DESIGN OF A FUZZY LOGIC BASED ADAPTIVE PROTECTION SCHEME IN DISTRIBUTION NETWORKS WITH DISTRIBUTED GENERATION

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A thesis submitted to the Department of Electrical Engineering of Pan African University Institute for Basic Sciences, Technology and Innovation in partial fulfillment of the requirements for the award of the degree of Master of Science in Electrical Engineering (Power Systems Option)

2018

DECLARATION

This thesis is my original work and has not been presented for the award of any degree in any university.

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DEDICATION

To the Almighty God

To my entire family, colleagues and friends

ACKNOWLEDGEMENT

First of all, I thank God for his mercy, grace and goodness to me on my life. My thanks to my supervisors Dr. Michael Juma Saulo and Prof. George. N. Nyakoe for their professional supervision, guidance, inspiration and advice during this research. I am grateful to the staff of PAUISTI especially those of Electrical Engineering program. I would like to take the opportunity to thank my family for their unconditional caring and support through their incomparable love. Thanks to my friends and colleagues for their friendship and support during my studies and the fulfillment of this research work. I finally thank the African Union for giving me a chance to achieve my dreams. I am really thankful for the scholarship you gave me to pursue my master's degree.

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LIST OF ABBREVIATIONS

ABC:	Ant Bees Colony
AC:	Alternating Current
APS:	Adaptive Protection Scheme
CB:	Circuit Breaker
CHP:	Combined Heat and Power
CTI:	Coordination Time Interval
DC:	Direct Current
DE:	Differential Evolution
DER:	Distributed Energy Resources
DG:	Distributed Generation
DN:	Distribution Network
DOCR:	Directional Overcurrent Relays
ETAP:	Electrical Transient and Analysis Program
FCL:	Fault Current Limiter
FLC:	Fuzzy Logic Controller
FRT:	Fault Ride-Through

FSWTs: Fixed Speed Wind Turbines

IBDG: Inverter Based Distributed Generation

IED: Intelligent Electronic Device

IEEE: Institute of Electrical and Electronics Engineers

I_f: Fault Current

I_{pickup}: Pickup Current

OCR: Overcurrent Relays

OR-FCL: Optimum Resistive type Fault Current Limiter

PDS: Power Delivery Systems

PV: Photo Voltaic

SFCL: Superconducting Fault Current Limiter

TMS: Time Multiplier Setting

T&D: Transmission and Distribution

TCC: Time Current Characteristic

TDS: Time Dial Setting

VSC: Voltage Source Converte

ABSTRACT

Integration of renewable energy-based DG in power systems has become an active research area for the last few decades due to various economic, environmental, and political factors. The integration of DGs brings several challenges even if it offers many advantages. Power system protection is one of the major issues of integrating DGs into an existing distribution network. Besides increasing fault current level of the system caused by the interconnection of the DG, Integrating DG causes the system to lose its radial power flow. The loss of coordination between primary and backup relays is one of the disadvantages of integrating DGs, since traditional relay settings may fail or work incorrectly under new conditions. Hence, new protection schemes able to maintain protection coordination are strongly needed in distribution networks with a significant integration of DGs. In distribution systems with renewable energy-based DG penetration, the fault levels are intermittent and continuously changing as per connection of DG. In this study, adaptive protection scheme in distribution networks considering intermittency of DG using a fuzzy logic controller was proposed. The controller chooses the best time multiplier setting (TMS) of the relay depending on the size of the DG connected. IEEE 13 bus radial distribution network was used and ETAP software was used to model the network and do load flow and short circuits analysis which are necessary for setting and coordination of overcurrent relays. Fuzzy logic toolbox of MATLAB was used to design the fuzzy logic controller. It was seen that the use of fuzzy logic based adaptive protection scheme mitigates the impact of integrating DG on protection coordination in the distribution network.

CHAPTER 1: INTRODUCTION

1.1 Background

A power grid or a power system is an interconnected complex system and can generally be defined as the complete set of machines, wires, and components that connect between the power plants and load points. Modern power systems can be subdivided into the following basic subsystems: generation subsystem, transmission and sub-transmission subsystem, distribution subsystem and utilization subsystem [1]. The main goal of any electricity supply system is to meet all energy demand for the customers. The power generated in power plants is transmitted through the transmission network to the substation; and from there, distribution systems distribute the power received from the supply points to customer facilities using the most appropriate voltage levels. The distribution network is the local network that consists of connections and transformers to transfer the power and convert it to the final utilization voltage. It is the link between the end user and the utility system [1].

Distribution systems can be subdivided into different classes depending on the type of current, type of construction and type of connection. Basing on the type of current, distribution systems can be divided into AC and DC systems. For electrical power distribution, AC systems are generally used because they are more economical and simple than DC systems. Overhead and underground systems are other classes of distribution systems based on type of construction. Overhead systems are mostly used due to their simplicity, while underground systems get their application for places where construction of overhead systems is not practicable or forbidden. Based on the type of connection, classes of distribution systems are radial, ring and interconnected systems [2].

Distribution systems are typically of radial configuration but the configurations depend on different arrangements which are based on the cost and reliability requirements. The distribution system can be in simple radial, primary selective, secondary selective or secondary network configuration. Each design will provide increasing reliability as well as increasing installation and operational cost. The radial configuration is the simplest and least reliable design of load distribution where the power is flowing in one direction from one substation to the loads. The radial system consists of one substation with one or more main feeders and many laterals connecting between the transformers and load points. It is less reliable compared to the secondary networked configuration but it is also less expensive and less complex due to fewer connections and protection devices [3].

The quality of electricity supplies is an important factor in the socio-economic development of any area. Good quality and high level of security of electricity supply can be achieved by providing good distribution network design using proven equipment. It is also essential to provide suitable protection schemes and relay settings to ensure that faults are quickly disconnected to minimize outage times and improve the continuity of supplies to customers [3]. There is great attention for distribution networks in the utilities around the world since the responsibility of the quality of service depends greatly on their appropriate performance. A very important role in the proper operation of distribution systems is played by the protective relays that, as always, have to perform reliably, rapidly and in selective form [4].

Safety of the electricity supply is a very important factor in power system. Supply system has to be well designed and properly maintained in order to restrain the number of faults that can occur. There are auxiliary systems associated with the distribution networks themselves that help to meet the prerequisites for reliability, quality, and safety of supply. Protection devices are the most important of these auxiliary systems. They are installed to clear faults and limit damages to distribution system equipment [4]. Insulation deterioration, lightning discharges, tree branches and animals contacting the electricity circuits are among the main causes of faults. The majority of faults are temporal and they can usually be cleared without loss of supply, or with short interruptions. Contrary, permanent faults can result in longer outages. To avoid loss of supply and damage, suitable and reliable protection should be installed in the network. Protective devices are used to isolate the faulted sections of the network in order to maintain supply elsewhere on the system. To ensure that the distribution network can operate with the prerequisites for safety of the network and humans , a properly coordinated protection system is very essential [4].

Currently, distribution systems are in a significant transition phase where the system is shifting from a passive distribution system with unidirectional power flow to an active distribution network with bidirectional flow and small-scale generators. Future power systems are encouraged by the necessity to diminish the impact of global climate change and lower the concentration of greenhouse gases in the atmosphere. [5].

Distribution system reliability means the probability of this system to provide power continuous without failure for a definite period of time. The evaluation of this reliability is the evaluation and calculation of the availability and expected frequency and duration of customer outages. The reliability assessment of future distribution networks is an important subject due to the increasing demand for more reliable service with less interruption frequency and duration. The connection of a future distribution network may be neither series nor parallel, and analyzing such a network is a complicated process and a time-consuming task. Future distribution systems are often referred to as smart grids where more intelligent technologies are integrated into the system to monitor, control, and operate the system. Therefore, the reliability of future grids is expected to become a more challenging issue in the near future, where the configuration of the system is more complicated and the high penetration of the small-scale units called distributed generations [5].

Distributed generation (DG) can be defined as “small-scale generating units located close to the loads that are being served” [6]. It is possible to classify DG technologies into two broad categories: non-renewable and renewable energy sources. The former comprises reciprocating engines, combustion gas turbines, micro-turbines, fuel cells, and micro combined heat and power (CHP) plants. The latter includes biomass, wind, solar PV, geothermal and tide power plants [6]. Many terminologies are used to refer this new type of generation such as embedded generation, distributed generation, and distributed energy resources [7].

Augmentation of distributed energy resources (DER) are motivated by economical, environmental, technical and political factors. There is an increasing interest in the penetration levels of DGs specifically of renewable energy based technologies like wind turbines and photovoltaics. Given the suitability of business, regulatory and policy landscape, decreasing technology prices, it is expected that penetration level of DGs will continue to increase [8].

When DGs are integrated into existing systems, they can offer numerous advantages. These include: increasing network reliability, reduction of line congestion, transmission loss reduction, generation cost reduction, postponement of investments in network expansion, and lowering capital investment costs [9],[10],[11]. Apart from these advantages, integrating DGs in the network can result in different problems such as: increase in short circuit level, bidirectional power flow, need for new protection techniques, and voltage fluctuation [11]. Increase in short circuit level and bidirectional power flow affect the protective relays because they are not designed to operate under these new conditions. Some of the consequences are like false tripping, under or over reach of relays, and loss of coordination between primary and backup relays [12],[13],[14].

1.2 Problem Statement

Nowadays, integration of DG into the distribution network (DN) becomes a common practice due to its advantages over the conventional sources on environmental, technical and economical issues. The incorporation of DG into distribution systems can offer several advantages. These benefits include reduced environmental pollution, improved voltage profile, reduced electric losses, increased system reliability, reduction of line congestion, transmission loss reduction, postponement of investments in network expansion, and lowering capital investment costs [11],[15]. However, besides providing many benefits, integrating DGs in the network can result in different problems such as: increase in short circuit level, bidirectional power flow, need for new protection techniques and voltage fluctuation. Increase in short circuit level and bidirectional power flow affect the protective relays because they are not designed to operate under these new conditions. Some of the consequences are like false tripping, loss of coordination between primary and backup relays, blinding of relays and islanding [11]. This is due to the fact that conventional relay settings for traditional systems may fail or may work incorrectly under new conditions. Hence, new protection schemes able to maintain protection coordination are strongly needed in distribution networks with a significant integration of DGs.

1.3 Justification

Protection systems are essential for the power system to operate safely and reliably. Their aim is to isolate faults and clear them when they occur. Proper protective devices and good coordination between relays are necessary in order to avoid damages and reduce the severity of faults. Despite many advantages of integrating DGs, it brought negative impacts especially on the protection system. Based on economical, technical and political motivation, there is expectation that integration of DGs in distribution systems will continue to increase. Hence, new protection schemes able to maintain protection coordination are strongly needed in distribution networks with a significant integration of DGs.

A number of studies have been introduced to alleviate the impact of integrating DG in distribution network [16]; and adaptive protection scheme (APS) is one of these studies. For this project, an adaptive protection scheme based on fuzzy logic controller (FLC) was used in order to mitigate the impact of integrating DG in distribution network considering the intermittency of renewable energy based DGs. Thus, by using this scheme, the impact of integrating DG was mitigated.

1.4 Objectives

1.4.1 General Objective

The general objective of this research is to design a fuzzy logic based adaptive protection scheme (APS) that can mitigate the negative impact on the protection coordination due to integrating DGs in radial distribution networks.

1.4.2 Specific Objectives

1. To set and coordinate overcurrent relays in radial distribution network without DG
2. To investigate the impact of DG penetration on the protection coordination when conventional settings are used for overcurrent relays in the distribution network
3. To design a fuzzy logic controller for adaptive protection scheme to be used in a distribution network with DG connected

4. To test the developed fuzzy logic based adaptive protection scheme in distribution network with DG connected

1.5 Scope

This research focused on mitigating the impact of DG integration on radial distribution networks protection, specifically its impact on the coordination of overcurrent relays (OCR) which are among the most used protection relays in electrical networks. The simulation was done using ETAP software; and the simulation results were presented to show the impact of DG on the performance of primary and backup protection relays. The study then presented an approach to solve this problem and restore the overcurrent relay performance by using an adaptive protection scheme. Considering the intermittency of distributed generation, a fuzzy logic controller was used in order to choose the best TMS depending on the capacity of the DG connected. In this study, the connection of a single DG at one bus in a radial distribution network was considered.

1.6 Thesis Outline

This thesis contains five chapters and it is organized as follow:

Chapter 1 provides an introductory background on the protection of distribution networks. It also highlights the benefits and the disadvantages of integrating DGs in the distribution systems. The problem statement, objectives and significance of the study are also presented in this chapter. Chapter 2 covers the theoretical review on setting and coordination of overcurrent relays. It also gives a small introduction on fuzzy logic control. The literature review on the methods used to mitigate the impact of integrating

DGs in the distribution systems are also highlighted in this chapter. In chapter 3, the methodology used to execute the proposed scheme is explained. Chapter 4 presents the results obtained through simulation of the proposed scheme. Finally, Chapter 5 gives the conclusion and recommendation of the thesis.

1.7 Note on Publication

A paper entitled "Application of Adaptive Protection Scheme in Distribution Networks with Distributed Generation: A Review" was published in International Journal of Engineering Technology and Scientific Innovation. Another paper entitled "Adaptive Protection Scheme in Distribution Networks Considering Intermittency of DG Using Fuzzy Logic Controller" was published in International Journal of Engineering Research and Technology. The papers are based on the research work presented in this thesis.

CHAPTER 2: LITERATURE REVIEW

2.1 Power system protection schemes

In a power system consisting of generators, transformers, transmission and distribution circuits, it is inevitable for failure to occur somewhere in the system. When a failure occurs on any part of the system, it must be quickly detected and disconnected from the system. There are two principal reasons for it. Firstly, if the fault is not cleared quickly, it may cause unnecessary interruption of service to the customers. Secondly, rapid disconnection of faulted apparatus limits the amount of damage to it and prevents the effects of fault from spreading into the system. The detection of a fault and disconnection of a faulty section or apparatus can be achieved by using fuses or relays in conjunction with circuit breakers. A fuse performs both detection and interruption functions automatically, but its use is limited for the protection of low voltage circuits only. For high voltage circuits (say above 3·3 kV), relays and circuit breakers are employed to serve the desired function of automatic protective gear. The relays detect the fault and supply information to the circuit breaker which performs the function of circuit interruption [2]. Protection systems can be classified into apparatus protection and system protection.

2.1.1 Apparatus protection

Apparatus protection deals with detection of a fault in the apparatus and consequent protection. Apparatus protection can be further classified into following: transmission line protection and feeder protection, transformer protection, generator protection, motor protection, busbar protection.

Considering the principle of operation, protection scheme can be classified as follow:

2.1.1.1 Overcurrent Protection

This scheme is based on the intuition that, short circuits lead to currents much above the load current. We can call them as overcurrents. Overcurrent relaying and fuse protection uses the principle that when the current exceeds a predetermined value, it indicates presence of a fault (short circuit). Overcurrent relays are classified as follow [4]:

1. Instantaneous Overcurrent (Define Current) Relays: They operate instantaneously when the current reaches a predetermined value.
2. Define Time Overcurrent Relays: In this type, two conditions must be satisfied for operation (tripping). Current must exceed the setting value and the fault must be continuous at least a time equal to time setting of the relay.
3. Inverse Time Overcurrent Relays: In this type of relays, operating time is inversely changed with current. So, high current will operate overcurrent relay faster than lower ones. Inverse Time relays are also referred to as Inverse Definite Minimum Time (IDMT) relay. They are subdivided into three categories
    - ✓ Standard Inverse
    - ✓ Very Inverse Time
    - ✓ Extremely Inverse
4. Directional Overcurrent Relays: They are commonly used in subtransmission networks where ring mains are used. Non-directional overcurrent relays find usage in radial distribution systems with a single source. Selectivity in this scheme is achieved

naturally and relaying decision is based solely on the magnitude of fault current. When the power system is not radial, a non-overcurrent relay may not be able to provide adequate protection. In this case, directional overcurrent relays are used for the purpose of selectivity. Directional overcurrent relays use both magnitude of current and phase angle information for decision making. These types of relays operate in one direction of current flow and block in the opposite direction. Three conditions must be satisfied for its operation: current magnitude, time delay and directionality [17].

2.1.1.2 Distance Protection

The basic principle of distance relay is that the apparent impedance seen by the relay, which is defined as the ratio of phase voltage to line current of a transmission line (Z_{app}), reduces drastically in the presence of a line fault. A distance relay compares this ratio with the positive sequence impedance (Z_1) of the transmission line. If the fraction Z_{app}/Z_1 is less than unity, it indicates a fault. This ratio also indicates the distance of the fault from the relay. Because, impedance is a complex number, the distance protection is inherently directional [18]

2.1.1.3 Differential Protection

Differential protection is based on the fact that any fault within an electrical equipment would cause the current entering it, to be different, from the current leaving it. Thus, by comparing the two currents either in magnitude or in phase or both we can determine a fault and issue a trip decision if the difference exceeds a predetermined set value [19].

2.1.2 System protection

System protection deals with detection of proximity of system to unstable operating region and consequent control actions to restore stable operating point and/or prevent damage to equipments [20]. Loss of system stability can lead to partial or complete system blackouts. Under-frequency relays, out of-step protection, islanding systems, rate of change of frequency relays, reverse power flow relays, voltage surge relays etc are used for system protection.

Overcurrent relaying is very well suited to distribution system protection for the following reasons:

- ✓ It is basically simple and inexpensive.
- ✓ Very often the relays do not need to be directional and hence no potential transformer (PT) supply is required.
- ✓ It is possible to use a set of two overcurrent relays for protection against inter-phase faults and a separate overcurrent relay for ground faults.

2.2 Setting and Coordination of Overcurrent Relays

2.2.1 Setting of Overcurrent Relays

The electrical power system may be subjected to many types of faults during its operation that can damage the equipment connected to this system. Hence, there is a great need for designing a reliable protective system. Setting overcurrent relays involves selecting the parameters that define the required time/current characteristic of both the time delay and instantaneous units. The operating time of an overcurrent relay has to be delayed to ensure that, in the presence of a fault, the relay does not trip before any other protection situated closer to the fault [4].

For definite-time relays and inverse time relays, there are two basic adjustable settings; one is the time multiplier setting (TMS) or Time Dial (TD) and the other is the current setting or pickup setting usually known as plug setting multiplier (PSM). The pickup setting, or plug setting, is used to define the pickup current of the relay, and fault currents seen by the relay are expressed as multiples of this. This value is usually referred to as the plug setting multiplier (PSM), which is defined as the ratio of the fault current in secondary amps to the relay pickup or plug setting. The Time Multiplier Setting (TMS) or time dial setting (TDS) adjusts the time delay before the relay operates whenever the fault current reaches a value equal to, or greater than, the relay current setting.

