HAWASSA UNIVERSITY
INSTITUTE OF TECHNOLOGY
SCHOOL OF ELECTRICAL AND COMPUTER ENGINEERING

IMPACT OF DISTRIBUTED GENERATION ON DISTRIBUTION NETWORK PROTECTION SCHEME AND ADAPTIVE PROTECTION COORDINATION USING HARRIS' HAWKS OPTIMIZATION

(CASE STUDY: HAWASSA DISTRIBUTION NETWORK)

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MSC THESIS

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This is to certify that the thesis entitled “IMPACT OF DISTRIBUTED GENERATION ON DISTRIBUTION NETWORK PROTECTION SCHEME AND ADAPTIVE PROTECTION COORDINATION USING HARRIS’ HAWKS OPTIMIZATION (CASE STUDY: HAWASSA DISTRIBUTION NETWORK)” submitted in partial fulfillment of the requirements for the degree of **Master’s** with specialization in “POWER SYSTEM AND ENERGY ENGINEERING”, the been carried out by ABENEZER KASSA USAMO ID. No. *PGEngW/001/10,* under my/our supervision.

Therefore I/we recommend that the student has fulfilled the requirements of and hence hereby can submit the thesis to department.

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Co-Advisor Signature Date

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ABSTRACT

The Modern Power System which has grown both in size and complexity, that means requires fast, accurate and reliable Protective schemes for protecting major equipment's and to maintain system stability and reliability. Distribution networks are evolving into active meshed networks with bidirectional power flow as the penetration of distributed generation (DG) sources is increasing. Interconnecting DG to an existing distribution system provides various benefits to several entities as for example the owner, utility, and the final user. DG provides an enhanced power quality, higher reliability of the distribution system and can peak shaves and fill valleys. Penetration of a DG into an existing distribution system has many impacts on the system, with the power system protection being one of the major issues. This necessitates the use of directional relaying schemes in these emerging active distribution networks. However, conventional directional overcurrent (OC) protection will not be adequate to protect these networks against the stochastic nature of DGs and the changing network architectures. Hence, this study proposes an adaptive directional overcurrent relay algorithm that determines optimal protection settings according to varying fault currents and paths induced by the DGs in active meshed distribution networks. Location and technology of the DG sources are changed to study the effect that these changes may have on the coordination of protective directional over-current relays (DOCR). Results are compared to that of the normal case to investigate the impact of the DG on the short circuit currents flowing through different branches of the network to deduce the effect on protective devices.

This study presents an adaptive protection coordination scheme for optimal coordination of DOCRs in interconnected power networks with the impact of DG. The used coordination technique is the Harris Hawks Optimization (HHO), selected due to adaptive & time-varying parameters allows HHO to handle difficulties of search including local optimal solution, multi-modality & deceptive optima. Adaptive relaying describes protection schemes that adjust settings and/or logic of operations based on the prevailing conditions of the system. These adjustments can help to avoid relay miss-operation. Adjustments could include, but are not limited to, the logging of data for post-mortem analysis, communication throughout the system, as well changing relay parameters. Several concepts will be discussed, one of which will be implemented to prove the value of the new tools available. The optimal coordination of DOCR is find by with MATLAB code using HHO technique and the adaptive protection scheme model will develop in DIgSILENT/Power Factory. The results validate the ability of the proposed protection scheme to capture the uncertainties of the DGs and determine optimal protection settings, while ensuring minimal operating time.

Keywords: Distributed Generation; Harris Hawks Optimization; Adaptive Protection; Directional Over Current Relay; Distribution Networks; DIgSILENT/Power Factory

List of Abbreviations

AC:	Alternating Current
APS:	Adaptive Protection Scheme
CT:	Current Transformer
CTI:	Coordination Time Interval
DC:	Direct Current
DER:	Distributed Energy Resources
DG:	Distributed Generation
DOCR:	Directional Overcurrent Relays
GA:	Genetic Algorithm
HHO:	Harris' Hawks Optimization
HV:	High Voltage
IBDG:	Inverter Based Distributed Generation
ICPU:	Intelligent Central protection Unit
If:	Fault Current
Ipickup:	Pickup Current
MG:	Micro Grid
MV:	Medium Voltage
OCR:	Over Current Relay
OCR:	Overcurrent Relays
PCC:	Point of Common Coupling
PSO:	Particle Swarm Optimization
PV:	Photo Voltaic
RES:	Renewable Energy Source
SADI:	Service Average Duration Index
SAIFI:	Service Average Interruption Frequency Index
TDS:	Time Dial Setting
TMS:	Time Multiplier Setting
VSC:	Voltage Source Converter
VT:	Voltage Transformer

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CHAPTER 1

INTRODUCTION

1.1 Background

Currently, distribution systems are in a significant transition phase where the system is shifting from a passive distribution system with one directional power flow to an active distribution network with two directional flow and small-scale generators called Distributed Generators (DGs). 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 [1]. Regarding to the power generation and flow of energy there are two concepts of power systems those are traditional concept(passive) and new concept(active) power system.

1.1.1 Traditional Concept of Power Systems

Nowadays, most of the power systems generate and supplies electricity having into account the following considerations [1],[2]; Electricity generation is produced in large power plants, usually located close to the primary energy source (for instance: coil mines, hydropower) and far away from the consumer centers. Electricity is delivered to the end customer using a large passive distribution infrastructure, which involves high voltage (HV), medium voltage (MV) and low voltage (LV) networks. These distribution networks are designed to operate radially. The power flows only in unidirectional from upper voltage levels down-to customers situated along the radial feeders. In this process, there are three levels to be passed through before the power reaching the final user, i.e., generation, transmission, and distribution.

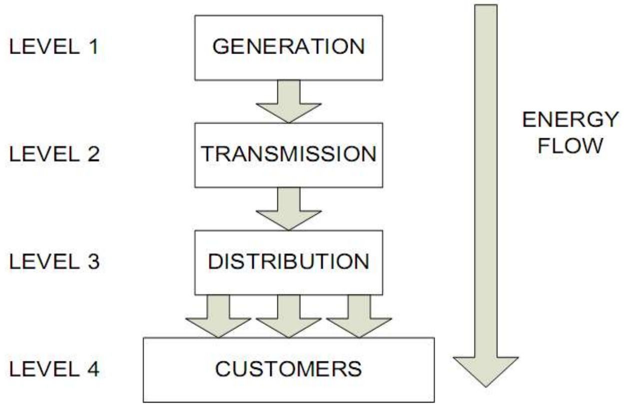


Figure 1. 1 Traditional Concept of Power System [1] [2]

In the first stage the electricity is generated in large generation plants, located in non-populated areas away from loads to get benefit with the economics of size and environmental issues. Second stage is accomplished with the support of various equipment’s such transformers, overhead transmission lines and underground cables. The last stage is the distribution system, the link between the utility system and the end customers. This stage is the most important part of the power system, as the final power quality depends on its reliability [2].

The electricity demand is increasing continuously. Consequently, electricity generation must increase to meet the demand requirements. Traditional power generation systems face this growth, installing new support systems in level 1 (see figure 1.1). Whilst addition in the transmission and distribution levels are less frequent.

1.1.2 New Concept of Power Systems

Nowadays, the technological evolutions, environmental policies, and the expansion of the finance and electrical markets, are promoting new alternative in the sector of the electricity generation [2].

New technologies allow the electricity to be generated in small sized plants and near to end customers. Moreover, the in renewable sources preferable power source to reduce the environmental impact of power generation leads to the development and application of new electrical energy supply schemes.

In this new power system conception, the generation is not exclusive to level 1. Hence some of the energy-demand is supplied by the centralized generation and another side is produced by distributed generation. The electricity is going to be produced near to the customers.

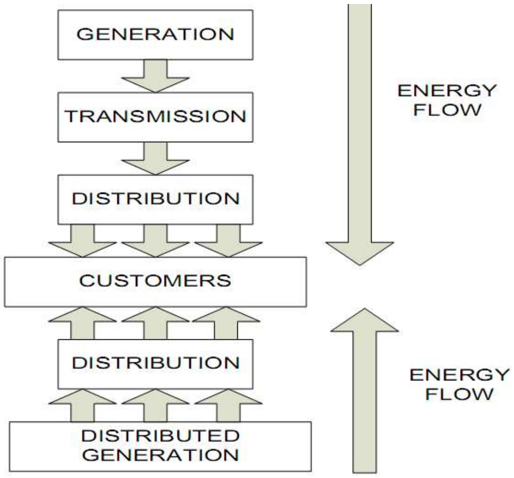


Figure 1. 2 New Concept of Power System [1] [2]

The electrical power system may be subjected to many different types of faults during its operation that can damage the equipment connected to this power system, so the importance of designing a reliable protective system arises, to achieve such reliability, a back-up protective scheme is work (active) in case of any failure in the primary protection. The back-up scheme should not operate unless the primary fails to take the appropriate action, which means it should operate after a certain time delay known as coordination time interval (CTI), giving the priority for the primary protection to operate first. The above-mentioned scenario to be ground for formulation of the protective relay coordination, which includes of selection of a suitable setting of each relay such that their fundamental protective function is achieve under the desirable qualities of protective relaying, namely sensitivity, reliability, selectivity, and speed. However, introducing DG into the power system territories changes the existing protection scheme. Although DG has a lot of advantages on system design and operation, also it has negative effects as well, one of these negative effects is its effect on distribution network protection, especially the disturbance caused to the existing relay coordination. This disturbance is caused by the change in value and direction of both the system's power flow (under normal operation) and short-circuits current (under fault conditions). The impact of DG depends on DGs: size, location, technology type, and method of interconnection with the power system. Due to of these impacts, the setting of all protection relays must be checked to ensure that no mis-coordination happened in the system, and if there was, the optimal protective relays' settings have to be determined and set again, these leads to the introduction of adaptive protection scheme. One of the techniques that can be used to get the optimal settings is the HHO.

1.2 Statement of Problem

Hawassa city is continuously growing city regarding all aspect, those all expansion needs additional electricity power, and the additional energy will be needed. To overcome those issue distributed generation (DG) become optimal solution because to use renewable energy as well as the substation have extra load and have system overload interruption. The interruption rate also very far from the standard of IEEE, System Average Interruption Frequency Index (SAIFI) Hawassa city is around 184.5 interruptions per customer of year and System Average Duration Index (SADI) is around 249.64 and according to IEEE Standard 1366-1998 the median value is approximately 1.10 interruptions per customer.

The problems arise when the new generation is integrated with the power distribution network, as the traditional distribution systems have been designed to operate radially, without considering the integration of this new generation in the future. In radial systems, the power flows from upper terminal voltage levels down to customers situated along the radial feeders. Therefore, over-current protection in radial systems is quite straight forward as the fault current can only flow in one direction. With the increase of penetration of DG, distribution networks are becoming similar to transmission networks where generation and load nodes are mixed, and more complex protection design is needed. In this new design considerations regarding the number, size, location, and technology of the DG connected must be taken into account as the short circuit levels are affected and miss coordination problems with protection devices may arise & to find the optimal placement and sizing of distributed generation, proper coordination setting of over-current relays with DG and adaptive protection control algorithm developed by HHO algorithm.

1.3 Objectives

1.3.1 General Objective

The main objective of this thesis is improving the power system stability & reliability of distribution network by investigate the penetration & impact of distributed generation and by developing adaptive protection system for distribution network.

1.3.2 Specific Objective

- To develop possible solutions for issues with protection in presence of a significant number of DG.
- To find the optimal placement and sizing of distributed generation using HHO algorithm on MATLAB.
- To develop optimal coordination of directional over-current relays using HHO coordination techniques.
- To develop optimal protective relays' settings using HHO coordination techniques.
- To develop model of Adaptive protection system using DIgSILENT/Power Factory.

1.4 Scope and Limitations

The scope and limitations of this research are as follows:

- Only the major technical issues with over-current protection coordination of a distribution system are covered.
- The distribution level to address the impact of DG, the distribution level 33 kV portions are only considered.
- Models have been developed in DIgSILENT/Power Factory and many of the standard models available in DIgSILENT have been used.
- The HHO algorithms is developed using MATLAB.

1.5 Case Study Area

Hawassa city categorize under fast growing city in Ethiopia regarding industrial and urbanization, these leads for continuous high demand electricity. When the demand of electricity increases the current power energy city does not supply for new demand, to overcome this issue the distributed generation play vital role.

Hawassa Substation have three feeders' transformers, two of them are 15KV transformer and the third feeder transformer is 33KV. Those three feeder's transformers are distributed to the customer through fourteen lines of distribution system, ten of them is 15KV distribution lines and the rest four are 33KV distribution lines. This study will focus the adaptive protection coordination of 33KV distribution system with impact of DG.

CHAPTER 2

LITERATURE REVIEW & THEORETICAL BACKGROUND

2.1 Literatures Reviewed

This chapter explains the detailed literature study related to Impact of Distributed Generation on Distribution Network Protection scheme and Adaptive Protection Coordination and respective solutions. The information was gathered from several sources such as books, journals, and websites. Each reference used is explained in detail as follows.

Salah K. ElSayed, Ehab E. Elattar, et.al (2021) study on Hybrid Harris hawk's optimization with sequential quadratic programming for optimal coordination of directional overcurrent relays incorporating distributed generation. This paper presents a new hybrid algorithm of Harris hawks' optimization with sequential quadratic programming (HHO-SQP) for optimal coordination of directional overcurrent relays to find optimal relays settings. The SQP procedure is employed in the hybrid algorism as a local search mechanism to enhance the performance of the original HHO method. The optimization problem is described based on a developed objective function as a non-linear and highly constrained optimization problem to minimize the total operating time for primary relays at the same time of maximizing the backup relays operating time. The developed objective function is subject to some constraints related to the coordination process including the absence of any miss coordination between primary and backup relays. The performance of the proposed algorithm based on the new objective function is implemented for two different test systems. The result of the proposed algorithm is compared with those obtained from other recent meta-heuristic techniques. The results show that the new hybrid algorithm outperforms the recently published meta-heuristic algorithms. [3] This study only two case scenarios if the incident out of predetermine scenario there is no solution and it's not adaptive.

A.B. Alkuhayli, et.al (2012) has studied reliability Evaluation of distribution system containing renewable distributed generation. The author used Monte Carlo simulation algorithm to Evaluate the network. The study used solar, wind and gas turbine as distributed generation source. To evaluate the reliability of the system three case carried out: without DG, with DG and with energy storage system.[4] The author did not use optimization algorithm for DG sizing and location.

Mahamad, Biswarup, Vinay Pant, et.al (2021) conducts on Protection scheme for reconfigurable radial distribution networks in presence of distributed generation, in this paper, a new scheme of recloser-fuse coordination for reconfigurable radial distribution networks considering distributed generations is introduced. Further, a new graph theory-based approach has been developed to obtain all possible topologies in radial distribution network. Also, a new constraint reduction strategy has been introduced to eliminate a large number of constraints in the formulation because of the consideration of various topologies. To solve the formulated optimum recloser-fuse coordination problem, an analytical interior-point method has been adopted. The obtained settings have been compared with conventional recloser-fuse settings thereby proving the effectiveness of the presented scheme.[5] The limitation of the study is focus only on the radial distribution network system and have not solution for mesh distribution network.

Ehsan, Bahador, Ehsan et.al (2019) study on A bi-level multi agent-based protection scheme for distribution networks with distributed generation, this paper proposes a bi-level multi agent system-based protection scheme with the aim of maintaining the coordination of over current relays in the presence of Distributed Generation resources. In the proposed scheme, the distribution network protection has been divided into two levels so that the first level protection is implemented through relay agents which are participated in the protection scheme via exchanging information to each other. The second protection level is performed by generation agents when the fault still remains, and the first level protection is not effective. To this end, the generation agents are categorized into the main and distributed zones and perform the protection through sharing information together. [6] This study has limitation like the relay functional based on only by the stored data and is not adaptive protection.

Feras, Naser, Eyad, Saad, et.al (2021) study on Highly sensitive and fast microgrid protection using optimal coordination scheme and non-standard tripping characteristics, tripping time and optimal overcurrent coordination are nowadays one of the main power system protection concerns, due to the high penetration of renewable energy sources in the electrical power network. Considering the impact of Distributed Generation (DG) on fault currents and locations on the network, this paper presents and verifies an optimal coordination scheme based on two optimization methods, Particle Swarm Optimization (PSO) algorithm and Genetic Algorithm (GA). The optimal coordination scheme aims to improve the sensitivity and reliability of the protection system by using a nonstandard tripping characteristic to reduce the operating time of OCRs. The results indicate that the proposed optimal nonstandard scheme successfully reduce the total operating time of OCRs and improve the relay sensitivity during minimum and maximum fault scenarios.[7] The system is not adaptive and over current relay operating only the stored data and not adapt the actual network.

Mahamad, Biswarup, Vinay, et.al (2021). Conducted on Protection scheme for reconfigurable radial distribution networks in presence of distributed generation, in this paper, a new scheme of recloser-fuse coordination for reconfigurable radial distribution networks considering distributed generations is introduced. Further, a new graph theory-based approach has been developed to obtain all possible topologies in radial distribution networks. Also, a new constraint reduction strategy has been introduced to eliminate many constraints in the formulation because of the consideration of various topologies. To solve the formulated optimum recloser-fuse coordination problem, an analytical interior-point method has been adopted. [8] The limitation of the study is focus only on the radial distribution network system, have not solution for mesh distribution network and recloser-fuse are functionally only by stored system data.

Seyed, Saeed, et.al (2021). Study on Protection of active distribution networks with conventional and inverter-based distributed generators, fault current limiter is one of the best choices for solving protection problems in active distribution networks comprising distributed generation. Due to the nonlinear nature of protection problems and characteristics of protective devices, the selection of fault current limiter type and specification is one of the main challenges of this approach. In this paper, a simple and effective analytical method for fault current limiter impedance calculation is proposed. The method addresses issues of miscoordination caused by increased fault current levels, reduction of reach of protective devices, miscoordination due to reduction of reach, blinding of protection, false tripping of protective devices, and fuse-fuse and overcurrent relay-fuse miscoordination. The suggested approach has also been simplified so that the selection of fault current limiter for one feeder only relies on DGs connected to this feeder. [9] This study has limitation like the relay functional based on only by the stored data and is not adaptive protection.

