence TCSC.

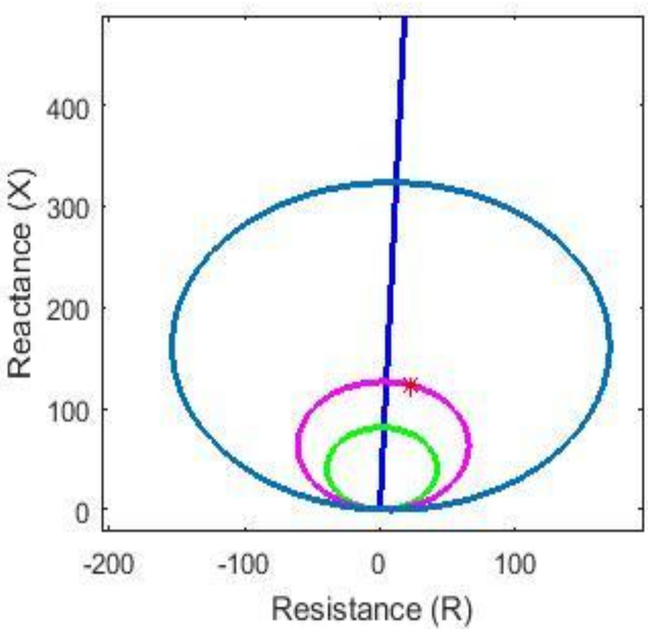

Figure 4.24: Mho characteristics of Relay B for Line to Ground fault at 50km in the presence TCSC.

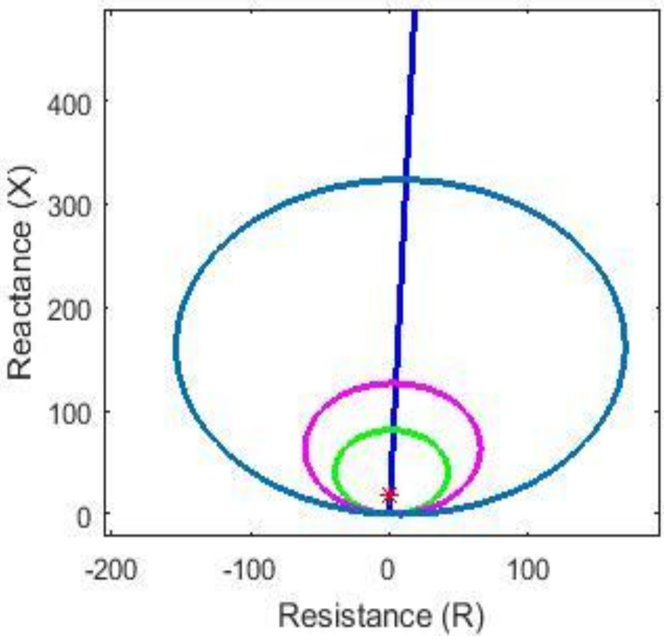

Figure 4.25: Mho characteristics of Relay A for 3 Phase fault at 100km in the presence TCSC

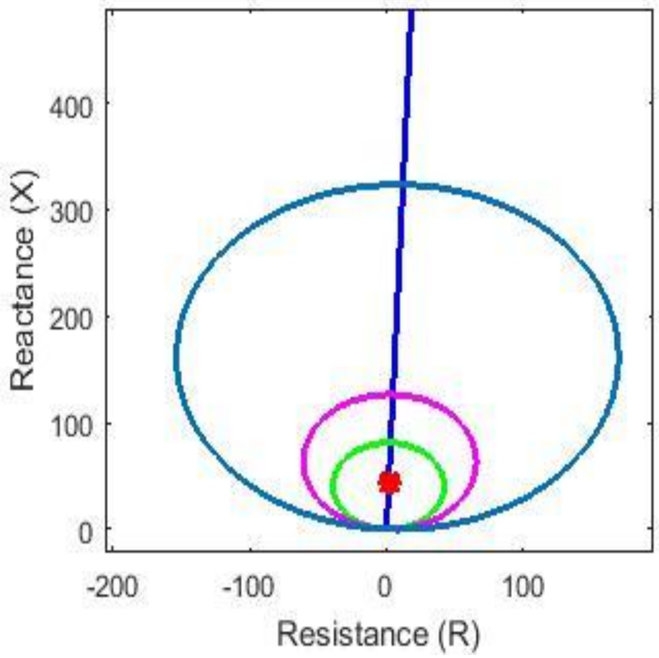

Figure 4.26: Mho characteristics of Relay B for 3 Phase fault at 100km in the presence TCSC

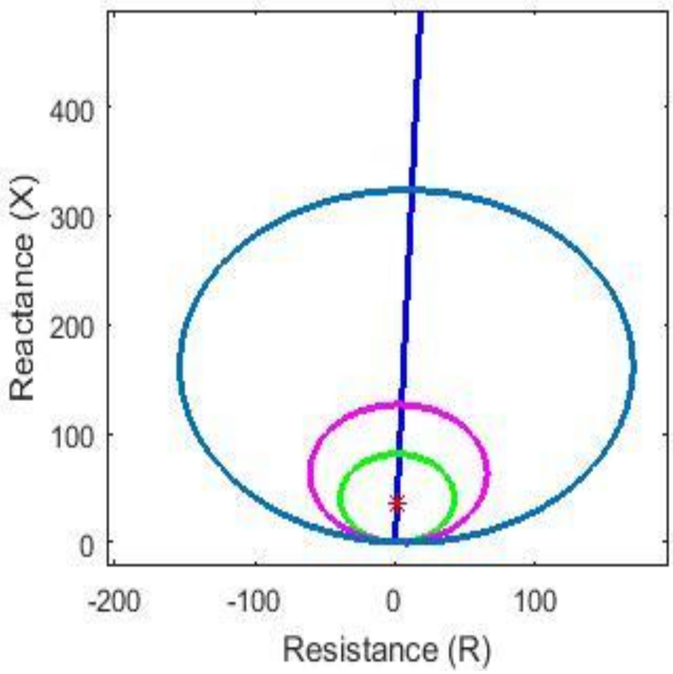

Figure 4.27: Mho characteristics of Relay A for Line to Line fault at 100km in the presence TCSC

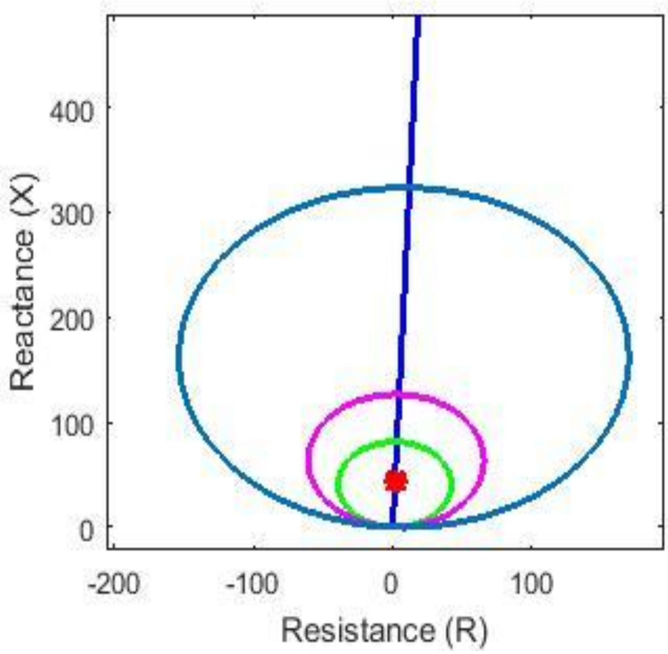

Figure 4.28: Mho characteristics of Relay B for Line to Line fault at 100km in the presence TCSC

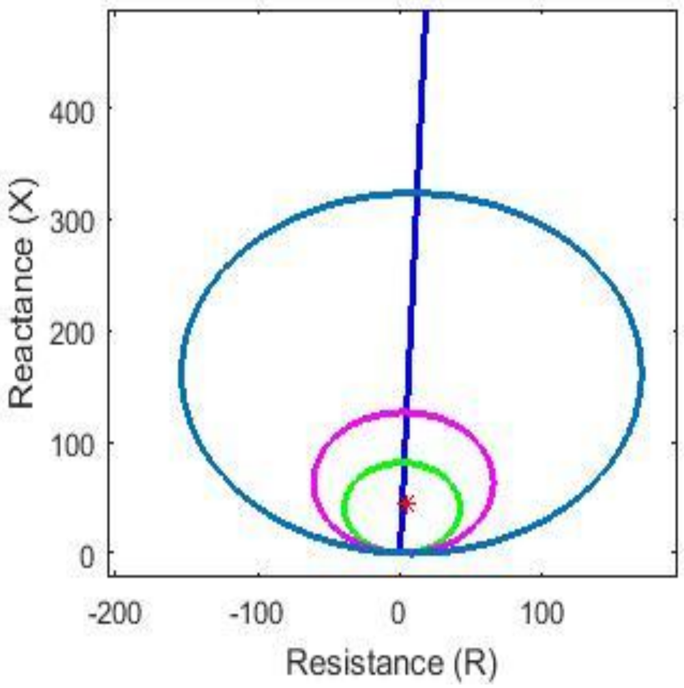

Figure 4.29: Mho characteristics of Relay A for Line to Ground fault at 100km in the presence TCSC

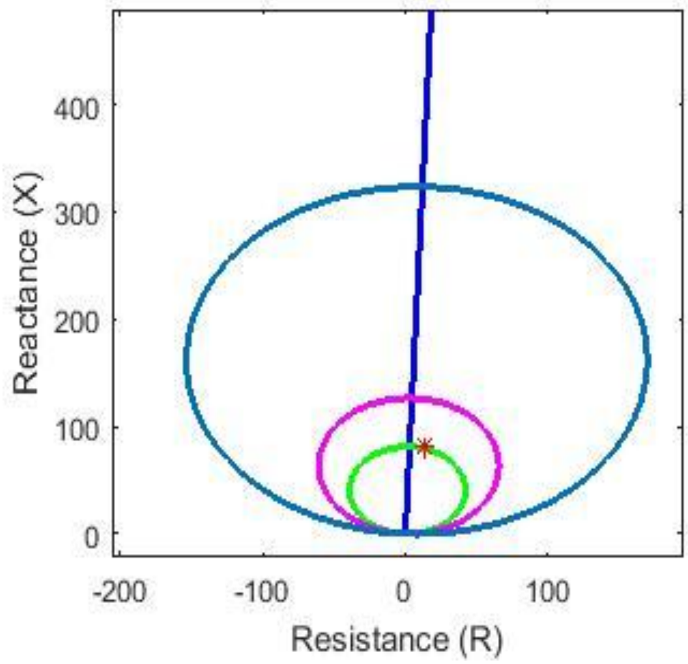

Figure 4.30: Mho characteristics of Relay B for Line to Ground fault at 100km in the presence TCSC

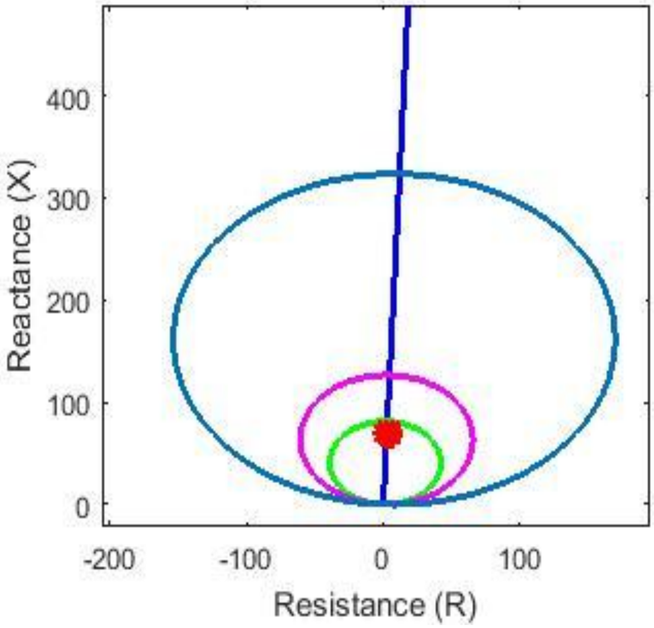

Figure 4.31: Mho characteristics of Relay A for 3 Phase fault at 250km in the presence TCSC

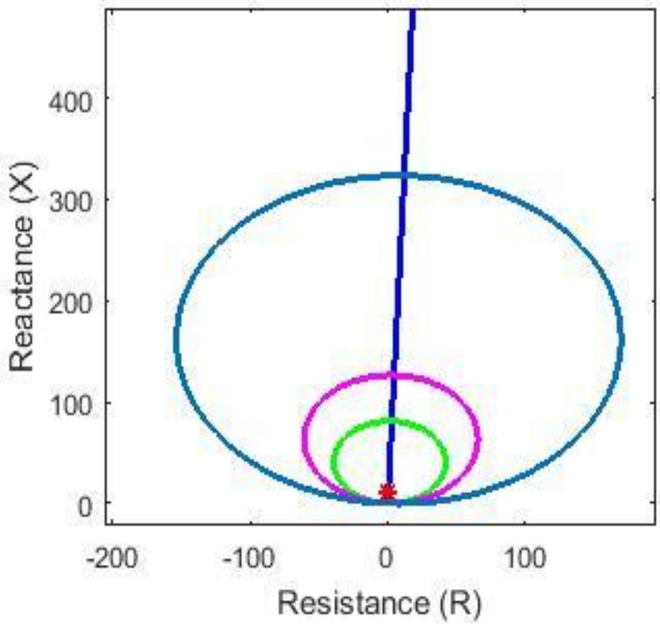

Figure 4.32: Mho characteristics of Relay B for 3 Phase fault at 250km in the presence TCSC

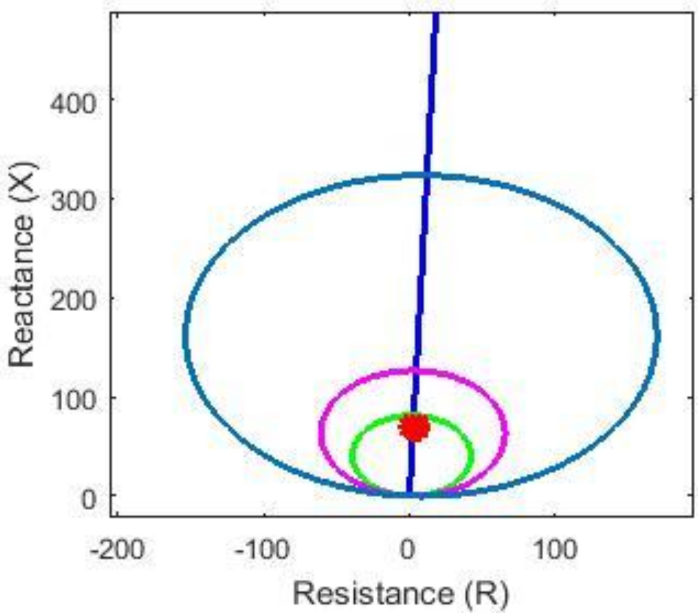

Figure 4.33: Mho characteristics of Relay A for Line to Line fault at 250km in the presence TCSC