The time current characteristic curve for inverse overcurrent relays is shown in Figure 2-1

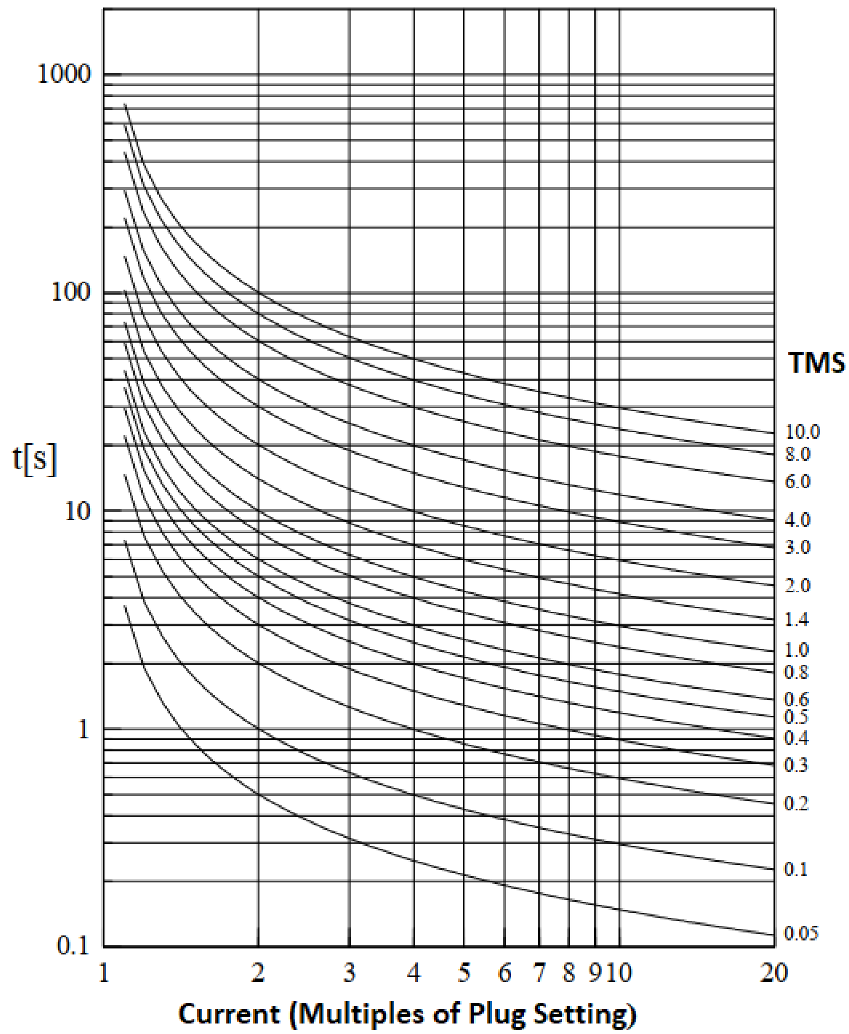

Figure 2-1: Time current characteristic curve for inverse overcurrent relays

IEC and ANSI/IEEE Standards define the operating time mathematically by the following expression in (2.1).

$$t = \frac{k\beta}{\left(\frac{I_f}{I_{pickup}}\right)^{\alpha} - 1} + L \qquad (2.1)$$

Where t is the relay operating time in seconds; k is the time dial (TD) or time multiplier setting (TMS); I_f is the fault current level in secondary amps; I_{pickup} is the pickup current selected; L is a constant. The constants α and β determine the slope of the relay characteristics. The values of α, β and L for various standard overcurrent relay types manufactured under ANSI/IEEE and IEC standards are given in Table 2-1[4]. The choice of the characteristics is governed by the required operating time of the relay. For example, extremely inverse characteristics are preferred where less time of operation of relay is required.

Table 2-1: ANSI/IEEE and IEC constants for standard overcurrent relays

Curve description	**Standard**	**α**	**β**	**L**
Moderately inverse	IEEE	0.02	0.0515	0.114
Very inverse	IEEE	2	19.61	0.491
Extremely inverse	IEEE	2	28.2	0.1217
Inverse	CO8	2	5.95	0.18
Short-time inverse	CO2	0.02	0.0239	0.0169
Standard inverse	IEC	0.02	0.14	0
Very inverse	IEC	1	13.5	0
Extremely inverse	IEC	2	80	0
Long-time inverse	UK	1	120	0

Having the relay characteristic, it is a straightforward task to calculate the time response for a given time multiplier setting, pickup setting, and the other values of the expression in equation (2.1). Likewise, if a particular time response and pickup setting have been determined, the time multiplier setting can be found from the same equation.

2.2.2 Coordination of Overcurrent Relays

Overcurrent relays have to play dual roles of both primary and backup protection. In order to have the delay time for the backup in overcurrent relays, the feature of time multiplier setting (TMS) is provided. The basic idea is that by increasing or decreasing the TMS, the relay operating time can be increased or decreased proportionately.

In order to obtain reliability needed for network protection, there should be a backup protection in case of any failure in the primary protection [21]. The backup protection should operate if the primary fails to take the appropriate action. This means it should operate after a certain time delay known as coordination time interval (CTI), giving the chance for the primary protection to operate first. The above mentioned scenario leads to the formulation of the protective relay coordination. It consists of selecting a suitable setting of each relay so that their fundamental protective functions are met under the required attributes of protective relaying, which are sensitivity, selectivity, reliability, and speed [21]. The value of CTI avoids losing selectivity due to one or more of the following [4]:

- ✓ Breaker opening time

- ✓ Relay overrun time after the fault has been cleared
- ✓ Variations in fault levels, deviations from the characteristic curves of the relays (for example, due to manufacturing tolerances), and errors in the current transformers.

In numerical relays there is no overrun, and therefore the coordination time interval can be as low as 0.2 s [22].

Commonly, distribution networks are designed in a radial configuration with only one source and single power flow. Their protection is simple and it is usually implemented using fuses, reclosers and overcurrent relays. When the fault occurs in a system, it is sensed by both primary and backup protection. If the relays are coordinated, the primary relay will be the first to operate when fault occurs, as its operating time is less than that of the backup relay [22]. In order to verify if the system protection is well coordinated, the performance of all protection devices in the fault current path between the sources and the fault point should be verified. These sources are the substation or feeder and the DGs. The main aspect of the protection coordination of a system is that the primary protecting device, closer to the fault point, should operate before the backup device [19].

There are different methods used to achieve correct relay coordination, and these include the following: time- based, current-based, and logic coordination.

2.2.2.1 Time Based Coordination

For this method, coordination settings are done by giving a proper time to each of the relays controlling the circuit breakers. This should be done making sure that the breaker closer to the fault opens first and the one closer to the source has long time delay [23].

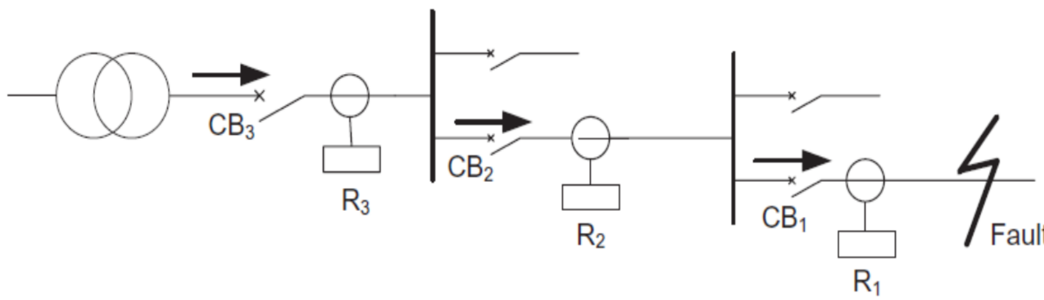

Figure 2-2: Time based coordination [23]

From Figure 2-2, relays R_1, R_2 and R_3 will detect the fault, and relay R_1 should operate first because it is near the fault. R_2 should operate after a given CTI if R_1 fails, while R_3 should operate lastly if R_1 and R_2 fail.

2.2.2.2 Current-Based Coordination

Due to change in value of impedance between the source and the fault, the fault current also varies for different locations of the fault. This brings the idea of current based coordination where relays are set to operate at different values of fault current. Relays setting are done so that the relay near to the fault will trip its circuit breaker first [23].

2.2.2.3 Logic Coordination

Both time based coordination and current based coordination have some limitations which are overcome by using logic coordination. Coordination time intervals between two successive relays are not needed. In addition, there is a reduction of tripping time delay for the circuit breaker closer to the source.

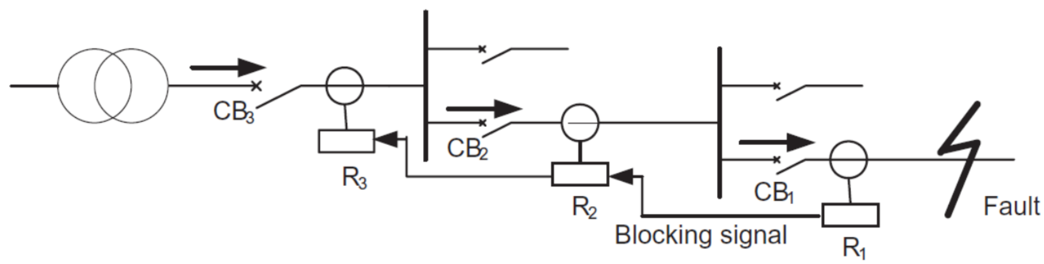

Figure 2-3: Logic coordination [23]

Considering Figure 2-3, relays R_1, R_2, and R_3 which are in an upstream direction from the fault, will be activated when the fault occurs. If R_1 is activated, it will send the blocking signal to R_2 as an order to increase the upstream relay time delay. This will also happen to R_3 if R_2 get activated.

Briefly, relay setting and coordination involves primarily following steps:

a) Identify all possible primary-backup relay pairs.

b) Decide the correct sequence for coordination of relays.

c) Decide the pickup value and hence PSM for relays.

d) Compute the TMS to meet the coordination.

e) Validation of the results.

2.3 Impact of DG Integration on Protection Coordination

Apart from offering many benefits, integrating DGs in the network can result in different problems. It changes the original network topology and fault current directions and values. The severity of these changes depend on the location, capacity and number of DGs.

2.3.1 False Tripping and Loss of Coordination

When a DG is interconnected on the distribution feeder it may cause a false tripping on a healthy feeder. If the fault occurs on any adjacent feeder then the fault current is contributed by connected DG in that feeder. If contributed fault current values are greater than protective device rating then healthy feeder also goes out of service till the fault is clear on the faulty feeder [24].

The definition of protection coordination loss can be taken as " violation of coordination time interval (CTI) constraint between the primary and backup relays " [25]. Figure 2-4 shows an example for the loss of coordination due to DG penetration. When a fault occurs at point F, R7-R8 and R7-R9 (primary-backup) can be considered as coordination pairs. Due to the connection of DG, these relays all sense an increase of short circuit current. For R7, this is not critical as it is the primary relay. But for R8 and R9, their CTI with respect to R7 may not be fulfilled as when there was no presence of DG. Therefore, there is a loss of coordination between pairs R7-R8 and R7-R9.

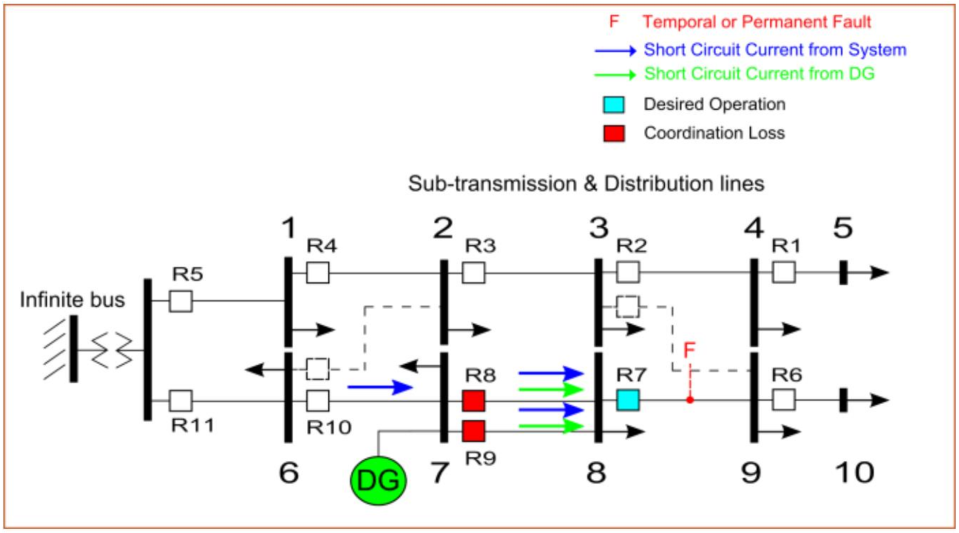

Figure 2-4: Loss of coordination caused by DG penetration [25]

Figure 2-5 illustrates the loss of coordination using inverse time relay characteristic curve for the coordination pair R7-R8. It can be clearly seen that after integrating the DG, the backup relay R8 accelerates its tripping time due to the increase of fault current; whereas the primary relay R7 is barely affected because its tripping time is already located at the horizontal asymptote curve. Hence, there is a loss of coordination because CTI is no longer preserved for the coordination pair R7-R8.

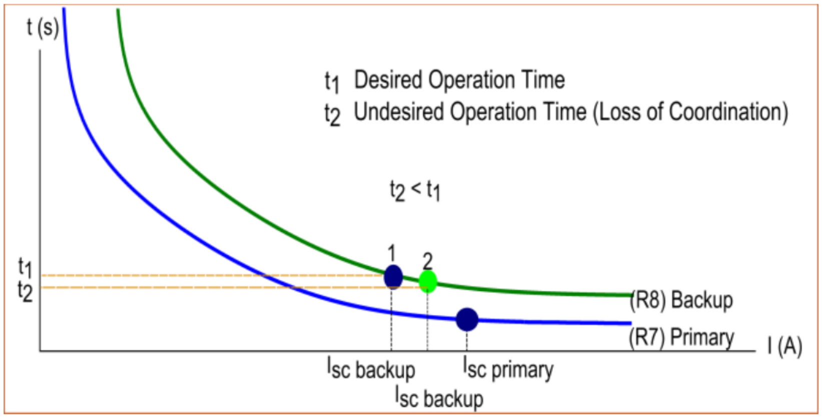

Figure 2-5: Illustration of coordination loss caused by DG penetration [25]

2.3.2 Protection Blinding

Integrating DGs to modern distribution networks introduces additional fault current sources, which can increase the total short circuit level in the network; this changes the magnitude and direction of fault currents detected by protective relays. If the DG is located between the utility substation and the fault location as in Figure 2-4, the total fault current will increase due to the partial contribution of DG. Contrary, the fault current seen by relay R10 will decrease for the same fault, because of fault current division between the sources, which may not exceed the pickup current setting of relay R10. This unwanted protection performance is generally known as protection blinding. The blinding phenomenon causes delayed protection operation or even total reduction of sensation in case of weak upstream system and large DG penetration. This phenomenon can also be called protection under-reach, since the actual reach of the feeder relay is decreased due to fault current contribution from the DG [26].

2.3.3 Nuisance Tripping of Feeder

Nuisance Tripping term is related to disconnection of DG, and this may occur due to power surge in the DG facility. In distribution system, power surge occurs due to loss of large load such as a motor in presence of a DG. This results in loss of large power flow in a grid and causes a relay to trip. A fault occurring outside the protective zone may cause nuisance tripping of DG means a sudden loss of generation from DG [24].

2.3.4 Islanding Operation

The islanding operation can be defined as isolation of a certain part of a network from the main network due to dispatch or natural condition [25]. Figure 2-6 shows how the island is formed. Assuming a permanent fault at point F, relay R10 will clear the fault by tripping the circuit breaker. The remaining circuit from bus 7 to 10 will form an island network supplied by the DG (assuming that the DG has enough capacity to maintain stable operation for the islanded network). Under new network operating condition if a fault occurs at any point along the lines between buses 7 to 10; then both primary and backup relays will suffer significant time delay in clearing the fault due to the relatively small fault current contribution by the DG. The relays can regain their operation speed if they were re-adjusted/re-coordinated for this new network operation and topology [25].

Islanding occurs in a distribution network when the substation is disconnected because of failure of feeder or maintenance purpose and due to that portion of a power system disconnected from the grid, the remaining part will be fed by DG. This islanding is generally avoided since it uses unacceptable limit of operating voltage, frequency, and power quality issue [24].

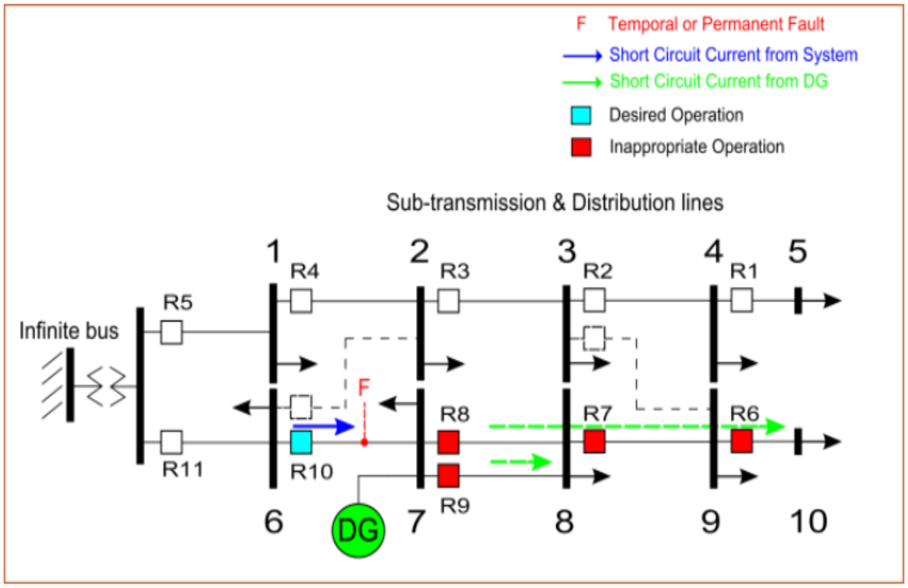

Figure 2-6: Islanding operation [25]

Figure 2-7 illustrates an inappropriate relay delay operation using inverse time relay characteristic curve for the coordination pair R7-R8. It can be seen that after entering island operation mode, the backup relay R8 increases its tripping time due to the fault current decrease; whereas the primary relay is barely affected because its tripping time is already located at the horizontal asymptote curve. Hence, there will be an undesired backup tripping time if a fault occurs during island operation mode.

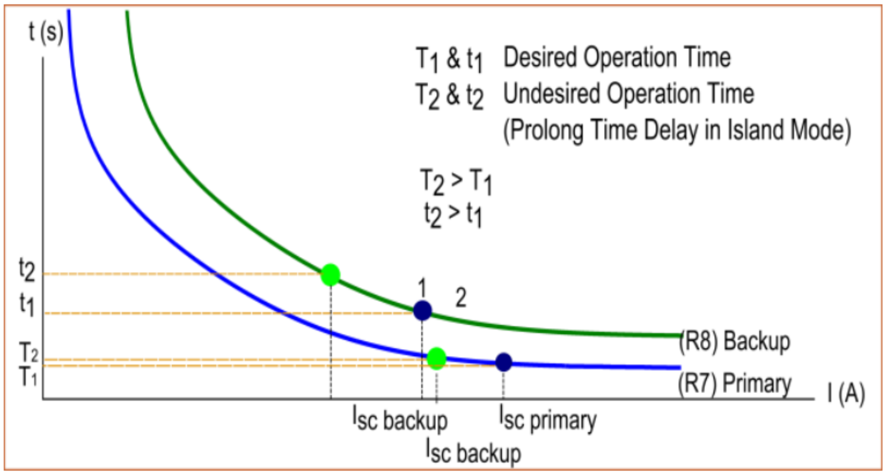

Figure 2-7: Relay delay operations caused by intentional or unintentional islanding [25]

2.4 Adaptive Protection Coordination Scheme

The configuration of the network is the basis for setting the coordination of the relays that protect the power system. It is not easy to change the settings of relays whenever the topology of the network is changed. To ease the task of the protection engineers, it was proposed to set and coordinate relays in the way they should respond to the changing system conditions and adapt according to the new prevailing conditions. This scheme is called adaptive protection. The changing system condition can be operational or topological, such as DG connection. Traditional protection relay coordination depends on standalone units that use local measurements and settings as the basis for the decision making. Communication plays a very limited role in these legacy systems. Contrary, Communication has a major role in an adaptive relaying [27].