Hadi, Azah, Hussain, Masoud, et.al (2012) study on A novel neural network and backtracking based protection coordination scheme for distribution system with distributed generation, With the increased installation of renewable energy based distributed generations in distribution systems, it brings about a change in the fault current level of the system and causes many problems in the current protection system. Hence, effective protection schemes are required to ensure safe and selective protection relay coordination in the power distribution system with DG units. In this paper, a novel adaptive protection scheme is proposed by integrating fault location with protection relay coordination strategies. An automated fault location method is developed using a two-stage radial basis function neural network in which the first radial basis function neural network determines the fault distance from each source while the second radial basis function neural network identifies the exact faulty line. After identifying the exact faulty line, then protection relay coordination is implemented. A new protection coordination strategy using the backtracking algorithm is proposed in which it considers the main protection algorithm to coordinate the operating states of relays so as to isolate the faulty line. Then a backup protection algorithm is considered to complete the protection coordination scheme for isolating the malfunction relays of the main protection system. Several case studies have been used to validate the accuracy of the proposed adaptive protection schemes. The results illustrate that the adaptive protection scheme can accurately identify faulty line and coordinate the relays in a power distribution system with DG units. The developed adaptive protection scheme is useful for assisting power engineers in performing service restoration quickly to decrease the total down time during faults.[10] The study is good and but using malfunction relays this relay are less effective compered to digital over current relays and the study is not addresses the economic effect of study.

Mahamad, Biswarup, Vinay, et.al (2020). Study on Protection coordination scheme for directional overcurrent relays considering change in network topology and On-Load Tap Changer tap position, this paper proposes a robust protection coordination scheme of directional overcurrent relays for multiple network topologies in the presence of on-load tap changers. The robust protection coordination scheme provides single settings of DOCRs which will be valid for all N-1 contingencies created after outage of a line, transformer, or generator. An efficient constraint reduction strategy is introduced to reduce the number of coordination constraints caused by consideration of multiple topologies. The impact of tap positions of the OLTCs has been incorporated in the required steady-state and short-circuit current calculations. The robust protection coordination scheme has been posed as an optimization problem and solved using an interior point method-based algorithm.[11] This study has limitation like the relay functional based on only by the stored data and is not adaptive protection.

Saman, Majid, Javad, et.al (2020). Study on Determining Optimal Size of Superconducting Fault Current Limiters to Achieve Protection Coordination of Fuse-Recloser in Radial Distribution Networks with Synchronous DGs, in this paper, Superconducting Fault Current Limiter has been used to restore the missing protection coordination between fuse and recloser in the distribution network in presence of distributed generation resources. To evaluate different Superconducting Fault Current Limiter models, various types of this equipment including resistive, inductive and hybrid are modelled and investigated for achieving protection coordination. Since increasing the size of Superconducting Fault Current Limiter increases its price, using the Genetic and the PSO Algorithms to calculate the minimum size of different types of Superconducting Fault Current Limiter to maintain network protection coordination. [12] This study has limitation like the relay functional based on only by the stored data and is not adaptive protection.

Kosaleswara, Devaraju, Vijaya, et.al (2021), Study on Coordination of IDMT (inverse definite minimum time) relays in the radial distribution system with distributed generation, Relay coordination is one of the most significant and difficult tasks in Radial Distribution System. The Radial Distribution System interconnected with the Distributed Generation like solar PV system and wind generator. It carries new challenges in standard protection systems and their coordination losses in between primary and backup relays. In this system relay pickup currents and time multiplier settings are changed for proper relay coordination. [13] This study limitation is the relay (IDMT) functional based on only by the stored data and the system is not adaptively protected.

Hossam, Ahmed, et.al (2015), study on Optimizing DG penetration in distribution networks concerning protection schemes and technical impact, Distributed generators provide many benefits for distribution networks, however they increase the fault current level and cause miscoordination between the protective devices. This paper presents a framework to determine the optimal locations and permissible capacity limits of inserting DGs in the distribution system using the genetic algorithm (GA). A multi-objective function is developed based on the overall maximum capacity of DGs, voltage enhancement, power loss reduction, and fault current level. The optimization process considers the voltage level and protective-devices coordination as two main constraints. The coordination constraint including fuse–recloser and recloser–relay schemes is added to the multi-objective function in an augmented fitness function. Furthermore, the effects of modifying the setting of overcurrent relay on the DGs capacity are investigated. The results show the possibility of integrating large DGs and achieving considerable loss reduction, voltage profile improvement and fault current reduction without replacing the existing protection systems. [14] This study limitation is the relay functional based on only by the stored data and the system is not adaptively protected.

Arash, Reza, et.al (2020) study on Adaptive coordination of overcurrent relays in active distribution networks based on independent change of relays' setting groups, the capability of network configuration change and high penetration of distributed generations are two important characteristics of modern distribution networks. One of the solutions to this problem is to use a setting group (SG)-based adaptive protection schemes. SG-based protective schemes protect various network states (different configurations and connection/disconnection of DGs) using a limited number of SGs. Therefore, it is needed to propose an algorithm to specify the settings of each SG and the determination of SG selection in different network states (NSTs). In this paper, previous attempts in the utilization of SG capability of Overcurrent relays (OCRs) are examined and a novel approach is proposed which can protect the same network with lower delay in relays' operation times although it requires a fewer number of SGs. In this paper, a new method based on integer linear programming (ILP) and particle swarm optimization (PSO) is utilized to specify the proper SG to activate for each relay in each NST, to minimize the total operating time of OCRs, considering coordination constraints. [15] This study is trying to control the system using over current relays plus and setting group, these means the system is not fully adaptive because if the fault is out of the setting group not handled.

Yavuz, Mehmet, Arif, et.al (2016), Study on Implementation of adaptive relay coordination in distribution systems including distributed generation, Conventional protection schemes in distribution systems are prone to potential threats with increasing number of DG units. The characteristics of DG systems such as wind and solar energy conversion systems are generally uncertain in nature. These units add complexity to conventional protections schemes in terms of directional protection challenges. Besides, the integration of DG units to grid results in availability of new local energy sources in the points where loads are connected. Thus, mis operations and imperfect selectivity of relays can occur within the distribution system. These issues call for the need of a bi-directional relay operation and an operation strategy where adaptive protection and relay coordination are applied in new distribution systems compatible with smart grid necessities. In this paper an adaptive protection scheme is proposed for distribution systems with DG. Relay coordination of adaptive protection scheme provides fast fault isolation and greater adaptation to different operating modes considering DG units. [16] The study is good and but only using bi-directional relay not adaptively protected system and the study is not addresses the economic effect of study.

W. Rebizant, et.al (2018) Study on Coordination of overcurrent protection relays in networks with superconducting fault current limiters, the paper concerns coordination of overcurrent protection relays in power networks with superconducting fault current limiters. At the beginning, information about designed superconducting fault current limiters and conditions that ensure overcurrent protection coordination are presented. Next, settings of the overcurrent relays were determined for a sample network with superconducting fault current limiters model installed. [17] The proposed system is using superconducting fault current limiters to control the system current, this less effective compared with overcurrent relays and the system is not adaptably protected.

All reviewed literatures indicates that when the distributed generation are interconnected to the system the existing protection coordination is not handle and miscoordination will be happen. To overcome the issue of protection most study focusses on non-adaptive protection, like recloser-fuse, Superconducting Fault Current Limiters, inverse definite minimum time relays, bi-directional relay operation, superconducting fault current limiters etc. My study on "Impact of Distributed Generation on Distribution Network Protection scheme and Adaptive Protection Coordination using Harris' Hawks Optimization" by using directional overcurrent relays and adaptive protection coordination scheme the above literatures limitation will be get solution as well as the system an economic analysis will be handled.

2.2. Theoretical Background

2.2.1 Introduction

Distributed Generation (DG) is one of the new trends in power systems used to support the increased energy-demand. There is not a common accepted definition of DG as the concept involves many technologies and applications. Different countries use different notations like "embedded generation", "dispersed generation" or "decentralized generation".

Furthermore, there are variations in the definition proposed by different organizations (IEEE, CIGRE…) that may cause confusion. Therefore, in this study, the following definition is used [18]: "Distributed generation is considered as an electrical source connected to the power system, in a point very close to/or at consumer´s site, which is small enough compared with the centralized power plants."

To clarify about the DG concept, some categories that define the size of the generation unit are presented in Table 2. 1.

Type	Sizes
Micro distributed generation	1W<5KW
Small distributed generation	5KW<5MW
Medium distributed generation	5MW<50MW
Large distributed generation	50MW<300MW

Table 2. 1: The Sizes of DG [19]

2.2.2. Types of Distributed Generation

The distributed Generation can be classified into two major groups: -

a) inverter-based DG, and
b) rotating machine DG.

Normally, inverters are used in DG systems after the generation process, as the generated voltage may be in DC or AC form, but it is required to be changed to the nominal voltage and frequency. Therefore, it must be converted first to DC and then back to AC with the nominal parameters through the rectifier [19].

There are different types distributed generation technologies some are Combined heat and power systems, Solar photovoltaic panels, Wind power, small size Hydropower, Biomass combustion or cofiring, Municipal solid waste incineration, Fuel cells fired by natural gas or biomass etc. and some of them described below.

2.2.2.1 Photovoltaic Systems

A photovoltaic system converts the light received from the sun into electric energy. In this system, semi conductive materials are used in the construction of solar cells, which transform the self-contained energy of photons into electricity, when they are exposed to sun light. The cells are placed in an array that is either fixed or moving to keep tracking the sun in order to generate the maximum power [20].

These systems are environmentally friend without any kind of emission, easy to use, with simple designs and it does not require any other fuel than solar light. On the other hand, they need large spaces, and the initial cost is high.

PV systems generate DC voltage then transferred to AC with the aid of inverters. There are two general designs that are typically used: with and without battery storages.

2.2.2.2 Wind Turbines

Wind turbines transform wind energy into electricity. The wind is a highly variable source, which cannot be stored, thus, it must be handled according to this characteristic. [20]

The principle of operation of a wind turbine is characterized by two conversion steps. First the rotor extracts the kinetic energy of the wind, changing it into mechanical torque in the shaft; and in the second step the generation system converts this torque into electricity.

In the most common system, the generator system gives an AC output voltage that is dependent on the wind speed. As wind speed is variable, the voltage generated must be transferred to DC and back again to AC with the aid of inverters. However, fixed speed wind turbines are directly connected to grid [20].

2.2.2.3 Micro-Turbines

A micro-turbine is a mechanism that uses the flow of a gas, to covert thermal energy into mechanical energy. The combustible (usually gas) is mixed in the combustor chamber with air, which is pumped by the compressor. This product makes the turbine to rotate, which at the same time, impulses the generator and the compressor. In the most used design, the compressor and turbine are mounted above the same shaft as the electric generator.

The output voltage from micro-turbines cannot be connected directly to the power grid or utility, it must be transferred to DC and then converted back to AC in order to have the nominal voltage and frequency of the utility.

The main advantage of micro-turbines is the clean operation with low emissions produced and good efficiency. On the other hand, its disadvantages are the high maintenance cost and the lack of experience in this field. Very little micro-turbines have been operated for enough time periods to establish a reliable field database. Furthermore, methods of control and dispatch for many micro turbines and selling the remaining energy have not been developed yet [19].

2.2.2.4 Fuel Cell

A fuel cell is a device that uses hydrogen as a fuel to produce electrons, protons, heat and water. Fuel cells are electrochemical devices that convert fuel (hydrogen) and air directly to electric power and provide thermal energy through electrochemical processes [20]. They convert hydrogen, or hydrogen-containing fuels, directly into electrical energy plus heat through the electrochemical reaction of hydrogen and oxygen into water. The process is that of electrolysis in reverse.

$$\text{Overall reaction: } 2H_2 \text{ (gas)} + O_2 \text{ (gas)} \rightarrow 2\,H_2O + \text{energy}$$

Because hydrogen and oxygen gases are electrochemically converted into water, fuel cells have many advantages overheat engines. These include high efficiency, virtually silent operation and, if hydrogen is the fuel, there are no pollutant emissions. If the hydrogen is produced from renewable energy sources, then the electrical power produced can be truly sustainable. The two principal reactions in the burning of any hydrocarbon fuel are the formation of water and carbon dioxide. As the hydrogen content in a fuel increase, the formation of water becomes more significant, resulting in proportionally lower emissions of carbon dioxide. As fuel use has developed through time, the percentage of hydrogen content in the fuels has increased. It seems a natural progression that the fuel of the future will be 100% hydrogen. [20]

2.2.3 Impact of DG on Power System Grids

The introduction of DG in systems originally radial and designed to operate without any generation on the distribution system, can significantly impact the power flow and voltage conditions at both, customers, and utility equipment.

These impacts can be manifested as having positive or negative influence, depending on the DG features and distribution system operation characteristics [21].

The objective of this thesis is to investigate the technical impact that the integration of DG has on the protection coordination of distributed power systems. A method to assess this impact, is based on investigate the behavior of an electric system, with and without the presence of DG.

The difference between the results obtained in these two operating conditions, gives important information for both, companies in the electric sector and customers.

In that sense, a general view of the main problems encountered in the integration of DG to the distributed network is presented.

2.2.3.1 Impact of DG on Harmonics

Harmonics are always present in power systems to some extent. They can be caused by for instance: non-linearity in transformer exciting impedance or loads such as fluorescent lights, AC to DC conversion equipment, variable-speed drives, switch mode power equipment, arc furnaces, and other equipment.

DG can be a source of harmonics to the network. Harmonics produced can be either from the generation unit itself (synchronous generator) or from the power electronics equipment such as inverters. In the case of inverters, their contribution to the harmonics currents is in part due to the SCR (Silicon Controlled-Rectifier) type power inverters that produce high levels of harmonic currents. Nowadays, inverters are designed with IGBT (Insulated Gate Bipolar Transistor) technology that use pulse width modulation to generate the injected “pure” sinusoidal wave. This new technology produces a cleaner output with fewer harmonic that should satisfy the IEEE 1547-2003 standards. [22]

When comparing different synchronous generator pitches the best configuration encountered is with a winding pitch of 2/3 as they are the least third harmonic producers. Third harmonic is additive in the neutral and is often the most prevalent. On the other hand, 2/3 winding pitch generators have lower impedance and may cause more harmonic currents to flow from other sources connected in parallel with it. Thus, grounding arrangement of the generator and step-up transformer will have main impact on limiting the feeder penetration of harmonics. Grounding schemes can be chosen to remove or decrease third harmonic injection to the utility system. This would tend to confine it to the DG site only.

Table 2. 2: Harmonic Current Injection Requirements for Distributed Generators Per IEEE 519-1992. [21]

Harmonic order	Allowed Level Relative to fundamental (Odd harmonics) *
<11th	4%
<11th to < 17th	2%
<17th to < 23rd	1.5%
<23rd to <35th	0.6%
<35th to greater	0.3%
Total Harmonic Distortion	5%

Even harmonics are limited to the 25 of odd values.

The design of a DG installation should be reviewed to determine whether harmonics will be confined within the DG site or also injected into the utility system. In addition, the installation needs to fulfil the IEEE-519 standard. According to [21], any analysis should consider the impact of DG currents on the background utility voltage distortion levels. The limits for utility system voltage distortion are 5% for THD (total harmonic distortion) and 3% for any individual harmonic.

2.2.3.2 Impact of DG on Short Circuit Levels of the Network

The presence of DG in a network affects the short circuit levels of the network. It creates an increase in the fault currents when compared to normal conditions at which no DG is installed in the network [21].
The influence of DG to faults depends on some factors such as the generating size of the DG, the distance of the DG from the fault location and the type of DG. This could affect the reliability and safety of the distribution system.

The fault contribution from a single small DG is not large, even so, there will be an increase in the fault current. In the case of many small units, or few large units, the short circuit levels can be altered enough to cause miss-coordination between protective devices, like fuses or relays. This could affect the reliability and safety of the distribution system. Figure 2.1 shows a typical fused lateral on a feeder where fuse saving (fault selective relaying) is utilized and DGs are embedded in the system. In this case if the fault current is large enough, the fuse may no longer coordinates with the feeder circuit breaker during a fault and fuse-breaker coordination may be no longer achieved. This can lead to unnecessary fuse operations and decreased reliability on the lateral [21].

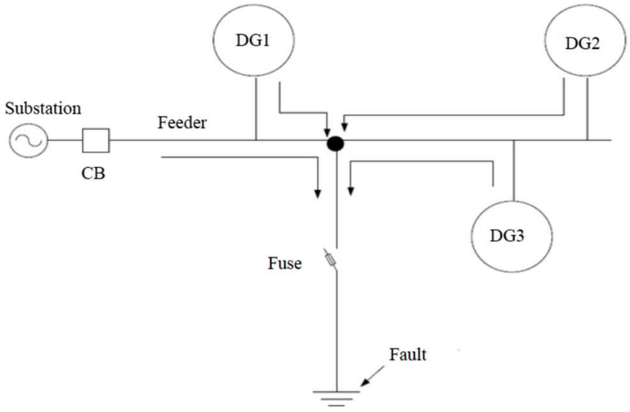


Figure 2. 1: Fault Contributions Due to DG Units

If the DG is located between the utility substation and the fault, a decrease in fault current from the utility substation may be observed. This decrease needs to be investigated for minimum tripping or coordination problems. On the other hand, if the DG source (or combined DG sources) is strong compared to the utility substation source, it may have a significant impact on the fault current coming from the utility substation. This may cause fail to trip, sequential tripping, or coordination problems [22].

The nature of the DG also affects the short circuit levels. The highest contributing DG to faults is the synchronous generator. During the first few cycles its contribution is equal to the induction generator and self-excited synchronous generator, while after the first few cycles the synchronous generator is the most fault current contributing DG type. The DG type that contributes the least amount of fault current is the inverter interfaced DG type; in some inverter types the fault contribution lasts for less than one cycle. Even though a few cycles are a short time, it may be long enough to impact fuse breaker coordination and breaker duties in some cases [23].

2.2.3.3 Impact of DG on Voltage Regulation

Radial distribution systems regulate the voltage by the aid of load tap changing transformers (LTC) at substations, additionally by line regulators on distribution feeders and shunt capacitors on feeders or along the line. Voltage regulation is based on one way power flow where regulators are equipped with line drop compensation.

The connection of DG may result in changes in voltage profile along a feeder by changing the direction and magnitude of real and reactive power flows. Nevertheless, DG impact on voltage regulation can be positive or negative depending on distribution system and distributed generator characteristics as well as DG location [21].