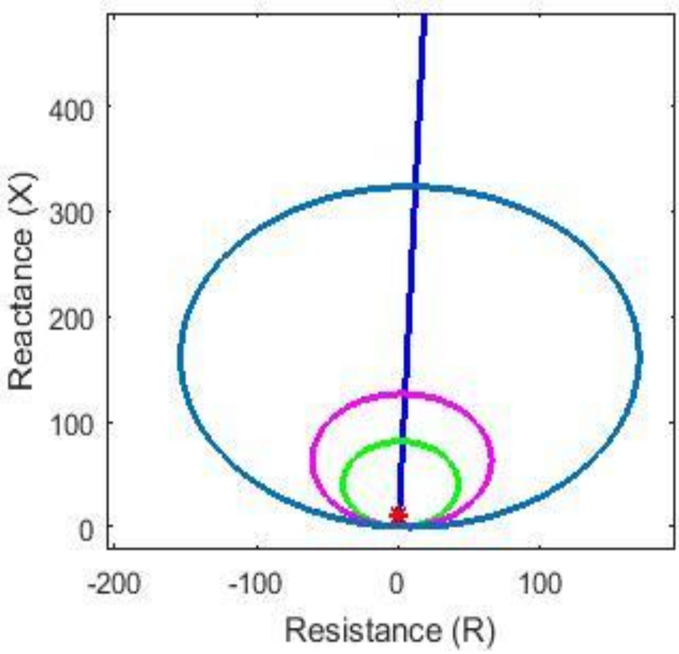

Figure 4.34: Mho characteristics of Relay B for Line to Line fault at 250km in the presence TCSC

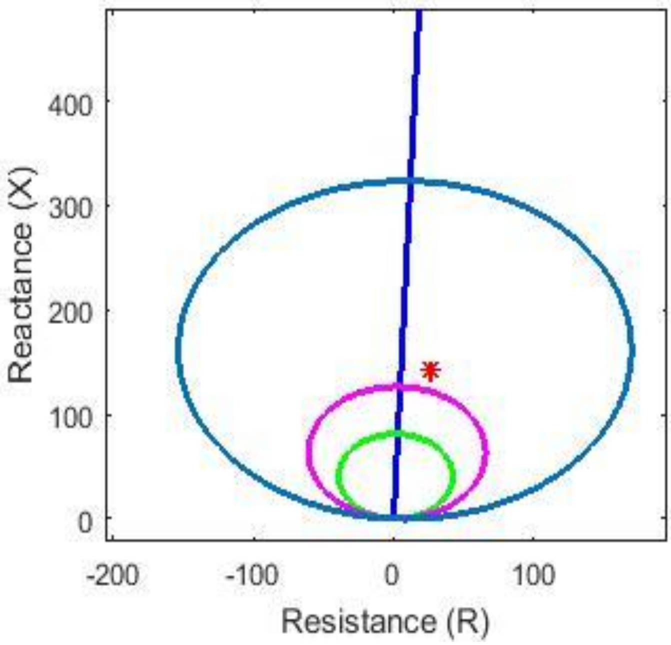

Figure 4.35: Mho characteristics of Relay A for Line to Ground fault at 250km in the presence TCSC

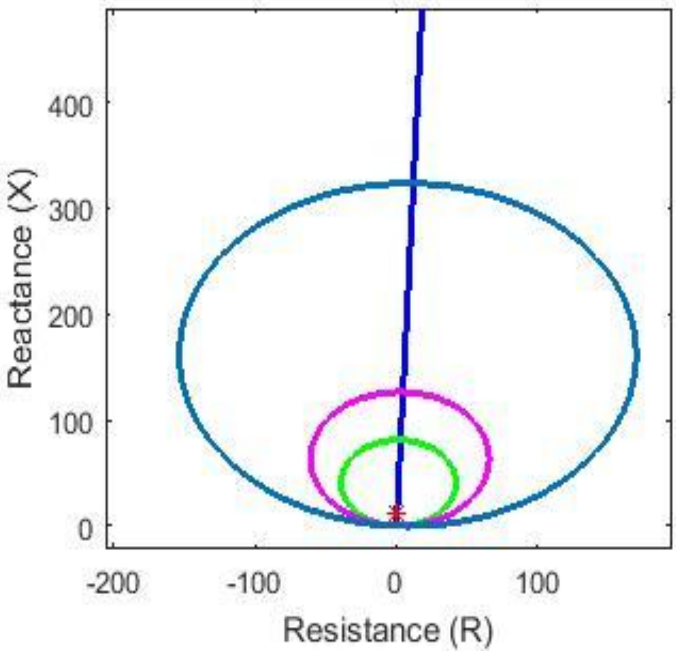

Figure 4.36: Mho characteristics of Relay B for Line to Ground fault at 250km in the presence TCSC

An increase in the level of percentage compensation of the TCSC will further affect the reach of the relays. This can be seen in Tables 4.2 to 4.4 below that show the corresponding values of resistance, reactance and fault location for different levels of compensation (20%, 40% and 60%) on the Ikeja West to Benin transmission line. These compensation levels were simulated for different fault location on the line (50km, 100km, 250km). The distributed parameters of the transmission line were also considered in the simulation.

Table 4.2: Relay A and Relay B fault location for 20% Compensation

Length(km)	Fault Type	R_A	X_A	R_B	X_B	L_A	L_B
50km	LG L – L 3Ph	1.288 0.601 0.6407	20.11 17.63 17.63	22.21 3.119 3.08	123.6 62.39 62.38	57.14 50.03 50.03	278.1 174.4 174.3
100km	LG L – L 3Ph	4.228 1.289 1.29	45.55 35.4 35.4	13.54 2.405 2.422	81.51 43.97 44.01	128.7 100.1 100.1	124 124.3 32.59
250km	LG L – L 3Ph	26.39 3.377 3.384	142.6 69.97 69.98	0.5959 0.3842 0.3833	11.47 10.57 10.57	279.1 194.7 194.7	32.59 30.02 30.02

Table 4.3: Relay A and Relay B fault location for 40% Compensation

Length(km)	Fault Type	R_A	X_A	R_B	X_B	L_A	L_B
50km	LG L – L 3Ph	1.287 0.6401 0.6394	22.49 3.225 3.254	105.3 41.6 41.73	57.13 50.03 50.03	57.13 51.15 50.03	271.6 117.6 118.1
100km	LG L – L 3Ph	4.225 1.289 1.289	45.53 35.4 35.4	13.96 2.531 2.56	23.67 23.81 23.81	128.7 100.1 100.1	182.8 67.46 67.84
250km	LG L – L 3Ph	26.46 3.35 3.365	123.9 49.06 49.09	0.5957 0.3842 0.3841	11.47 10.57 10.57	277.1 138.2 138.3	32.59 30.02 30.02

Table 4.4: Relay A and Relay B fault location for 60% Compensation

Length(km)	Fault Type	R_A	X_A	R_B	X_B	L_A	L_B
50km	LG L – L 3Ph	1.287 0.6401 0.6399	20.1 17.63 17.63	22.86 3.4 3.457	86.63 20.89 21.15	57.12 50.03 50.03	246.5 59.99 60.76
100km	LG L – L 3Ph	4.222 1.289 1.289	45.52 35.4 35.4	14.44 2.725 2.725	46.56 3.445 3.711	128.6 100.1 100.1	137.2 12.47 13.17
250km	LG L – L 3Ph	26.51 3.304 3.331	106.2 28.27 28.32	0.5954 0.3842 0.3842	11.46 10.57 10.57	294 80.56 80.69	32.59 30.02 30.02

Figures 4.19 – 4.36 show the case transmission line with FACTS device incorporated at the middle of the line. It can be seen from the Mho relay characteristics trajectories that the Thyristor Controlled Series Capacitor (TCSC) compensation affects the apparent impedance and fault location. The relay mal-operated whenever the TCSC falls within the fault path. Figures 4.1 – 4.12 show occasions where the fault locations are before TCSC at 50km and 100km. The Mho relay A located the faults correctly in its primary zone 1, but for a fault at 250km occurring after the TCSC the relay mal-operated and tripped the fault in it zone 1 instead of protection zone 2. This is because for 250km fault, relay A equivalent impedance involves the TCSC capacitive reactance and the fault current passing through the TCSC is due to a strong source connected at the relay A. The strong source at relay A can supply larger fault current than the source at the relay B and has a greater effect on the equivalent impedance of the TCSC circuit. The second case trajectories verify

the fact that the Mho relay mal-operates whenever faults occur in the presence of FACTS compensation as can be seen in all fault types simulated.

Table 4.1 to 4.4 elucidated the effects of various compensation levels (20%, 40% and 60%) to the fault impedance and location in the power system. It can be seen from the table that an increase in compensation level further affects fault impedance and consequently the zones coordination of the distance relay.

4.3 A Case of Different Fault types with TCSC (Considering MOV Action)

The MOV is used for overvoltage surge protection of FACTS devices and it has non linear characteristics. The effects of MOV protection to the distance relay protection scheme in the presence of TCSC on the transmission line between Benin and Ikeja West in the Nigeria electric power system are shown figures 4.37 – 4.54. Also operational behaviour of the MOV is shown in Figures 4.55 – 4.57. The MOV partially bypasses the capacitor as seen in the figures 4.55 – 4.57 and modifies the equivalent MOV/TCSC impedance. Larger fault current has a greater effect on equivalent impedance. For very higher fault current, the compensation is reduced further to nearly zero percent this is due to the MOV action of protecting the TCSC during this condition and this would have a similar effect on the apparent impedance as shown in the Mho characteristics trajectories. Without adjusting the distance relay settings, overreaching or under-reaching may occur and will cause the relay to maloperate.

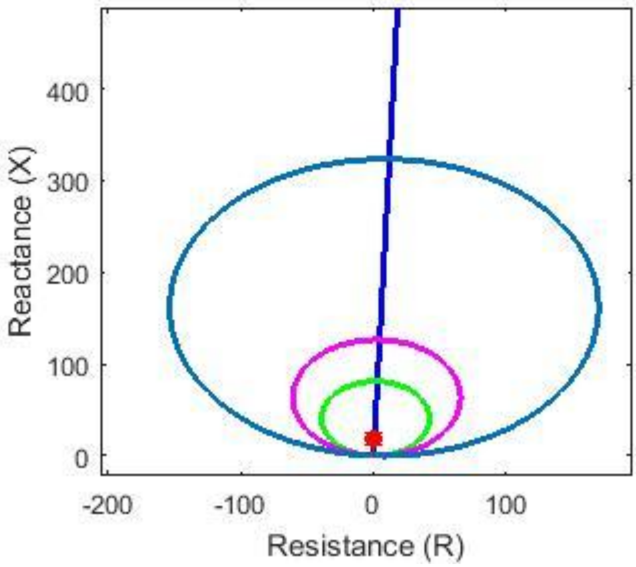

Figure 4.37: Mho characteristics of Relay A for 3 phase fault at 50km in the presence TCSC considering MOV protection

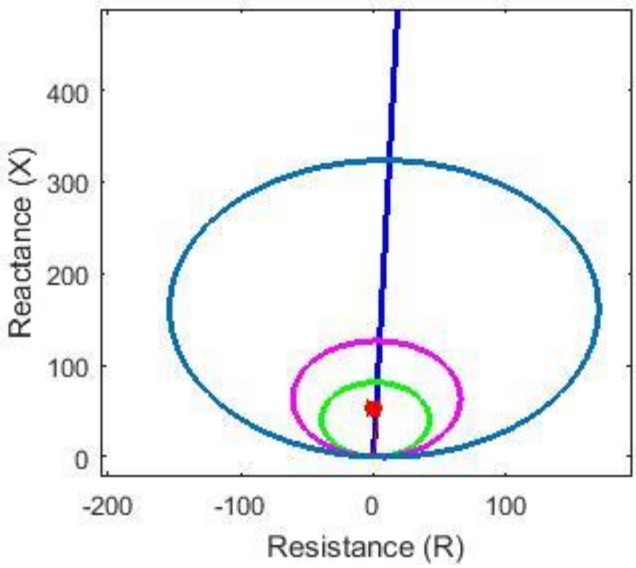

Figure 4.38: Mho characteristics of Relay B for 3 phase fault at 50km in the presence TCSC considering MOV protection

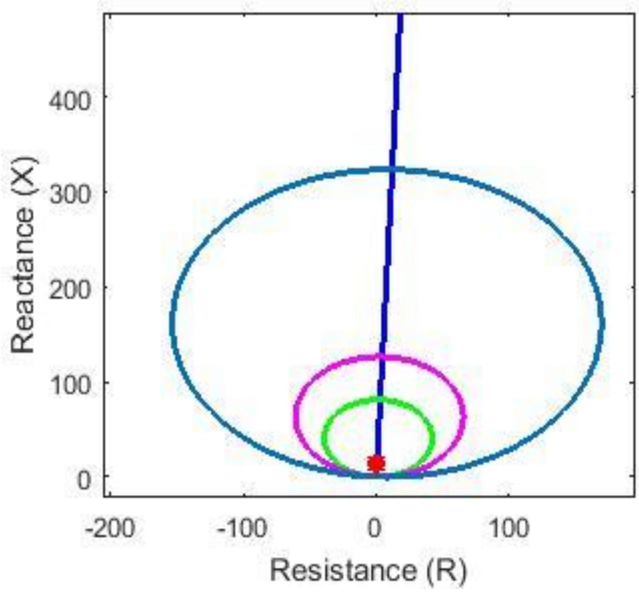

Figure 4.39: Mho characteristics of Relay A for line to ground fault at 50km in the presence TCSC considering MOV protection

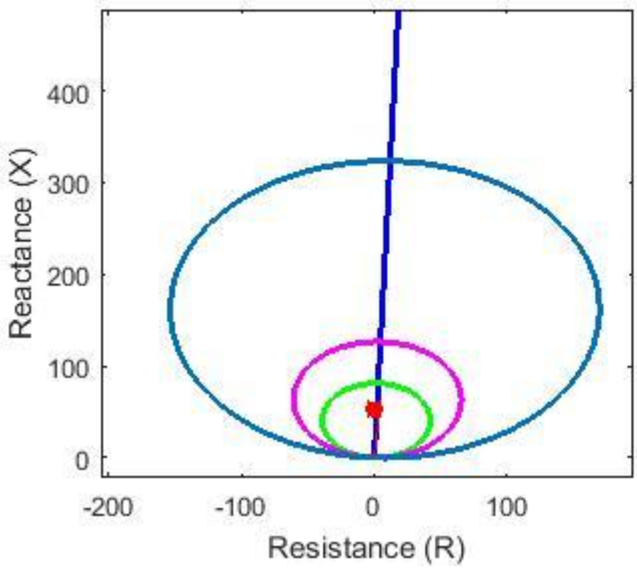

Figure 4.40: Mho characteristics of Relay B for line to ground fault at 50km in the presence TCSC considering MOV protection