In Adaptive protection scheme, the network condition should be monitored in order to identify the operational and topological changes of the network. When the change in the network is identified, the latest breaker and network configuration and/or the status of DGs are input into the centralized processing server. Based on the network status data, the server performs load flow, fault, contingency and sensitivity analysis. Then, it recalculates the new settings of relays and optimizes the relay coordination [25]. The new settings are updated to the relays via communication network so that the relays become best-tuned to the present network operating condition; a single cycle is then completed. For every change of new operating condition, the cycle is executed again.

When adaptive protection scheme is employed for the mitigation of DG penetration impact on protection coordination, additional benefit can be obtained other than maintaining selectivity for all coordination pairs; namely the increase of sensitivity [25].

This scheme turns to the advantage of communication technology and digital protective devices that exist nowadays to design an automatic protection coordination based on the network operator experience. It is already a well-known fact that, the modern relays have the ability to switch between multiple groups of time current characteristic curves based on the system operating conditions [26]. The aim of adaptive protective scheme is to update immediately the feature and settings of the protective relay when the DG is connected in order to maintain the operating time and the coordination for the relays. This study proposes an adaptive protection scheme which is able to overcome protection problems associated with connection of the DG.

2.5 Fuzzy Logic Control

2.5.1 Introduction to fuzzy logic

Fuzzy logic means approximate reasoning, information granulation, computing with words and so on. Ambiguity is always present in any realistic process. This ambiguity may arise from the interpretation of the data inputs and in the rules used to describe the relationships between the informative attributes. Fuzzy logic provides an inference structure that enables the human reasoning capabilities to be applied to artificial knowledge-based systems. Fuzzy logic provides a means for converting linguistic strategy into control actions and thus offers a high-level computation [28].

Fuzzy logic-based systems are useful in decision-making by incorporating expert knowledge. The fuzzy logic systems allow for partial membership to a particular set for an object unlike the classical logic set theory that only takes two cases (e.g. 1 or 0, ON or OFF). The fuzzy logic inference system (FIS) performs numerical computation using membership functions for modeling of fuzzy set linguistic variables. The fuzzy logic is useful for imprecise, uncertain information and complex-ill based systems and incorporates human experience based on if-then fuzzy rules in decision-making [28]

Fuzzy logic control or simply “fuzzy control” belongs to the class of “intelligent control,” “knowledge-based control,” or “expert control.” Fuzzy control uses knowledge-based decision-making employing techniques of fuzzy logic [29]. Fuzzy control uses the principles of fuzzy logic-based decision-making to arrive at the control actions. The decision-making approach is typically based on the compositional rule of inference (CRI).

Fuzzy logic controllers (FLCs) based on fuzzy set theory are used to represent the experience and knowledge of a human operator in terms of linguistic variables called fuzzy rules. Since an experienced human operator adjusts the system inputs to get a desired output by just looking at the system output without any knowledge of the system's dynamics and interior parameter variations, the implementation of linguistic fuzzy rules based on the procedures done by human operators does not also require a mathematical model of the system [30].

The majority of fuzzy logic control systems are knowledge-based systems in that either their fuzzy models or their fuzzy logic controllers are described by fuzzy IF-THEN rules, which have to be established based on experts' knowledge about the systems, controllers, performance, etc. Moreover, the introduction of input-output intervals and membership functions is more or less subjective, depending on the designer's experience and the available information [31].

2.5.2 Structure of a Fuzzy Logic Controller

The general structure of a fuzzy logic controller (FLC), or fuzzy controller (FC) for short, consists of three basic portions: the fuzzification unit at the input terminal, the inference engine built on the fuzzy logic control rule base in the core, and the defuzzification unit at the output terminal, as shown in Figure 2-8 [31].

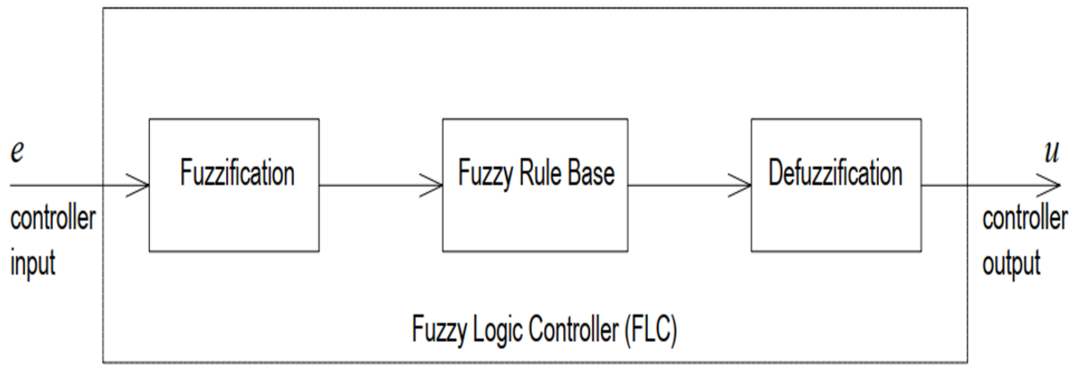

Figure 2-8: General structure of a fuzzy logic controller

The fuzzification module transforms the physical values of the input to the fuzzy logic controller, into a normalized fuzzy subset consisting of a subset (interval) for the range of the input values and an associate membership function describing the degrees of the confidence of the input belonging to this range. The purpose of this fuzzification step is to make the input physical signal compatible with the fuzzy control rule base in the core of the controller.

The role of the inference engine in the FLC is key to make the controller work and work effectively. The job of the "engine" is to create the control actions, in fuzzy terms, according to the information provided by the fuzzification module. The defuzzification interface converts back the fuzzy sets to crisp output using different defuzzification methods like centre of gravity, mean of maximum, centroid, weighted average etc.

2.5.3 Types of Fuzzy Inference System

There are three commonly used types of fuzzy system [30] , namely:

a) Mamdani fuzzy system: The output of this model are fuzzy sets.

b) Takagi-Sugeno (TKS) fuzzy system: The output of this TKS model is a linear function of the input variables plus a constant term.

c) Tsukamoto fuzzy system: The consequent of each fuzzy if-then rule is represented by a fuzzy set with a monotonical membership function.

The most important two types of fuzzy inference method are Mamdani's fuzzy inference method, which is the most commonly seen inference method. This method was introduced by Mamdani and Assilian (1975). Another well-known inference method is the so-called Sugeno or Takagi–Sugeno–Kang method of fuzzy inference process. This method was introduced by Sugeno (1985). This method is also called as TS method. The main difference between the two methods lies in the consequent of fuzzy rules [28].The main difference between Mamdani and Sugeno is that the Sugeno output membership functions are either linear or constant. A typical rule in a Sugeno fuzzy model has the form IF x is A and y is B THEN z = f(x,y) and z = ax + by + c.

When *f(x,y)* is a first-order polynomial, we have the first-order Sugeno fuzzy model. When *f* is a constant, we then have the zero-order Sugeno fuzzy model, which can be viewed either as a special case of the Mamdani FIS where each rule's consequent is specified by a fuzzy singleton, or a special case of Tsukamoto's fuzzy model where each rule's consequent is specified by a membership function of a step function centered at the constant. Moreover, a zero-order Sugeno fuzzy model is functionally equivalent to a radial basis function network under certain minor constraints [28].

Over the past two decades, there has been a tremendous growth in the use of fuzzy logic controllers in power systems as well as power electronic applications [32].The use of FLC has increased rapidly in power systems, such as in load frequency control, bus bar voltage regulation, stability, load estimation, power flow analysis, parameter estimation, protection systems and many other fields [30],[33]–[37]. The advantages of using fuzzy logic in such applications include the following:

- ✓ Fuzzy logic controllers are not dependent on accurate mathematical models. This is particularly useful in power system applications where large systems are difficult to model. It is also relevant to smaller applications with significant non-linearities in the system.
- ✓ Fuzzy logic controllers are based on heuristics and therefore able to incorporate human intuition and experience.

2.6 Review on Techniques Used to Mitigate the Impact of DG Penetration on Protection Relays Coordination

Various researchers have proposed different solutions to mitigate the negative impact of penetrating DGs in sub-transmission and distribution networks on protective relays coordination. These solutions include the following:

- ❖ Disconnecting the DGs immediately after fault detection [38]
- ❖ Limiting the capacity of installed DGs [39],[40]
- ❖ Modifying the protection system by installing more protective devices [41]

- Installing the fault current limiters (FCLs) to preserve or restore the original relay settings [42][43][44][45]
- Employing fault ride through control strategy of inverter based DGs [46][47]
- Controlling the fault current by solid-state-switch-based field discharge circuit for synchronous DGs [48]
- Adaptive protection schemes (APS) [49][50][22]

Stefania Conti [38], identified and discussed through examples several potential conflicts between DG and distribution operation considering structure and protection schemes of typical distribution networks. He highlighted the need for distribution protection philosophies that should be made by planners and distribution operators in order to deliver improved service continuity to consumers with increasing DG penetration in distribution networks. He found that it could be thought that if generators are able to detect the fault and rapidly disconnect from the network, they cannot disturb the normal operation of protection system, especially when their fault currents contribution seams relatively small and the system is not depending on DG to support the load. According to [38], most interconnection standards, included the Italian ones, besides limiting DG installed capacity, were requiring the disconnection of DG when a fault occurs.

Surachai Chaitusaney and Akihiko Yokoyama [39] reported on a way to prevent degradation of reliability caused by recloser-fuse miscoordination. To maximize the DG utilization, they have found the largest acceptable DG that should be considered as the limitation level in order to reduce the impact of DG. They used mathematical equations of protective devices to set up protection coordination and to calculate the largest possible value of DG. Jinfu Chen *et al.* [40] in their work , they did calculation of penetration level of DG mainly based on the reliable action of relay protection device in distribution network.

Hamed B.Funmilayo and Karen L. Butler-Purry [41] presented an approach that revises the existing over current protection scheme of a radial feeder to address the presence of DG. Their work discussed a non-communication based approach to maintain coordination between the recloser and fuses and mitigate the identified overcurrent protection issues. This approach involved adding multi-function devices (recloser and relay) on the lateral with DG. They discussed this approach to alleviate the impact of DG on the overcurrent protection scheme for radial distribution systems. The overcurrent protection issues like fuse misoperation, fuse fatigue, and nuisance fuse blowing were addressed by this approach.

Walid El-Khattam and Tarlochan S.Sidhu [42] proposed an approach that used a fault current limiter to limit the DG fault current locally, and restore the original relay coordination. This approach was proposed in order to solve the coordination problem of directional overcurrent relay, caused by connecting DG in looped power delivery systems. This method was performed without changing the original relay settings or disconnecting DGs during fault. Youngwood Kim *et al*. [43] proposed a systematic procedure to analyze the impacts of superconducting fault current limiter (SFCL) placement on DG expansion in a power system while maintaining the original protective relays coordination. In their work, the SFCL-placement problem was solved to determine the placement location for optimizing the maximum fault-current level reduction, while maintaining the original relay settings.

Abbas Esmaeili *et al.*[44] used a simultaneous network reconfiguration and optimal planning fault current limiters (thyristor-controlled impedances) that could either be resistive, inductive, or capacitive, to maintain fault current levels and reduce power losses in a smart grid under various operating conditions. They discussed two methods which are: the reconfiguration of a distribution network for efficient operation and protection coordination in the form of a multi-objective optimization problem. They did the optimal programming of fault current limiters using a two-stage stochastic model to achieve their objectives, which were to reduce losses and maintaining short circuits levels under different utilization scenarios of DGs.

A. Elmitwally *et al*. [45] in their work, they investigated the optimal utilization of fault current limiters in order to sustain the coordination of the directional over current relays without any need of resetting the relays for all status of DGs. They formulated a multi-objective optimization problem for the size and location of FCLs. To determine the optimal location and size of FCLs, multi-objective Particle Swarm Optimization was used to solve the optimization problem. Their focus was to maintain the coordination of the relays in power distribution system with DGs. The authors have seen that using FCLs is an effective solution that does not need resetting of overcurrent relays for any change of DG status.

E. Ebrahimi *et al*. [46] in their work, they used fault ride through approach to decrease the impacts of integrating the DGs in the grid. The inverter based DGs were properly controlled in the fault condition instead of disconnecting them from the grid. The simulation results showed that the fault current was kept in the desired range by using the proposed algorithm and the protection coordination before connection of DG remained intact even after the connection of DG. Control strategy was proposed and applied to the voltage source converter (VSC) so that the protection coordination remains unchanged and there was no need to change the protection system coordination and devices. The authors have seen that not only the DG output current can be reduced to the value that keeps the protection device coordinated, but also the voltage sag is improved during the fault condition due to the reactive power injection by Inverter Based DG.

Seyed Behzad Naderi *et al*. [47] in their work, they proposed an optimum resistive type fault current limiter (ORFCL) as an efficient method to get maximum fault ride-through capability of fixed speed wind turbines during different faults conditions. They designed a control circuit for the proposed ORFCL and by means of this control circuit, the ORFCL calculated an optimum resistance value with respect to pre-fault operation conditions, including the fault location and the pre-fault output active power of the induction generator.

H. Yazdanpanahi *et al*. [48] proposed a field discharge circuit to limit the generator's fault current, in order to mitigate the impacts of synchronous-machine DG on the protection of distribution network. The method was implemented by equipping the generator with a solid-state-switch-based field discharge circuit. Authors studied the operation of this circuit and investigated its effects on the output current of generator during the fault. It was seen that the proposed scheme was able to remove the steady-state component of the fault current and accelerate the decay of the transient AC component of the current. It was shown through results that the proposed field discharge circuit is competent to avoid miscoordination of inverse-time overcurrent relays used for network protection.

Even though these approaches can sufficiently mitigate the negative impacts of penetrating DGs on the way protective relays perform, they can have various limitations as well. Disconnecting large DGs immediately after fault detection may lead to severe voltage sags as the contribution of reactive power from DGs will be cut off. Moreover, most faults are temporary, thus disconnecting the DGs is not economically beneficial since the DGs will need to be reconnected to the network after the clearance of temporal fault in order to profit from the renewable energy. Also, stability problem may occur if there were high penetrations of DGs in the network.

Limiting the DGs capacity is a provisional solution, since renewable energy is cheap, it should be fully exploited to gain more profit and also to avoid excess CO_2 emission mostly generated from conventional power plants. Modifying the protection scheme by installing extra protective devices like circuit breakers for sectionalization, reconfiguration of networks or change of protection principles is costly, and also the use of numerous protection principles in a certain area of the power system may lead to more complicated protection coordination scenario and difficult post-event analysis.

Both the fault ride-through control strategy of inverter based DGs and control of fault current by solid-state-switch-based field discharge circuit for synchronous DGs are low-cost solution compared to the previous ones [25]. The first consists of a commutation control strategy of the inverter switches in order to limit the fault current contribution. The second consists of installing a solid-state-switch-based field discharge circuit for synchronous DGs in order to drain the excess fault currents. However, both are only partial solutions to the problem since the first solution is only applicable to inverter-based DGs and the second only to synchronous DGs. These shortcomings lead to another alternative called adaptive protection scheme (APS). The exceptionally good aspect of this protection scheme is that it can monitor the network and immediately update the relay settings according to the variations that occur in the network.

R. Sitharthan *et.al* [49] used an adaptive protection scheme to provide protection for microgrids by utilizing microprocessor-based over current relays . They also used auto reclosers, through which the proposed adaptive protection scheme recovers faster from the fault and increase the consistency of the microgrid as result. Rahmati and Dimassi [50] proposed an adaptive protection that uses a least square algorithm to determine the Thevenin circuit equivalent using local measurements. This method does not require any online-information and communication facilities regarding varying short-circuit levels caused by distributed energy resources infeed. Yen *et al*. [22] proposed an adaptive protection scheme using differential evolution algorithm (DE) in order to mitigate the impacts of integrating DG on directional overcurrent relays (DOCR) coordination. The scheme consisted of automatic online re-adjustment of relay settings so that the relays are best attuned for different network operating condition due to dispatch or natural condition.

With the advancement in technology and development in computer-based relaying, protection engineers now have many options to choose a reliable protection scheme based on the network topology and requirement. Introduction of microprocessor-based protective devices, Intelligent Electronic Devices (IEDs) and communication systems stimulated this very important aspect of adaptive relaying. The adaptive protection schemes are likely to have widespread and being used in the current and future complex structure of distribution systems in the presence of renewable energy-based DG penetration.

2.7 Research Gap

Several researchers have used adaptive protection, having the goal of changing the relay settings in real time in order to adapt the protection system to the changes that occur in distribution systems caused by introducing DGs. Different optimization methods like ABC algorithm [21], Differential evolution algorithm (DE) [25] have been used to apply adaptive protection scheme, but in those algorithms, a fixed capacity of DG was considered. The adaptive protection schemes are promising in the current and future complex structure of distribution systems in the presence of renewable energy-based DG penetration. In these networks, the fault levels are intermittent and continuously changing as per connection of distributed energy resources (DER) in the network. Therefore, there is need to take into account this intermittency of the renewable energy based DGs. Apart from using optimization techniques in adaptive protection scheme, different controllers including fuzzy logic controllers can also be used. The motivation of using such control techniques is activated by the improved robustness of the new intelligent controllers over conventional linear control algorithms.

Considering the intermittency of DGs, fuzzy logic systems are advantageous when compared to traditional systems in the sense that they employ a set of quantitative rules which are defined by semantic expressions. Fuzzy systems also allow a larger solution space and find applications in areas that derive inferences from uncertain, undefined data. Due to the uncertain nature of renewable energy based DGs, various scenarios have to be taken into consideration and the characteristics of fuzzy systems are suited for such kind of applications [51]. Following this direction, in this study, an adaptive protection scheme based on a fuzzy logic controller was proposed to be used in the distribution networks with DG integration. The controller chooses the best Time Multiplier Setting (TMS) of the relay depending on the size of the DG connected. This allows the protection scheme to automatically change the relay settings based on change in network configuration due to connection of DG.

CHAPTER 3: METHODOLOGY

This chapter highlights the steps followed in addressing the research objectives.

Penetration of DG in the distribution networks, its impact on the protection coordination and application of adaptive protection scheme, was studied in three scenarios:

i. Distribution network without DG and employing a traditional protection coordination

ii. Distribution network with DG connected and employing traditional protection coordination

iii. Distribution network with DG connected and employing the adaptive protection scheme

3.1 Setting and Coordination of Overcurrent Relays in Radial Distribution Networks without DG

3.1.1 System Description and Simulation Setup

In this study, the IEEE 13 bus radial distribution feeder network adopted from [52] as shown in Figure 3-1, was used for simulations. It is an 11 kV Distribution network connected to the utility of 110 kV, through a 110/11 kV transformer. ETAP software was used to draw the network, simulate the load flow and short circuits studies which are needed for relay setting and coordination. The fuzzy logic toolbox in MATLAB was also used to design a fuzzy logic controller (FLC). The two softwares work independently and TMS values got from the FLC in MATLAB were brought in ETAP for coordination.