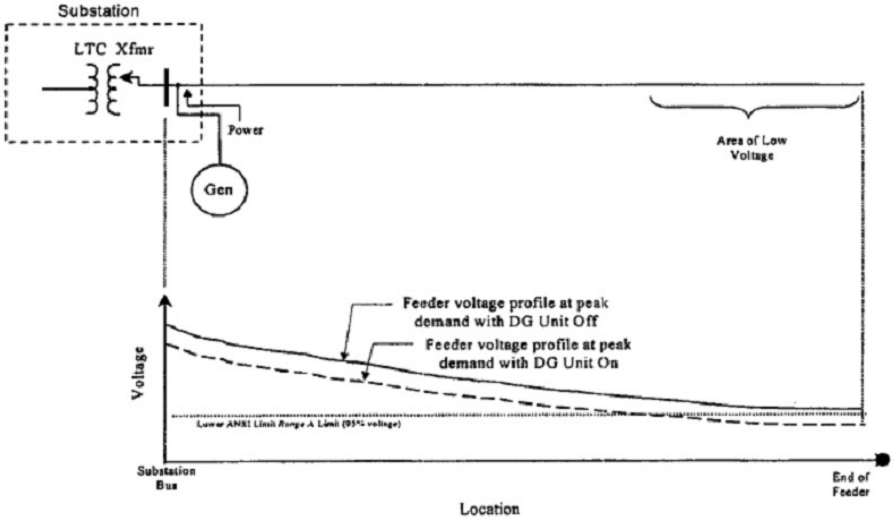


Figure 2. 2: Voltage Profiles With and Without DG [21]

In Fig. 2.2 the DG is installed downstream the LTC transformer which is equipped with a line drop compensator (LDC). It is shown that the voltage becomes lower on the feeder with DG than without the DG installed in the network. The voltage regulator will be deceived, setting a voltage lower than is required for sufficient service. The DG reduces the load observed from the load compensation control side, which makes the regulator to set less voltage at the end of the feeder. This phenomenon has the opposite effect to which is expected with the introduction of DG (voltage support) [21].

2.2.3.4 Impact of DG on Losses

One of the major impacts of Distributed generation is on the losses in a feeder. Locating the DG units is an important criterion that must be analyzed to be able to achieve a better reliability of the system with reduced losses [21].

According to [21], locating DG units to minimize losses is like locating capacitor banks to reduce losses. The main difference between both situations is that DG may contribute with active power and reactive power (P and Q). On the other hand, capacitor banks only contribute with reactive power flow (Q). Mainly, generators in the system operate with a power factor range between 0.85 lagging and unity, but the presence of inverters and synchronous generators provides a contribution to reactive power compensation (leading current).

The optimum location of DG can be obtained using load flow analysis software, which is able to investigate the suitable location of DG within the system to reduce the losses. For instance: if feeders have high losses, adding a few small capacities DGs will show an important positive effect on the losses and have a great benefit to the system. On the other hand, if larger units are added, they must be installed considering the feeder capacity boundaries [21]. For example: the feeder capacity may be limited as overhead lines and cables have thermal characteristic that cannot be exceed.

Most DG units are owned by the customers. The grid operators cannot decide the locations of the DG units. Normally, it is assumed that losses decrease when generation takes place closer to the load site. However, as it was mentioned, local increase in power flow in low voltage cables may have undesired consequences due to thermal characteristics [24].

2.2.4 Over-current Protection of Distributed Systems

Faults generally results in high current levels in electrical power systems. These currents are used to decide the occurrence of faults and require protection devices, which may differ in design depending on the complexity and accuracy necessary. The ordinary type of protection devices are thermo-magnetic switches, moulded-case circuit breakers (MCCBs), fuses, and over-current relays. Amongst these types, over-current relay is the most common protection device used to counteract excessive currents in power systems [25].

Over-current protection is principally intended to operate only under fault conditions and therefore, over-current relays should not be installed merely to protect systems against over-loads. Nevertheless, relay settings are often selected taking both into account, over-load, and over-current circumstances.

An over-current protection relay is a device able to sense any change in the signal, which it is receiving normally from a current and/or voltage transformer and carry out a specific operation in case that the incoming signal is outside a predetermined range. Usually, the relay operates closing or opening electrical contacts, as for example the tripping of a circuit breaker [25].

2.2.4.1 Types of Over-current Relays

Concerning the relay operating characteristics, over-current relays may be classified into three major groups: definite current, definite time, and inverse time.

2.2.4.1.1 Definite Current Relay

This type of characteristic makes the relay to operate instantaneously when the current reaches a predetermined value. This feature is shown in Figure 2.3.

The setting is chosen in such a way that the relay, which is installed at the furthest substation away from the source, will operate for a small current value and the relay operating currents are gradually increased at each substation, moving towards the source. Thereby, the furthest relay from the source operates first disconnecting the load in the neighboring site of the fault [25].

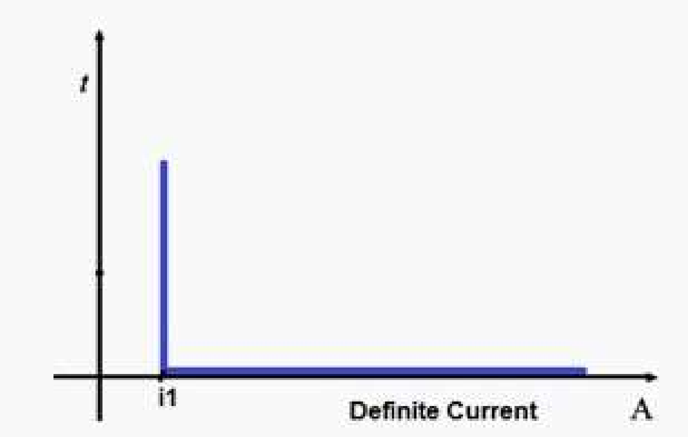


Figure 2. 3: Definite Current Characteristic of Over-Current Relays [25]

2.2.4.1.2 Definite Time Relay

In this type of relay, the setting may be changed to deal with different levels of current by using different operating times. The settings can be attuned in such a way that the relay, which is installed at the furthest substation away from the source, is tripped in the shortest time, and the remaining relays are tripped in sequence having longer time delays, moving back in the direction of the source [25].

Definite time protection is more selective as the operating time can be set in fixed steps. However, faults close to the source, which results in higher currents may be cleared in a relatively long time. This relay allow setting of two independent parameters, the pickup setting and the time dial setting. The pickup setting defines the current value necessary to operate the relay and the time dial sets the exact timing of the relay operation. In Figure 2.4, the characteristic curve of a definite time relay is shown [25].

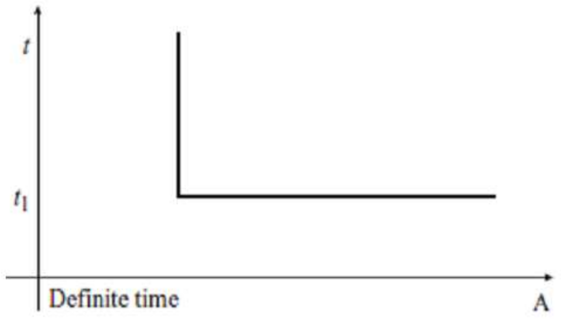


Figure 2. 4: Definite Time/Current or Definite Time Characteristic of Over-Current Relays

2.2.4.1.3 Inverse Time Relays

These relays operate in a time that is inversely proportional to the fault current. Inverse time relays have the advantage of that shorter tripping times can be achieved without risking the protection selectivity. Their defining curve shape is shown in Figure 2.5.

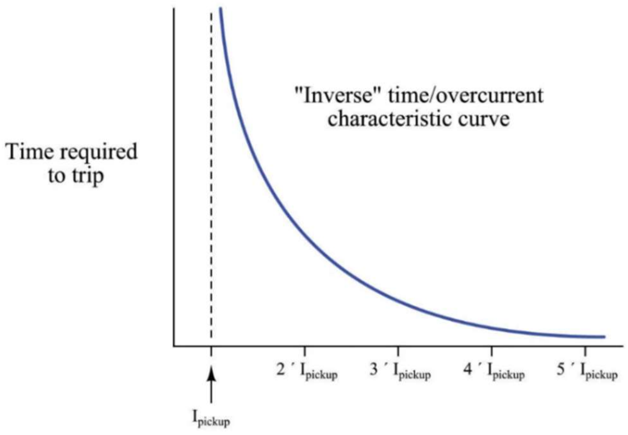


Figure 2. 5: Inverse Time/ Current Characteristic of Over-Current Relays [25]

Relay characteristic uses time delay to provide tripping. The relay, which is located at the furthest point from the source, is tripped in the shortest time. Other relays are tripped in a sequence with increasing time delays as going back in the direction of the source. These relays are classified based on their characteristic curves and standard characteristics as follows:

i. Standard Inverse (SI)

$$t = \frac{TDS*0.14}{(\frac{I_f}{I_p})^{0.02}-1} \qquad 1$$

ii. Very Inverse (VI)

$$t = \frac{TDS*13.5}{\frac{I_f}{I_P}-1} \qquad 2$$

iii. Extreme Inverse (EI)

$$t = \frac{TDS*80}{(\frac{I_f}{I_p})^2-1} \qquad 3$$

where t is operating time of relay, TDS is Time dial setting, I_p is pick up current of relay, I_f is fault current of relay and n (0.14, 13.5 & 80) is are the constants which depend on the relay characteristics. Their defining curve shape is shown in Figure 2.6.

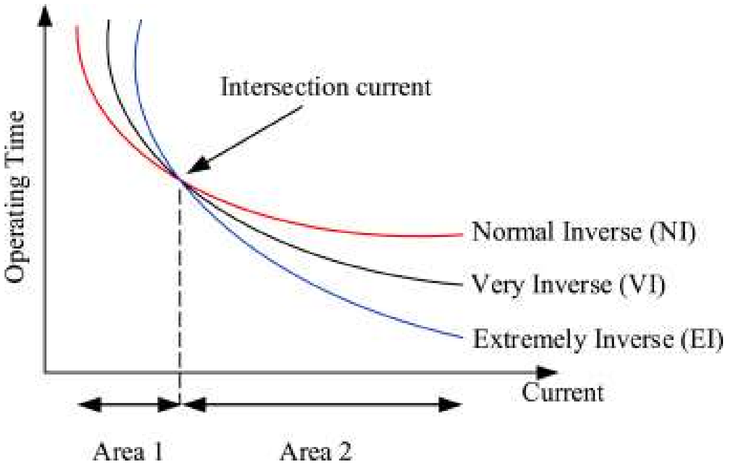


Figure 2. 6: Standard Inverse, Very Inverse & Extremely Inverse Time/Current characteristic of Over Current Relays

2.2.5 Protection Coordination

For DG to have a positive benefit, it must be at least suitably coordinated with the system operating philosophy and feeder design. Distributed Generation is connected to the network through an interconnection point called the point of common coupling (PCC). The PCC has to be properly protected to avoid any damage to both sides, the DG equipment and the utility equipment, during fault conditions [26].

In the interconnection of the DG to the distribution utility grid, there are some protection requirements that are established by the utility. Adequate interconnection protection should consider both parties ensuring the fulfilment of the utility requirements. Interconnection protection is usually dependent on size, type of generator, interconnection point and interconnecting transformer connection [27].

Distributed generation must be installed with a transformer characteristics and grounding arrangement compatible with the utility system to which it is to be connected. If this requirement is not satisfied, over voltages may arise which can cause damage in the utility system or customer equipment. The type of transformer selected has a major impact on the grounding perceived by the utility primary distribution system and for the generator to appear as a grounded source to the utility primary system. Therefore, it is demanded that the transformer allows a ground path (zero-sequence path) from the low voltage side to the high voltage side [21].

There is not a universally "best" transformer connection accepted for all cases. In Figure 9, some usual connections used are presented.

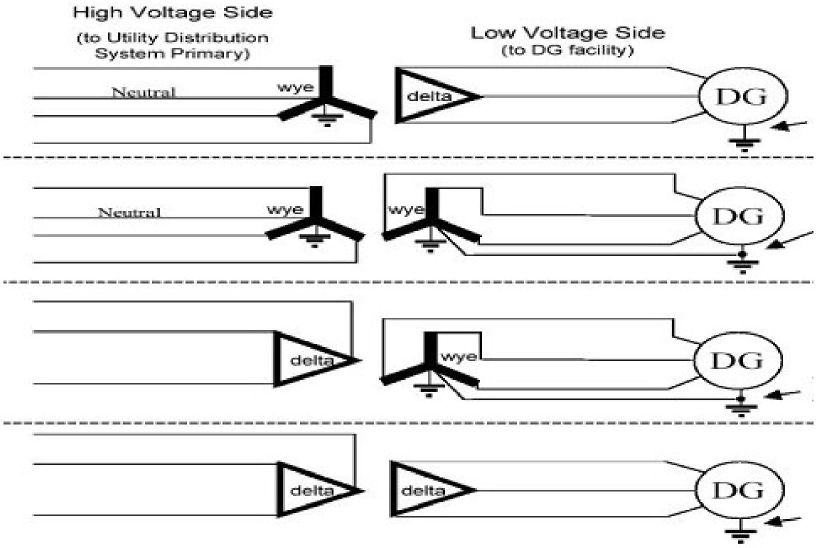


Figure 2. 7: Commonly Transformer Connections Used with DG [28]

Each of these connections has advantages and disadvantages to the utility with both circuit design and protection coordination affected. The utility establishes the connection requirements and determines which type of connection is appropriate.

In Figure 2.7, the top two configurations can provide a grounded path to the primary. Moreover, to make the source appear as effectively grounded; the generator´s neutral must be grounded. The first arrangement is preferred for four-wired-multi-grounded neutral systems.

The two bottom configurations show that, even though the source is properly grounded on the low voltage side of the transformer, the system may still appear to the utility primary to be ungrounded at the high voltage side. These two arrangements act as grounded sources and are preferred on three-wire ungrounded distribution systems [28].

To fulfil the desired safe scenario, the protection is based on the following factors [26][27]:

1. Protection should respond to the failure of parallel operation of the DG and the utility.
2. Protecting the system from fault currents and transient over voltages generated by the DG during fault conditions in the system.
3. Protecting the DG from hazards it may face during any disturbance occurring in the system such as automatic reclosing of re-closers as this can cause damage depending on the type of the generator used by the DG.
4. Network characteristics at the point of DG interconnection. Considering the capability of power transfer at this point and the type of interconnection.

The generator protection is one of the most important devices, typically located at the generator´s terminals. Its function is to detect internal short circuits and abnormal operating conditions of the generator itself, for instance: reverse power flow, over excitation of the generator and unbalanced currents [27].

For the utilities to operate in a safe mode, some aspects must be analyzed.

1. Configuration of the interconnecting transformer winding.
2. Current and voltage transformer requirements.
3. Interconnection relays class.
4. Speed of DG isolation to be faster than that of the utility system automatic reclosing during fault conditions to avoid islanding cases.

2.2.6 Adaptive Protection

The distribution system protection can be improved using an adaptative protection philosophy. According to [26] 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". In other words, in adaptive protection, the relays should respond to the changing system conditions and adapt according to the actual system state. For the practical implementation of an adaptive protection some requirements must be fulfilled:

Use of digital DOCR. Fuses or electromechanical and standard solid-state relays are unsuitable. They do not provide the flexibility for changing the settings of tripping characteristics and they have no current direction sensitivity characteristic.

Digital DOCR must have the possibility for using different tripping characteristics (several settings groups) that can be attuned locally or remotely and automatically or manually.

Use of standard communication protocols, so that individual relays can communicate and exchange information with a central computer or between different individual relays fast and reliably to guarantee a required application performance.

Communication is a major activity in adaptive relaying system. Data networks capable of transferring data in a secure manner and with adequate latency are indispensable in this task. Data are needed in real time to achieve high speed control and protection and in slower time to communicate system state data to substation-based control and to prepare them for predictable abnormalities. Communication allows the relays to exchange information between the station computers and the master computer. Some of the new trends in communication used in protection relaying as GPS or intranet [26].

Adaptative protection can face the problems with over-current protection, by designing proper communication between relays in such a way that selectivity is attained for primary protection and backup protection is also accomplished. On the other hand, the implementation of a communication system is considerable complex, requires high cost and may be uneconomical for small distribution systems.

CHAPTER 3

METHODOLOGY

3.1 Reliability Evaluation of Existing System

Hawassa substation have 14 outgoing feeders out of which 4 feeders are 33 kV, these feeders have more than 53.6 MW peak load, and more than 31,045 customers (i.e., industrial, commercial, and residential). There is various problem faced with the existing Hawassa power distribution network. Hawassa substation is selected due to the availability of load supply data. Various faults occur in Hawassa substation it frequently causes interruption. The causes of the interruptions are:

Technical problem: Technical problems are interruption that cause due to failure of distribution system equipment. Outage or disconnections of lines by the operator for maintenance purpose are also technical cases. Technical problems are transformer and arrestor explosion, oil leakage from transformer tank, aging of wood towers and breaker failure to trip.

External causes: external causes are different from technical problems that occur due to failure of equipment. It's a result of natural phenomena or human errors on distribution system from external.

There are different causes of interruption in the distribution system. Some momentary faults are difficult to detect the types of faults and what cause them. The reason is the distribution system works in manual fault clearing and fault detection mechanisms are traditional. The main types of faults causing interruption in the current distribution system are:

a) Permanent Earth fault (PEF)

Permanent Earth fault is due to the distribution line or equipment getting in contact with the ground directly or indirectly for long time. Such types of faults are cause by transformer oil leakage and connection to earthling wire. Distribution line in contact with trees and branches causes faults. Underground cable water leakage also one of the faults that cause interruption in the distribution networks.

b) Temporary Earth Fault (TEF)

Such faults happen frequently during rainy season because of the supporting steel structure gets in contact with distribution line and water leaking to insulator cubs that result in interruption. Wind blows distribution line to each other that lie on the trees and branches cause temporary faults. This type of fault does not persist long and results circuit breaker to trip.

c) Permanent short circuit (PSC)

These types of faults happen when the distribution lines contact each other. One distribution line falls onto nearby lines causing short circuit due to untightened fixation of power lines to tower. The existence of high voltage and medium voltage lines in close range of distance experience electric field forces. The forces that occur between the line narrows the air gap across the line. Broken tree branch touching the two lines at the same time also cause short circuit.

d) Temporary short circuit (TSC)

The distribution line contacts each other due to wind crate short circuit and it cause the breaker to trip. A similar event occurs during tree movement by wind crating contact with distribution lines. The tree touches two lines same time causing line to line faults. Moreover, contact of birds dead on lines and stormy rain season caused interruption. The rain pushes the dielectric strength of the air beyond limit this form corona and the circuit breaker trips because of this till the rain stops.

e) Lines Overload (LOL)

High tension on distribution line, disconnect sections of power networks. To investigate demand imbalance newly emerging firms and business center consumption must know. Circuit breakers trip to avoid damage on the line during public festival customer time of use there will be high consumption of power. High demand crates time shifting of supply by the dispatch center. For this case deliberate sectional disconnection of load points is undertaken.

f) System Overload (SOL)

Faults in generation plants cause power shortage to deliver all loads. Some generation plants faced technical problems and power deliver to the load had been short. System overload also occur due to demand imbalance and shortage of power during peak hour. There are seasons that water levels of hydropower plant decrease and generating capacities are small.