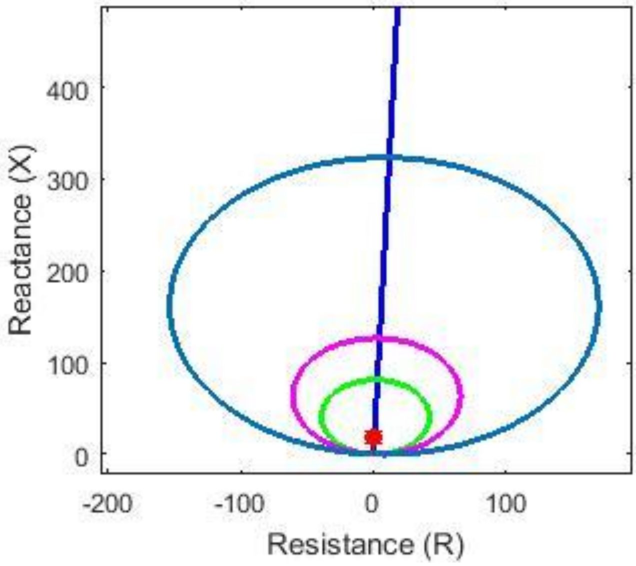

Figure 4.41: Mho characteristics of Relay A for line to line fault at 50km in the presence TCSC considering MOV protection

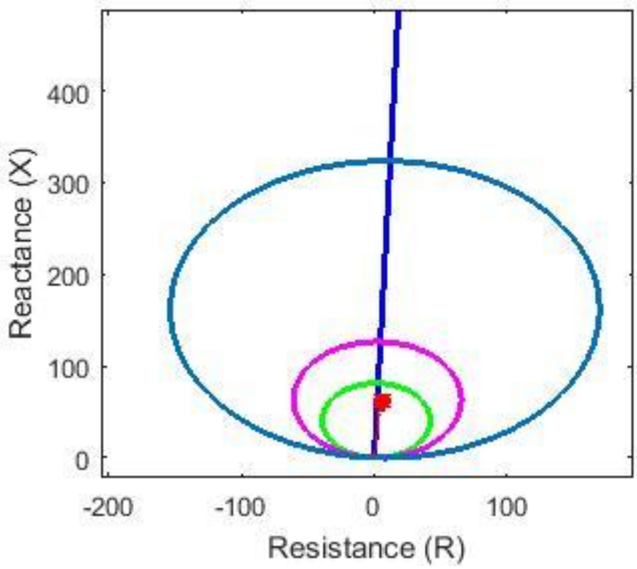

Figure 4.42: Mho characteristics of Relay B for line to line fault at 50km in the presence TCSC considering MOV protection

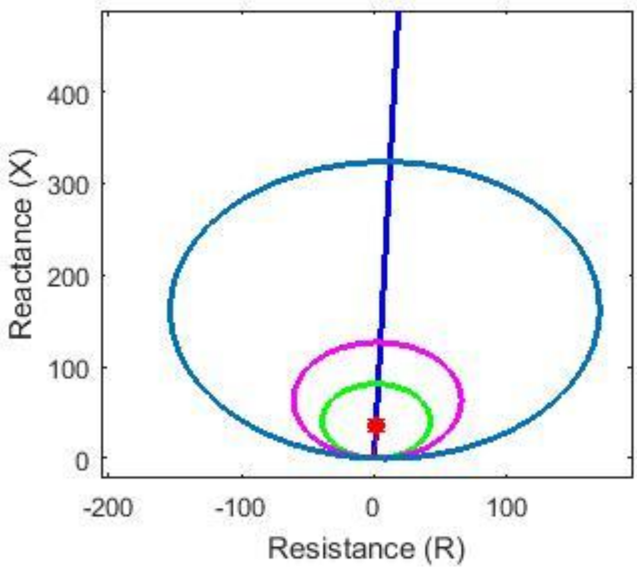

Figure 4.43: Mho characteristics of Relay A for three phase fault at 100km in the presence TCSC considering MOV protection

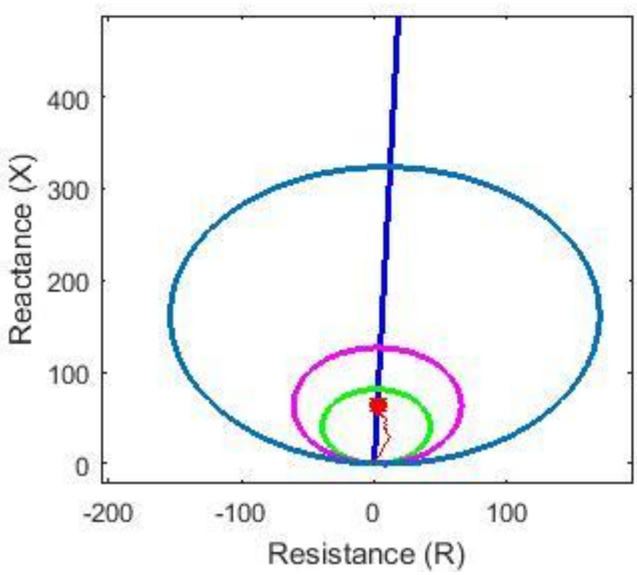

Figure 4.44: Mho characteristics of Relay B for three phase fault at 100km in the presence TCSC considering MOV protection

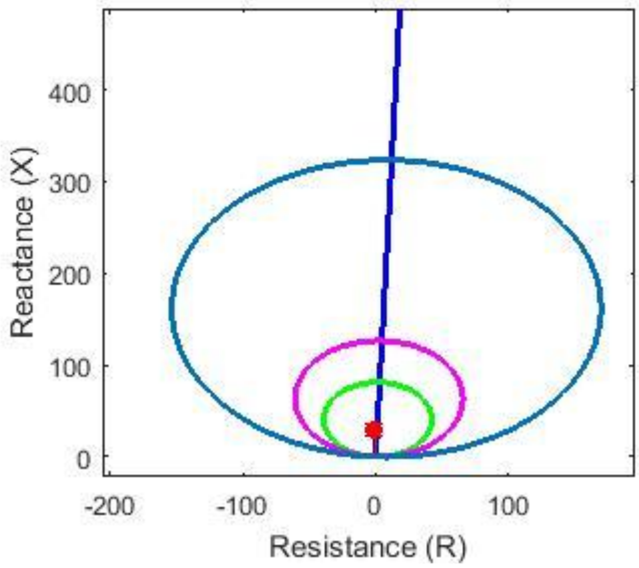

Figure 4.45: Mho characteristics of Relay A for line to ground fault at 100km in the presence TCSC considering MOV protection

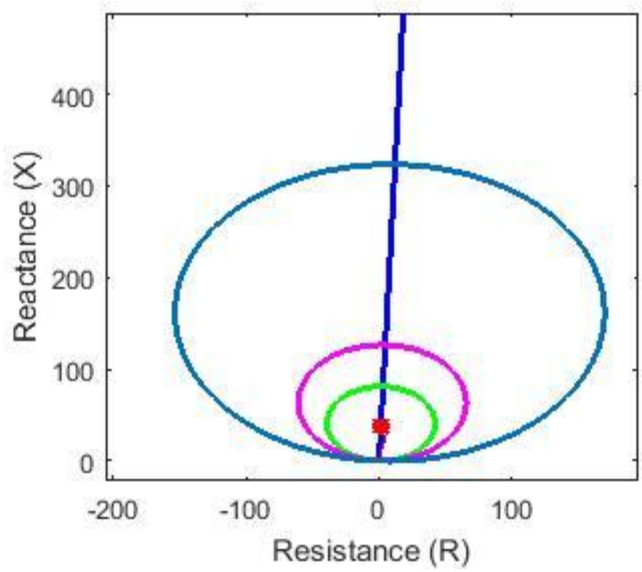

Figure 4.46: Mho characteristics of Relay B for line to ground fault at 100km in the presence TCSC considering MOV protection

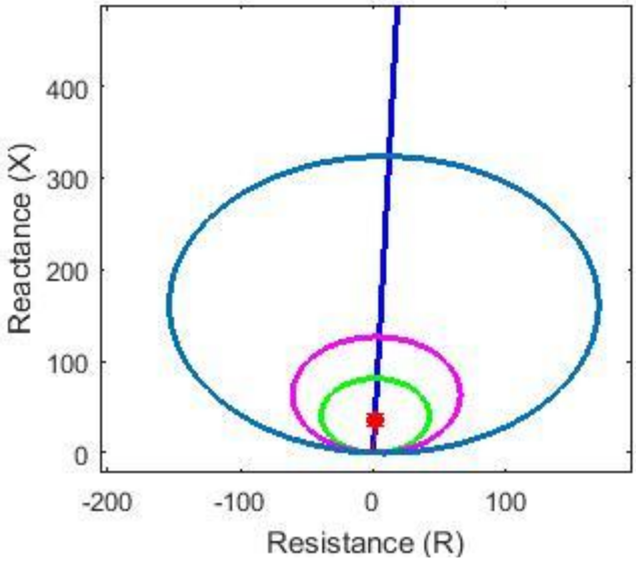

Figure 4.47: Mho characteristics of Relay A for line to line fault at 100km in the presence TCSC considering MOV protection

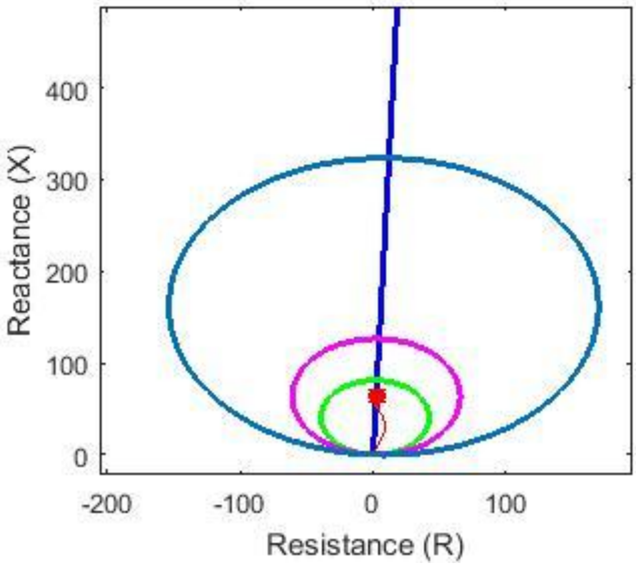

Figure 4.48: Mho characteristics of Relay B for line to line fault at 100km in the presence TCSC considering MOV protection

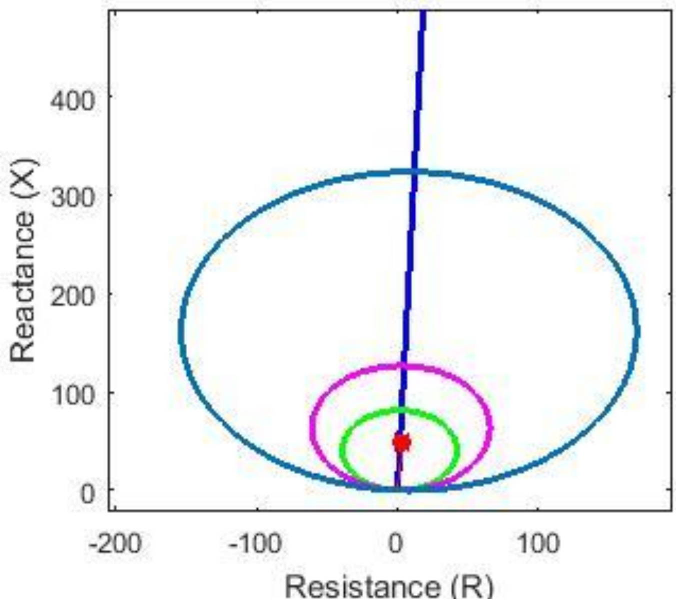

Figure 4.49: Mho characteristics of Relay A for three phase fault at 250km in the presence TCSC considering MOV protection

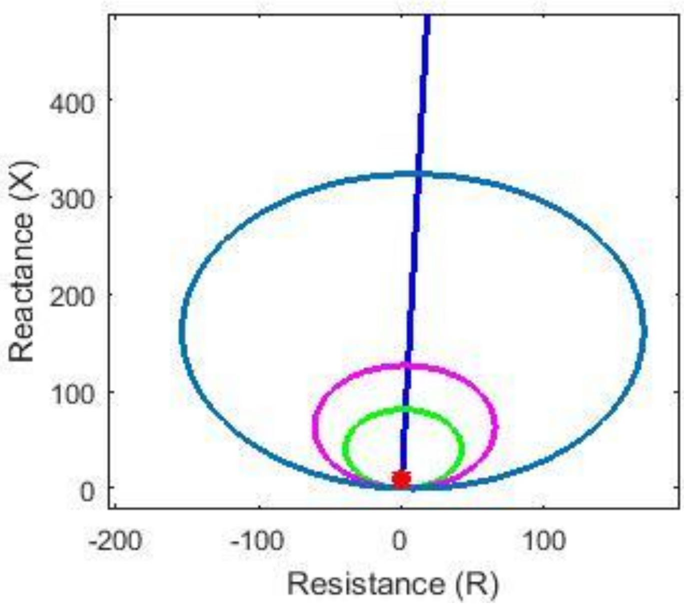

Figure 4.50: Mho characteristics of Relay B for three phase fault at 250km in the presence TCSC considering MOV protection

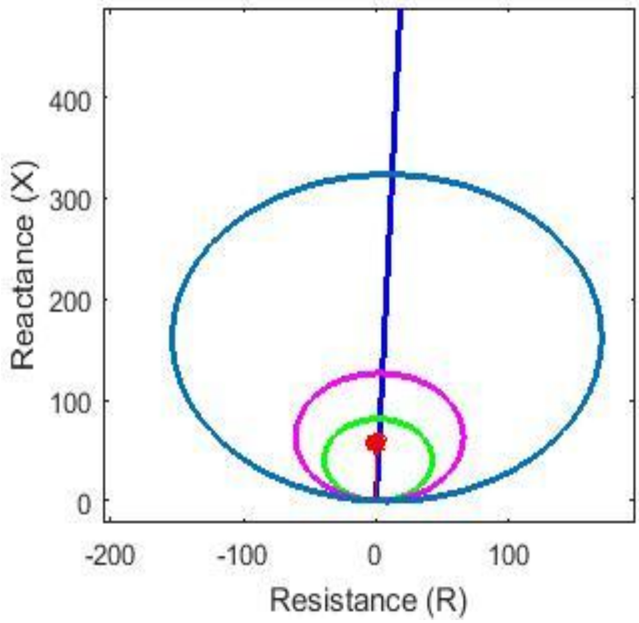

Figure 4.51: Mho characteristics of Relay A for line to ground fault at 250km in the presence TCSC considering MOV protection