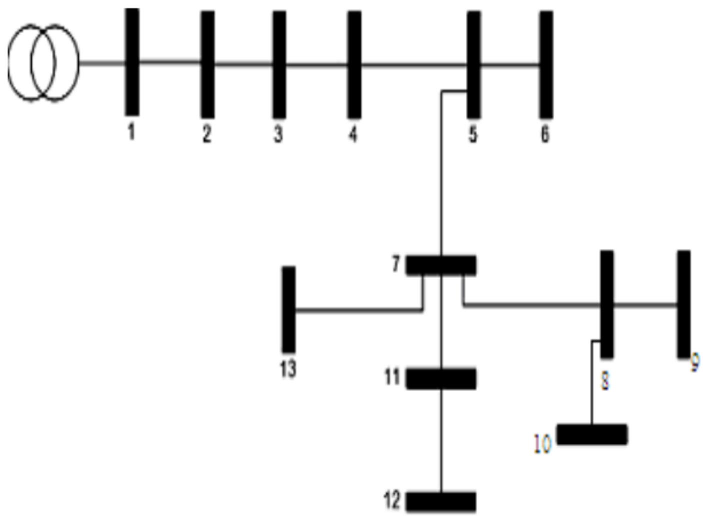

Figure 3-1: The 13-bus radial distribution system

Table 3-1: Load data on the buses

No.bus	P(kW)	Q(kVar)
1	0	0
2	890	468
3	628	470
4	1112	764
5	636	378
6	474	344
7	1342	1078
8	920	292
9	766	498
10	662	480
11	690	186
12	1292	554
13	1124	480

Table 3-1 indicates the load data on the buses of the network used. These data are the active and reactive powers. Table 3-2 shows the impedance data of the lines connecting buses, which are the resistance and reactance for each line.

Table 3-2: Impedance data on the lines

From bus	To bus	R(ohm)	X(ohm)
1	2	0.176	0.138
2	3	0.176	0.138
3	4	0.045	0.035
4	5	0.089	0.069
5	6	0.045	0.035
5	7	0.116	0.091
7	8	0.073	0.073
8	9	0.074	0.058
8	10	0.093	0.093
7	11	0.063	0.05
11	12	0.068	0.053
7	13	0.062	0.053

Three-phase faults were created for different locations in the network and the fault currents were found. Then, the operating time t_i for the primary and the backup relays were obtained based on the inverse characteristic of overcurrent relay. The IEC standard inverse characteristic equation 3.1 of overcurrent relay [4] was used.

$$t_i = \frac{0.14 * TMS}{\left[\dfrac{I_f}{i_{pickup}}\right]^{0.02} - 1} \qquad (3.1)$$

Where:

TMS is the time multiplier setting of the relay

I_f is the fault current seen by the relay

I_{pickup} is the pickup current of the relay

Pick up current settings for the relays should be above the feeder load currents and not the bus load currents. In fact, one should consider the maximum possible loading conditions, to decide conservatively pick-up current settings. A rule of thumb is to set the pick-up current at 1.25 times maximum load current. Another 'rule of thumb' is to limit pick-up current to 2/3rd of the minimum fault current. This decides the range available for setting relay pick-up [53].

In this study, the pickup currents for different relays have been selected based on the above stated rule. Due to the fact that the DG can be connected at any bus in the system, directional overcurrent relays have been used in order to obtain the selectivity needed. R1, R2, R4, R6, R8, R10, R12, R14, R16, R18, R20, R22 and R24 are supposed to operate in forward direction and these are the relays concerned in coordination for the network before connecting the DG. On the other hand, R3, R5, R7, R9, R11, R13, R15, R17, R19, R21 and R23 are supposed to operate in the reverse direction depending on where the DG is connected and the concerned relays.

Table 3-3 shows the pickup currents for different relays that operate in forward direction and these values have been selected to be between 1.25* the full load current in each line and 2/3rd of minimum fault current. Table 3-4 indicates the pickup currents for the relays operating in reverse direction when the DG is connected at bus 11.

Table 3-3: Pickup currents for different relays operating in forward direction

Relay Number	R1, R2	R4	R6	R8	R10	R12	R14	R16	R18	R20	R22	R24
Pickup Current (A)	900	800	800	800	50	600	200	75	75	200	100	100

Table 3-4: Pickup currents for relays operating in reverse direction when DG is connected at bus 11

Relay Number	R3	R5	R7	R9	R13	R21	Rdg
pickup current (A)	50	75	150	200	300	800	800

When doing a protection coordination for a radial distribution network, we start with the relays which do not have coordination responsibility (relays at the far end nodes) and TMS for these relays can be set to the minimum. After selecting the pickup currents for the relays and having the fault currents, the operating time for the far end relay was found. Using a coordination time interval (CTI) of 0.3 s, the expected operating time for the backup relay was found and this time was used to calculate the TMS for the backup. This process was done for different coordination pairs depending on the fault location and the relays concerned in clearing the fault.

3.2 Investigating the Impact of DG Integration on Relays Coordination

To investigate the impact of integrating DG in distribution network, two scenarios were considered. For the first scenario, an 8 MVA DG was connected at bus 2 and for the second scenario, the same DG was connected at bus 11. The output voltage of DG is 6.6 kV, and it is connected to the system through a 6.6/11 kV transformer. The reason of selecting the DG location was based on the fact that the two buses were reported in [52] as the optimal placement of DG for the IEEE13 bus radial distribution network used in this study.

Three-phase faults were generated on different bus-bars in the distribution system, with and without DG. For the distribution network without DG, the fault currents and operating time of the relays as well as the coordination time interval between the primary and the backup relays were recorded. The DG was then connected on the distribution network. For the two scenarios considered, the fault currents were recorded by specifying the contributed current from the main feeder, and from the DG. The operating time of the relays as well as the coordination time interval between the primary and the backup relays were also recorded. These values were used to analyze the impact of penetrating DG on the fault current and on protection coordination that was already set.

3.3 Designing a Fuzzy Logic Controller for Adaptive Protection Scheme to be Used in Distribution Network with DG Connected

3.3.1 Application of Adaptive Protection Scheme for Protection Coordination

One of major problems in distribution systems penetrated with DGs is the topological variation of the network whenever a DG is connected or disconnected from the system for any reason. This problem arises due to the fact that one setting for the protection relays cannot respond correctly to the changing network topology and will affect the reliability and safety of the distribution network. Thus, to avoid relay malfunction, the relays have to be adaptively set whenever a new system topology is detected. Adaptive protection is "an online activity that modifies the preferred protective response to a change in system conditions or requirements in a timely manner by means of externally generated signals or control action" [54]. Adaptive protection of distribution systems penetrated with distributed generation can be realized with the use of microprocessor-based relays that have the advantage of easily changing their tripping characteristics. Implementing adaptive protection increases the sensitivity and achieves faster operating times.

The approach proposed in this study based on the adaptive setting method is an on-line activity that changes the Time Multiplier Setting (TMS) of the protective relays in a case of any change in system configuration by means of control action. The proposed adaptive feature in numerical relays modifies automatically the protective device settings based on the system topology and DG capacity to maintain the coordinated overcurrent relays with the optimum selectivity and sensitivity. The proposed adaptive protection scheme keeps the proper operations and coordination of overcurrent relays with the system data from the digital protection relay even when the operating conditions change due to connection of DG. This is done by updating relays settings to achieve the correct coordination without extra costs or equipment in the distribution system.

In this study, an adaptive protection scheme method is proposed to solve the impact of integrating DG in distribution networks on overcurrent protection. The proposed protective scheme uses digital over current relays. These digital relay can store, collect information, handle complex logic and communicate with other relays and control devices. These characteristics have made these relays able to continuously monitor the state of power system, analyze it in real time and vary the relay settings based on network conditions. The required settings of over current relays are updated in online manner as per variation in fault current levels seen by relays during changing network conditions [55].

Figure 3-2 shows the flow chart of the proposed adaptive protection scheme and shows how it will work from the start to the end.

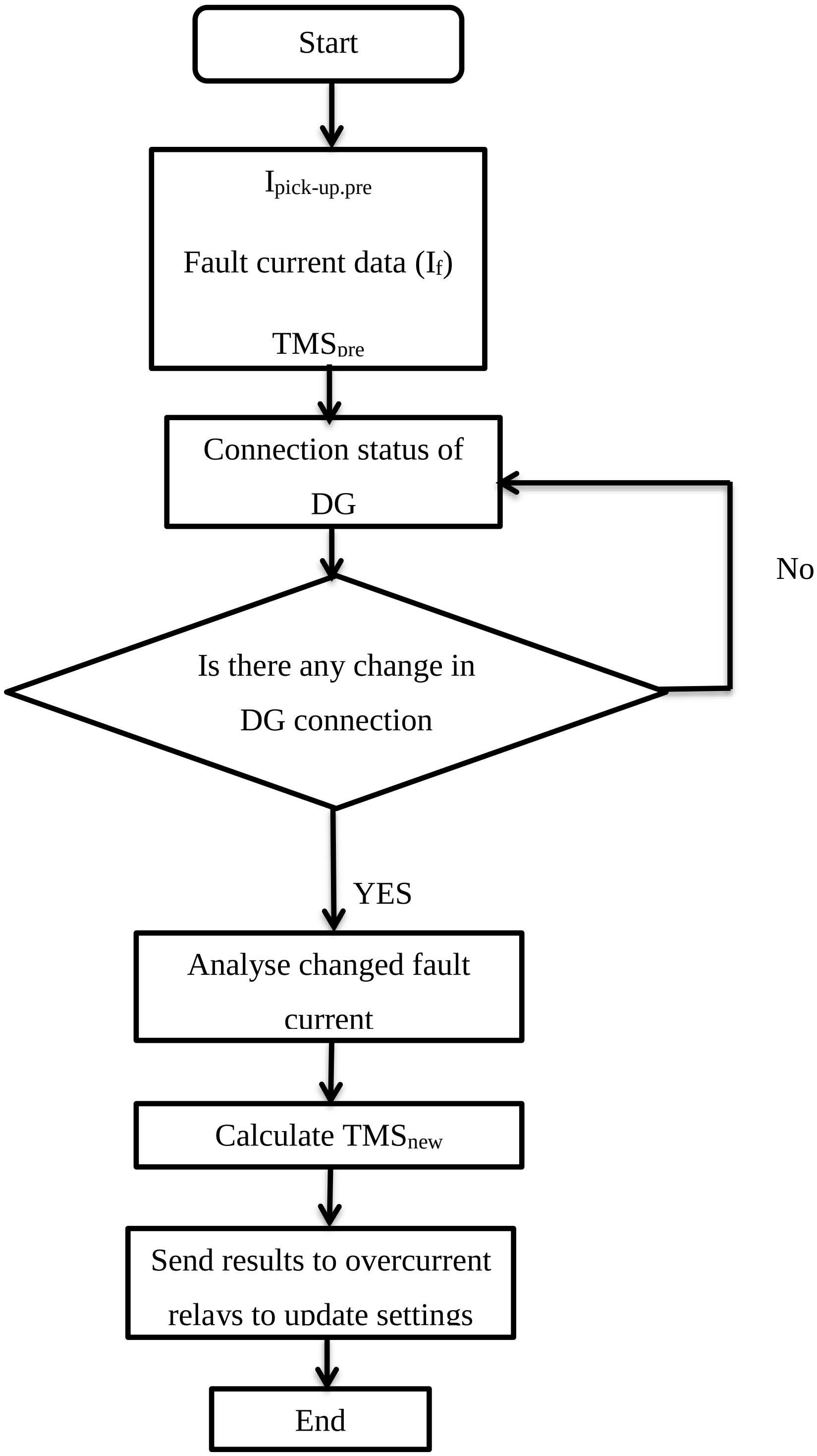

Figure 3-2: Flow chart of the proposed adaptive protection scheme

The adaptive protection coordination approaches have promising future application for Distributed Energy Resources (DER) connected distribution systems. In these networks, the fault levels are intermittent and continuously changing as per connection of DER in the network.

3.3.2 Determination of TMS Values of Relays for Maximum Capacity of DG

The adaptive protection scheme was applied by changing the time multiplier setting of the overcurrent relays in order to maintain the same operating time and coordination time interval the way they were before connecting the DG. Equation (3.2) was used to get the values of the new TMS values.

$$TMS_{Ri_{new}} = \frac{t_{Ri_{old}} * \left\{\left(\frac{I_{fault_{new}}}{I_{Pickup}}\right)^{0.02} - 1\right\}}{0.14} \qquad (3.2)$$

Where

$TMS_{Ri_{new}}$ is the new TMS value of the relay i,

$t_{Ri_{old}}$ is the operating time of relay i before connecting the DG

$I_{fault_{new}}$ is the new fault current seen by relay i after connecting the DG

I_{Pickup} is the pickup current of relay i

3.3.3 Designing the Fuzzy Logic Controller

Considering the intermittency of renewable energy based DGs, the fuzzy logic controller has been used in order to choose the best TMS value of the relay, if the output of the DG changes for any reason. For the change in the capacity of the DG connected, the values of fault currents in the network also will change and it affects the coordination of the relays. In order to use adaptive protection scheme, the change in time multiplier setting, can be done by a control action using a fuzzy logic controller.

In this research, the fuzzy logic controller should sense the DG output to update to a new protection setting related to a new network configuration due to the DG connected.

The following sets of process parameters were considered:

i. Controller input: Size of the DG

ii. Controller Output: Time Multiplier Setting (TMS)

The fuzzy based approach was used for identifying the operational network topology, which in turn determines the fault current to be used when coordinating afresh after connecting the DG. This was achieved by fuzzification of the rule base corresponding to given topology which come in existence due to connection of DG. Size or capacity of the DG connected was utilized in defining the input membership function. The output after defuzzification was in terms of Time Multiplier Setting (TMS) of the relay.

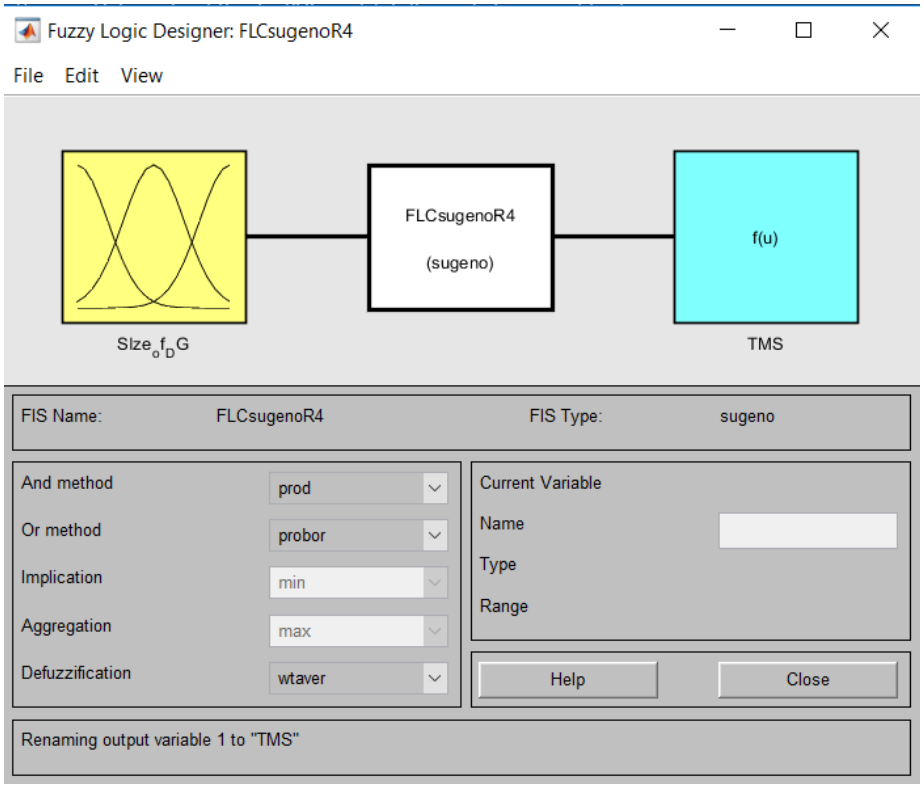

Figure 3-3: Fuzzy logic designer

Figure 3-3 shows the fuzzy logic designer from the fuzzy logic toolbox of the MATLAB software. This indicates the type of the fuzzy inference system (FIS) used,different methods used in defining rules and the deffuzification method.

A Sugeno-type fuzzy inference system (FIS) was used in this study because it works well with optimization and adaptive techniques. The output of a zero-order model is a smooth function of its input variable. Input fuzzy sets and rules are converted into an output fuzzy set, and then into a crisp output for determining the TMS of the relay.

To design the fuzzy logic controller, the size or the capacity of the DG was considered as the input, while the TMS of the relay was considered as the output. The input variable “size of the DG” is ranged between 0 and 8 MVA and its membership function is represented in Figure 3-4.