Table (3.1), show types of faults occurring frequency and duration. This categorization enables to identify what reliability measures must be taken to improve power delivery reliability. Average values of frequencies and durations are assumed to conclude which fault has induced higher interruption in the system.

Fault type	**2019/20**	**2020/21**
PEF	1080	776
PSC	1455	2265
TEF	3828	2511
TSC	1170	1124
LOL	145	217
SOL	35	147
Total	7713	7040

Table 3. 1: Frequency of Interruption Type of Faults

There are several solution ideas for reliability improvement of the existing distribution system, some of them are periodic maintenance of distribution equipment, proper load forecasting mechanism, replacement of aged equipment, upgrading existing distribution system, using smart technologies, intelligent electronic device (IED), automatic sectionalize, smart recloser and others.

This thesis is going to improve the reliability of the distribution system by penetration distributed generation solar system, when the DG is interconnected to the existing system the secure protection scheme become necessary point and to answer the protection issue this thesis use digital DOCR.

3.2 Distributed Generation Technology Selection

There are different types of distributed generation technology as discussed above. Distributed generation can be renewable and non-renewable energy sources. Selection of DG for a certain area is based on availability of resources in the area, cost, effectiveness, and efficiency of the resource. Resources availability varies from area to area due to geographical location. Some areas have solar energy resource based on solar radiation in the area and others have wind and geothermal based on wind speed and places. Different types of DG resources have different level of emissions of gas and cost. As discussed in chapter two, there are different technologies or resources of distributed generation. Among those resources, the selection of a specific DG technology to a certain area depends on availability of resources, suitability to environment, and cost of DG technology. DG technologies also differ in their positive and negative impacts that they impose on the surrounding environment. Among these impacts their emission level to the environment and the feasibility is given the consideration. The following table shows the emission level and cost of various DG technologies.

Table 3. 2: Emission and Cost Levels of Different DGs [29]

Technology	Emission Level	Cost
PV	NO	Moderate
Fuel Cell	Low	High
Wind	No harmful emission	Moderate
Deisel Generator	High	Low
Microturbine	Low	Moderate

Even though, the PV systems and wind turbines are free energy sources with low cost and low emission level, but wind turbine is not advisable to implement in Hawassa substation due to feasibility analysis of wind speed in specific location. In this study distribution system reliability analysis is assessed using distributed generation of PV.

3.2.1 Photovoltaic system

A p-n junction in the layer of semiconductor forms a photovoltaic cell structure that can convert solar energy into electrical energy. Weather data (irradiance and temperature) are used as input data for PV modelling. For modelling, it is necessary to analyses the influence of different factors on photovoltaic cells and to take consideration the characteristics given by producers. The model takes in to account the variation of the photoelectric current. when the radiation and temperature changes, the variation of the diode saturation current will change.[30]

3.2.1.1 Mathematical Modelling of Photovoltaic system

The building block of PV arrays is the solar cell, which is basically a p-n junction that directly converts solar energy into electricity. It has an equivalent circuit as shown in Figure 3.1.

The current source *Iph* represents the cell photo current; *Rj* is used to represent the non-linear impedance of the $p-n$ junction; *Rsh* and *Rs* are used to represent the intrinsic series and shunt resistance of the cell, respectively. Usually, the value of *Rsh* is very large and that of is very small, hence they may be neglected to simplify the analysis. *Irs* is the cell reverse saturation current, which is assumed zero. PV cells are grouped in larger units called PV modules, which are further interconnected in series-parallel configuration to form PV arrays or PV generators. The PV mathematical model used to simplify our PV array is represented by the Equations (1) to (5):

(Assuming *Rs* = 0, *Rsh* = ∞ and *Irs* = 0, for simplifying the study) and applying Kirchhoff law; The electrical powers generated by a PV array consist of modules is computed using the following equations:[57]

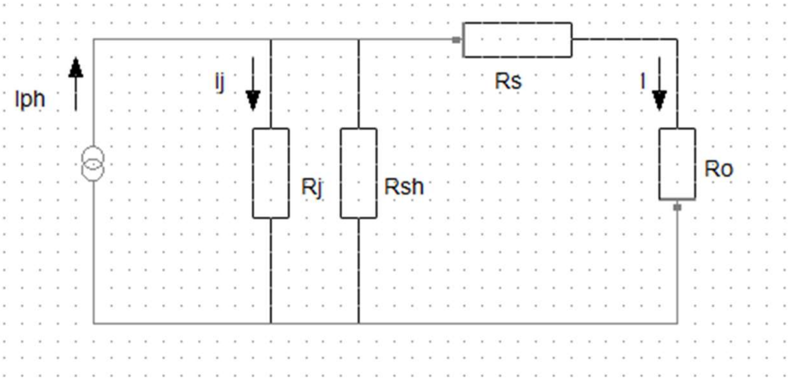


Figure 3. 1: Equivalent Circuit of a PV Cell

$$T_C = T_A + \frac{(N_{oct}-20)S}{80} \quad 4$$

$$I = I_{ph} = [I_{sc} + K_i(T_c - 25)]\frac{S}{100} \quad 5$$

$$V = V_{OC} - K_v T_c \quad 6$$

$$FF = \frac{V_{mpp} * I_{mpp}}{V_{oc} I_{sc}} \quad 7$$

$$P_{out} = N * FF * I = n_s * n_p * FF * V * I \quad 8$$

Where, *I* is the PV array output current, *V* is the PV array output voltage, *ns, np* is the number of cells in series and in parallel, *N* is number of module, *TC, TA* are the cell effective and ambient temperatures in ◦C, respectively, *Isc* is the cell short-circuit current, *Voc* is the open circuit voltage, *Impp, Vmpp* are the current and voltage at maximum power point, respectively, *Ki* is the short circuit current temperature coefficient, *Kv* is the open circuit voltage temperature coefficient, *S* is the solar radiation in mW/cm2 and *FF* is the fill factor.

3.2.1.2 Types of PV Systems

With growing demand for PV systems, the utilities provided an option for the consumers to connect their systems to the grid. This step introduced a new term called "Net Metering." Net metering allows the consumers to send back the electricity they generate from their PV systems to the grid. This is possible because of the grid-tied connection enabled by the utility. Similarly, we also have systems that are independent and do not require themselves to be connected to the grid such systems are called off-grid systems or standalone systems. Both the systems have been explained in detail below:[36]

1. Standalone or Off-Grid Systems

The off-grid system term states the system not relating to the gird facility. Primarily, the system which is not connected to the main electrical grid is term as off-grid PV system. Off-grid system also called standalone system or mini grid which can generate the power and run the appliances by itself. Off-grid systems are suitable for the electrification of small community. Off-grid electrification system is viable for the remote areas in the countries where they do have little or no access to the electricity because of the distinct living and spread population in the vast area. [57]

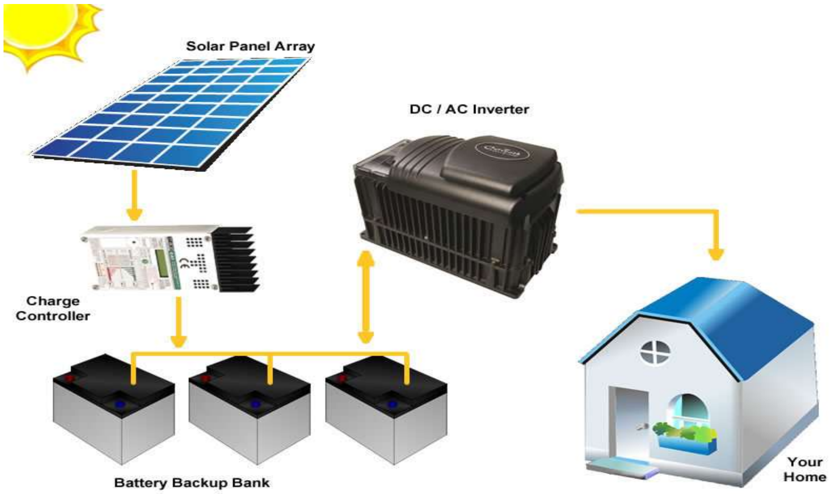


Figure 3. 2: Off-Grid Solar PV System [36]

2. Integrated or Grid-Tied System

Grid connected photovoltaic power system is an electricity generating system which is linked to the utility gird. This photovoltaic system contains solar panel, inverter, and the equipment to provide connection to the grid. Grid connected systems are feasible for various setup such as residential. Commercial and larger scale grid tied system different than the off grid solar power systems. Usually, grid connected system does not need battery backup, because when system generate the energy more than the load it will automatically transfer to the linked utility gird.[36]

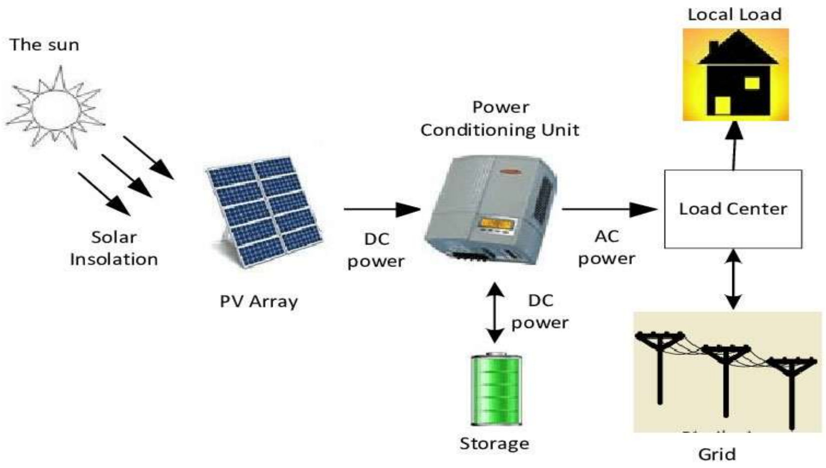


Figure 3. 3: Grid-Tied PV System [36]

3.2.1.3 Meteorological Data of Solar Radiation

The solar energy generation is mostly weather dependent since the total amount of solar radiation varies with weather condition. In the below figure (3.4) annual solar radiation of the area using Homer software downloaded from NASA prediction of Worldwide Energy Resource (Power) database monthly average for global horizontal radiation over 22-year period (Jul 2000 – Jun 2020) and scaled annual average KWh/m^2/day is 5.89KWh/m^2/day.

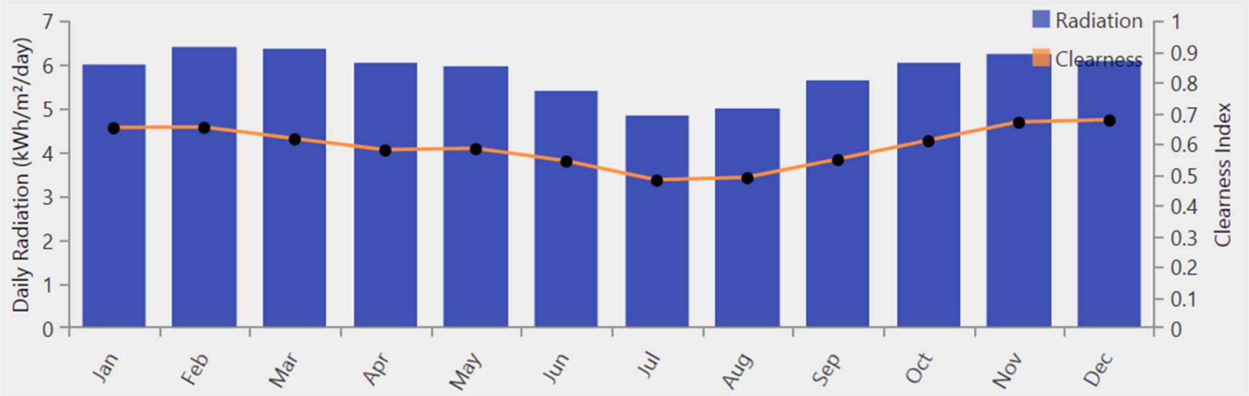


Figure 3. 4: Solar Radiation Profile and Clearness Index of The Selected Location using HOMER software

3.3 Directional Over-current Relay Protection Coordination

Directional over-current relaying (DOCR) is simple, economic, have the possibility to choose different tripping characteristics and therefore is commonly used as primary power system protection in distribution systems. A primary protection should operate every time a protection element detects a fault on the power system. Also, back up relay protection should be provided to operate when, for whatever reason, the primary protection does not work. The backup protection should be designed with a time-delay to postpone the operation of the relay and give time for the primary protection to operate first [25].

3.3.1 Coordination problem formulation

The coordination studies of DOCRs are to find an optimal Time Dial Setting (TDS), objective function, considering linear or nonlinear relay characteristic, relay type, primary and backup relay constraints, and coordination constraints [32]. The coordination problem of overcurrent relays is formulated as an optimization problem. To optimize the nonlinear objective function, various nonlinear inequality constraints shall be satisfied.

A) Objective Function

DOCR coordination problem can be formulated as optimization problem, where the objective function to be minimized is the sum of the operating times of the relays connected to the system function in its Time Dial Setting (TDS). The above problem can be formulated mathematically as: [32]

$$min \sum_i \sum_j T_{ijprimary} \qquad 9$$

where T_{ij} is the operating time of the primary relay i for a fault j. In this work, the following formula is used to approximately represent the OCR characteristics:

$$T = K_1 \frac{TDS}{M^{K_2+K_3}} \qquad 10$$

Where, $M = \frac{I}{I_P}$

I is relay current, I_P is the relay's pickup current and K_1, K_2, K_3 are constants depending on the type of the relay simulated.

B) Constraints

The objective function is possible to be achieved if relay parameters constraints and coordination constraints are fulfilled.

The relay parameters constraints are *TDS* and *PS* boundaries:

$$I_{ipmin} \leq I_{pi} \leq I_{pimax}$$

The boundary of the Ip can be calculated as:

$$I_{ipmin} = 1.25 * I_n \ , \ I_{pimax} = \frac{2}{3} * I_{fmin}$$

Where I_n is the normal current rating which protected by the relay R_i. $I_{f\,min}$ is the minimum value of current which is detected as fault by relay R_i

The boundary of TDS is given as:

$$TDS_{imi} \leq TDS_i \leq TDS_{imax}$$

The TDS value is the time delay that varies. Where TDS_{min} is minimum limit and TDS_{max} is maximum limit value of TDS for relay R_i.

The coordination constraints are in between Back-up and Primary relay. The selectivity should fulfill the time interval required. The primary relay should react in advanced during fault occurrences as compared to back-up relay and not vice versa to escape any sympathy trips.

$$CTI = T_{backup} - T_{primary}$$

Where $T_{primary}$ is primary relay time operating, T_{backup} is the back-up relay time operating.

The coordination problem is subject to the following constraints:[32]

1) Coordination criteria: to achieve a reliable protection system, the primary protection must be backed up by another protection scheme. The two protective schemes should be coordinated together, i.e., a predefined CTI collapses before the backup scheme comes into action. This CTI depends upon the type of the relays (electromechanical or microprocessor based), speed of the circuit breakers, and other system parameters.

$$T_{backup} - T_{primary} \geq CTI \qquad 11$$

2) Relay settings bounds: the main target of DOCR coordination study is the calculation of its TDS and I_P.

$$TDS_{imin} \leq TDS_i \leq TDS_{imax} \;\; , \; I_{ipmin} \leq I_{pi} \leq I_{pimax} \qquad 12$$

In this paper, the coordination problem is addressed as a linear optimization one, i.e., HHO is used to solve coordination problem of finding TDS of the relays for a given IP's. Also, it should be clear that HHO can address both linear and non-linear optimization problems.

3.3.2 Coordination with the impact of DG

The main target of this study is the distribution level to address the impact of DG, the distribution level (33 kV) portions are only considered.[33]

Two cases are examined to show the impact of adding DG on the setting of the protective relays and the mis-coordination that may be happen.

Case A: It is the base case with well-established relay coordination, where there is no DG presented in the system.

Case B: DG is added to the system, where relays mis-coordination happened.

Case A: Relay Coordination for the Original system. This case is considered as a base system case without DGs to evaluate the most optimal relay settings. HHO is used to find the optimal TDS of the system. A MatLab program is developed to calculate short circuit and load flow for this system, the three phase faults are applied at the near-end of each relay (close-in faults), also another MatLab program is used to simulate the HHO technique, the convergence of HHO to the optimum solution.

Case B: The presence of DG will change the normal power flow as well as the short-circuit current all over the system, which is not restricted to the DG connected bus. Due to the presence of DG a relay mis-coordination happened.

New relay coordination must be done again, to evaluate the new optimal relay settings, HHO technique is used to find the optimal TDS of the system.