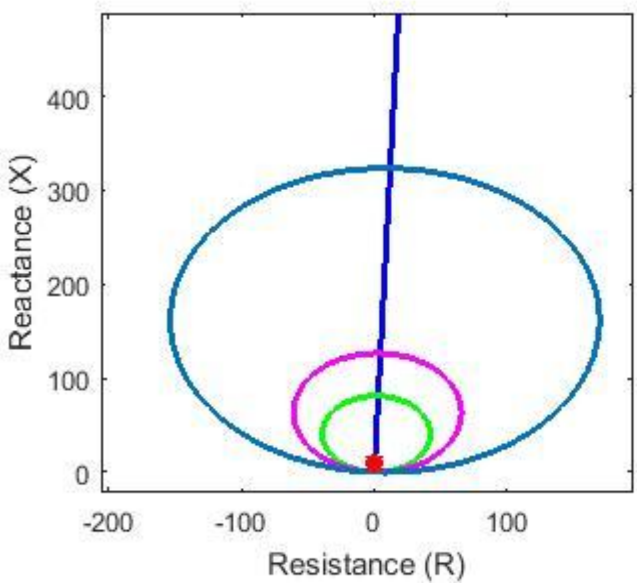

Figure 4.52: Mho characteristics of Relay B for line to ground fault at 250km in the presence TCSC considering MOV protection

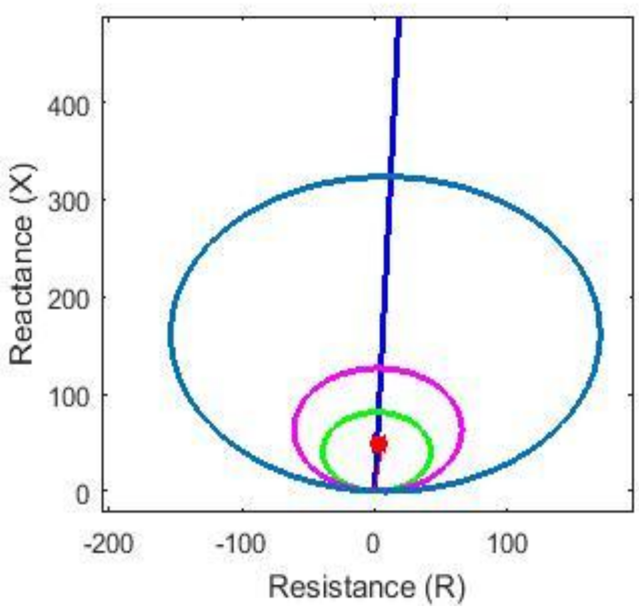

Figure 4.53: Mho characteristics of Relay A for line to line fault at 250km in the presence TCSC considering MOV protection

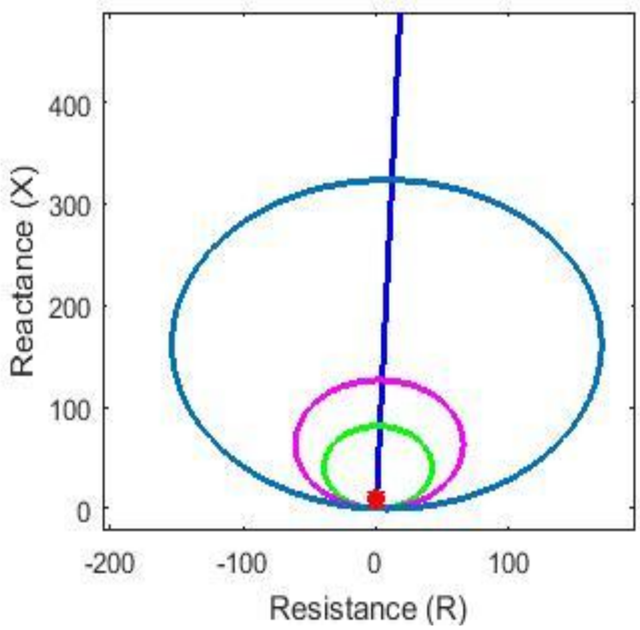

Figure 4.54: Mho characteristics of Relay B for line to line fault at 250km in the presence TCSC considering MOV protection

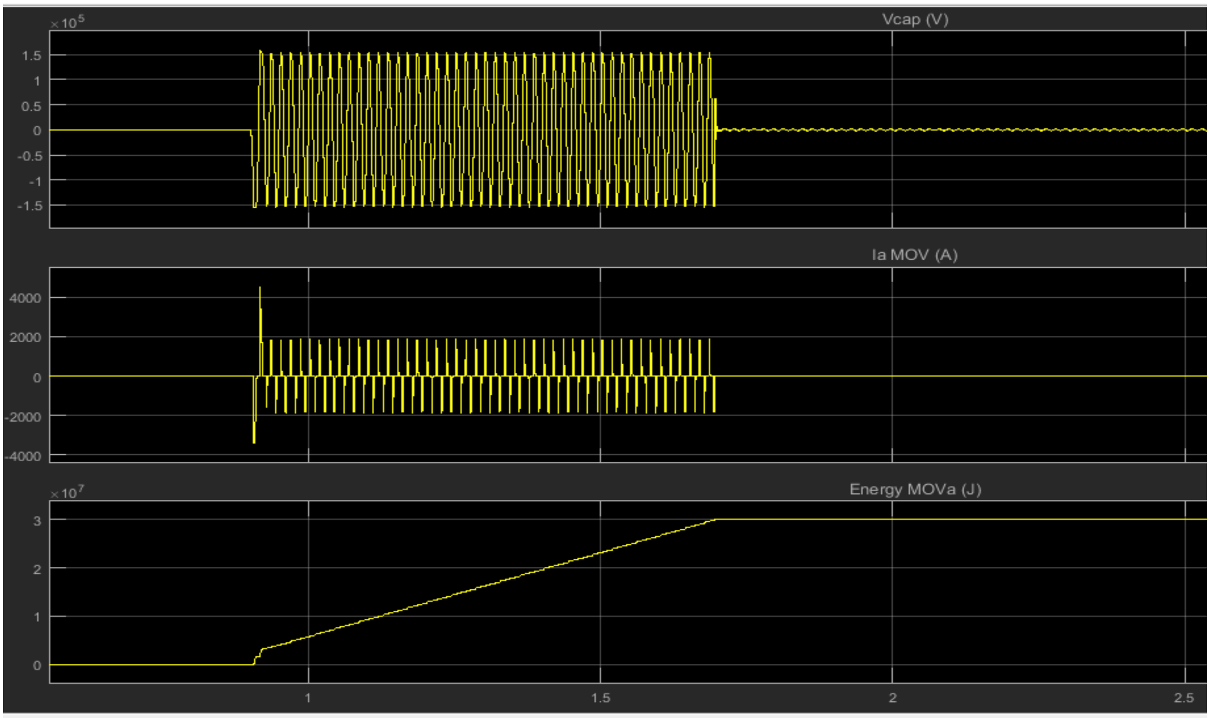

Figure 4.55: MOV characteristics of Phase "a" for three phase fault on the line

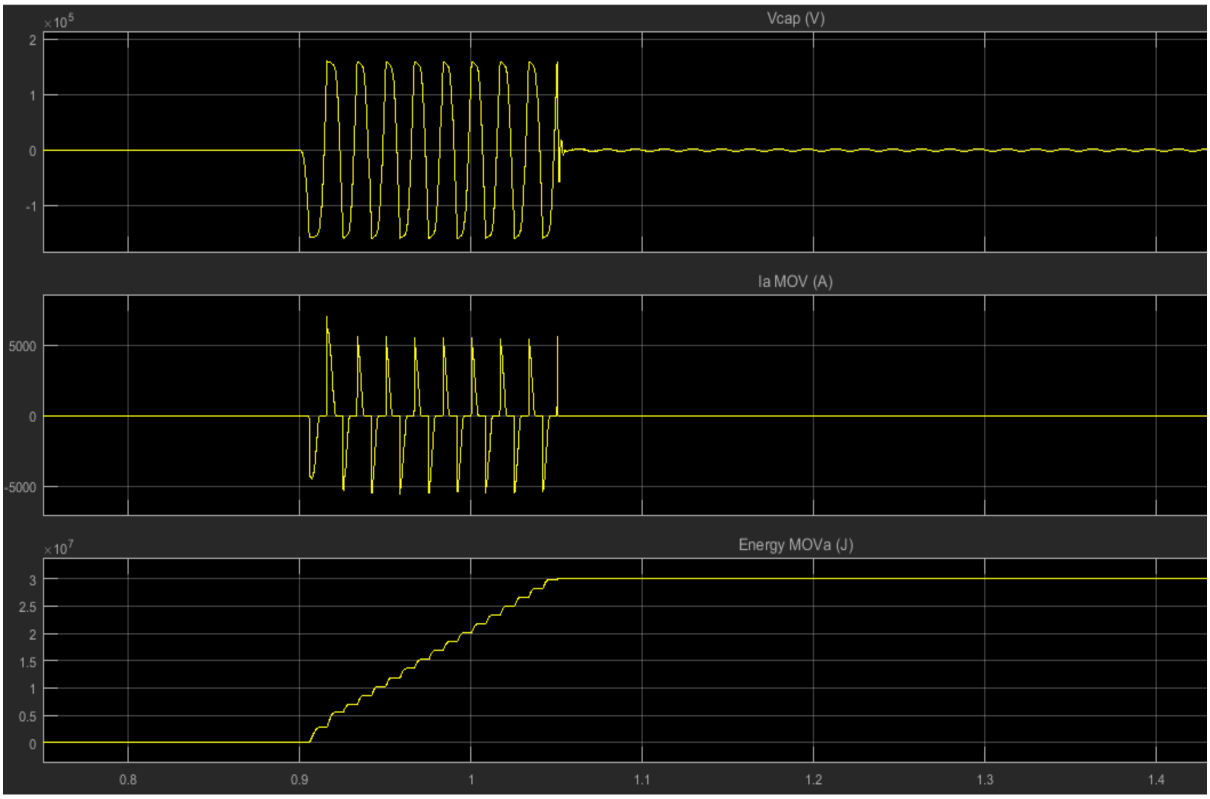

Figure 4.56: MOV characteristics of Phase "a" for line to line fault on the line

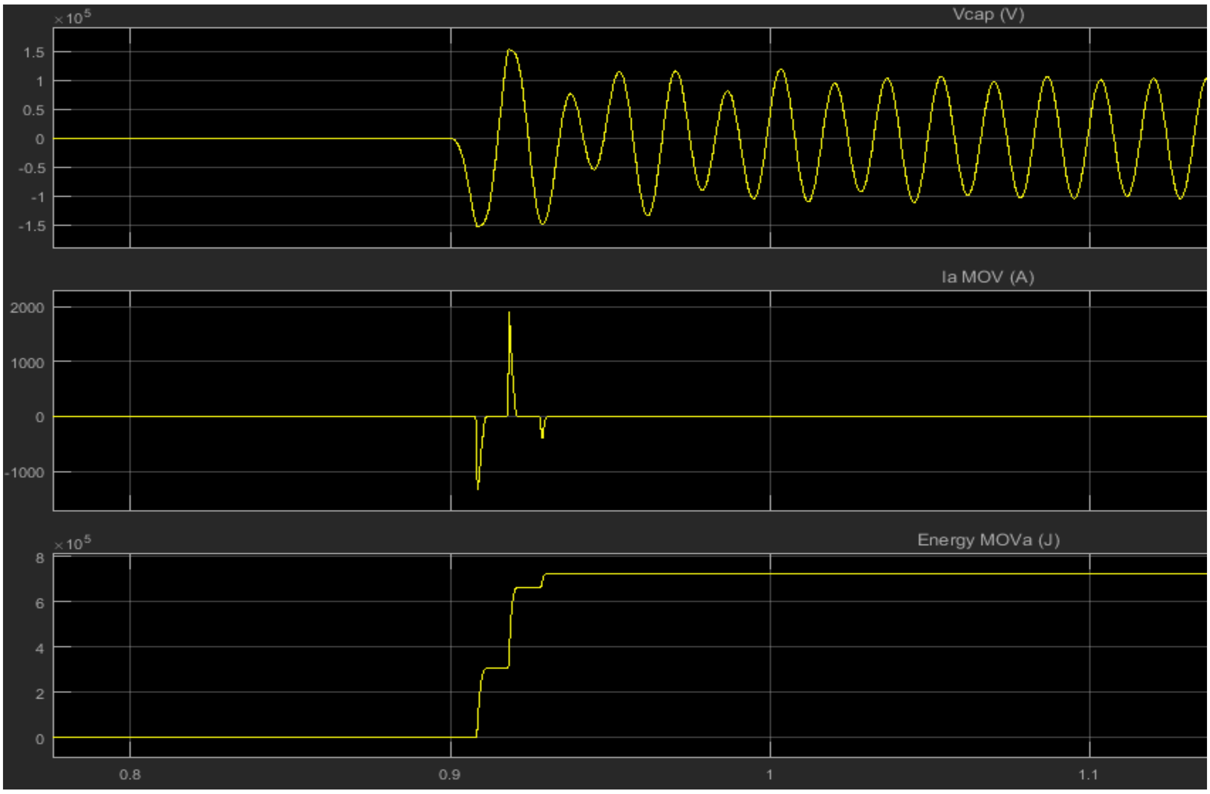

Figure 4.57: MOV characteristics of Phase “a” for Line to ground fault at 100km on the line

The MOV is usually used to protect the FACTS device from very high fault current. Figures 4.37 – 4.54 show examples of the effect of MOV action for different fault locations on a TCSC compensated transmission line. For 40% compensation on the Ikeja West to Benin transmission line, it is shown that for faults behind the MOV/TCSC, the equivalent MOV/TCSC impedance have small resistive components due to relatively small fault current passing through the TCSC from the source. For faults at 250km (after the MOV/TCSC), the fault current passing the MOV/TCSC becomes more significant. Inaccuracies will be more evident with increase in fault current. Larger fault current has a greater effect on the equivalent impedance as the compensation is reduced and the MOV partially bypasses the TCSC to protect it from the high fault current. The compensation level is reduced to nearly zero percent which would have similar effect on the apparent impedance thereby resulting to overreaching or under-reaching of the relay. The effect of distributed parameters was also considered in the system simulations.