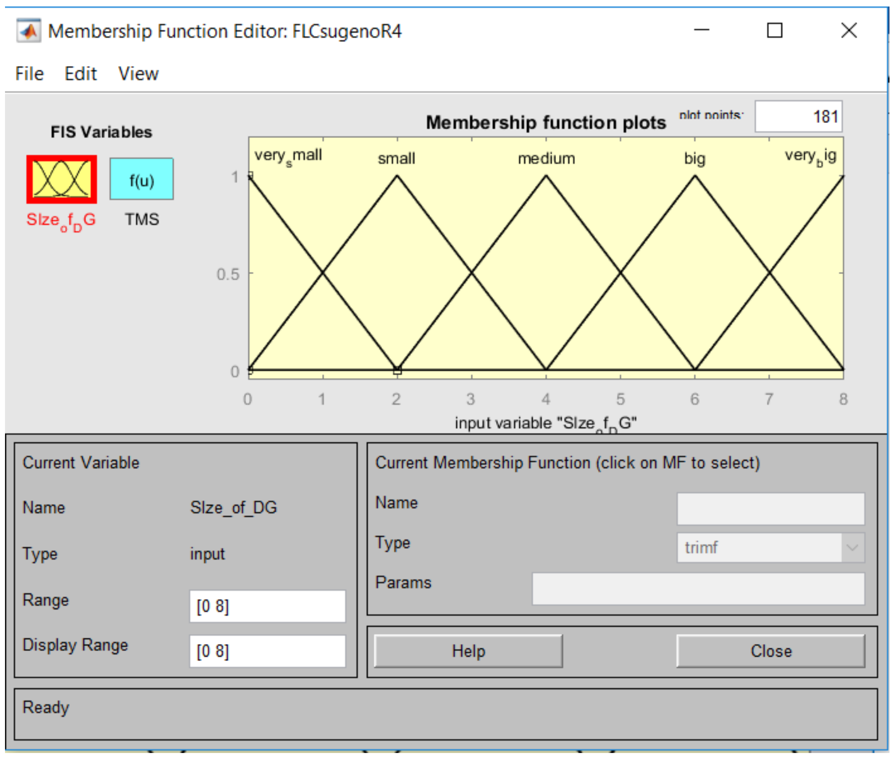

Figure 3-4: Membership function for the size of DG

To take the range for the output variable “TMS”, the lower limit was considered to be the TMS value of relays for the network before connecting the DG. The upper limit is the value of TMS got after connecting the maximum size of DG. Figure 3-5 represents the membership function for the output variable “TMS” for a sample relay R4

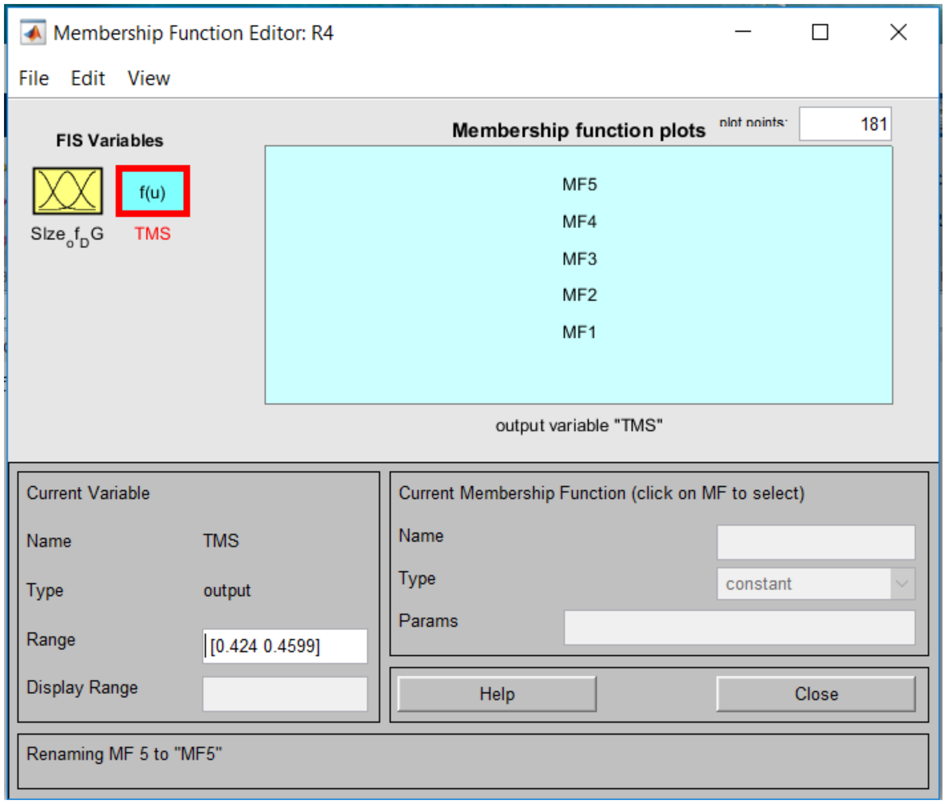

Figure 3-5: Membership function for TMS

The output of the system contained 5 membership functions, and Figure 3-5 shows the structure of the output for a sample relay R4 as it is seen in MATLAB.

The rules are developed in linguistic form of IF / THEN statements and the sample of them is like: If size of DG is very small then the TMS is MF1. Figure 3-6 shows the rule editor in the fuzzy toolbox and the rules used for the controller designed.

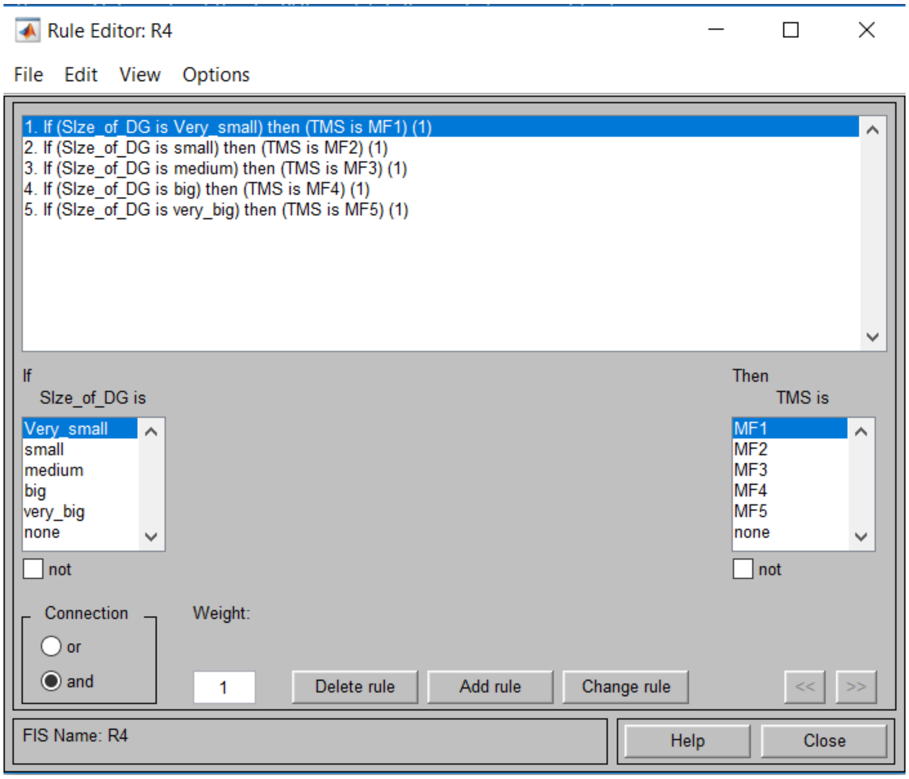

Figure 3-6: Rule editor for the designed controller

3.4 Testing the Developed Fuzzy Logic Based Adaptive Protection Scheme in Distribution Network with DG Connected

After designing a fuzzy logic controller, it was used to find the TMS values of relays for different sizes of the DG between 0 and 8 MVA which is the maximum size of the DG. In order to evaluate the performance of the developed fuzzy logic based adaptive protection scheme, the TMS values for the relays involved in coordination were found using the designed controller. These values were used in coordination to see if the operating time and the coordination time interval for different coordination pairs will remain the way they were before connecting the DG.

CHAPTER 4: RESULTS AND DISCUSSIONS

4.1 Overcurrent relays coordination in radial distribution network without DG

Figure 4-1 shows the 13-bus radial distribution network used in this study. This network was modelled using ETAP software.

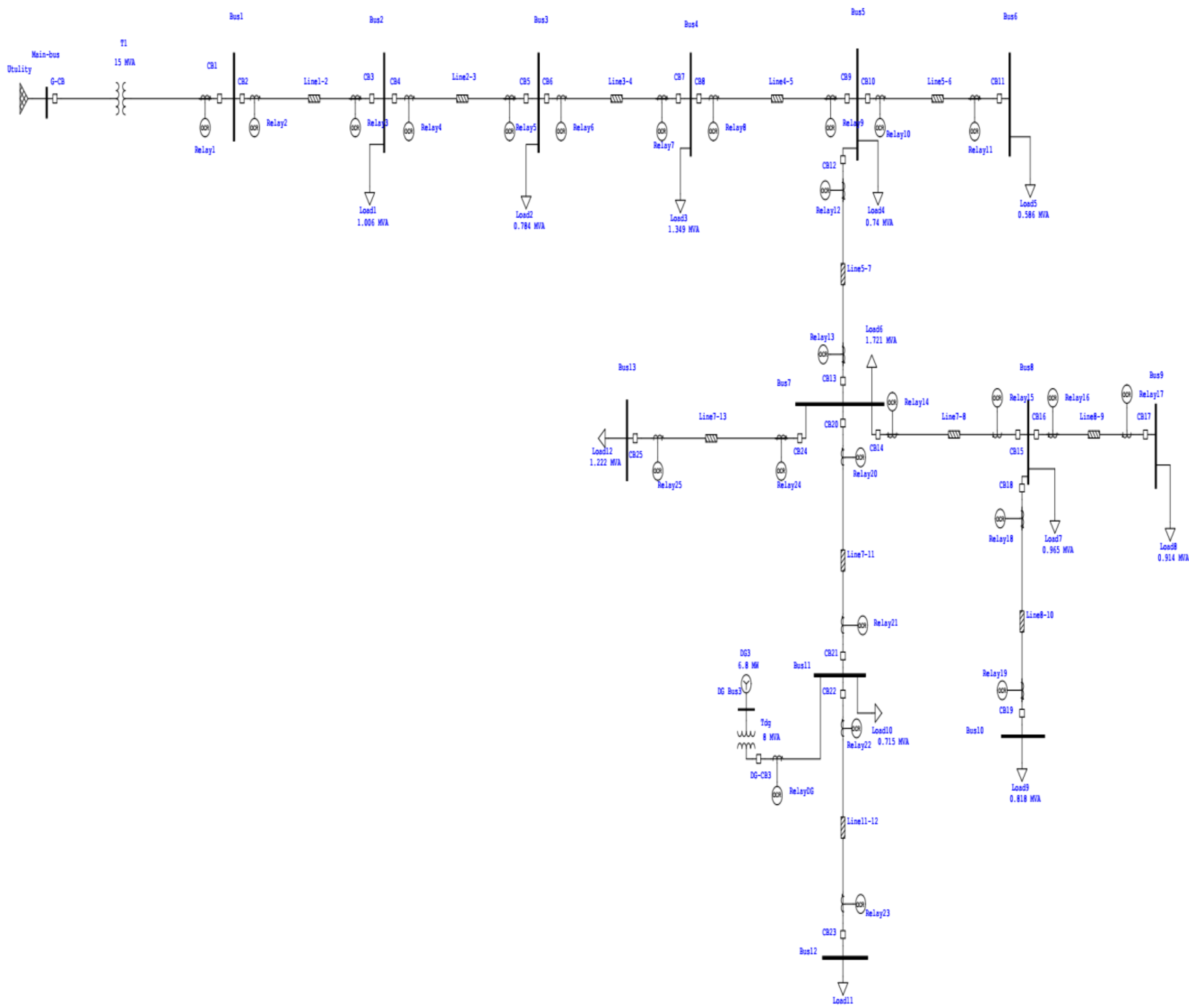

Figure 4-1: 13 Bus radial distribution network used with DG connected at bus 11

Table 4-1 shows the fault currents simulated using ETAP for the distribution network before connecting the DG.

Table 4-1: Fault currents for different fault locations before connecting DG

Fault location (Bus)	1	2	3	4	5	6	7	8	9	10	11	12	13
Fault current without DG (kA)	9.75	7.71	6.24	5.94	5.42	5.19	4.86	4.51	4.24	4.13	4.6	4.33	4.58

With the knowledge of I_f, I_{pickup} and TMS, the desired relay operating time can be calculated. To start the coordination, the far end relay R22 was given a TMS of 0.05 and the CTI of 0.3 s was used during coordination.

The coordination was done keeping in mind that the backup relay should trip after a coordination time interval of 0.3 s. An example of how the coordination was done is detailed below:

Considering a fault at bus 3, the fault current is 6240 A. for this fault, relay R4 is the primary relay while relay R2 is the back up relay.

Using the TMS of 0.4240 which is found during coordination process, the operating time of R4 is

$$t_{R4} = \frac{0.14 * 0.4240}{\left(\frac{6240}{800}\right)^{0.02} - 1} = 1.4154\ s$$

So, for this fault, R4 will operate at 1.4154 s, R2 will be the backup and it has to operate after a coordination time interval (CTI) of 0.3 s, if R4 fails to operate.

Expected operating time for relay R2, $t_{R2} = 1.4154 + 0.3 = 1.7154\ s$

The relay R2 has to be set with a different TMS compared to the one of relay R4

$$TMS_{R2} = \frac{1.7020 * \left\{\left(\frac{6240}{900}\right)^{0.02} - 1\right\}}{0.14} = 0.4838$$

Now, for a fault at bus 2, where the relay R2 has to operate as the primary, its operating time is

$$t_{R2} = \frac{0.14 * 0.4838}{\left(\frac{7710}{800}\right)^{0.02} - 1} = 1.5431\ s$$

Table 4-2 shows the TMS values for different relays involved in coordination for the network before connecting the DG. These values were obtained during coordination process which started from the far end relay R22.

Table 4-2: TMS values for relays before connecting the DG

Relay	TMS before connecting DG
R1	0.5779
R2	0.4838
R4	0.424
R6	0.3363
R8	0.2527
R10	0.4367
R12	0.2023
R14	0.1782
R16	0.0577
R18	0.0594
R20	0.1764
R22	0.05
R24	0.2173

Table 4-3 shows the operating time for primary and backup relays for different coordination pairs. It also shows the coordination time interval for those coordination pairs.

Table 4-3: Operating time of relays before connecting the DG

Faulted bus	Coordination pairs	Primary relay operating time (s)	Backup relay operating time (s)	CTI (s)
13	R24-R12	0.3827	0.6827	0.3
12	R22-R20	0.0894	0.3893	0.2999
11	R20-R12	0.3819	0.6819	0.3
10	R18-R14	0.0996	0.3996	0.3
9	R16-R14	0.0961	0.3961	0.3
8	R14-R12	0.388	0.688	0.3
7	R12-R8	0.6629	0.9629	0.3
6	R10-R8	0.6284	0.9284	0.3
5	R8-R6	0.907	1.207	0.3
4	R6-R4	1.1508	1.4509	0.3001
3	R4-R2	1.4154	1.7153	0.2999
2	R2-R1	1.5431	1.8432	0.3001

Referring to Table 4-3, the coordination time interval for all the coordination pairs is almost 0.3 s and this means that the computed TMS values for the relays meet the coordination.

4.2 Impact of DG Integration on Overcurrent Relays Coordination

To investigate the impact of integrating DG in distribution network, Three phase faults that give maximum fault currents in most cases, were created on different locations in the distribution network, with and without DG. The fault currents before connecting DG and the fault currents after connecting DG were compared. The operating time of the relays and the coordination time interval between the primary and the backup relays for different coordination pairs were also found. These values were compared to the values got before connecting the DG, in order to get the impact of the DG connection on coordination done before.

Scenario 1: DG connected at bus 2

Table 4-4 shows the faults currents for the network with the DG connected at bus 2. It also indicates the fault currents contribution from the grid and from the DG for different fault locations.

The amount of the contribution in fault current from the DG, depends on the faulted bus and the DG location. The contribution from the DG becomes more if the DG is located near the faulted bus. Referring to Table 4-4, the contribution in the fault current from the DG was high when the fault occurred on the bus where the DG is connected. Generally, the more the faulted bus is near the DG, the more the DG contribution in the fault current.

Table 4-4: Fault currents with DG connected at bus 2

Fault location (Bus)	Fault current with DG (kA)	Fault current contribution (kA)	
		From grid	From DG
1	11.75	9.75	2
2	9.73	7.63	2.1
3	7.55	5.92	1.63
4	7.12	5.58	1.54
5	6.39	5.01	1.38
6	6.07	4.76	1.31
7	5.62	4.41	1.21
8	5.16	4.05	1.11
9	4.81	3.77	1.04
10	4.67	3.66	1.01
11	5.27	4.13	1.14
12	4.93	3.87	1.06
13	5.26	4.13	1.13

Figure 4-2 compares the fault currents for different fault location in the network before and after connecting the DG at bus 2. It shows that the fault currents have increased due to connection of the DG.

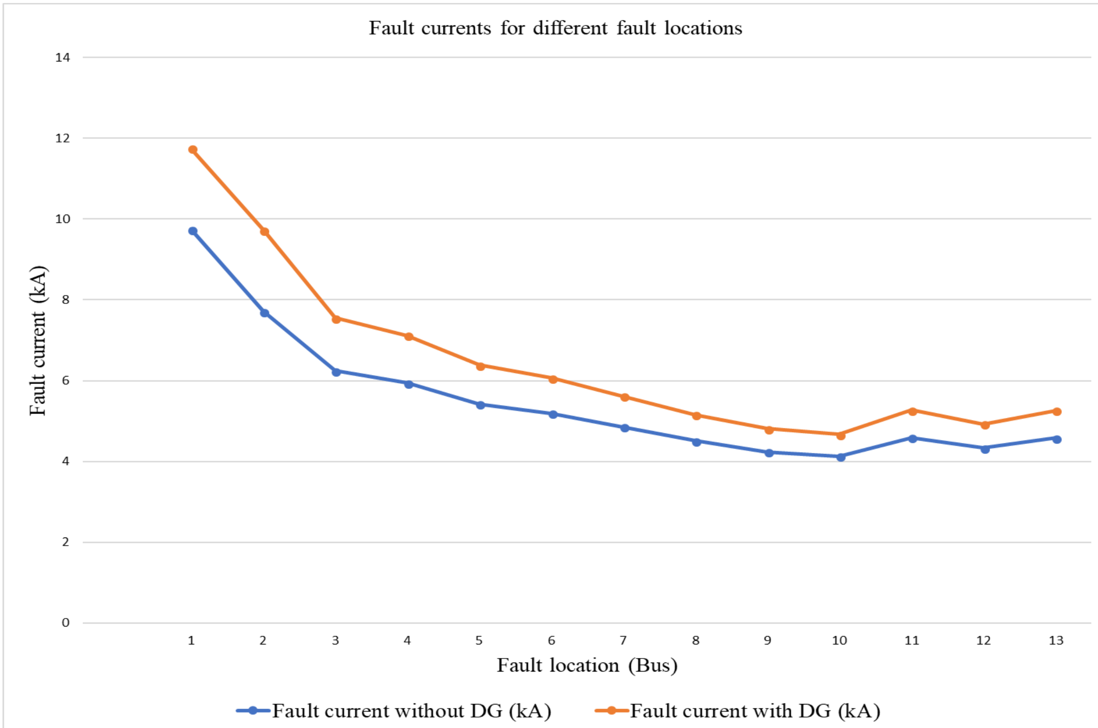

Figure 4-2: Comparison of fault currents before and after connecting DG at bus 2

When the DG is connected, the fault current (for a fault at bus 3) becomes 7550 A. The fault current has increased from 6240 A to 7550 A. The new Operating time for the relay R4 which is the primary becomes

$$t_{R4} = \frac{0.14 * 0.4240}{\left(\frac{7550}{800}\right)^{0.02} - 1} = 1.2928\ s$$

This time is lower compared to the way it was before connecting the DG. The difference is 0.1226 seconds.

Table 4-5 shows the operating time of the primary and backup relays as well as the coordination time interval for different coordination pairs, after connecting the DG at bus 2 and when the old settings are used.

Table 4-5: Operating time of relays after connecting the DG at bus 2 using old settings

Faulted bus	Coordination pair	Primary relay operating time (s)	Backup relay operating time (s)	CTI (s)
13	R24-R12	0.3688	0.6382	0.2694
12	R22-R20	0.0811	0.3731	0.292
11	R20-R12	0.3652	0.6377	0.2725
10	R18-R14	0.0965	0.3836	0.2871
9	R16-R14	0.0931	0.3799	0.2868
8	R14-R12	0.3714	0.6441	0.2727
7	R12-R8	0.6189	0.8898	0.2709
6	R10-R8	0.6069	0.855	0.2481
5	R8-R6	0.8337	1.1096	0.2759
4	R6-R4	1.0535	1.3282	0.2747
3	R4-R2	1.2928	1.5586	0.2658
2	R2-R1	1.389	1.6592	0.2702

It was seen that the operating time for both the primary and the backup relays were changed, and this definitely changed the coordination time interval for the coordination pairs as well.

Figure 4-3 illustrates the change in operating time for both the primary and the backup relays when the DG was connected. The big changes are remarqued for the relays near the sources because there was also a big change in fault currents seen by those relays.