3.3.3 Flowchart of the optimal DOCR setting and coordination

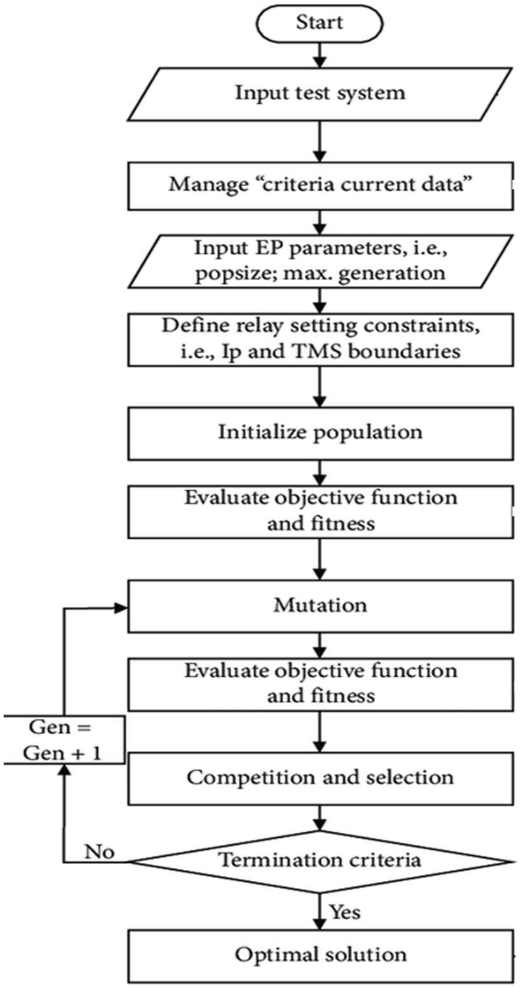


Figure 3. 5: The Flowchart of Optimal DOCR Setting & Coordination

3.4 Model of Directional Over-current Relay

Over-current relays are modelled in DIgSILENT/Power Factory combining the definite time and inverse time characteristic as better protection selectivity is achieved.

Furthermore, it must be considered that when distributed generation is connected to a distribution system, the protection topology must be changed as fault currents can circulate in both directions throughout a system device (see Figure 3.6). Therefore, directional over-current relays should be used to guarantee a safe operation scenario.

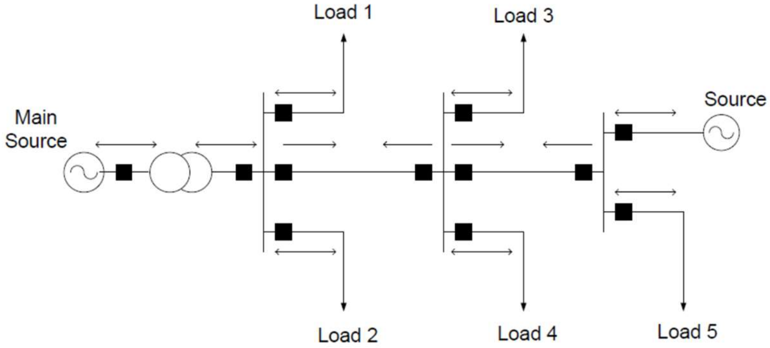


Figure 3. 6: Sample of Directional Over-Current Relays in Multi-Source Networks

Directional over-current relays are formed by adding a directional block on an over-current unit, which determines the direction of the power flow in the associated distribution element. The directional unit typically requires a reference signal to determine the angle of the fault to decide if the relay should operate. The reference signal is provided by voltage and current transformers [25]. In Figure 3.7, the blocks used to model the relay in DIgSILENT are shown**.**

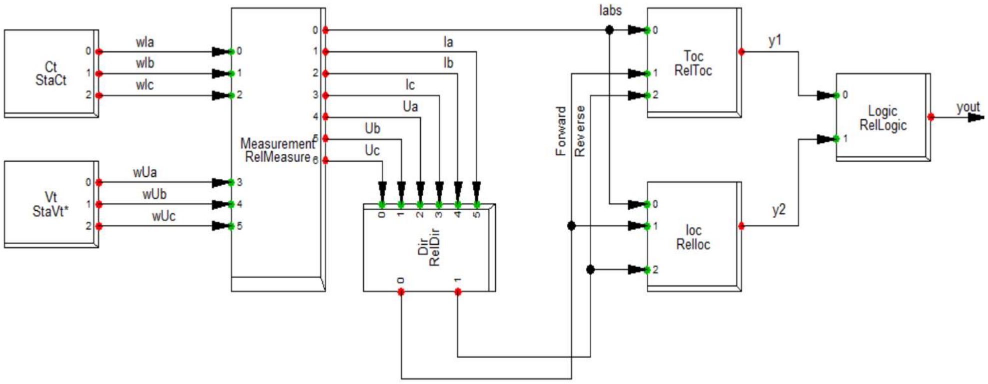


Figure 3. 7: Sample Block Diagram of Directional Over-Current Relay

The current transformer (Ct) and voltage transformer (Vt) sense the currents and voltages, respectively, which are measured by the *RelMeasure* block. Once the measurements are carried out, signals are sent to the *RelDir* detection block, which determines if the current is flowing in a reverse or forward direction and send the appropriate signal to the time over-current block (RelToc) and to the instantaneous over-current block (RelIoc). If the current is higher than the instantaneous pick up current (I_{inst}) then the *RelIoc* block gives trip signal. If the current is lower than I_{inst} but higher than the pickup current (I_p), a trip signal is produced depending on the characteristic curve of the *RelToc* block. Any of these signals can activate relay pick up (OR operation), which is represented by the logic block (RelLogic).

3.5 Proposed Adaptive Protection Scheme Design

The adaptive algorithm selects the right sets of setting according to the incident conditions on the network, and therefore, ICPU updates the relay settings accordingly.[34]

To build the adaptive protection scheme the following equipment and infrastructures must be need. Requirements of adaptive protection scheme are: -

i. Substation master computer (Intelligent Central Protection Unit (ICPU))

The master computer is the main component of this scheme, it communicates with all the relays in the system choosing the correct settings for each relay using communication module, also the master computer monitors the system for any topological changes.

ii. Microprocessor relays

To follow instruction, read information, communicate with the outside world, store settings and switch between them. Microprocessor-based relay firmware should evaluate the need to apply updated firmware. While many firmware updates may not be critical to the relay protection functions, updated firmware that corrects critical protection functions should be given priority.

iii. Communication facility

An important part of wide-scale Adaptive Protection is the communication system required to transmit data and commands between substation's computer and relays. IEC and IEEE have standard communication protocols for digital relays that should be adopted by all the relays' manufacturers, promoting the use and security of the more advanced features of digital relays, the communication could be through the internet.

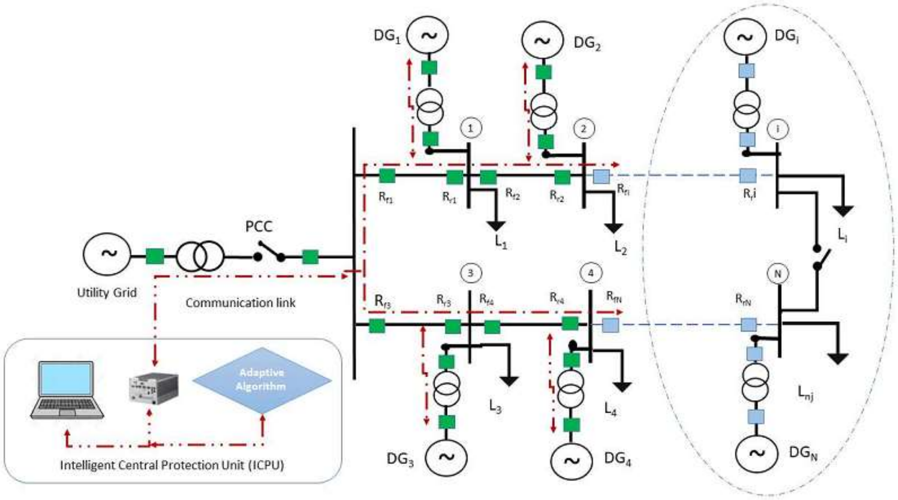


Figure 3. 8: Adaptive Protection Scheme for Generalized N-Bus Microgrid [34]

3.5.1 Flowchart of Adaptive protection Scheme

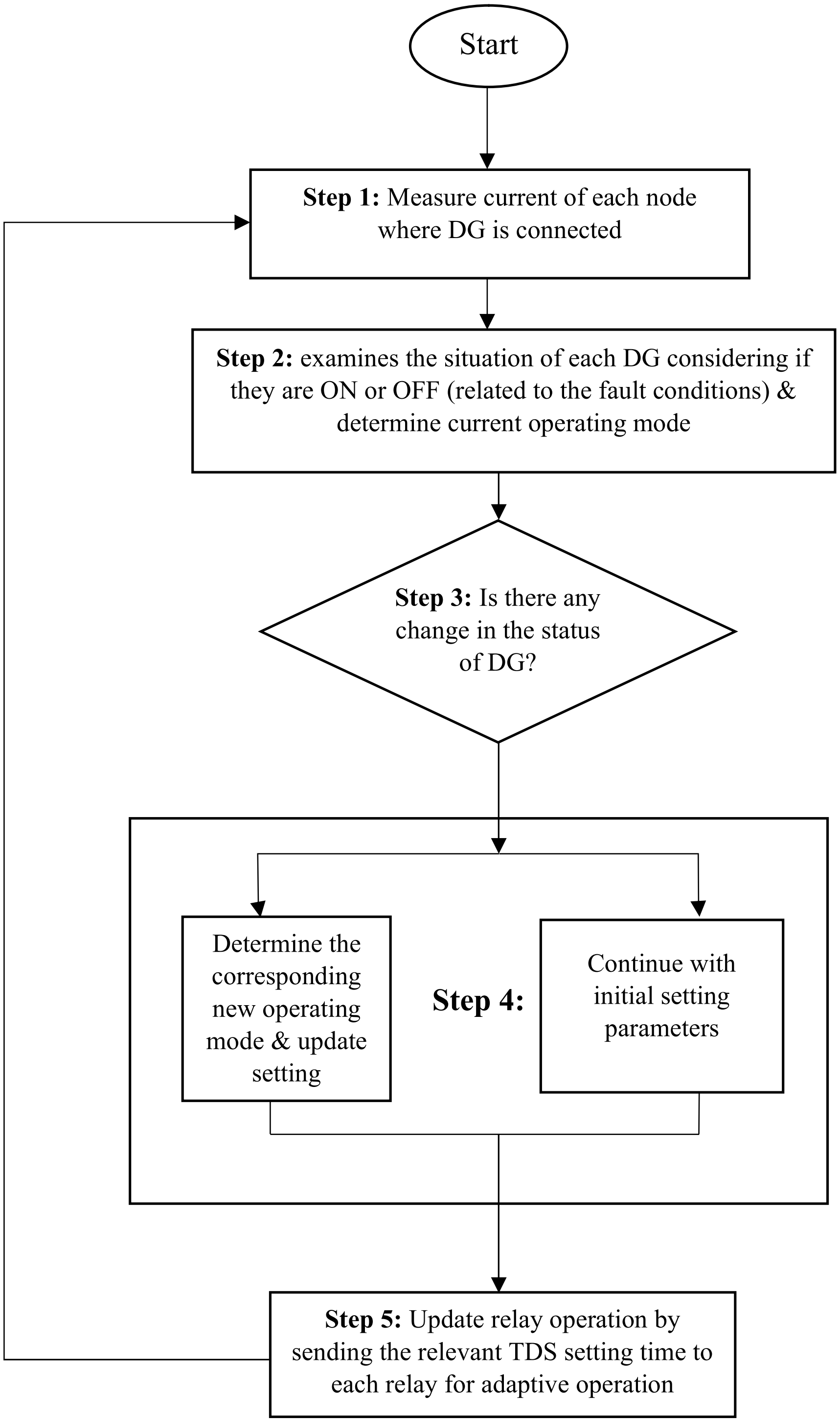


Figure 3. 9: The Flowchart of Adaptive Protection Scheme

3.6 Harris Hawks Optimization (HHO)

In 1997, Louis Lefebvre proposed an approach to measure the avian ‘‘IQ’’ based on the observed innovations in feeding behaviors. The Harris’ hawk (Parabuteo unicinctus) is a well-known bird of prey that survives in somewhat steady groups found in southern half of Arizona, USA. Harmonized foraging involving several animals for catching and then, sharing the slain animal has been persuasively observed for only particular mammalian carnivores. The Harris’s hawk is distinguished because of its unique cooperative foraging activities together with other family members living in the same stable group while other raptors usually attack to discover and catch a quarry, alone. This avian desert predator shows evolved innovative team chasing capabilities in tracing, encircling, flushing out, and eventually attacking the potential quarry. These smart birds can organize dinner parties consisting of several individuals in the non-breeding season. They are known as truly cooperative predators in the raptor realm. As reported by Bednarz [59] in 1998, they begin the team mission at morning twilight, with leaving the rest roosts and often perching on giant trees or power poles inside their home realm. They know their family members and try to be aware of their moves during the attack. When assembled and party gets started, some hawks one after the other make short tours and then, land on rather high perches. In this manner, the hawks occasionally will perform a ‘‘leapfrog’’ motion all over the target site and they rejoin and split several times to actively search for the covered animal, which is usually a rabbit.[35]

The main tactic of Harris’ hawks to capture a prey is ‘‘surprise pounce’’, which is also known as ‘‘seven kills’’ strategy. In this intelligent strategy, several hawks try to cooperatively attack from different directions and simultaneously converge on a detected escaping rabbit outside the cover. The attack may rapidly be completed by capturing the surprised prey in few seconds, but occasionally, regarding the escaping capabilities and behaviors of the prey, the seven kills may include multiple, short-length, quick dives nearby the prey during several minutes. Harris’ hawks can demonstrate a variety of chasing styles dependent on the dynamic nature of circumstances and escaping patterns of a prey. A switching tactic occurs when the best hawk (leader) stoops at the prey and get lost, and the chase will be continued by one of the party members. These switching activities can be observed in different situations because they are beneficial for confusing the escaping rabbit. The main advantage of these cooperative tactics is that the Harris’ hawks can pursue the detected rabbit to exhaustion, which increases its vulnerability. Moreover, by perplexing the escaping prey, it cannot recover its defensive capabilities and finally, it cannot escape from the confronted team besiege since one of the hawks, which is often the most powerful and experienced one, effortlessly captures the tired rabbit and shares it with other party members.[35]

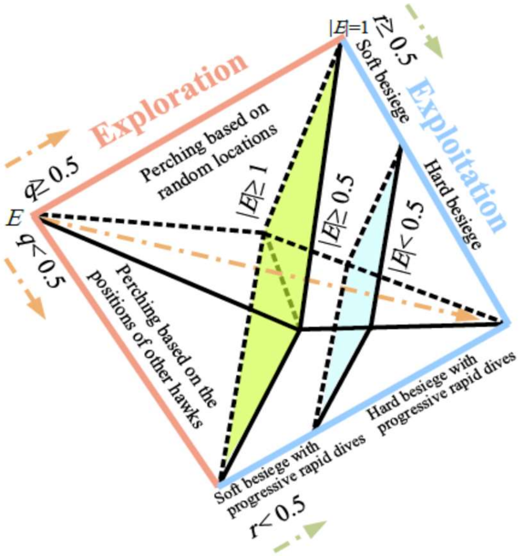


Figure 3. 10:Different Phases of HHO [35]

3.6.1 Exploration phase

In this part, the exploration mechanism of HHO is proposed. If we consider the nature of Harris' hawks, they can track and detect the prey by their powerful eyes, but occasionally the prey cannot be seen easily. Hence, the hawks wait, observe, and monitor the desert site to detect a prey maybe after several hours. In HHO, the Harris' hawks are the candidate solutions and the best candidate solution in each step is considered as the intended prey or nearly the optimum. In HHO, the Harris' hawks perch randomly on some locations and wait to detect a prey based on two strategies. If we consider an equal chance q for each perching strategy, they perch based on the positions of other family members (to be close enough to them when attacking) and the rabbit, which is modeled in Eq. (13) for the condition of q < 0.5, or perch on random tall trees (random locations inside the group's home range), which is modeled in Eq. (13) for condition of q ≥ 0.5.

$$X(t+1) = \begin{cases} X_{rand}(t) - r_1 |X_{rand}(t) - 2r_2 X(t)| & q \geq 0.5 \\ (X_{rabbit}(t) - X_m(t)) - r_3(LB + r_4(UB - LB)) & q < 0.5 \end{cases} \qquad 13$$

where X (t + 1) is the position vector of hawks in the next iteration t, Xrabbit(t) is the position of rabbit, X(t) is the current position vector of hawks, r1, r2, r3, r4, and q are random numbers inside (0,1), which are updated in each iteration, LB and UB show the upper and lower bounds of variables, Xrand(t) is a randomly selected hawk from the current population, and Xm is the average position of the current population of hawks. The average position of hawks is attained using Eq. (14):

We proposed a simple model to generate random locations inside the group's home range (LB, UB). The first rule generates solutions based on a random location and other hawks. In second rule of Eq. (13), we have the difference of the location of best so far and the average position of the group plus a randomly scaled component based on range of variables, while r_3 is a scaling coefficient to further increase the random nature of rule once r_4 takes close values to 1 and similar distribution patterns may occur. In this rule, we add a randomly scaled movement length to the LB. Then, we considered a random scaling coefficient for the component to provide more diversification trends and explore different regions of the feature space. It is possible to construct different updating rules, but we utilized the simplest rule, which can mimic the behaviors of hawks. The average position of hawks is attained using Eq. (14):

$$X_m(t) = \frac{1}{N}\sum_{i=1}^{N} X_i(t) \qquad 14$$

where Xi(t) indicates the location of each hawk in iteration t and N denotes the total number of hawks. It is possible to obtain the average location in different ways, but we utilized the simplest rule.[59]

3.6.2 Transition from Exploration to Exploitation

To model this step, the energy of a rabbit is modeled as:

$$E = 2E_0(1 - \frac{t}{T}) \qquad 15$$

where E indicates the escaping energy of the prey, T is the maximum number of iterations, and E_0 is the initial state of its energy. The time-dependent behavior of E is also demonstrated in Figure (3.11).

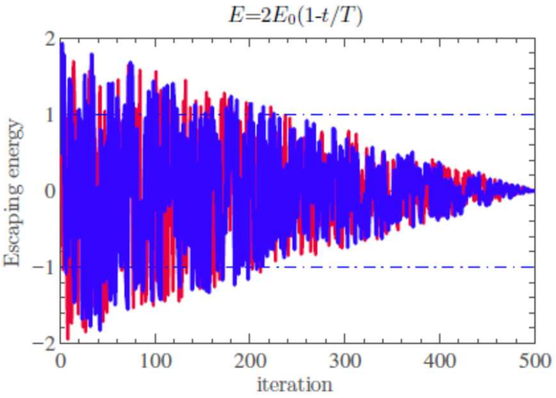


Figure 3. 11: Behavior of E During Two Runs and 500 Iterations [35]

3.6.3 Exploitation phase

3.6.3.1 Soft besiege

This behavior is modeled by the following rules:

$$X(t+1) = \Delta X(t) - E\left|JX_{rabbit}(t) - X(t)\right| \qquad 16$$

$$\Delta X(t) = X_{rabbit}(t) - X(t) \qquad 17$$

where _X(t) is the difference between the position vector of the rabbit and the current location in iteration t, r_5 is a random number inside (0,1), and $J = 2(1-r_5)$ represents the random jump strength of the rabbit throughout the escaping procedure. The J value changes randomly in each iteration to simulate the nature of rabbit motions.