In the first case, the fault occurred at the instant of 5.0seconds and was cleared at 5.1667 seconds. For the three phase fault, the result showed that all MOVs (for each of the three phases) have approximately the same conducting currents and absorbed energy. The MOV voltage, current and energy consumption of phase ‘a’ for a three phase fault, line to line fault and single line to ground fault are shown in figure 4.55, figure 4.56 and figure 4.57 respectively. Only the MOV on phase ‘a’ conducts fault current, while the MOV on phases ‘b’ and ‘c’ do not conduct fault current for a single line to ground fault

4.4 Adaptive Relay Setting Results in the presence of TCSC Compensation (Considering MOV Action).

The developed adaptive setting algorithm in figure 3.20 was applied on the Ikeja West to Benin transmission line so as to alleviate the effects of TCSC compensation and MOV action. The simulations were run for 40% compensation case at different fault locations along the line. Figures 4.58 – 4.75 show the relay settings and fault trajectories.

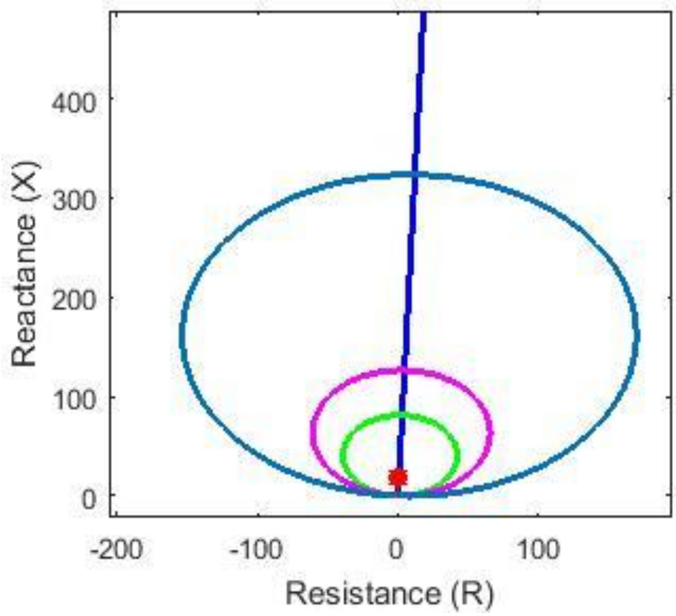

Figure 4.58: Relay A adaptive Setting for three phase fault at 50km in the presence TCSC considering MOV protection

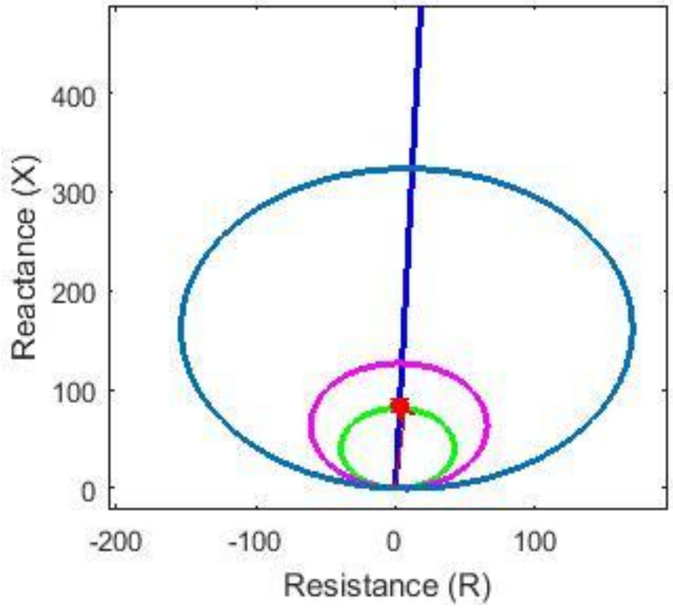

Figure 4.59: Relay B adaptive Setting for three phase fault at 50km in the presence TCSC considering MOV protection

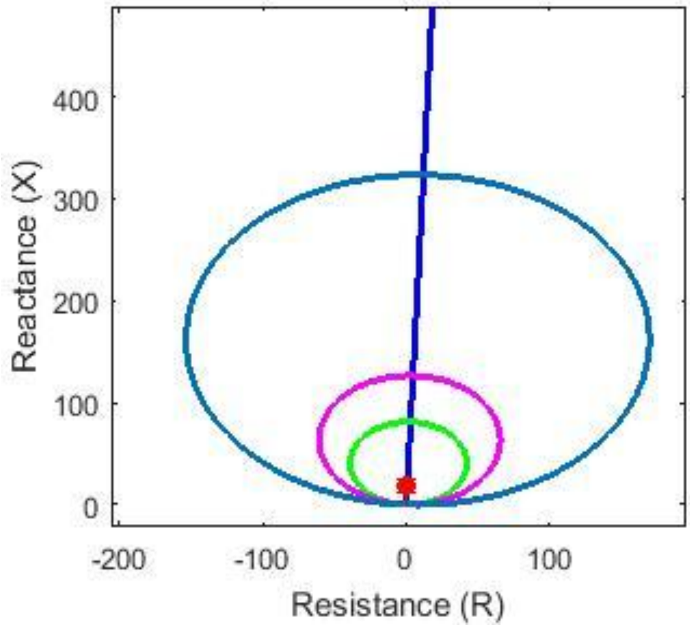

Figure 4.60: Relay A adaptive Setting for line to line fault at 50km in the presence TCSC considering MOV protection

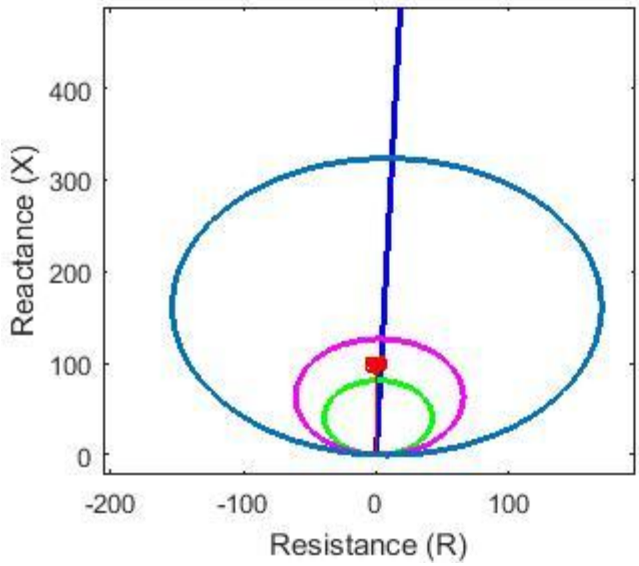

Figure 4.61: Relay B adaptive Setting for line to line fault at 50km in the presence TCSC considering MOV protection

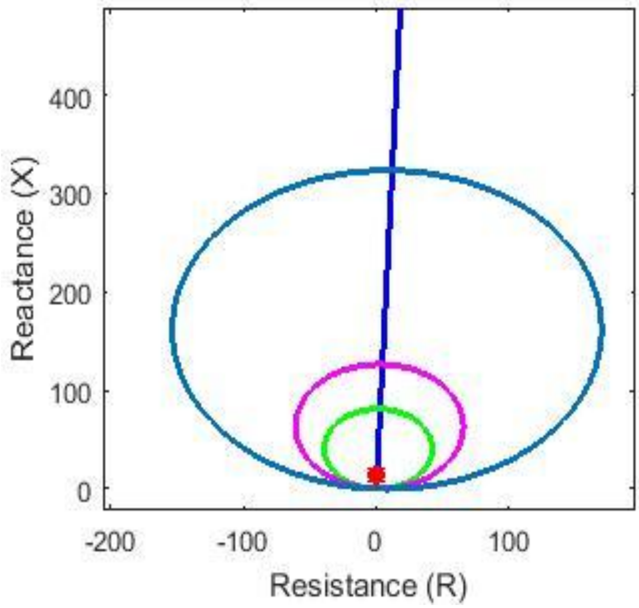

Figure 4.62: Relay A adaptive Setting for line to ground fault at 50km in the presence TCSC considering MOV protection

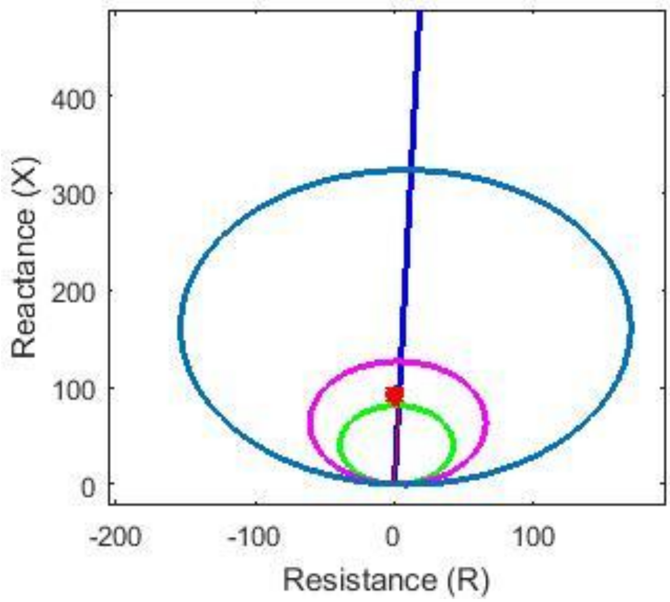

Figure 4.63: Relay B adaptive Setting for line to ground fault at 50km in the presence TCSC considering MOV protection

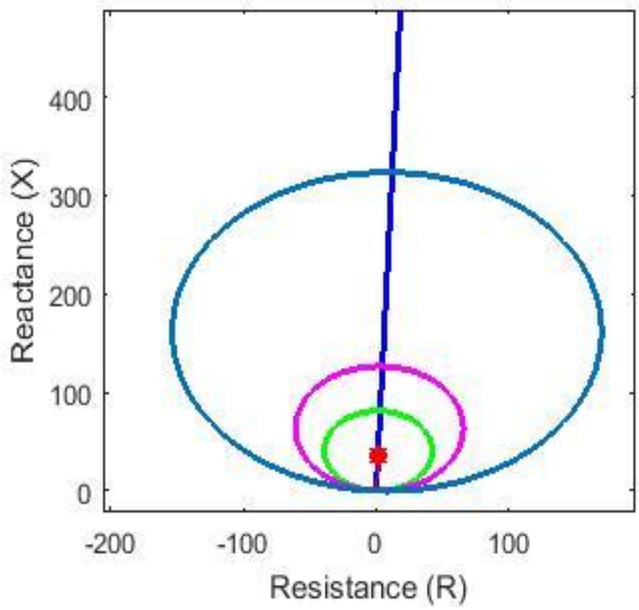

Figure 4.64: Relay A adaptive Setting for three phase fault at 100km in the presence TCSC considering MOV protection

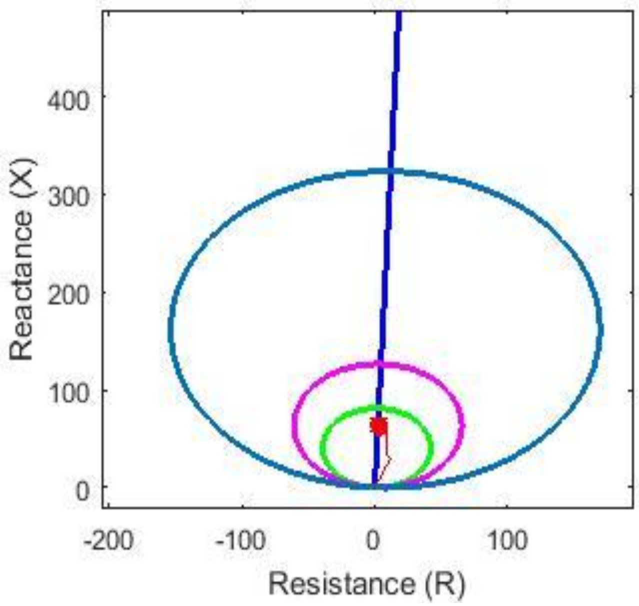

Figure 4.65: Relay B adaptive Setting for three phase fault at 100km in the presence TCSC considering MOV protection

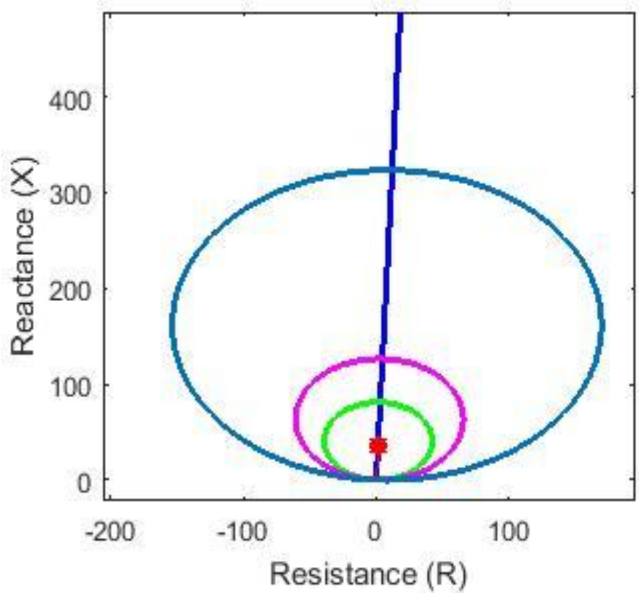

Figure 4.66: Relay A adaptive Setting for line to line fault at 100km in the presence TCSC considering MOV protection

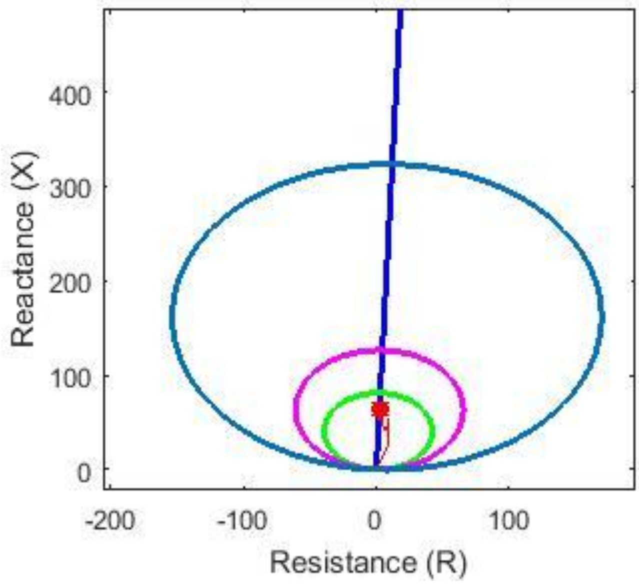

Figure 4.67: Relay B adaptive Setting for line to line fault at 100km in the presence TCSC considering MOV protection