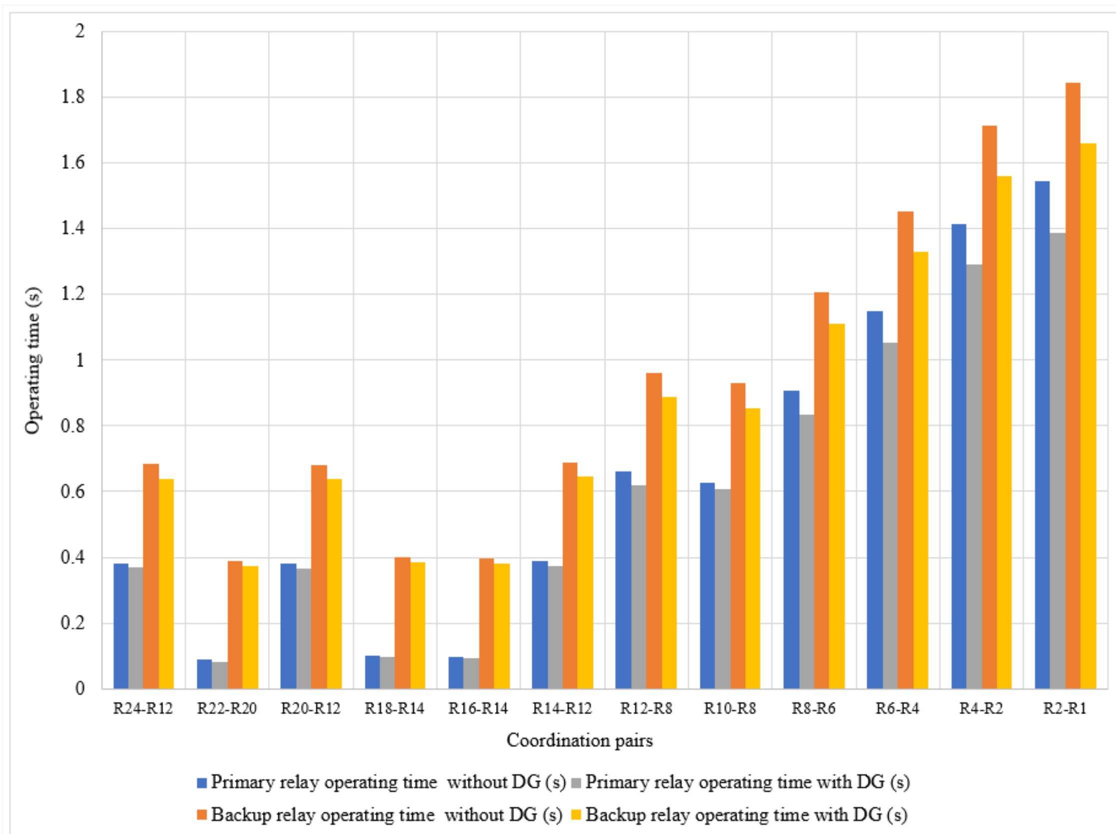

Figure 4-3: Change in operating time of relays due to connection of DG at bus 2

Figure 4-4 illustrates the change in coordination time interval (CTI) for different coordination pairs. It was seen that connecting the DG to the network caused the CTI to reduce for all the coordination pairs. This change in coordination time interval is a result of the change in operating time for the primary and the backup relays.

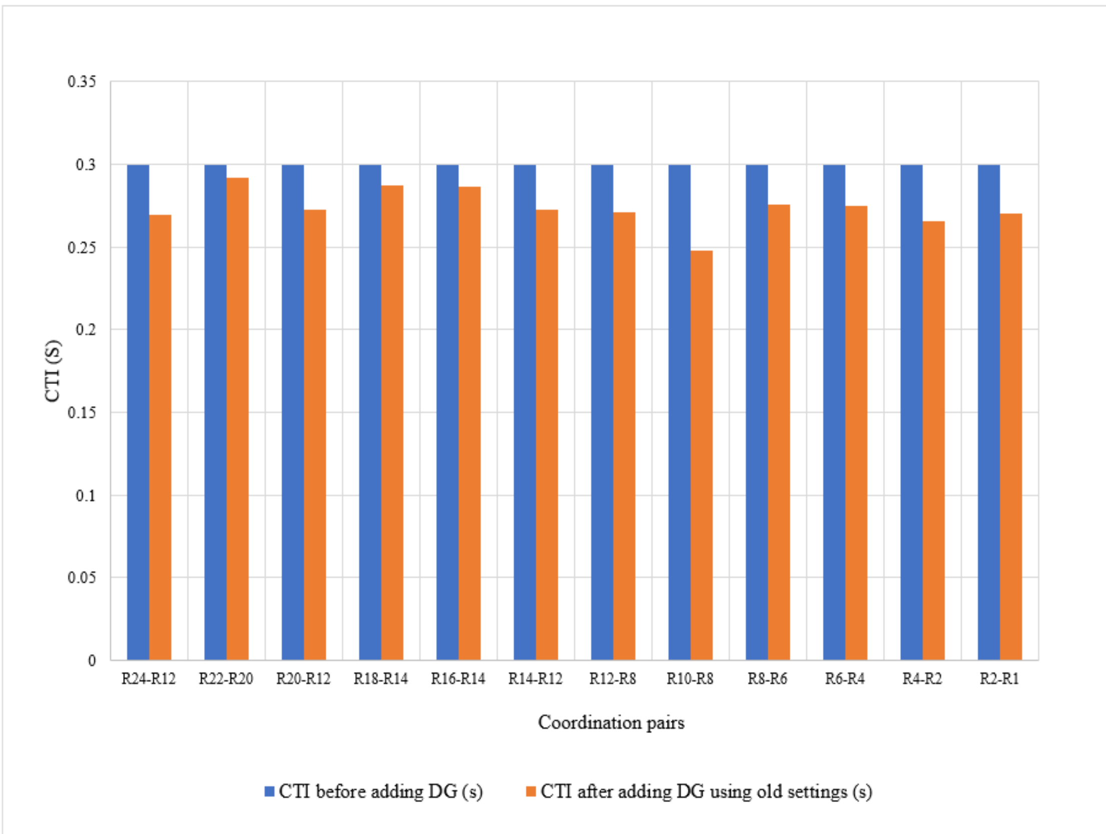

Figure 4-4: Change in CTI for relays due to connection of DG at bus 2

Scenario 2: DG connected at bus 11

Table 4-6 shows the faults currents for the network with the DG connected at bus 11.

It also indicates the fault currents contribution from the grid and from the DG for different fault locations.

Table 4-6: Fault currents with the DG connected at bus 11

Fault location (Bus)	Total Fault current (kA)	Fault current contribution	
		From grid	From DG
1	11.51	9.75	1.76
2	9.55	7.71	1.84
3	8.17	6.24	1.93
4	7.89	5.94	1.95
5	7.42	5.42	2
6	7.02	5.13	1.89
7	6.92	4.86	2.06
8	6.28	4.41	1.87
9	5.81	4.08	1.73
10	5.61	3.94	1.67
11	6.69	4.59	2.1
12	6.21	4.26	1.95
13	6.43	4.51	1.92

Table 4-7 shows the fault current seen by the primary relay, the fault current seen by the backup relay, primary relay operating time, backup relay operating time and the coordination time interval between the primary and backup relays for different coordination pairs.

Table 4-7: Operating time of the relays when the DG is connected at bus 11

Faulted bus	Coordination pair	Fault current seen by the primary relay (kA)	Fault current seen by the backup relay (kA)	Primary relay operating time (s)	Backup relay operating time (s)	CTI (s)
13	R24-R12	6.43	4.51	0.3503	0.688	0.3377
12	R22-R20	6.21	4.26	0.0813	0.3915	0.3102
11	R20-R12	4.59	4.59	0.3819	0.6819	0.3
10	R18-R14	5.61	5.61	0.0923	0.3618	0.2695
9	R16-R14	5.81	5.81	0.0909	0.3579	0.267
8	R14-R12	6.28	4.41	0.3496	0.6959	0.3463
7	R12-R8	4.86	4.86	0.6629	0.9629	0.3
6	R10-R8	7.02	5.13	0.5882	0.9343	0.3461
5	R8-R6	5.42	5.42	0.907	1.207	0.3
4	R6-R4	5.94	5.94	1.1508	1.4509	0.3001
3	R4-R2	6.24	6.24	1.4154	1.7153	0.2999
2	R2-R1	7.71	7.71	1.5431	1.8432	0.3001

When the DG was connected at bus 11, it caused the power to flow in two directions. Due to the power flow from the DG, when the fault occurs, the fault current seen by the primary relay is different to the fault current seen by the backup relay for some coordination pairs. Taking an example for the coordination pair R24-R12, the fault current seen by R24 as the primary relay for a fault at bus 13 is 6.43 kA while the fault current seen by the R12 as a backup is 4.51 kA.

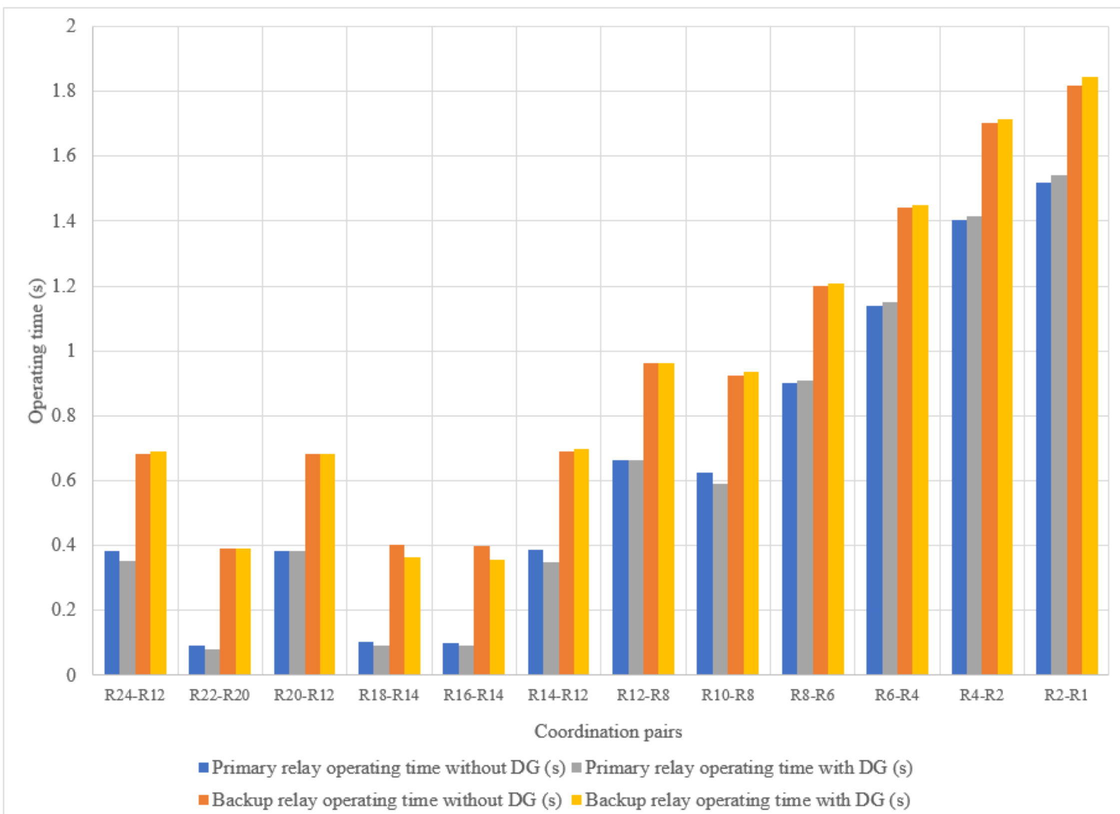

Figure 4-5: Change in operating time of relays due to connection of DG at bus 11

Referring to Figure 4-5, some relays experienced an increase in operating time while others experienced a decrease in operating time due to connection of the DG. Taking coordination pair R14-R12 as an example, the operating time of R14 which is the primary relay for a fault at bus 8 decreased, but the operating time of relay R12 which is the backup slightly increased. This phenomenon caused the CTI between the two relays to increase.

Figure 4-6 shows the change in coordination time interval for different coordination pairs after connecting the DG at bus 11.

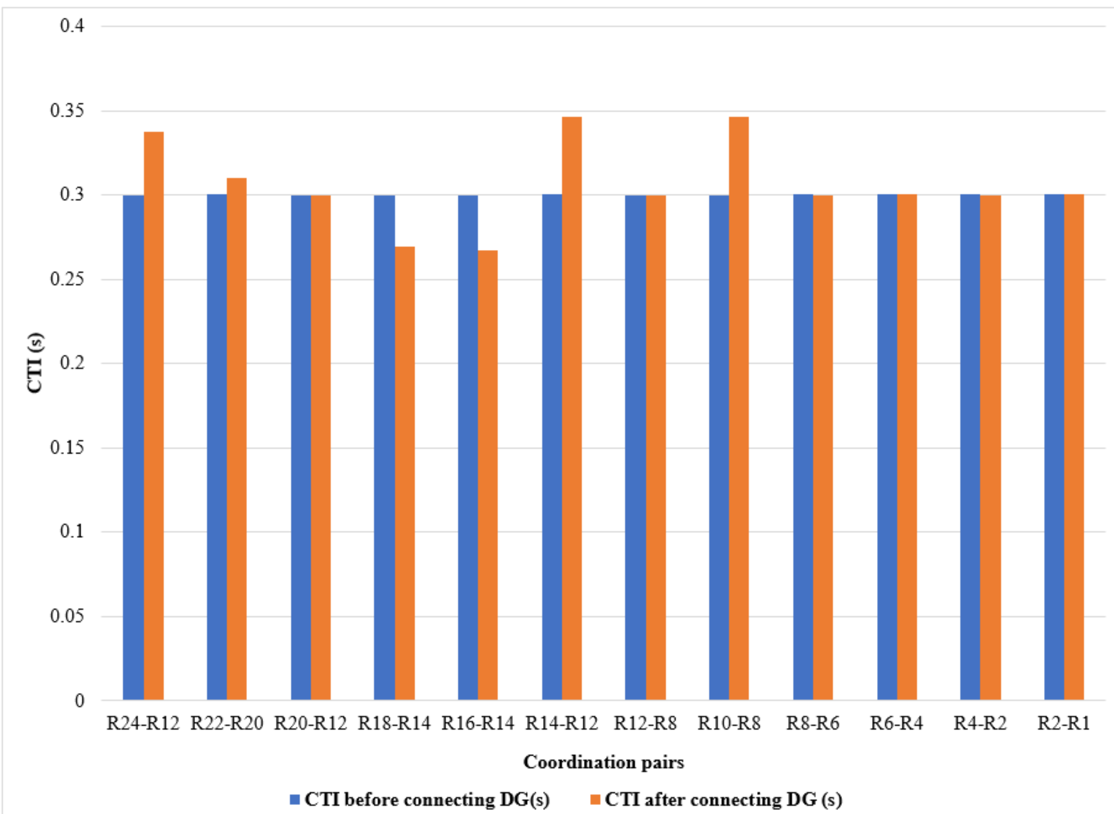

Figure 4-6: Change in CTI for relays due to connection of DG at bus 11

From Figure 4-6, the CTI for some coordination pairs like R14-R12, R10-R8 and R24-R12, was increased. For the coordination pairs R18-R14 and R16-R14, the CTI was reduced. This was due to the change in magnitude and direction of fault currents caused by connecting the DG in the network.

Figure 4-7 compares the fault currents for the distribution network without DG, the distribution network with DG connected at bus 2 and the distribution network with DG connected at bus 11. The contribution in total fault currents from the grid and from the DG after connecting the DG are also shown

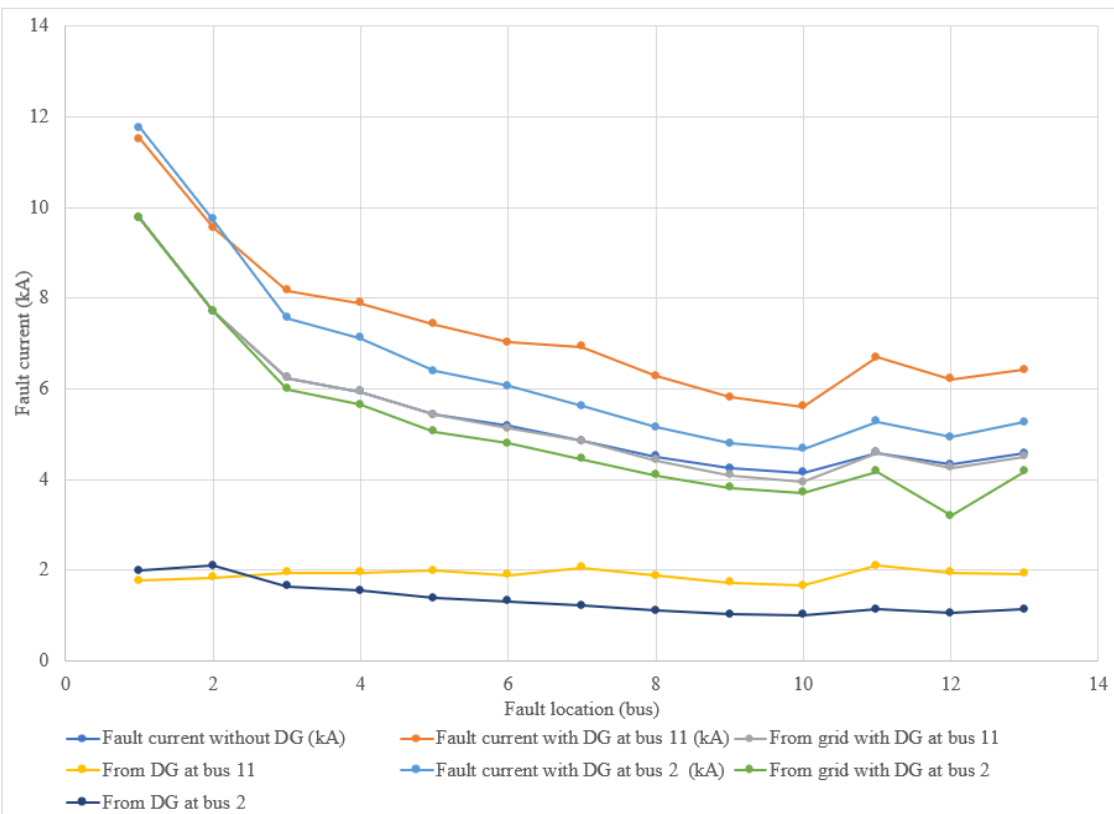

Figure 4-7: Comparison of fault currents for two scenarios considered

Generally, it was seen that after connecting the DG, there is an increase in fault current value, due to the contributed current from the DG. For the scenario where the DG is connected at bus 2, it was observed that in most cases, the fault current contribution from the utility decreased, and this is due to the presence and the participation from the DG which fed the fault.

The increase in the fault current decreased the operating time for the relays located downstream from the faulted bus and increase the operating time for the relays between the substation and DG. Those conditions can cause nuisance trip in the protective devices operation and disturb the protection coordination. The decrease in fault current contribution from the substation may lead to blinding of the relays located upstream to faulted bus, when the fault current goes below the pickup current.

For the scenario where the DG is connected at bus 11, the fault current from the grid has not changed a lot but the total fault currents increased due to contribution from the DG. The contribution in fault current from the DG depend on the faulted bus and DG location. For this scenario, some relays have to be coordinated in reverse direction in order to operate for the reverse fault currents from the DG that can feed the fault in reverse direction depending on the faulted bus.