3.6.3.2 Hard besiege

In this situation, the current positions are updated using Eq. (18):

$$X(t+1) = X_{rabbit}(t) - E|\Delta X(t)| \qquad 18$$

A simple example of this step with one hawk is depicted in Figure 3.12.

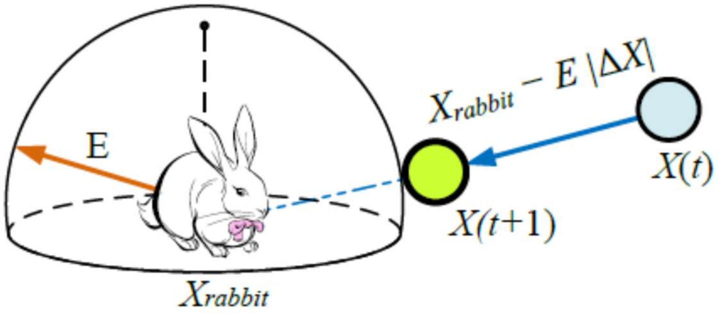


Figure 3. 12: Example of Overall Vectors in the Case of Hard Besiege [35]

3.6.3.3 Soft besiege with progressive rapid dives

To perform a soft besiege, we supposed that the hawks can evaluate (decide) their next move based on the following rule in Eq. (13):

$$Y = X_{rabbit}(t) - E|JX_{rabbit}(t) - X(t)| \qquad 19$$

We supposed that they will dive based on the LF-based patterns using the following rule:

$$Z = Y + S \times LF(D) \qquad 20$$

where D is the dimension of problem and S is a random vector by size 1 x D and LF is the levy flight function, which is calculated using Eq. (21):

$$LF(x) = 0.01 \times \frac{u \times \sigma}{|v|^{\frac{1}{\beta}}}, \sigma = \left(\frac{F(1+\beta) \times sin\left(\frac{\pi\beta}{2}\right)}{F(\frac{1+\beta}{2}) \times \beta \times 2^{\left(\frac{\beta-1}{2}\right)})} \right)^{\frac{1}{\beta}} \qquad 21$$

where u, v are random values inside (0,1), β is a default constant set to 1.5.

Hence, the final strategy for updating the positions of hawks in the soft besiege phase can be performed by Eq. (22):

$$X(t+1) = \begin{cases} Y & if\ F(Y) < F(X(t)) \\ Z & if\ F(Z) < F(X(t)) \end{cases} \qquad 22$$

where Y and Z are obtained using Eqs. (24) and (25).

A simple illustration of this step for one hawk is demonstrated in Fig. 3.13.

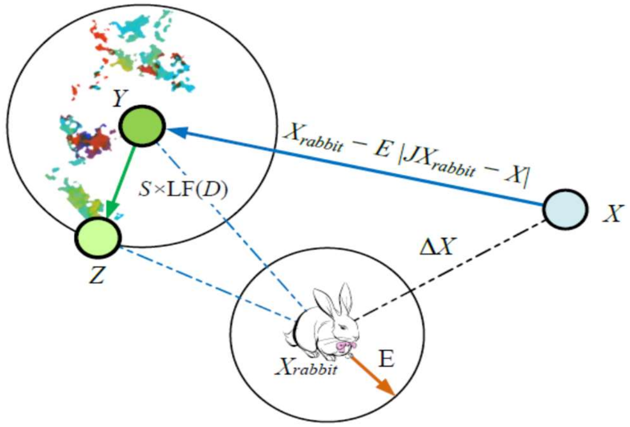


Figure 3. 13:Example of Overall Vectors in the Case of Soft Besiege with Progressive Rapid Dives [35]

3.6.3.4 Hard besiege with progressive rapid dives

The following rule is performed in hard besiege condition:

$$X(t+1) = \begin{cases} Y & if\ F(Y) < F(X(t)) \\ Z & if\ F(Z) < F(X(t)) \end{cases} \qquad 23$$

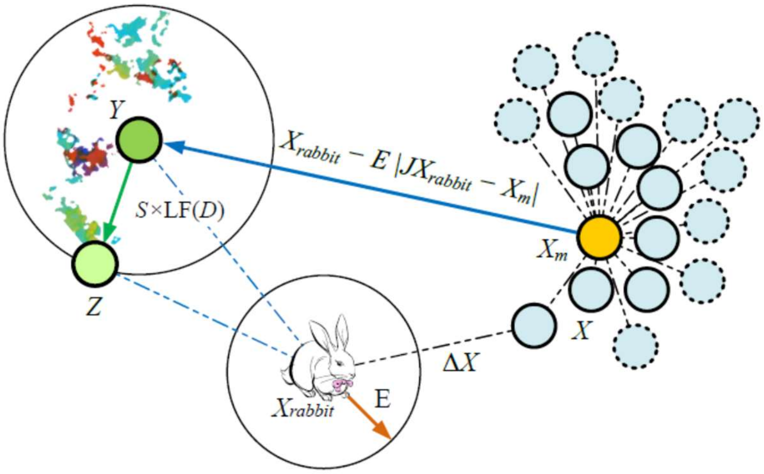
where Y and Z are obtained using new rules in Eqs. (24) and (25).

$$Y = X_{rabbit}(t) - E|JX_{rabbit}(t) - X_m(t)| \qquad 24$$

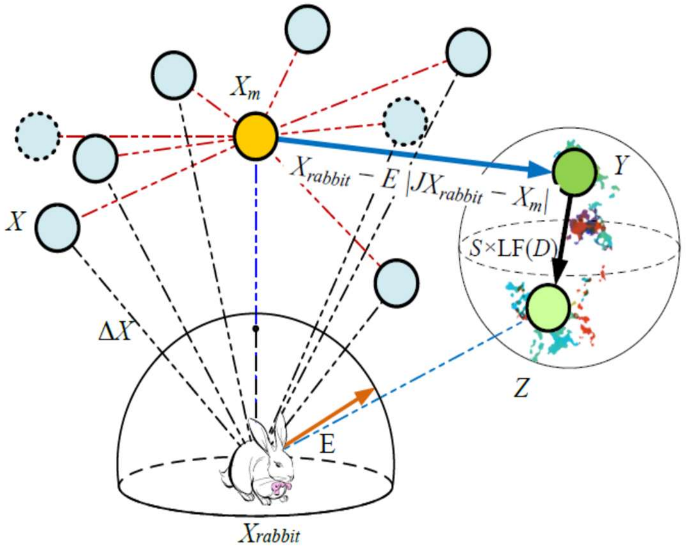
$$Z = Y + S \times LF(D) \qquad 25$$

where $X_m(t)$ is obtained using Eq. (14).

A simple example of this step is demonstrated in Figure (3.14).



(a) The process in 2D space



(b) The process in 3D space

Figure 3. 14: Example of Overall Vectors in the Case of Hard Besiege with Progressive Rapid Dives in 2D and 3D Space [35]

3.6.4 Pseudocode of HHO

The pseudocode of the proposed HHO algorithm is reported in Algorithm 1.[35]

```
Algorithm 1 Pseudo-code of HHO algorithm
Inputs: The population size N and maximum number of iterations T
Outputs: The location of rabbit and its fitness value
Initialize the random population Xi (i = 1; 2;...; N)
while (stopping condition is not met) do
    Calculate the fitness values of hawks
    Set $X_{rabbit}$ as the location of rabbit (best location)
    for (each hawk (Xi)) do
        Update the initial energy E0 and jump strength J        ▷E0=2rand()-1, J=2(1-rand())
        Update the E using Eq. (15)
        if (|E| ≥ 1) then                                      ▷Exploration phase
            Update the location vector using Eq. (13)
        if (|E| < 1) then                                      ▷Exploitation phase
            if (r ≥0.5 and |E|≥ 0:5) then                      ▷Soft besiege
                Update the location vector using Eq. (16)
            else if (r ≥0.5 and |E| < 0:5) then                ▷Hard besiege
```

```
        Update the location vector using Eq. (18)
    else if ($r$ <0.5 and |E|≥ 0:5) then        ▷Soft besiege with progressive rapid dives
            Update the location vector using Eq. (22)
    else if ($r$ <0.5 and |E| < 0:5) then        ▷Hard besiege with progressive rapid dives
            Update the location vector using Eq. (23)
Return $X_{rabbit}$
```

3.6.5 Flowchart of HHO

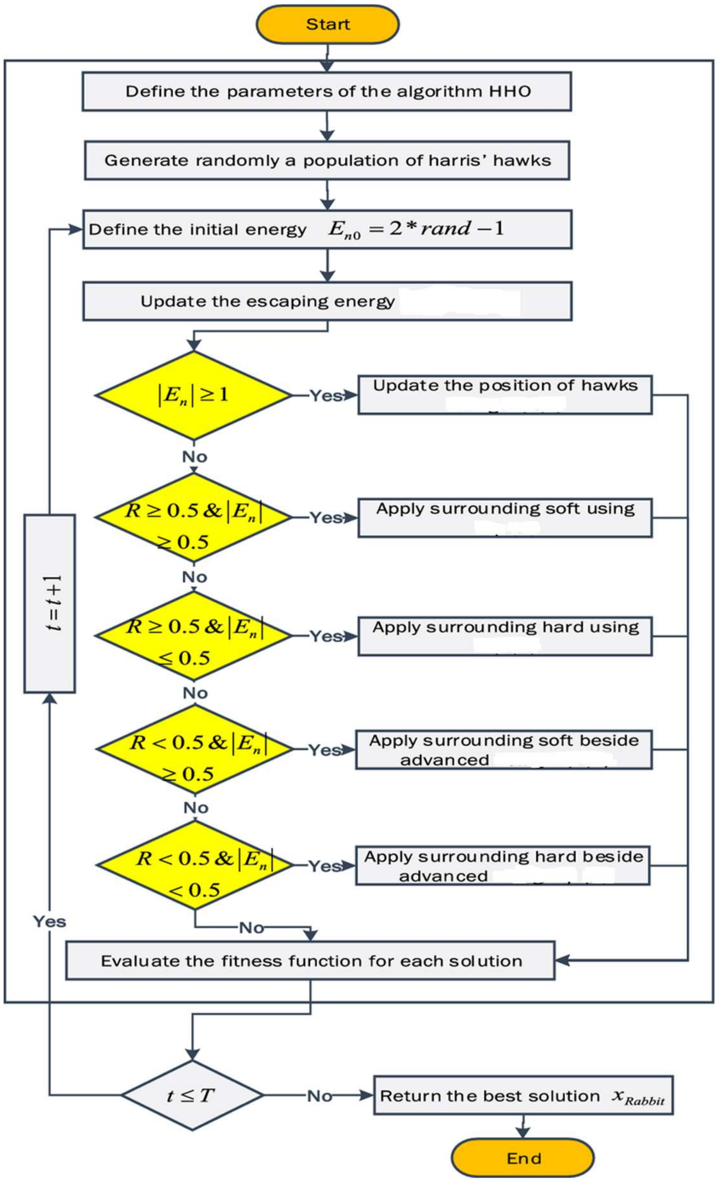


Figure 3. 15: Flowchart of HHO

CHAPTER 4

RESULT AND DISCUSSION

4.1 Modelling of Distribution System

In this study a 33 kV distribution network in Hawassa substation has been chosen. The single line diagram of the distribution system is shown in figure 4.1. The network is formed by four 33KV radial feeders. The substation has fourteen feeders are outgoing out these outgoing feeders ten are 15KV feeders and the rest 33KV feeder are shown on below distribution model.

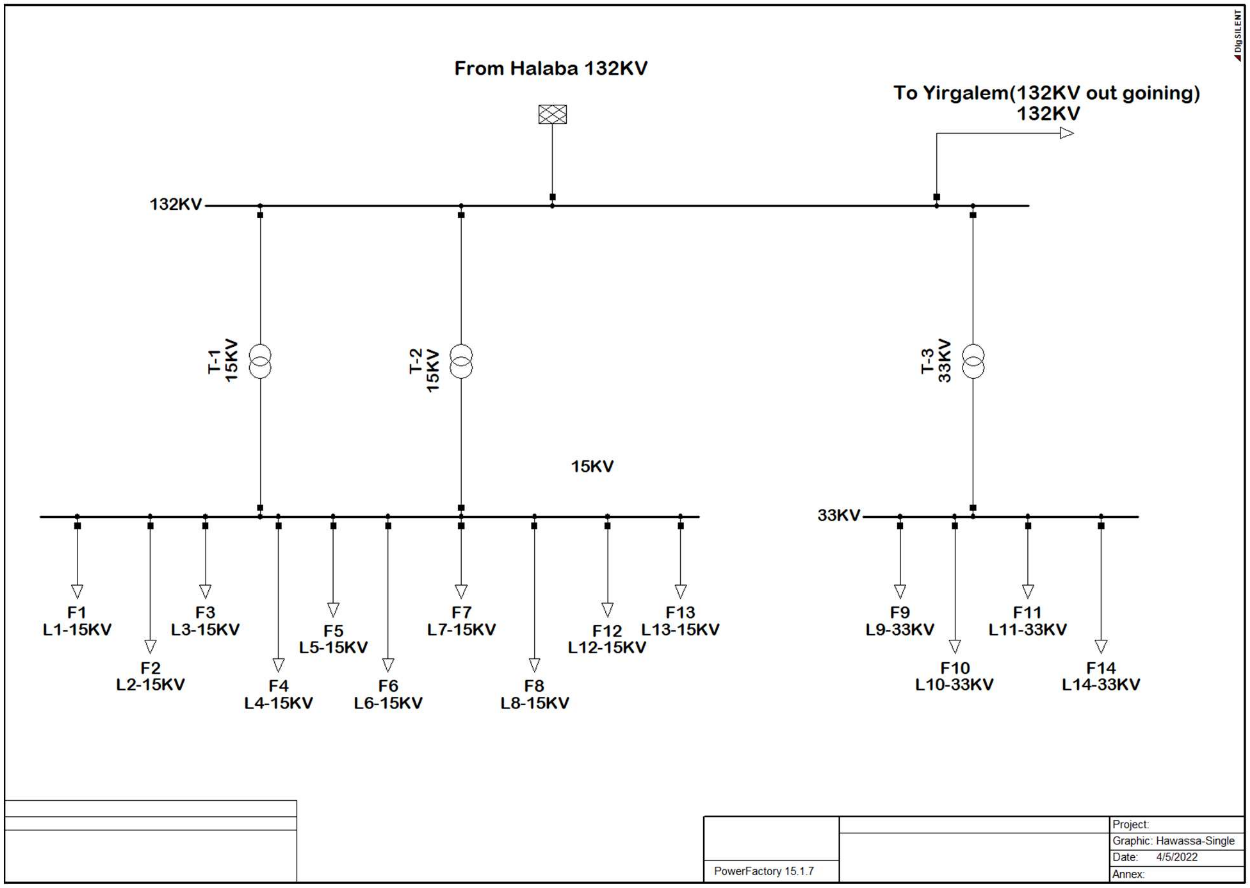


Figure 4. 1: Local Distribution Network at Hawassa Substation

Out of four feeders of 33KV the selected feeder for investigation can be model as below using the DigSilent (Power Factory) software, for selection of feeder the HHO algorithm was used and further discussion on next section of the chapter.

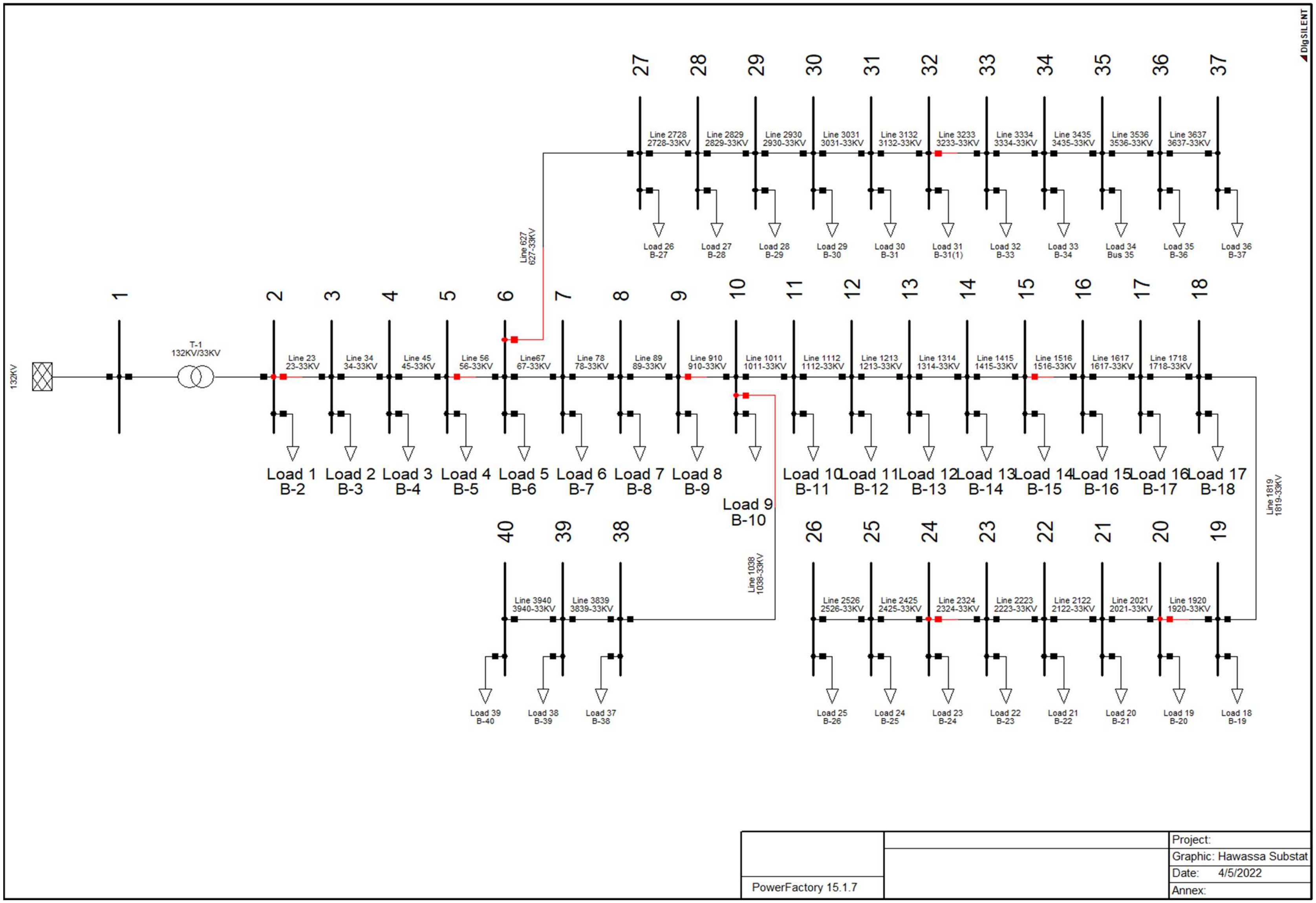


Figure 4. 2: The Model of Distribution Network of Feeder 10 with 40 Buses

4.2 Optimal Placement and Sizing of DG in Distribution System Using HHO Algorithm

The major goal of this section is to determine the best placement and size for DGs with the least amount of network power loss and a better voltage profile. In this work, the inequality constraints are converted to the penalty functions (PFs), and these PFs are added to the OF to construct the fitness function (FF) defined in Equation (26).

$$Minimum\, FF = OF + PF \times \sum_{j=1}^{VB} (\Delta V_j)^2 \qquad 26$$

Here, FF is essential to be minimized to get minimum loss value, VB represents the set of overloaded lines and voltage violated load buses, and PF represents the penalty factor, OF is objective function.

$$OF = Minimize\ (P_{Loss}) \qquad 27$$

Where, $P_{Loss} = \sum_{k=1}^{n} gk(V_i^2 + V_j^2 - 2V_i \times V_j \times \cos(\delta_i - \delta_j))$ 28

where gk is the conductance of branch k; Vi and Vj are the magnitude of voltages at sending and receiving bus, respectively; δi is the phase angle at ith and jth bus, respectively.