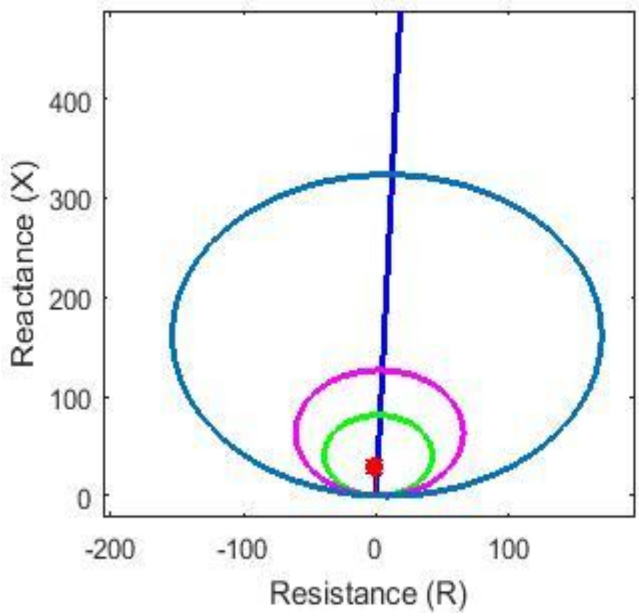

Figure 4.68: Relay A adaptive Setting for line to ground fault at 100km in the presence TCSC considering MOV protection

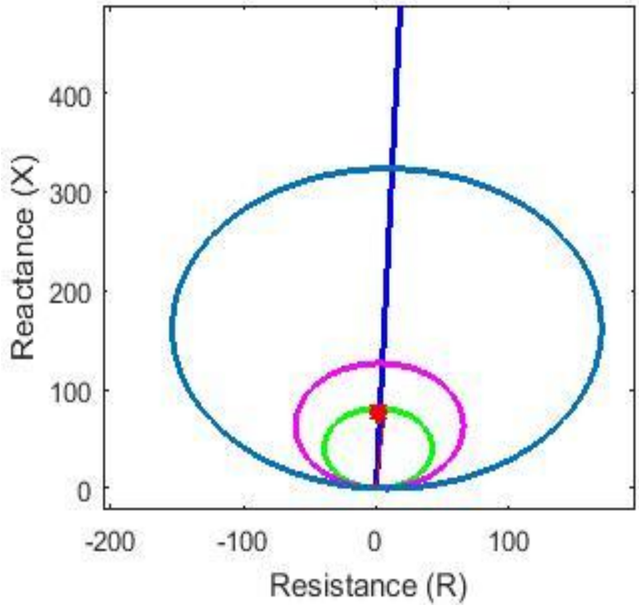

Figure 4.69: Relay B adaptive Setting for line to ground fault at 100km in the presence TCSC considering MOV protection

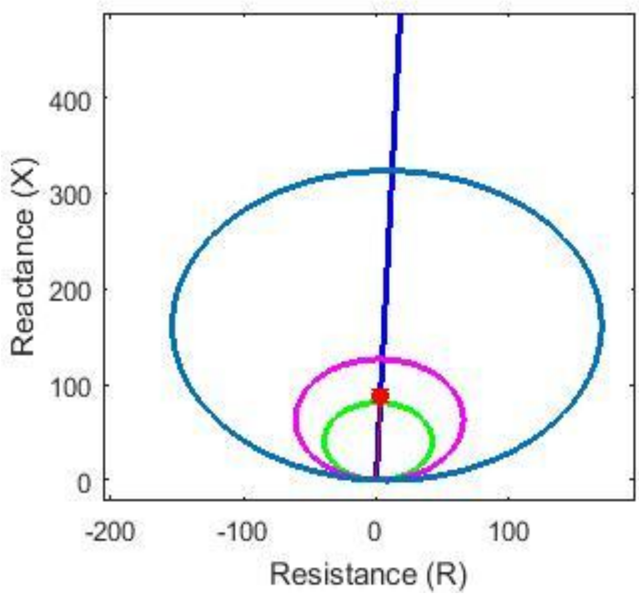

Figure 4.70: Relay A adaptive Setting for three phase fault at 250km in the presence TCSC considering MOV protection

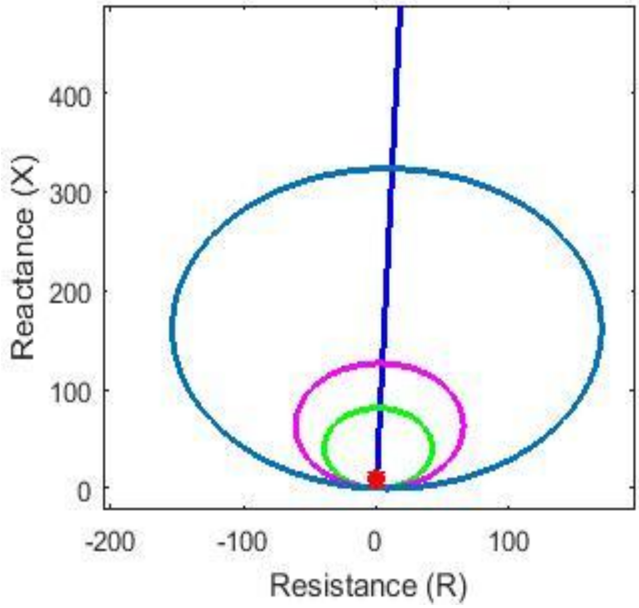

Figure 4.71: Relay B adaptive Setting for three phase fault at 250km in the presence TCSC considering MOV protection

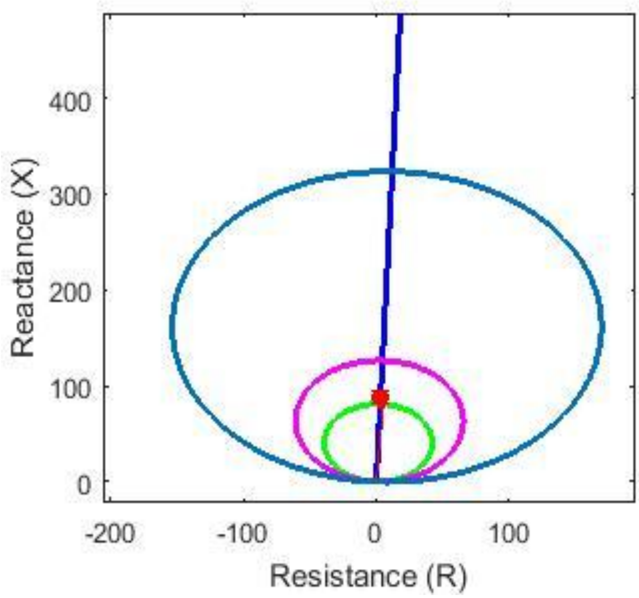

Figure 4.72: Relay A adaptive Setting for line to line fault at 250km in the presence TCSC considering MOV protection

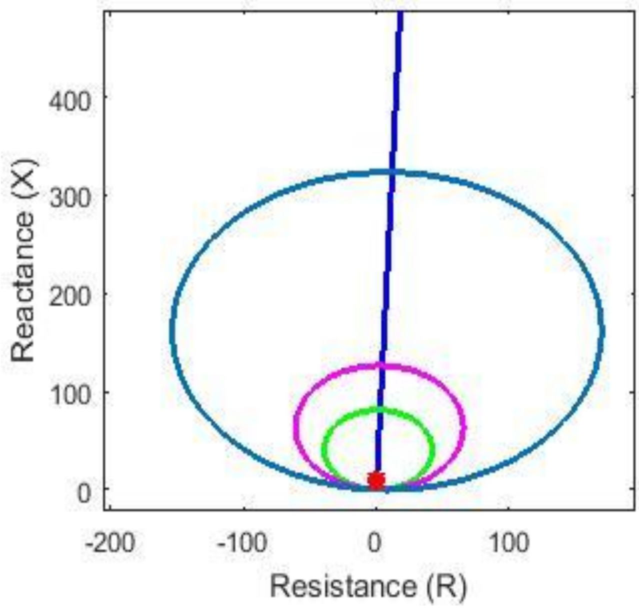

Figure 4.73: Relay B adaptive Setting for line to line fault at 250km in the presence TCSC considering MOV protection

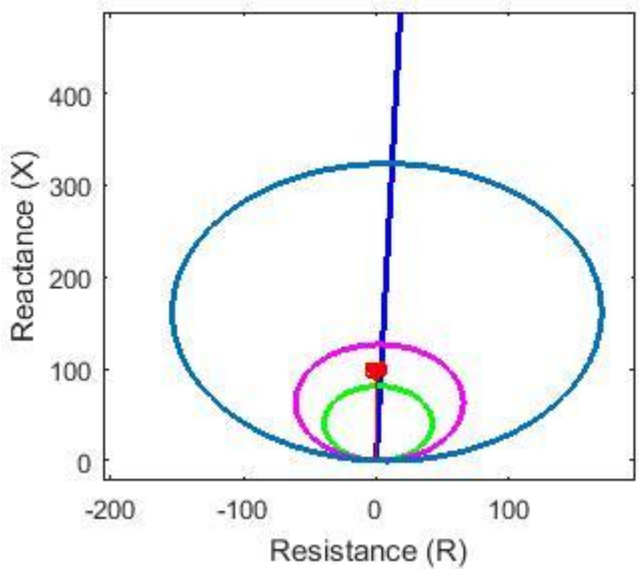

Figure 4.74: Relay A adaptive Setting for line to ground fault at 250km in the presence TCSC considering MOV protection

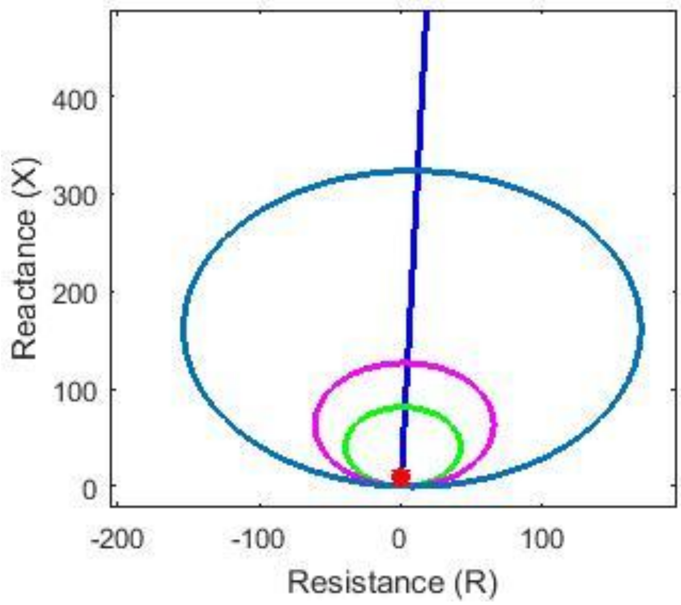

Figure 4.75: Relay B adaptive Setting for line to ground fault at 250km in the presence TCSC considering MOV protection

To ameliorate the effect of TCSC compensation and the protective MOV, this dissertation proposed an adaptive relay setting method for the Benin to Ikeja West transmission line. In this method, the relay operates in accordance to the developed relay algorithm in figure 3.20. This is done by comparing the apparent impedance measured by both relay A and relay B, and adjusting the zones settings of the Mho relay in response to that. The results in Figures 4.58 – 4.75 could be explained to relate that when the measured impedance seen by relay A is greater than or equal to the apparent impedance seen by relay B, then the equivalent impedance of the MOV/TCSC ($Z_{MOV/TCSC}$) is added to the zone1 and zone 2 settings of the relay. Also when the relay A impedance is less than the apparent impedance of the relay B, the equivalent impedance of the MOV/TCSC ($Z_{MOV/TCSC}$) is added to the zone 1 and zone 2 settings of relay B.

With this proposed adaptive commands, the relay can make a better decision on whether the fault occurred before or after the TCSC. Then the relay settings will be adjusted and makes a better decision based on the protection zone coordination as described in figure 3.20. Figures 4.49 – 4.54 show that for a fault at 250km which had tripped incorrectly in zone 1 due to the presence of TCSC and MOV protection, has now correctly and accurately tripped in zone 2 as shown in figures 4.70 – 4.75 when the proposed algorithm was implemented in the system. This can also be evidently seen by comparing the results in figures 4.37 to 4.42 with the adaptive settings results in figures 4.58 to figure 4.63 for all fault conditions.

Therefore the proposed algorithm proves very effective in adjusting the relay settings for both relay A and relay B so as to adapt to the correct protection zones coordination of the Mho relays in response to any fault location on the transmission line.

CHAPTER FIVE

CONCLUSION AND RECOMMENDATIONS

5.1 Conclusion

The results from the case system showed different fault types at various locations and were generated from system modelling and simulations for conditions without TCSC, with TCSC and with MOV protection. For the case without TCSC, it was affirmed that the distance relay operated accurately in accordance to the zones coordination. When TCSC was incorporated in the case system under fault conditions, the relay either overreached or under-reached. Also the MOV used for protecting the TCSC when considered in the system model with distributed parameters introduced additional complexity to the system performance and resulted to further relay mal-operation.

This dissertation developed an adaptive relay algorithm that would adjust the settings of the relay with respect to the location and direction of faults on the transmission line. The results from the implementation of this algorithm proved very effective for alleviating the effects of TCSC and MOV allocation on the relay protective zone coordination. Thus this work provides a pivotal platform for a new paradigm of research aimed at articulating solutions to these imminent effects of FACTS devices if these devices get incorporated in the Nigeria power system as widely advocated.

5.2 Recommendations

The Mho characteristics of distance relay was used in this dissertation work, other relay characteristics such as the quadrilateral type may be used to study the different types of faults with arc resistance. The use of Phasor Measurement Unit (PMU) could be considered for a coordinated adaptive setting involving multiple MOV protected lines.

5.3 Contributions to Knowledge

The contributions of this dissertation work include:

I. Inclusion of FACTS compensation in the Nigeria power system raises several protection challenges. The adaptive relay algorithm developed in this dissertation effectively solved such related issues by adjusting the relay settings so as to make better decision on fault locations in the presence of FACTS device on a transmission line.

II. Effects of series compensation on distance relays are more significant on long transmission lines. This dissertation articulated these challenges on the Nigeria power system by considering line distributed parameters in the researched work thereby mitigating cascade tripping prevalent on long lines.

III. MOV protection is germane for a series compensated line as it protects the FACTS device from the incident high fault current. In this dissertation, data at both end of the line were applied for adaptive zone1/zone2 setting. This method was obtained by considering MOV operation for apparent impedance calculation thereby providing accurate trip boundary setting for all fault locations, for any level of compensation and MOV operation.