4.3 Application of Adaptive Protection Scheme for Relay Coordination

In order to mitigate the impact of integrating DG in the distribution network, Adaptive protection scheme is the effective way.

This is applied by changing the settings of the protective relays in order to maintain the same operating time and coordination as it was before connecting the DG.

In this work, the Time Multiplier Setting (TMS) of the relay was changed for the relays in order to maintain the operating time and the coordination time interval as they were before connecting the DG.

In order to maintain the operating time of the relay R22 as it was before connecting the DG, the TMS of the relay can be changed as follow:

$$TMS_{new} = \frac{0.0894 * \left\{\left(\frac{4950}{100}\right)^{0.02} - 1\right\}}{0.14} = 0.0518$$

Table 4-8 shows the values of TMS calculated to be used in the adaptive coordination after connecting DG at bus 2 and at bus 11 respectively. Comparing the values of TMS got in the coordination before connecting the DG and the values of TMS got after connecting the DG using adaptive protection scheme , it was seen that if the operating time of the relay is reduced due to increase in fault current seen by that relay, its TMS value need to be increased in order to maintain the operating time as it was before connecting the DG. Similarly, if the operating time of the relay is increased due to decrease in fault current seen by that relay, its TMS value need to be decreased in order to maintain the operating time as it was before connecting the DG.

Table 4-8: TMS values after connecting the DG using adaptive protection scheme

Relay	TMS After connecting DG at bus 2 using APS	TMS After connecting DG at bus 11 using APS
R1	0.6329	0.5775
R2	0.5284	0.4834
R4	0.4599	0.4235
R6	0.3641	0.3358
R8	0.2731	0.2522
R10	0.4493	0.4696
R12	0.2163	0.2017
R14	0.1864	0.2007
R16	0.0604	0.0669
R18	0.0623	0.0692
R20	0.1844	0.1755
R22	0.0518	0.055
R24	0.2253	0.2394

Table 4-9 shows the operating time and the coordination time interval for different coordination pairs when the new TMS values are used for relay coordination.

Table 4-9: Operating time of relays after connecting the DG at bus 2 using calculated new TMS

Faulted bus	Coordination pair	Primary relay operating time (s)	Backup relay operating time (s)	CTI (s)
13	R24-R12	0.3824	0.6824	0.3
12	R22-R20	0.0894	0.39	0.3006
11	R20-R12	0.3818	0.6818	0.3
10	R18-R14	0.1013	0.4012	0.2999
9	R16-R14	0.0974	0.3974	0.3
8	R14-R12	0.3885	0.6886	0.3001
7	R12-R8	0.6618	0.9616	0.2998
6	R10-R8	0.6244	0.9244	0.3
5	R8-R6	0.901	1.2013	0.3003
4	R6-R4	1.1406	1.4407	0.3001
3	R4-R2	1.4022	1.7023	0.3001
2	R2-R1	1.517	1.8171	0.3001

Figure 4-8 compares the operating time of the relays before connecting DG, and operating time of relays after connecting DG at bus 2 got using adaptive protection scheme.

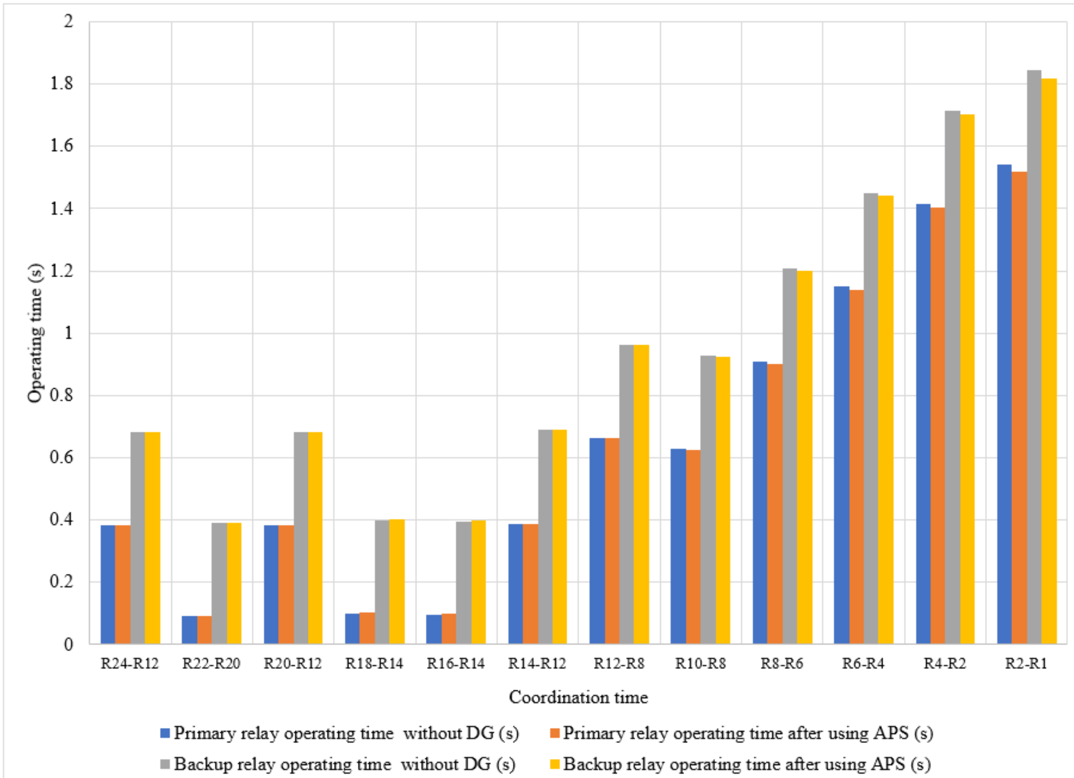

Figure 4-8: Operating time of the relays after using adaptive protection scheme

From Figure 4-8, it can be seen that the operating time of relays after using adaptive protection scheme was kept almost as it was before connecting the DG . This is done by changing the TMS value for each relay. Figure 4-9 shows the comparison of the CTI values for different coordination pairs in 3 different scenarios. The first scenario is the distribution network without DG and employing a traditional protection coordination. The second one is the distribution network with DG connected at bus 2 and employing traditional protection coordination. The third one is the distribution network with DG connected at bus 2 and employing the adaptive protection scheme.

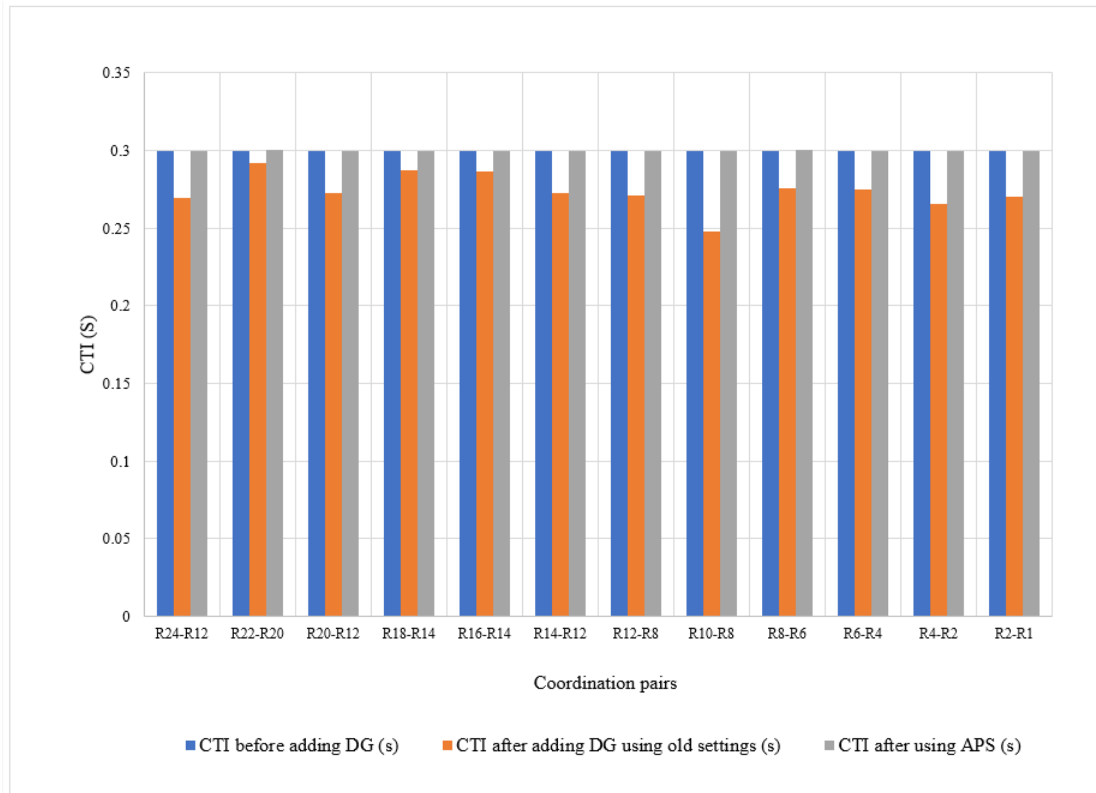

Figure 4-9: Comparison of the CTI values for different coordination pairs in 3 different scenarios

From Figure 4-9, the CTI values for different coordination pairs were reduced after connecting DG to the network. This causes the loss of coordination between the primary and the backup relays. After using the adaptive protection scheme, the CTI values were brought back almost to the value of CTI used for coordination in the network before connecting the DG which was 0.3 s.

Table 4-10 indicates the operating time for the primary and the backup relays, as well as the CTI coordination pairs after using adaptive protection scheme for the network with DG connected at bus 11.

Table 4-10: Operating time of relays after connecting the DG at bus 11 using calculated new TMS

Faulted bus	Coordination pair	Fault current seen by the primary relay (kA)	Fault current seen by the backup relay (kA)	Primary relay operating time with DG using APS (s)	Backup relay operating time with DG using APS (s)	CTI after connecting DG using APS (s)
13	R24-R12	6.43	4.51	0.386	0.6859	0.2999
12	R22-R20	6.21	4.26	0.0895	0.3895	0.3
11	R20-R12	4.59	4.59	0.3799	0.6799	0.3
10	R18-R14	5.61	5.61	0.1075	0.4075	0.3
9	R16-R14	5.81	5.81	0.103	0.403	0.3
8	R14-R12	6.28	4.41	0.3937	0.6938	0.3001
7	R12-R8	4.86	4.86	0.6609	0.961	0.3001
6	R10-R8	7.02	5.13	0.6325	0.9325	0.3
5	R8-R6	5.42	5.42	0.9052	1.2052	0.3
4	R6-R4	5.94	5.94	1.1491	1.4492	0.3001
3	R4-R2	6.24	6.24	1.4138	1.7139	0.3001
2	R2-R1	7.71	7.71	1.5418	1.842	0.3002

Figure 4-10 compares the operating time of relays before connecting the DG and after connecting the DG at bus 11 using adaptive protection

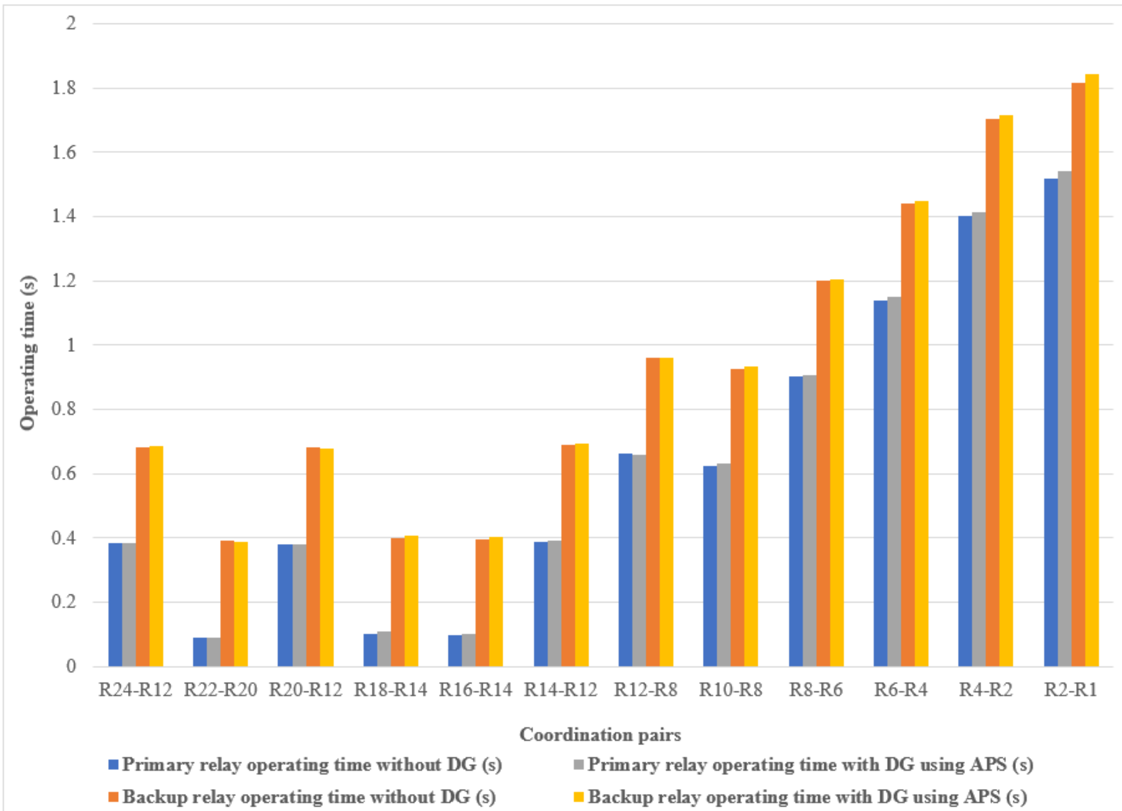

Figure 4-10: Operating time of relays after using adaptive protection scheme with DG connected at bus 11

From Figure 4-10, it can be seen that the operating time of relays after using adaptive protection scheme was kept almost as it was before connecting the DG. Figure 4-11 shows the comparison of the CTI values for different coordination pairs in 3 different scenarios. The first scenario is the distribution network without DG and employing a traditional protection coordination. The second one is the distribution network with DG connected at bus 11 and employing traditional protection coordination. The third one is the distribution network with DG connected at bus 11 and employing the adaptive protection scheme.

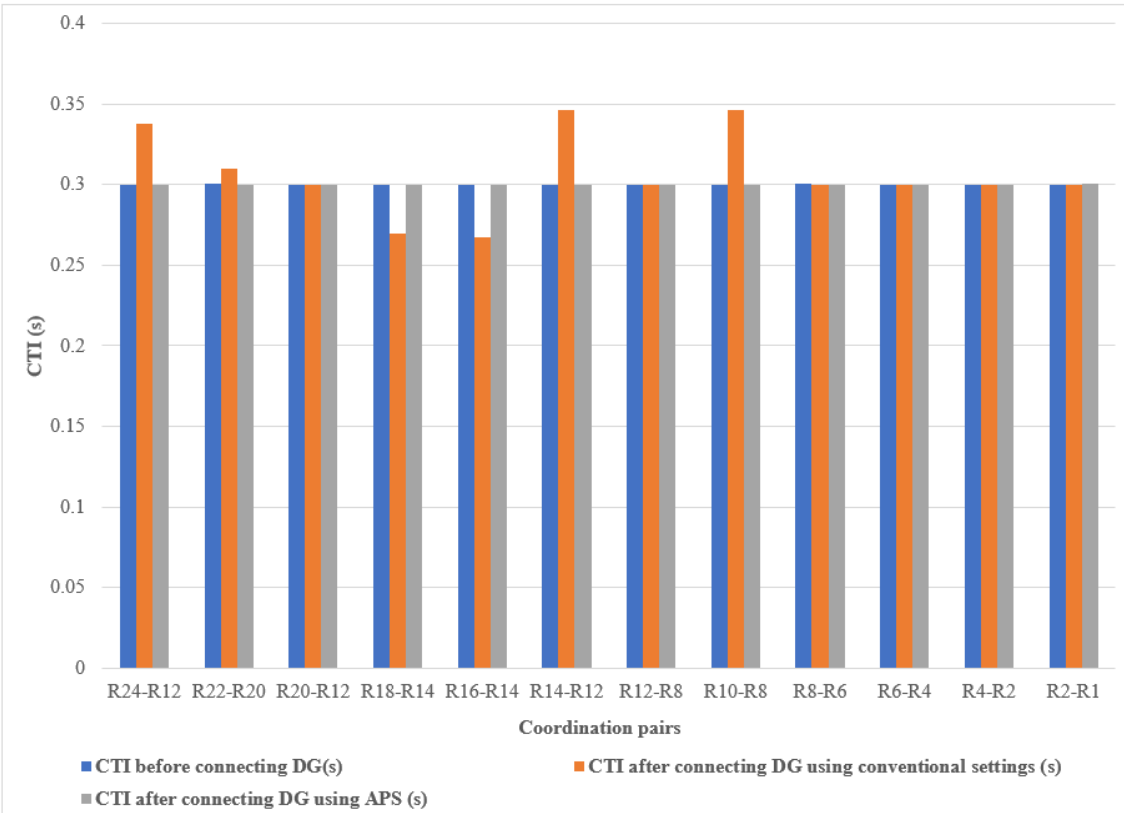

Figure 4-11: Comparison of the CTI values for different coordination pairs after connecting the DG at bus 11

From Figure 4-11, the CTI values for some coordination pairs were reduced while they were increased for others after connecting DG to the network. This causes the loss of coordination between the primary and the backup relays. After using the adaptive protection scheme, the CTI values were brought back almost to the value of CTI used for coordination in the network before connecting the DG which was 0.3 s.

The fact of keeping the operating time of the relays and the coordination time interval for different coordination pairs to the way they were before connecting the DG, made the network to remain well protected and well-coordinated after connecting the DG to the network by using adaptive protection.

Apart from the relays that were coordinated adaptively to operate in forward direction, when the DG was connected at bus 11, R3, R5, R7, R9, R13, R21 and Rdg were coordinated in reverse direction in order to operate for faults coming from the DG.

Table 4-11 indicates the TMS values for the relays operating in reverse direction when the DG was connected at bus 11

Table 4-11: TMS values of relays operating in reverse direction when DG connected at bus 11

Relay Number	R3	R5	R7	R9	R13	R21	Rdg
TMS	0	75	150	200	300	800	800

Table 4-12 shows the fault currents seen by the primary and backup relays operating in reverse direction when the DG was connected at bus 11. It also shows the operating time of those relays and the coordination time interval for coordination pairs.