The violation in inequality constraints such as load bus voltage and line power flows were handled using the penalty function approach. PF that represents penalty factor was taken as 10,000 throughout the simulation process.

4.2.1 Computational Practice of HHO for DG Location and Size

Step 1- Read the input data of the system, such as the maximum number of iterations, number of DG units, and population size.

Step 2- Generate the value of the size of DG within their upper (DG_{max}) and lower limits (DG_{min}). The same is shown in Equation (29).

$$DG_i = DG_i^{min} + rand \times \left(DG_i^{max} - DG_i^{min}\right) \qquad 29$$

Here, DG_i represents the size of i_{th} DG unit. Now, constitute a vector X_j, that contains the possible locations (LOC) and size of DGs as mentioned in Equation (30).

$$X_j = \left[DG_{j,1}, DG_{j,2}, \ldots\ldots\ldots, DG_{j,n}, LOC_{j,1,} LOC_{j,2}, \ldots\ldots, LOC_{j,n}\right] \qquad 30$$

The LOC is generated randomly. Initial solution set X is then formulated as shown in Equation (31).

$$X = [X_1, X_2, \ldots\ldots\ldots\ldots\ldots, X_N] \qquad 31$$

Step 3- Evaluation of the fitness function is processed using Equation (30) for individual Harris hawks, and the best hawk location is acknowledged.

Step 4 Calculate E using Equation (32).

$$E = 2E_0(1 - \frac{t}{T}) \qquad 32$$

Step 5- Exploration phase: Update the location of Harris hawks using Equation (33).

$$X(t+1) = \begin{cases} X_{rand}(t) - r_1 |X_{rand}\,(t) - 2r_2 X(t)| & q \geq 0.5 \\ (X_{rabbit}(t) - X_m(t)) - r_3(LB + r_4(UB - LB)) & q < 0.5 \end{cases} \qquad 33$$

Step 6- Exploitation phase: Update the position using Equation (24), (35), (36), and (37).

$$X(t+1) = \Delta X(t) - E|JX_{rabbit}(t) - X(t)| \qquad 34$$

$$X(t+1) \ = \ X_{rabbit}(t) - E|\Delta X(t)| \qquad 35$$

$$X(t+1) = \begin{cases} Y & if\ F(Y) < F(X(t)) \\ Z & if\ F(Z) < F(X(t)) \end{cases} \quad 36$$

$$X(t+1) = \begin{cases} Y & if\ F(Y) < F(X(t)) \\ Z & if\ F(Z) < F(X(t)) \end{cases} \quad 37$$

Step 7- Once the number of iterations reaches the maximum value, then terminate. Else, go back to Step 3.

4.2.2 Simulation Results and Discussions

The proposed HHO-based approach is applied to find the suitable location and capacity of the DGs in the 40-bus radial distribution system test system where the network and load data. From 40-bus radial distribution system has a total of 40 buses, among which 39 are load buses and 1 is a generator bus. It can be visualized from Figure (4.2) that at bus number 1 generator is connected; the other buses may have any type of load connected, as per the requirement. The total active power demand is 3.996 MW while reactive is 1.94 MVAR. Total power loss of the system is 0.78395 MW.

To find candidate buses for locating a DG using this approach for each individual bus, it is assumed that there is a DG at that bus at a time. For optimal sizing of a DG at this stage, it is assumed that the DG may produce electric power in all possible ranges (e.g., 0–10 MW). The proposed HHO algorithm is applied for the minimization of overall loss as the objective function of the problem. First, only one DG is used to relax the congestion in lines, and the results obtained are tabulated in Table (4.1). With the application of proposed HHO on distribution problem, the losses are reduced to 129.2KW from 783.95kW with only one DG in installation of size 0.95 MW.

For further improvement, the problem is tested by installing two DGs in the power network. The results obtained are presented in Table (4.1). The overall active power losses decreased to 86.9KW with the application of two DGs, using HHO.

Table 4. 1: Variation in Power Loss with Change in an Optimal Allocation of DGs

Test System	Buses Counts	DG Location	DG size (MW)	P_{Loss} (KW)	Loss Reduction (%)
40 bus system	1	30	0.95	129.20	48.76
	2	2, 30	0.95, 0.9118	86.90	68.81

4.3 Design of Over-Current Relays for the Distribution System Protection Coordination

The protection coordination of relays, for the test distribution system, is designed based on the condition of the distribution system. Two cases are simulated, and they are: Case-1 is the normal situation without the presence of DG & Case-2 is the situation where DG is installed in the system. Digital directional over-current relays (DOCR) are used for the protection of the radial distribution system to facilitate its operation with DG. Figure (4.3) is modified form figure (4.2) without any DG based on the similarities of transformer and adding the active and reactive loads of the buses. The relays are represented by "**R**" in figure (4.3) with numbers describing the buses that define the beginning and the end of a protection zone. Relay R89 only see forward current when there is a fault in its protection zone and therefore it is designed to trip for smaller current. Considering that if a fault occurs in Line89 close to Bus 8, relay R89 will trip first to clear the fault and relay R78 will provide the backup function. Relays 67, R56, R45, R34 and R23 are designed similarly. The current values are chosen from design study of the test distribution system.

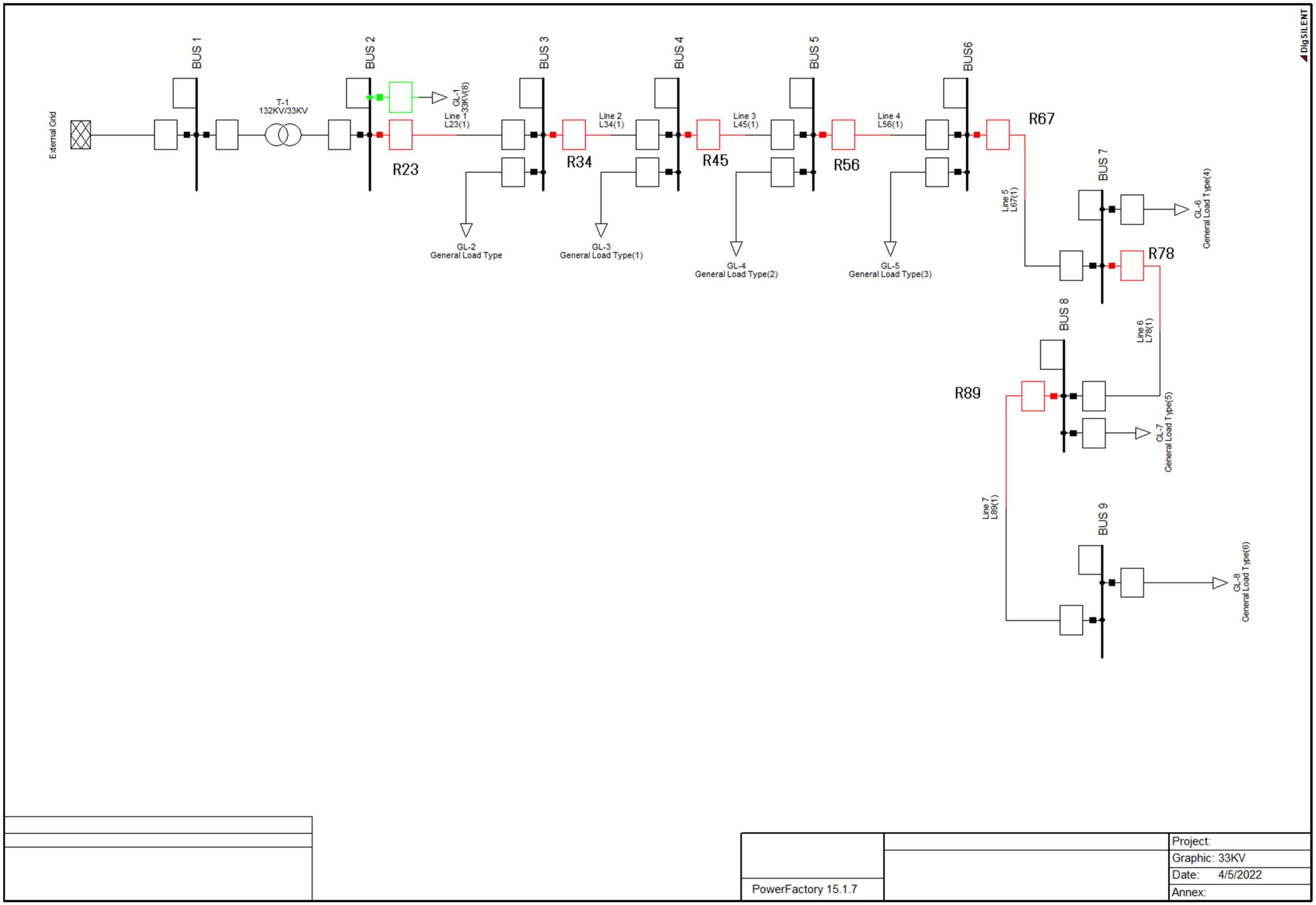


Figure 4. 3: Modified Radial Distribution System for Case-1

The time over current characteristic of relay, pickup current, Time dial setting (TDS) and the instantaneous pickup current is found by using HHO algorithm.

Table 4. 2: The Pickup Currents, Time Dial Setting and Instantaneous Pickup Current for the Individual Relay are Listed.

Relay	I_p (A)	TDS (s)	Instantaneous Pickup Current (A)
R23	650	0.262	5303
R34	525	0.251	5010
R45	410	0.245	4850
R56	325	0.242	4620
R67	250	0.239	4230
R78	200	0.221	3680
R89	150	0.022	3090

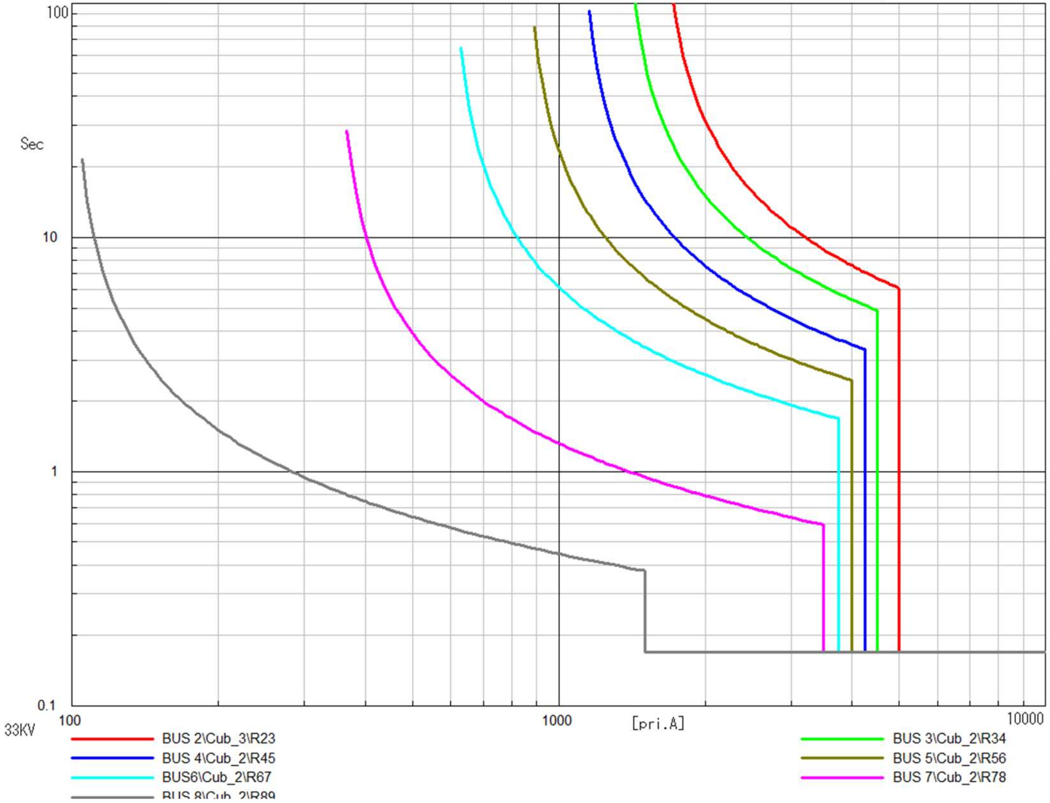


Figure 4. 4: Time Over-Current Characteristic Plot of Relays R23, R34, R45, R56, R67, R78 and R89 for Case1

Time over-current characteristic plot of relays R23, R34, R45, R56, R67, R78 and R89 for Case-1. It is noticed that the proper coordination between relays is achieved.

A three-phase fault, with a resistance of **0.05Ω**, is simulated in Line89 close to Bus 8, when the DG is not connected to the system. Figure (4.5) shows the breaker status; 1 represents that the breaker is closed and 0 represents that it is open. The relay´s time over-current characteristics are as in Figure (4.4). It can be appreciated from the figure that the fault is cleared by opening the breaker for R89, *150ms* after the fault, due to the activation of instantaneous pickup.

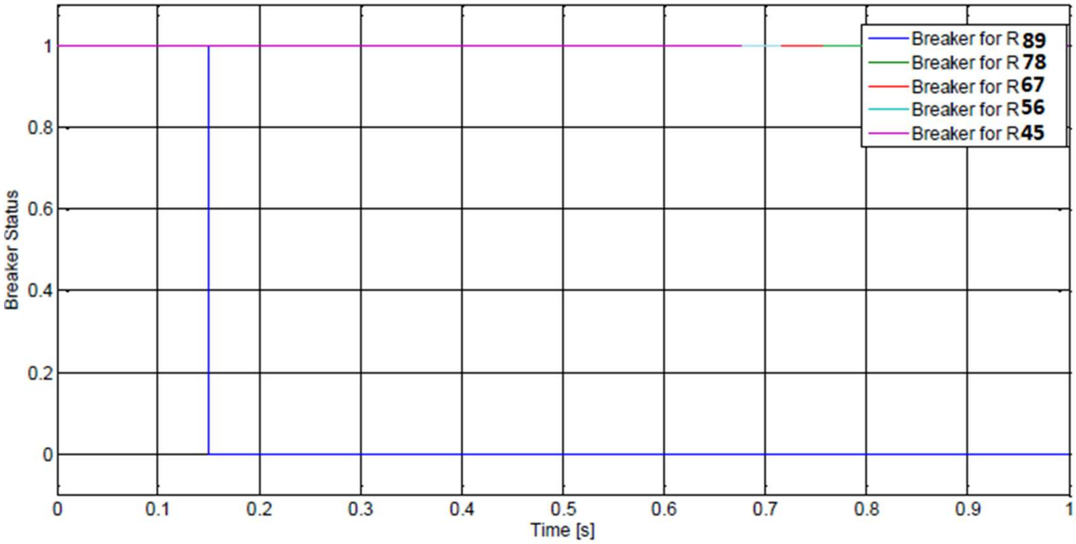


Figure 4. 5:Status of Circuit Breaker at R89 for a Three-Phase Fault in Line89 for Case-1 when Relays are Setting According to Fig. 4.4

The coordination time interval (CTI) between the relay when the fault was happened on the L89 without the DG interconnected the system (Case-1)

Table 4. 3: Coordination Time Interval (CTI) For Case-1

Relays	CTI (Sec)
Between R89 & R78	0.625
Between R78 & R67	1.815
Between R67 & R56	1.911
Between R56 & R45	3.190
Between R45 & R34	7.813
Between R34 & R23	17.437

Time Over-Current Characteristics of Relays R109, R89, R78, R67, R56, R45, R34, R23 And R112 by interconnected of the DG to the existing distribution system without changing the settings of relay and as shown of figure (4.6) the relays miscoordination is happed.