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APPENDICES

Appendix 1: Existing power stations

S/N	Generating Station	Installed Capacity (MW)	Actual Generation (MW)
1	Kainji	760	320
2	Jebba	578.4	475
3	Shiroro	600	450
4	Geregu	414	276
5	Papalanto	304	70
6	Egbin	1320	667
7	Omotosho	304	76
8	Delta	437	385
9	Sapele	1020	695
10	Okpai	450	60
11	Afam	1630.4	544
12	Trans Amadi	32.63	18
13	Alaoji	320	Not Scheduled
14	Gbaran	225	Not Scheduled
15	Omoku	100	Not Scheduled
16	Ibom,	156	Not Scheduled
17	Mambila	2000	Not Scheduled
18	Guarara	30	Not Scheduled
19	Calabar	561	Not Scheduled
21	Egbema	338	Not Scheduled
22	Eyean	451	Not Scheduled

Source: Power Holding Company of Nigeria (PHCN), 2013.

Appendix 2: Source data

Parameter	Data
Line-to-Line voltage (V)	330 kV
Positive sequence source resistance	0.8929 ohms
Positive sequence inductance	16.58 mH
Power system frequency	50Hz

Appendix 3: Transmission line data

Parameter	Data
System Voltage	330kV
System Frequency	50Hz
Transmission line length	280km
Positive sequence	R = 0.0368 Ω/km L = 0.55 mH/km C = 0.028µF
Zero sequence	R = 0.0328 Ω/km L = 1.7722 mH/km C = 0.024µF

Appendix 4: TCSC & MOV data

Parameter	Data
TCSC	$Q_{max} = 42\text{MVAR}$ C = 306µF L = 4.4mH
MOV	Reference voltage = 330kv Reference current = 1000A

Appendix 5: Transmission line parameters for the Nigeria 330kv network

Transmission Line Number	Line between buses and the number of circuits		Length of line (km)	Line impedance	
S/N	From	To		R (p.u)	X (p.u)
1	Onitsha	Alaoji	138	0.049	0.042
2	Onitsha	New haven	96	0.0038	0.0284
3	Benin	Onitsha	137	0.0054	0.0405
4	Delta	Benin	107	0.0042	0.0316
5	Sapelle	Benin	50	0.0009	0.0070
6	Okapi	Onitsha	56	0.0005	0.0042
7	Afam	Alaoji	25	0.0006	0.0043
8	Afam	PH main	38	0.0015	0.0112
9	P.H Main	Trans Amadi	10	0.0004	0.003
10	Sapelle	Aladja	63	0.0025	0.0186
11	Delta	Aladja	30	0.0009	0.0072
12	Benin	Ajaokuta	195	0.007	0.056
13	Benin	Sapele	50	0.001	0.0139
14	Benin	Omotosho	120	0.0049	0.0365
15	Benin	Oshogbo	251	0.0089	0.0763
16	Ikeja	Benin	280	0.0100	0.0279
17	Ikeja	Aiyede	137	0.0049	0.0416
18	Ikeja	Papalanto	30	0.0011	0.0091
19	Ikeja	Omotosho	160	0.0057	0.0486
20	Ikeja	Akangba	18	0.002	0.017
21.	Papalanto	Aiyede	60	0.0021	0.0182
22	Egbin	Aja	14	0.002	0.0172
23	Oshogbo	Aiyede	115	0.0041	0.0349
24	Oshogbo	Jebba (TS)	151	0.0056	0.0477
25	Kaduna	Kano	230	0.0082	0.0699
26	Kaduna	Shiroro	96	0.0034	0.0292
27	Jos	Gombe	265	0.0095	0.081
28	Shiroro	Katampe	144	0.0	0.0
29	Shiroro	Jebba	244	0.0095	0.0702
30	Benin Kebbi	Kanji	734	0.0111	0.0942
31	Jebba GS	Jebba TS	8	0.0003	0.0022
32	Kainji	Jebba TS	81	0.0029	0.0246

Source: Power Holding Company of Nigeria (PHCN), 2013

Appendix 6

This appendix presents the MATLAB codes of the functions used in the Mho Relay A&B Apparent Impedance Plots

```
theta = 0:.01:(2*pi);
p=0;
q=-100:0.6:550;
r=-300:0.3:300;
s=0;

R1= 0.01273;
X1= 0.3519966;
Xc= 12.74e-9*377;
%R1= 0.3864;
%X1= 1.555616;
%Xc=7.751e-9*377;
Xcc=0;

Zt= R1+1i*X1;
Yt= 1i*Xc;
zc= sqrt(Zt/Yt);
gam= sqrt(Zt*Yt);
Lset= 280;

Zset1=zc*tanh(gam*Lset*0.80);
Zset2=zc*tanh(gam*Lset*1.2);
ZsetT=zc*tanh(gam*Lset*1);
Zset3=zc*tanh(gam*Lset*2.4);
%Zone 1
Req1=real(Zset1);
Xeq1=imag(Zset1);
Zangle1=atan(Xeq1/Req1);

%Zone 2
Req2=real(Zset2);
Xeq2=imag(Zset2);
Zangle2=atan(Xeq2/Req2);

%Zone 3
Req3=real(Zset3);
```

```
Xeq3=imag(Zset3);
Zangle3=atan(Xeq3/Req3);

%Radius of zone 1 circle
R_zone1= sqrt((Req1)^2+(Xeq1)^2)/2;

%center of zone 1 circle (a,b)
a=R_zone1*(cos(Zangle1));
b=R_zone1*(sin(Zangle1));

%circle of zone 1 center at (a,b)
c=R_zone1*cos(theta)+a;
d=R_zone1*sin(theta)+b;

%Radius of zone 2 circle
R_zone2= sqrt((Req2)^2+(Xeq2)^2)/2;

%center of zone 2 circle (f,e)
f=R_zone2*(cos(Zangle2));
e=R_zone2*(sin(Zangle2));

%circle of zone 2 center at (f,e)
g=R_zone2*cos(theta)+f;
h=R_zone2*sin(theta)+e;

%Radius of zone 3 circle
R_zone3= sqrt((Req3)^2+(Xeq3)^2)/2;

%center of zone 3 circle (f,e)
k=R_zone3*(cos(Zangle3));
l=R_zone3*(sin(Zangle3));

%circle of zone 2 center at (f,e)
m=R_zone3*cos(theta)+k;
n=R_zone3*sin(theta)+l;

%impedance line
t=0:0.1:250;
u=t*(b/a);
ResRea1=[Resistance1,Reactance1];
ResReaL1=length(ResRea1);
for ResReaa1=1:ResReaL1
    if ResRea1(ResReaa1,1)== 0 && ResRea1(ResReaa1,2)==0
```

```
        ResReab1=ResReaa1;
    end
end
ResReac1=1:ResReab1;
%ResRea1(ResReac1,:)=[];
Res1=ResRea1(:,1);
Rea1=ResRea1(:,2);

% tcscResReaIdu=[tcscResistanceIdu,tcscReactanceIdu];
% tcscResReaIduL=length(tcscResReaIdu);
% for tcscResReaIdua=1:tcscResReaIduL
%     if tcscResReaIdu(tcscResReaIdua,1)== 0 &&
tcscResReaIdu(tcscResReaIdua,2)==0
%         tcscResReaIdub=tcscResReaIdua;
%     end
% end

%tcscResReaCap=[tcscResistanceCap,tcscReactanceCap];
%tcscResReaCapL=length(tcscResReaCap);
%for tcscResReaCapa=1:tcscResReaCapL
 %   if tcscResReaCap(tcscResReaCapa,1)== 0 &&
tcscResReaCap(tcscResReaCapa,2)==0
  %     tcscResReaCapb=tcscResReaCapa;
   % end
%end

% tcscResReaIduc=1:tcscResReaIdub;
% % tcscResReaIdu(tcscResReaIduc,:)=[];
% % tcscResIdu=tcscResReaIdu(:,1);
% % tcscReaIdu=tcscResReaIdu(:,2);
% %
% % tcscResReaCapc=1:tcscResReaCapb;
% % tcscResReaCap(tcscResReaCapc,:)=[];
% % tcscResCap=tcscResReaCap(:,1);
% % tcscReaCap=tcscResReaCap(:,2);

plot1= figure('position',[455 200 350 300]);
set(gca,'fontsize',13)
plot2=plot(t,u,'b',c,d,'g',g,h,'m',m,n,'LineWidth',2);
hold on
plot3=plot(p,q,'k--',r,s,'k--','LineWidth',0.4);
plot4=plot(Res1,Rea1,'r');
plot7=plot(Res1(end),Rea1(end),'r*','Linewidth',2);
```

```
% plot5=plot(tcscResIdu,tcscReaIdu,'go');
% plot6=plot(tcscResCap,tcscReaCap,'ro');
ymax=1.511*max(n);
ymin=-22;
xmax=1.15*max(m);
xmin=1.34*min(m);
axis([xmin xmax ymin ymax]);
xlabel('Resistance (R)');
ylabel('Reactance (X)');
hold off
grid off

ResRea2=[Resistance2,Reactance2];
ResReaL2=length(ResRea2);
for ResReaa2=1:ResReaL2
   if ResRea2(ResReaa2,1)== 0 && ResRea2(ResReaa2,2)==0
      ResReab2=ResReaa2;
   end
end
ResReac2=1:ResReab2;
%ResRea2(ResReac2,:)=[];
Res2=ResRea2(:,1);
Rea2=ResRea2(:,2);

plot12= figure('position',[455 200 350 300]);
set(gca,'fontsize',13)
plot22=plot(t,u,'b',c,d,'g',g,h,'m',m,n,'LineWidth',2);
hold on
plot32=plot(p,q,'k--',r,s,'k--','LineWidth',0.4);
plot42=plot(Res2,Rea2,'r');
plot72=plot(Res2(end),Rea2(end),'r*','Linewidth',2);
% plot52=plot(tcscResIdu,tcscReaIdu,'go');
% plot62=plot(tcscResCap,tcscReaCap,'ro');
ymax=1.511*max(n);
ymin=-22;
xmax=1.15*max(m);
xmin=1.34*min(m);
axis([xmin xmax ymin ymax]);
xlabel('Resistance (R)');
ylabel('Reactance (X)');
hold off
grid off
```

Appendix 7

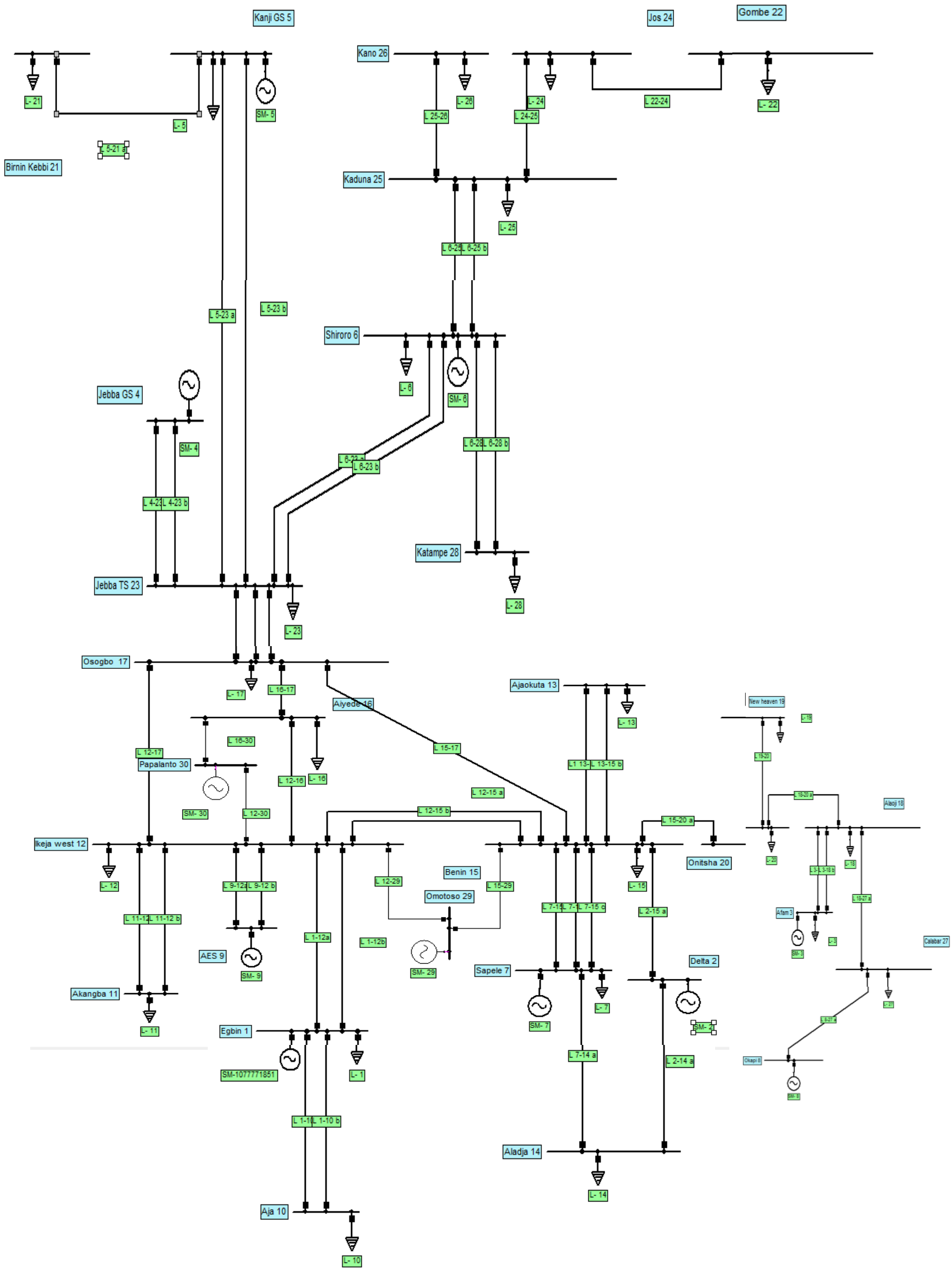
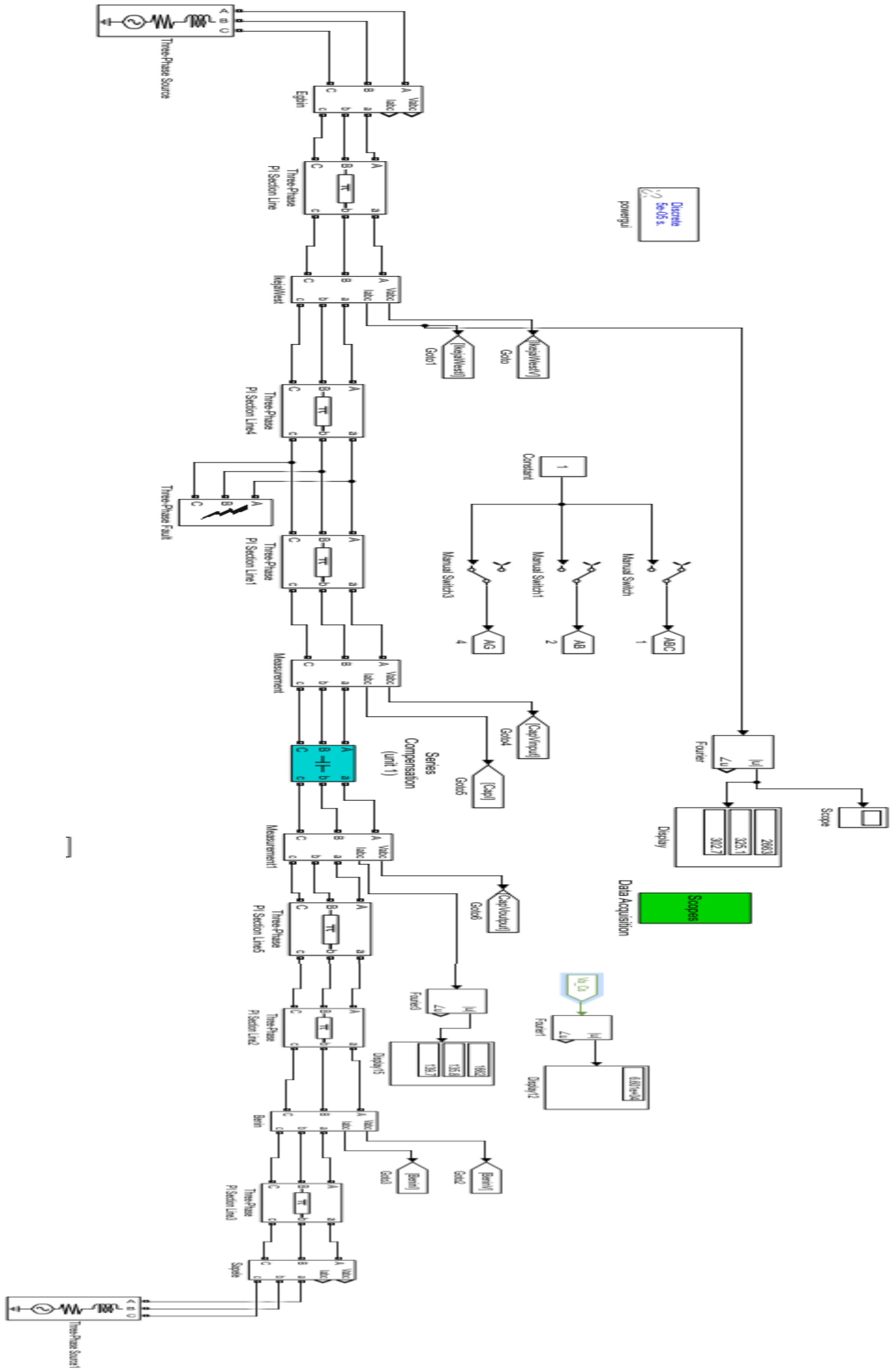