Table 4-12: Operating time of relays operating in reverse direction when DG connected at bus 11

Faulted bus	Coordination pair	Fault current seen by the primary relay (kA)	Fault current seen by the backup relay (kA)	Primary relay operating time (s)	Backup relay operating time (s)	CTI
7	R21-Rdg	2.06	2.06	1.505	1.8049	0.2999
5	R13-R21	2	2	1.2544	1.5541	0.2997
4	R9-R13	1.95	1.95	0.9716	1.2717	0.3001
3	R7-R9	1.93	1.93	0.676	0.9761	0.3001
2	R5-R7	1.84	1.84	0.3891	0.6892	0.3001
1	R3-R5	1.76	1.76	0.0948	0.3948	0.3

4.4 Testing the Developed Fuzzy Logic Based Adaptive Protection Scheme in Distribution Network with DG Connected

After designing a fuzzy logic controller, it was used to find the TMS values of relays for different sizes of the DG between 0 and 8 MVA which is the maximum size of the DG. Figure 4-12 shows the rule viewer for a DG of 3 MVA connected at bus 2. It shows that for that capacity, the TMS for relay R4 is 0.437. Figure 4-13 indicates the rule viewer for a DG of 5 MVA and it shows that for that capacity, the TMS for relay R4 became 0.446

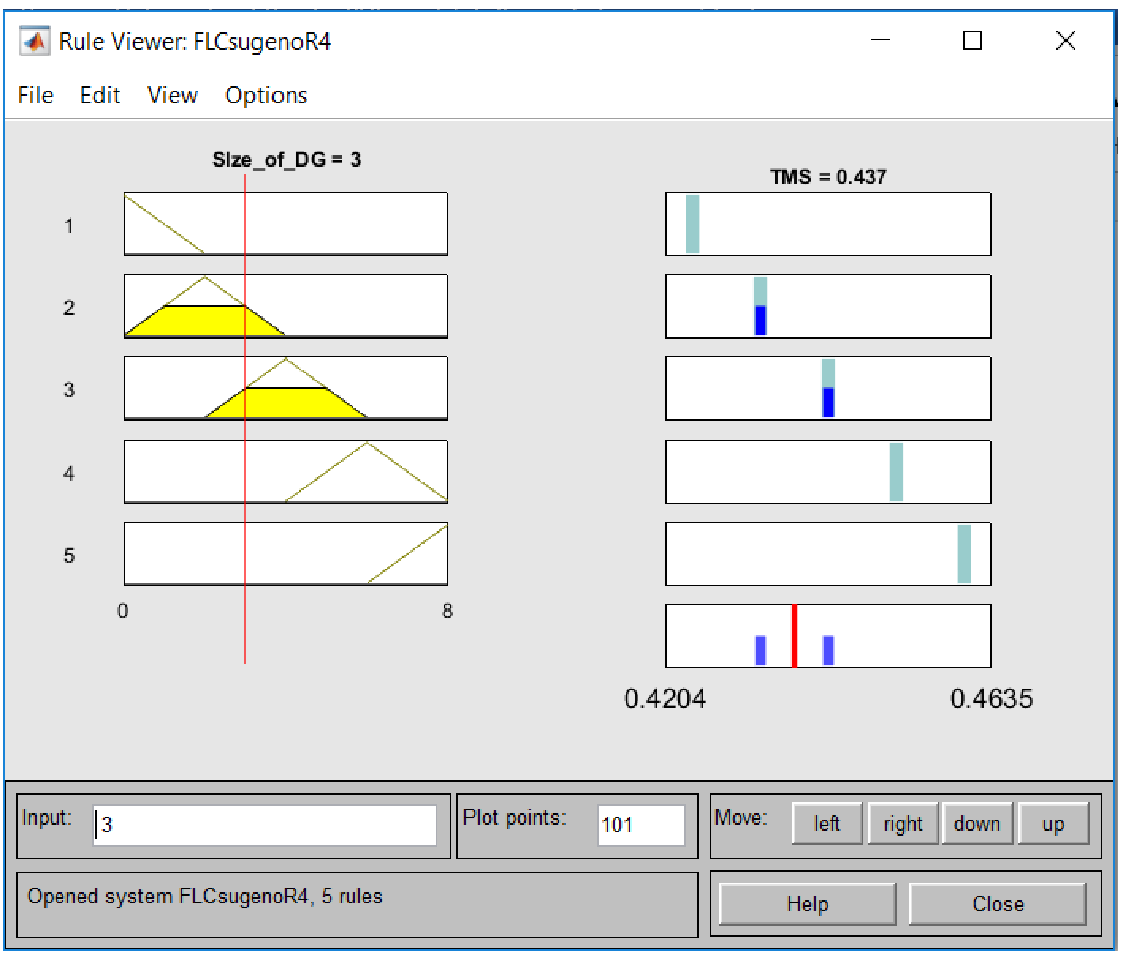

Figure 4-12: Rule viewer for a 3 MVA DG

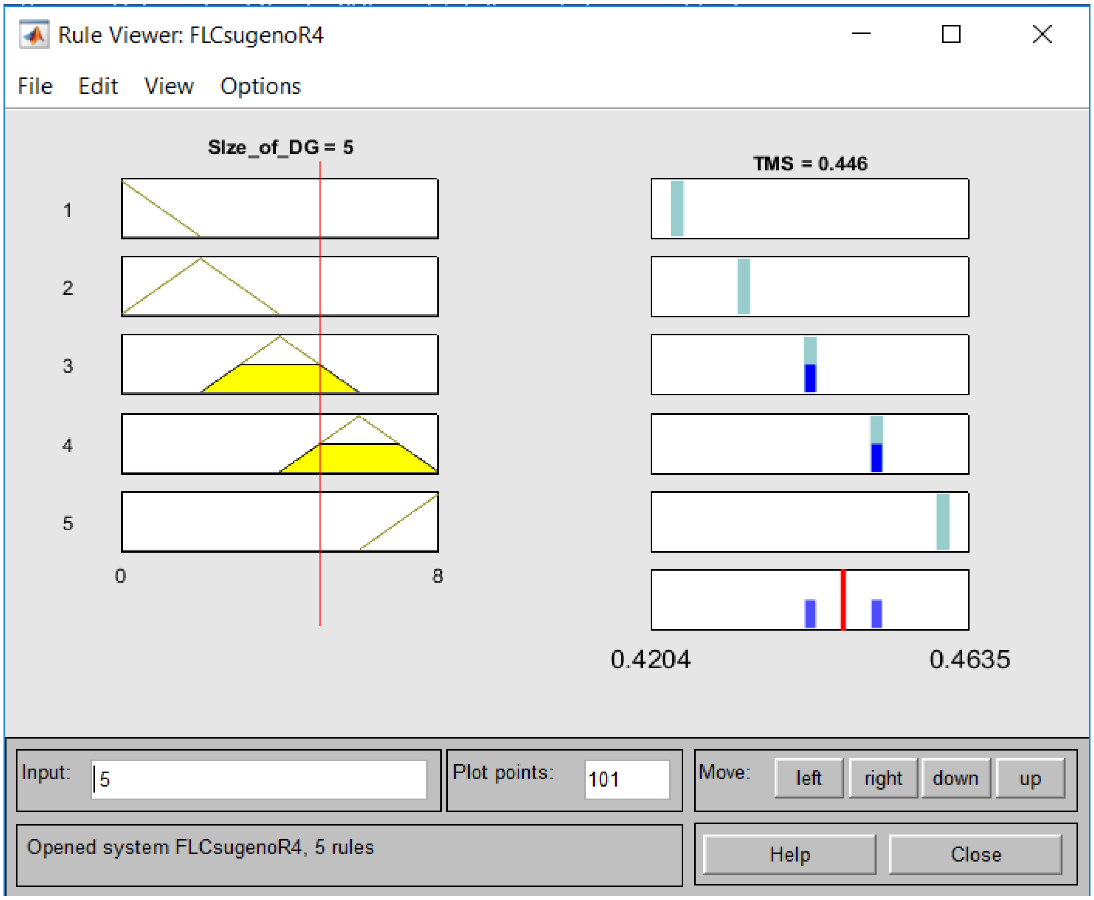

Figure 4-13: Rule viewer for a 5 MVA DG

In order to evaluate the performance of the designed fuzzy logic controller, the TMS values for the relays involved in coordination were found using the designed controller. These values were used in coordination to see if the operating time and the coordination time interval for different coordination pairs will remain the way they were before connecting the DG.

Table 4-13 shows the TMS values obtained using the designed fuzzy logic controller for a DG of 5 MVA and 3 MVA respectively, connected at bus 2.

Table 4-13: TMS values got using the designed controller

Relay	TMS for 5 MVA DG	TMS for 3 MVA DG
R1	0.612	0.599
R2	0.512	0.501
R4	0.446	0.437
R6	0.354	0.347
R8	0.266	0.261
R10	0.445	0.441
R12	0.211	0.208
R14	0.183	0.181
R16	0.0594	0.0587
R18	0.0612	0.0605
R20	0.181	0.179
R22	0.0511	0.0507
R24	0.222	0.22

Table 4-14 indicates the operating time for the primary and the backup relays, as well as the coordination time interval for different coordination pairs, got during coordination using the TMS values obtained using a fuzzy logic controller for a 5 MVA DG connected at bus 2.

Table 4-14: Operating time of relays using TMS values got from the controller for a 5 MVA DG connected

Faulted bus	Coordination pair	Primary relay operating time (s)	Backup relay operating time (s)	CTI (s)
13	R24-R12	0.3797	0.6749	0.2952
12	R22-R20	0.0889	0.3861	0.2972
11	R20-R12	0.3782	0.6742	0.296
10	R18-R14	0.1001	0.397	0.2969
9	R16-R14	0.0964	0.3934	0.297
8	R14-R12	0.3848	0.6806	0.2958
7	R12-R8	0.6547	0.9483	0.2936
6	R10-R8	0.6228	0.915	0.2922
5	R8-R6	0.8889	1.1874	0.2985
4	R6-R4	1.1286	1.4219	0.2933
3	R4-R2	1.3845	1.6811	0.2966
2	R2-R1	1.4977	1.7902	0.2925

Also, using the TMS values obtained using the fuzzy logic controller for a 3 MVA DG connected at bus 2, the operating time as well as the coordination time interval for different coordination pairs were found and are indicated in Table 4-15

Table 4-15: Operating time of relays using TMS values got from the controller for a 3 MVA DG connected

Faulted bus	Coordination pair	Primary relay operating time (s)	Backup relay operating time (s)	CTI (s)
13	R24-R12	0.3791	0.6742	0.2951
12	R22-R20	0.0888	0.385	0.2962
11	R20-R12	0.3776	0.6742	0.2966
10	R18-R14	0.0996	0.3962	0.2966
9	R16-R14	0.0959	0.3924	0.2965
8	R14-R12	0.3841	0.6802	0.2961
7	R12-R8	0.6545	0.9454	0.2909
6	R10-R8	0.6216	0.9131	0.2915
5	R8-R6	0.8874	1.1844	0.297
4	R6-R4	1.1269	1.4192	0.2923
3	R4-R2	1.3827	1.6784	0.2957
2	R2-R1	1.4987	1.7919	0.2932

Figure 4-14 compares the operating time of the primary and the backup relays for 3 the cases. The case where the network had no DG connected, the network with 5 MVA DG connected at bus 2 using a fuzzy based adaptive protection scheme and the case for the network with a 3 MVA DG connected at bus 2 using fuzzy based adaptive protection scheme. Referring to Figure 4-14, it was seen that the operating time for primary and backup relays for different coordination pairs are almost the same for the case of the network with a 5 MVA DG connected and the one for the network with a 3 MVA DG connected. In addition, the operating time for those above two cases are close to the way it was before connecting the DG.

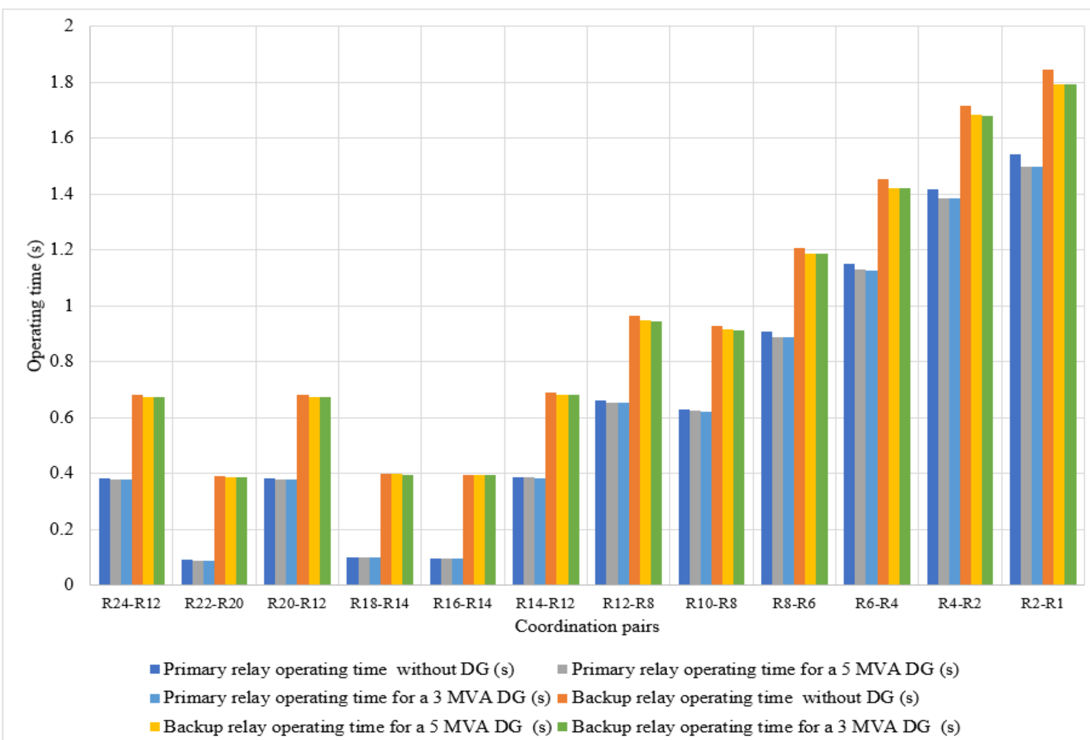

Figure 4-14: Comparison of operating time for different coordination pairs after using a fuzzy based adaptive protection scheme

Figure 4-15 compares the coordination time intervals for different coordination pairs for 4 the cases. The case where the network had no DG connected, the network with DG connected at bus 2 using old settings, the network with 5 MVA DG connected at bus 2 using a fuzzy based adaptive protection scheme and the case for the network with a 3 MVA DG connected at bus 2 using fuzzy based adaptive protection scheme.

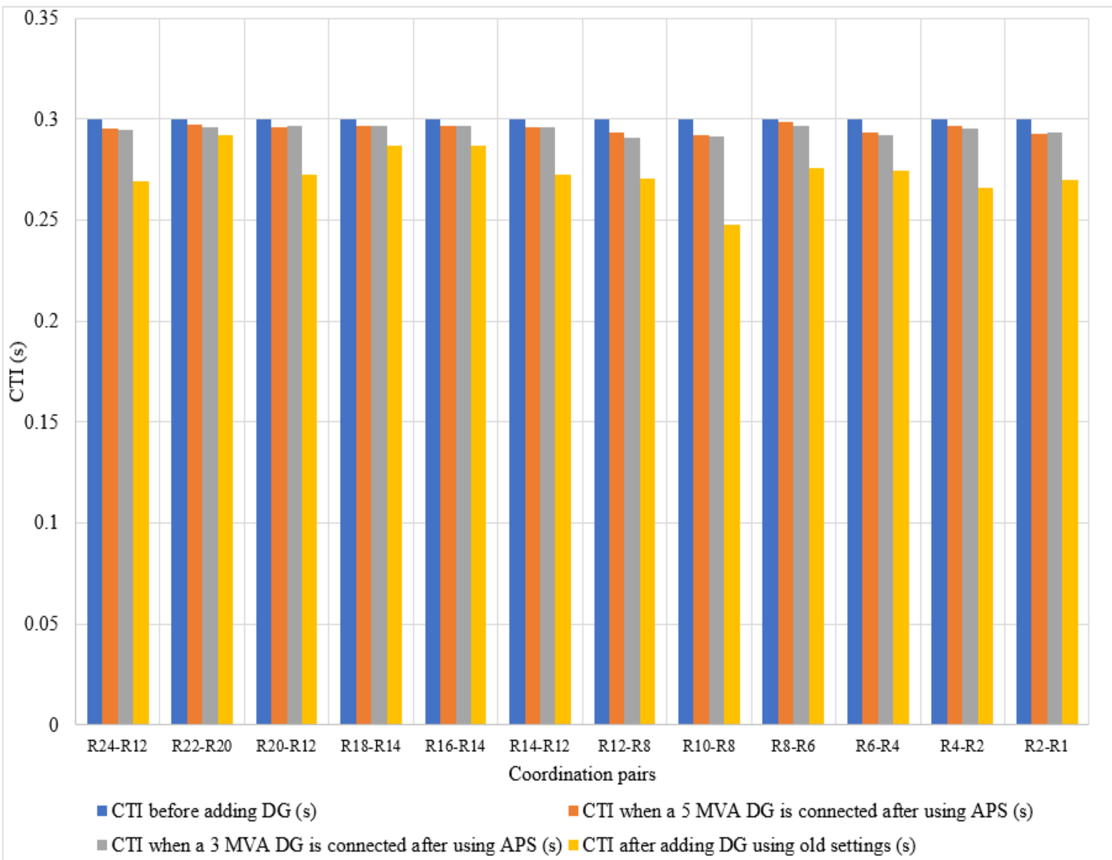

Figure 4-15: Comparison of coordination time intervals for different coordination pairs after using a fuzzy based adaptive protective scheme

Referring to figure 4-15, the coordination time interval for the coordination pairs in the network before connecting the DG was 0.3 s. After connecting the DG in the network and using the old settings for the relays, the coordination time interval was reduced for all the coordination pairs. When the fuzzy based adaptive protection scheme was used, the coordination time interval for the coordination pairs was increased again to nearly the way they were before connecting the DG and become around 0.3 s.

The activity of maintaining the operating time for the primary and the backup relays and the coordination time interval for different coordination pairs to nearly the way they were before connecting the DG, keeps the network well protected and well coordinated even after connecting the DG in the network.

CHAPTER 5: CONCLUSION AND RECOMMENDATIONS

5.1 Conclusion

This work focused on overcurrent relays related concerns of integrating DG to the distribution systems. From this study, it was observed that connecting the DG to the distribution network changes the operating time of the relays both the primary and the backups. It also causes the loss of coordination between the primary and the backup relays by violating the coordination time interval, and this influence negatively the performance of the protection systems. This is due to the fact that conventional relay settings for traditional systems may fail or may work incorrectly under new conditions. Thus, protection schemes able to maintain protection coordination are strongly needed in distribution networks with a significant integration of DGs. In these networks, the fault levels are intermittent and continuously changing as per connection of DG in the network. The trend is to use adaptive protection scheme which changes the settings of protection relays depending on the prevailing network configuration.

In this research, adaptive protection scheme in distribution networks considering intermittency of DG using a fuzzy logic controller was proposed. The controller chooses the best time multiplier setting (TMS) of the relay depending on the size or the capacity of the DG connected. It was found that the proposed fuzzy logic based adaptive protection scheme keeps the network well protected and coordinated with the required selectivity and security.

5.2 Recommendations

Currently, integration of distributed generations is encouraged by many governments due to many advantages they provide. Utilities are encouraged to use the numerical protective relays which have the ability to be used in adaptive protection. The adaptive protection coordination approaches have promising future application for distributed energy resources (DER) connected distribution systems. In these networks, the fault levels are intermittent and continuously changing as per connection of DER in the network. This scheme is able to maintain the network well protected and coordinated with maximum selectivity and security without changing the devices even though the network will experience new fault currents after connecting DG.

For this research, radial distribution network was considered because the traditional distribution networks were radial in nature. However, with the integration of DGs, the distribution networks are currently becoming ring. For this reason, ring network will be considered for further research. Again, in the future research, the Adaptive Neuro Fuzzy Inference System (ANFIS) will be considered to incorporate the learning capability of neuro networks in the designed fuzzy logic controller, in order to improve the performance.

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