Figure 1: The Nigeria Power System

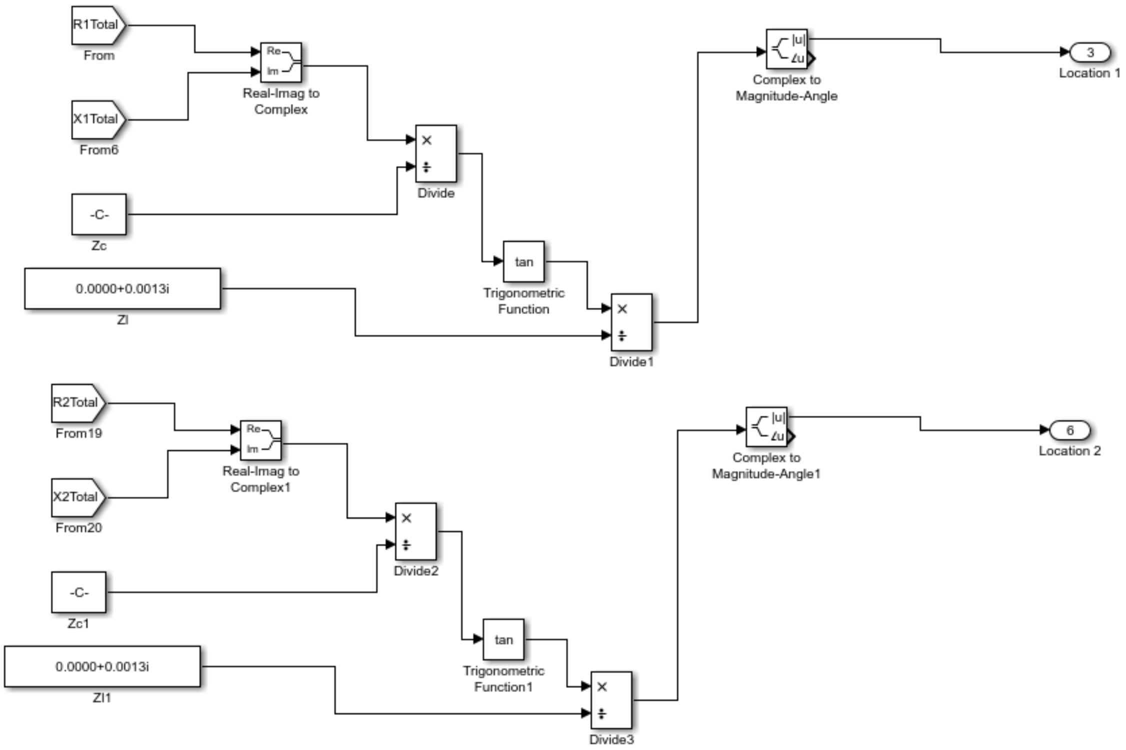
Appendix 8

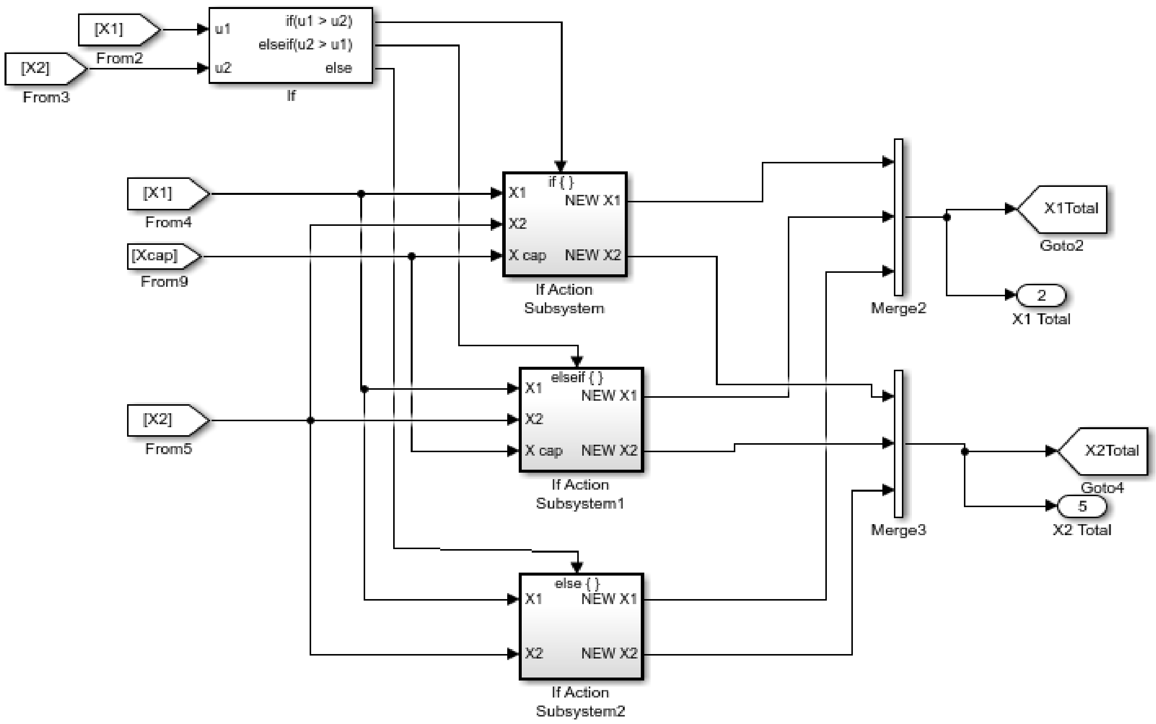
This Appendix presents the Simulink blocksets for the Benin to Ikeja West transmission line



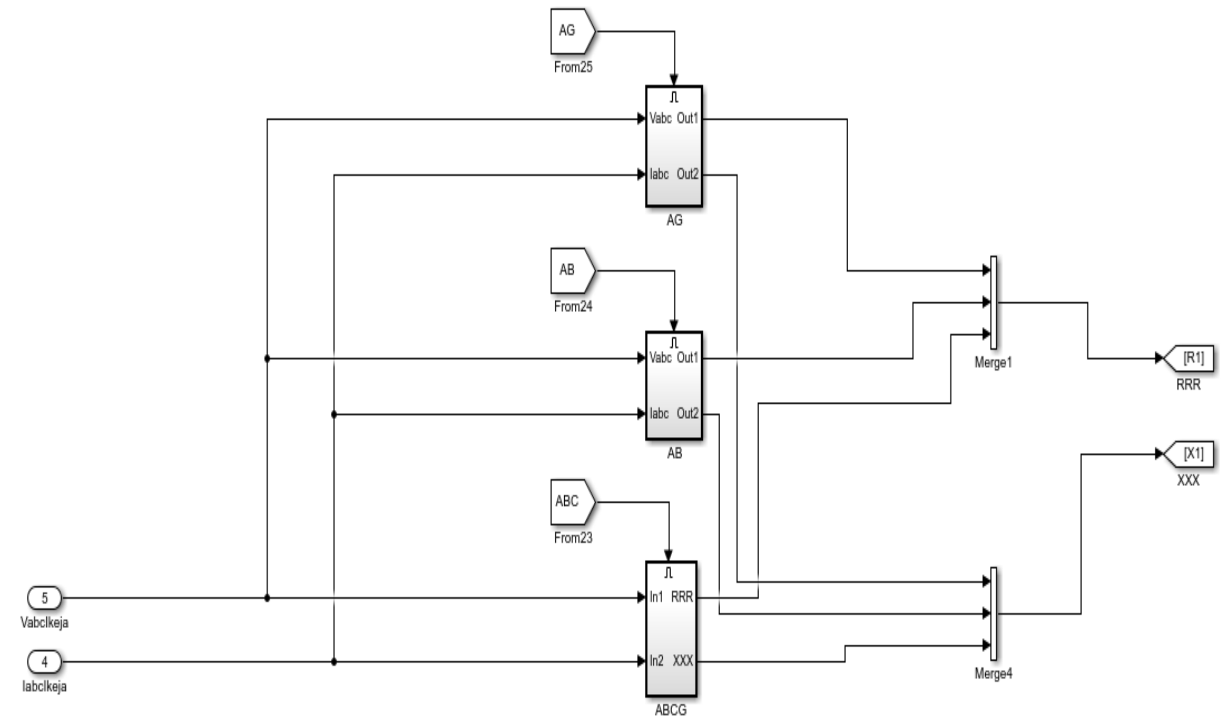
Appendix 9

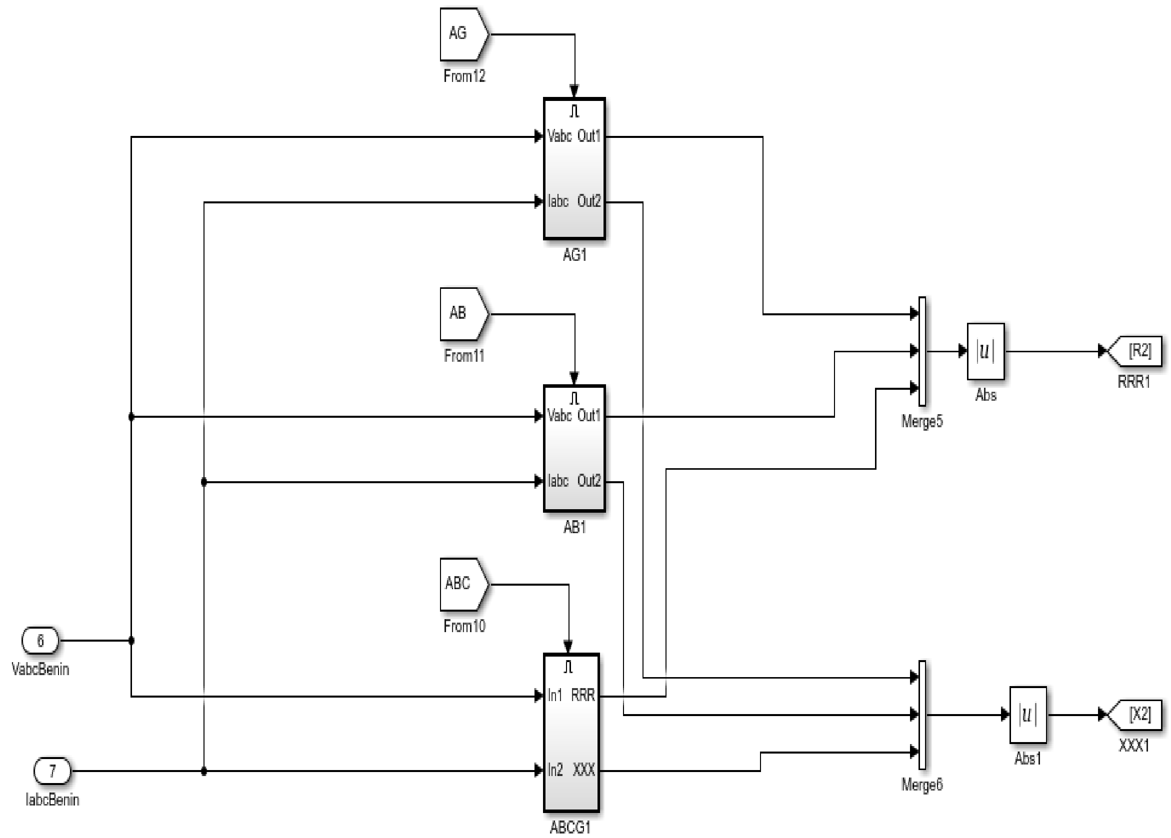
Simulink subsystems for the adaptive relay setting implementation





RRR2


AG
From25
Vabc Out1
Iabc Out2
AG
AB
From24
Vabc Out1
Iabc Out2
AB
ABC
From23
In1 RRR
In2 XXX
ABCG
5
Vabclkeja
4
Iabclkeja
Merge1
[R1]
RRR
[X1]
XXX
Merge4


AG
From12
Vabc Out1
Iabc Out2
AG1
AB
From11
Vabc Out1
Iabc Out2
AB1
ABC
From10
In1 RRR
In2 XXX
ABCG1
6
VabcBenin
7
IabcBenin
Merge5
|u|
Abs
[R2]
RRR1
Merge6
|u|
Abs1
[X2]
XXX1