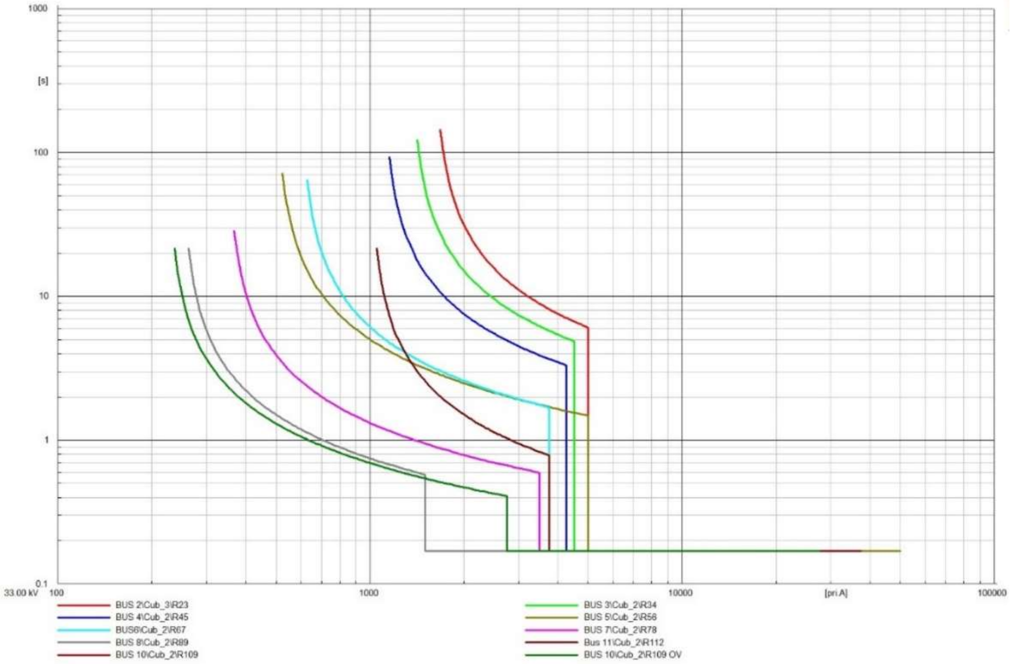


Figure 4. 6: Time Over-Current Characteristics of Relays R109, R89, R78, R67, R56, R45, R34, R23 And R112 when Relays are Setting According to Fig. 4.4

After the DG is interconnected in the system and the same fault is simulated again. Figure (4.7) shows the breaker´s status. As it can be seen all breakers are opening at the same time, *t=150ms* to clear the fault. This situation is not desirable as the coordination purpose is to isolate only the faulted zone.

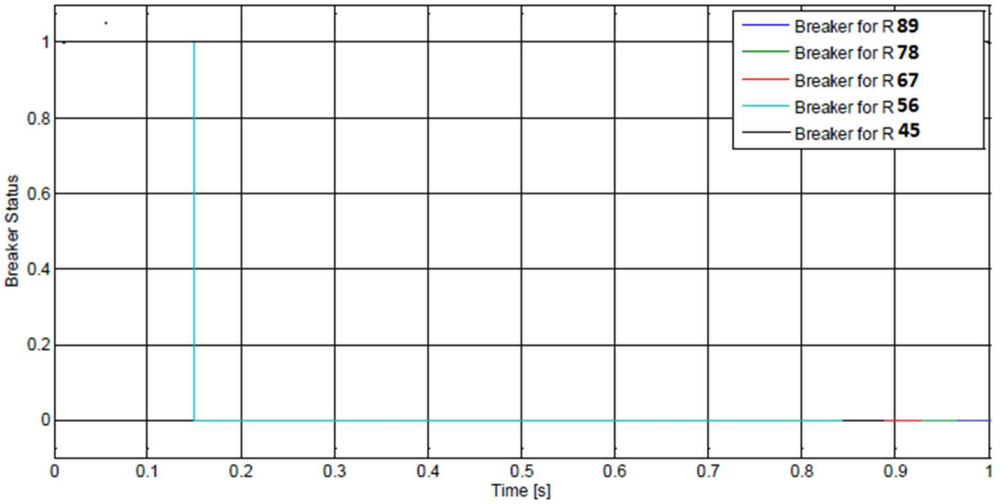


Figure 4. 7: Status of Circuit Breaker R89, R78, R67, R56, R45, & R34 for a Three-Phase Fault in Line89 for Case-2 when Relays are Setting According to Fig. 4.4

There is a significant difference in fault current when the distribution system changes the state from “radial” system to “mesh” type system and hence, coordination may not be attained if the same relay settings are used when DG is interconnected in the system. Figure (4.8) shows the different currents seen in Line89 when a three-phase fault is simulated near to Bus 8 for the case where DG is not considered in the system (see Fig. 4.3) and for the case-2 (DG connected in the system) (see Fig. 4.9). It is observed that this increase in the current is from the contribution of the DG installed in the test system.

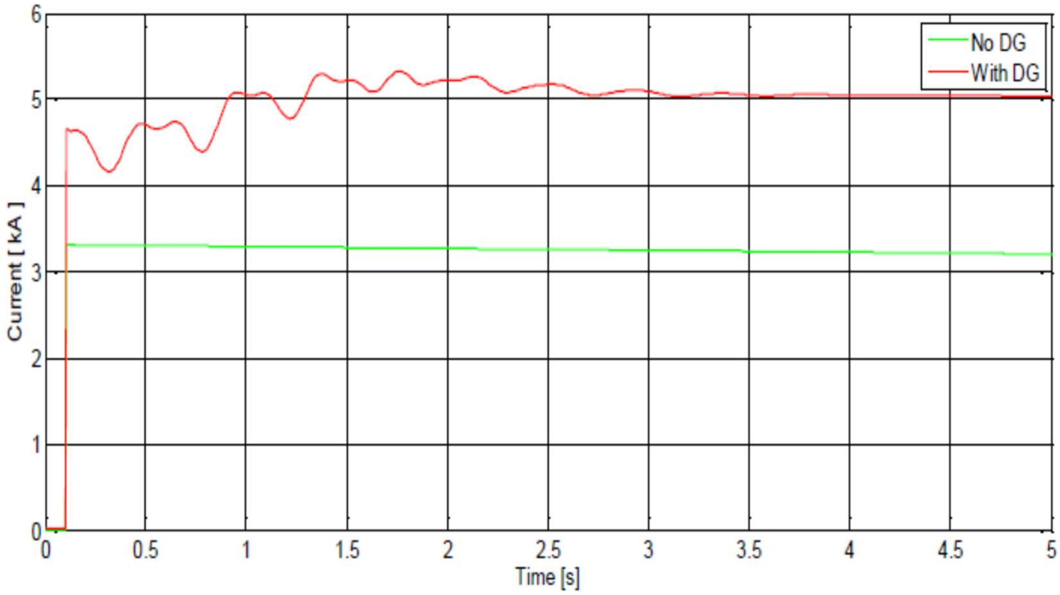


Figure 4. 8: Short-Circuit Current Comparison in Line89 for Case-1 and Case-2

Therefore, the trip characteristics of relays R89, R78, R67, R56, R45, R34 and R23 are calculated for the “mesh” condition as well. In Figure (4.8) the whole system with the DG connected is shown. If a fault occurs in Line109 close to Bus 9 relay R109 picks up after *50ms* (instantaneous pickup) to clear the fault.

If it fails, then R89 picks up *500ms* after fault for I^{89}max109 (current seen by the R89 when a fault occurs in Line109). It is assumed that clearing of a fault takes around *70ms* after the picking up of the relays and the reset time is well within *30ms* [47]. Relays R78, R67, R56, R45, R34, and R23 are designed similarly for their respective currents seen when a fault occurs in Line109. The sources of the fault current for a fault in Line109 are synchronous Generator and the transmission grid. Relay R109 see only forward current when there is a fault in its protective zone and, consequently, it is designed to trip for smaller current.

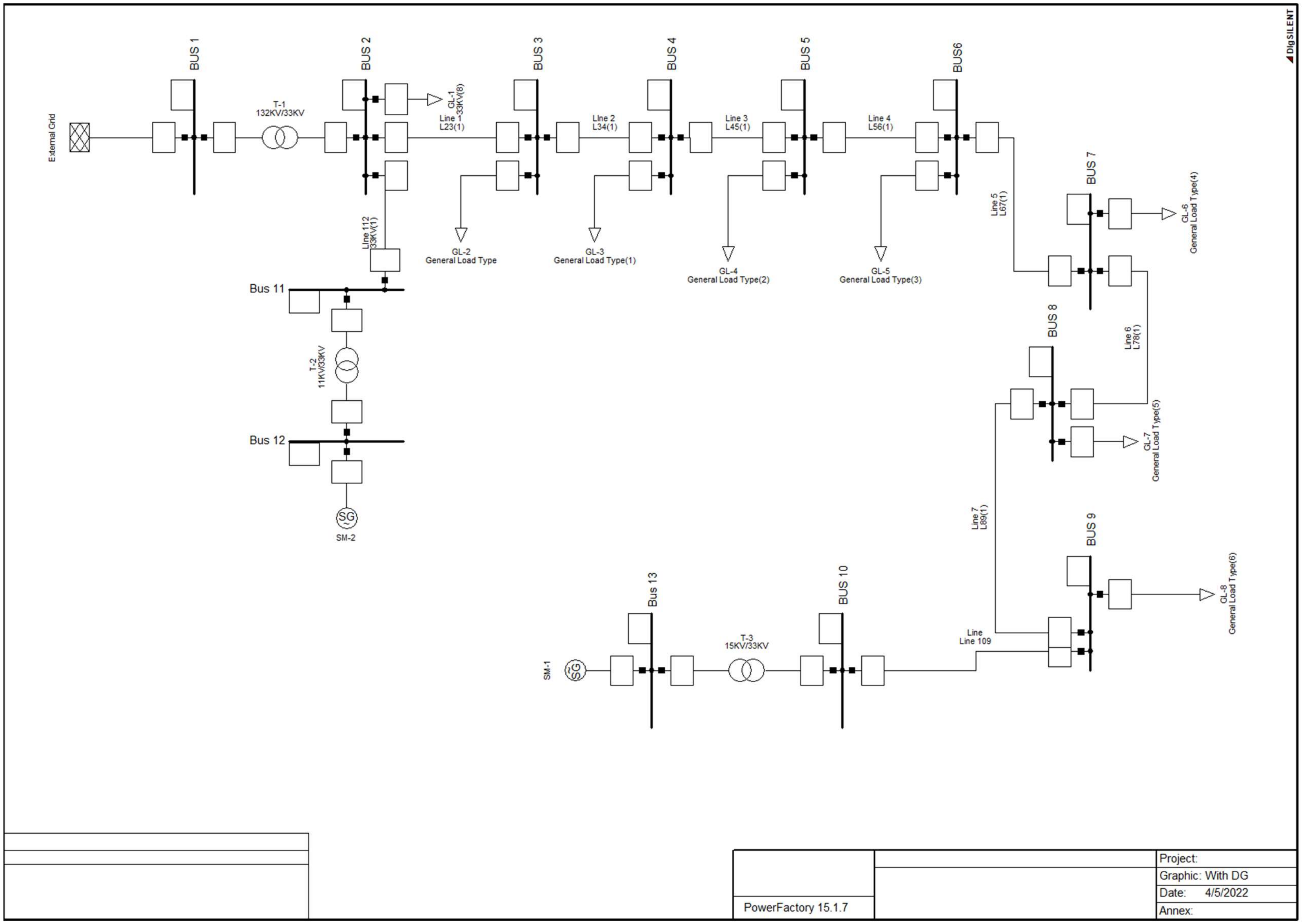


Figure 4. 9: Model of the Test Distribution Network with DGs

The pickup currents, time dial settings and instantaneous pick-up currents for the individual relays are listed in Table (4.4).

Table 4. 4: Time Over-Current Characteristics of Relays R109, R98, R78, R67, R56, R45, R34, R23 and R112 for Case2

Relay	I_p (A)	TDS (s)	Instantaneous Pickup Current (A)
R23	810	0.188	9820
R34	745	0.181	8510
R45	700	0.172	7700
R56	640	0.164	6370
R67	490	0.162	4870
R78	450	0.160	2930
R89	300	0.158	2600
R109	250	0.020	2450
R112	1140	0.155	6590

Figure (4.10) shows the time over-current plots of relays R109, R89, R78, R67, R56, R45, R34, R23 and R112 for Case-2. From a simple observation of Figure (4.10) it looks like relays lose selectivity as the time over-current characteristic of R112 crosses the time over-current characteristics of other relays. Nevertheless, this is not the case, as R112 see forward current only from the Synchronous generator 2 (PV DG-1), whilst the other relays see current from both the synchronous generator and the transmission grid for a fault beyond Bus 02.

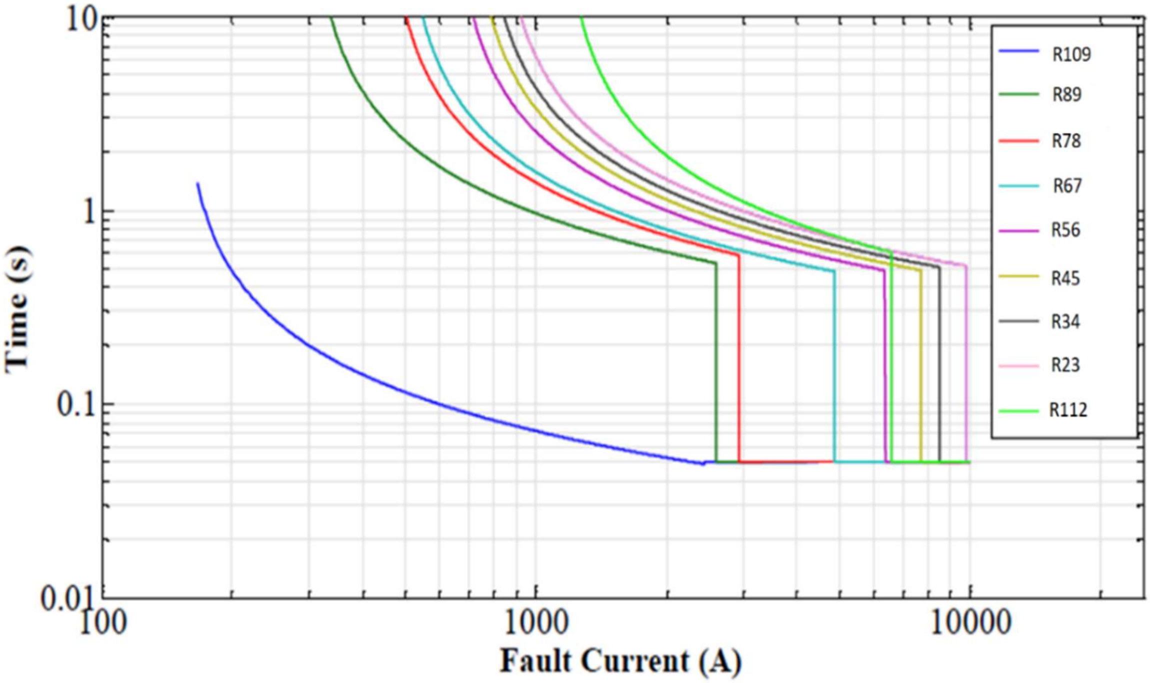


Figure 4. 10: Time Over-Current Characteristics of Relays R109, R89, R78, R67, R56, R45, R34, R23 And R112 For Case2

A three-phase fault, with a resistance of *0.05Ω,* is simulated in Line109 close to Bus 9, when the DG is connected to the system. The relay´s time over-current characteristics are as in Figure (4.10). Figure (4.11) shows the breaker status. It can be appreciated from the figure that the fault is cleared by opening the breaker for R109, *150ms* after the fault, due to the activation of instantaneous pickup.

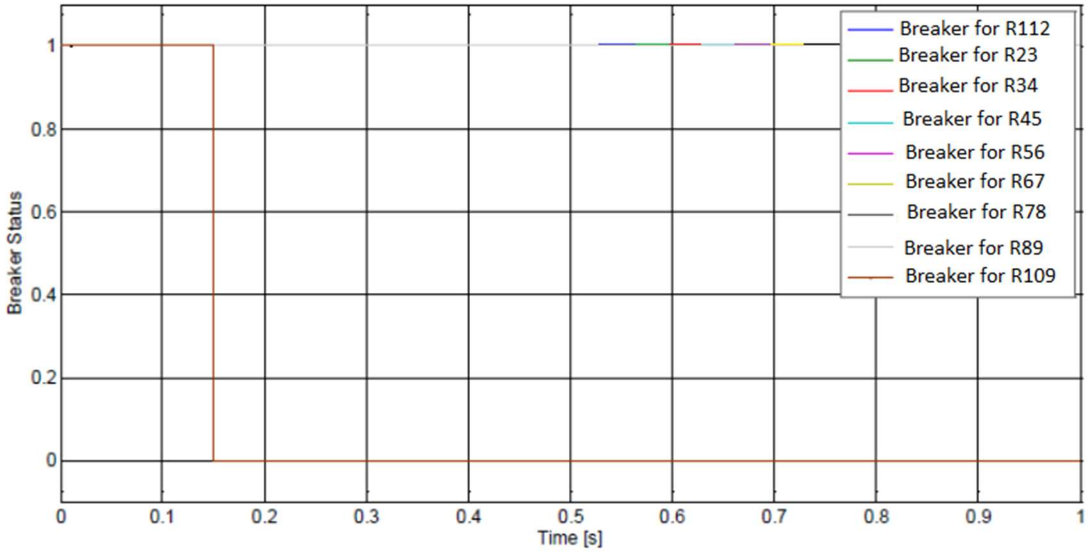


Figure 4. 11: Status of Circuit Breaker for a Three-Phase Fault in Line109 for Case2 when Relays are Setting According to Fig. 4.10

The coordination time interval (CTI) between the relay when the fault was happened on the L89 with the DG interconnected the system (Case-2)

Table 4. 5: The Coordination Time Interval (CTI) For Case-2

Relays	CTI (Sec)
Between R109 & R89	0.436
Between R89 & R78	0.688
Between R78 & R67	0.969
Between R67 & R56	1.194
Between R56 & R45	2.447
Between R45 & R34	2.916
Between R34 & R23	3.457
Between R23 & R112	5.321

When distribution network is interconnected with the Distributed Generation (DG), bidirectional flow of current will be existed in the system to control unnecessary flow direction of current the Directional Over current relay (DOCR) play important role.

To set the backward relays R910, R98, R87, R76, R65, R54, R43, R32 and R211, a three-phase fault is simulated in Line112 near to Bus 02. The sources of the fault current are SG1(DG-1 Solar), SG2(DG-2 Solar) and the transmission grid. The fault contribution from the Solar is very small, almost negligible, and therefore R211 only sees the fault current coming from the transmission grid, which is the highest source of fault current in the distribution system. Even if the transmission grid is disconnected the fault current contribution from the PV continue being insignificant.

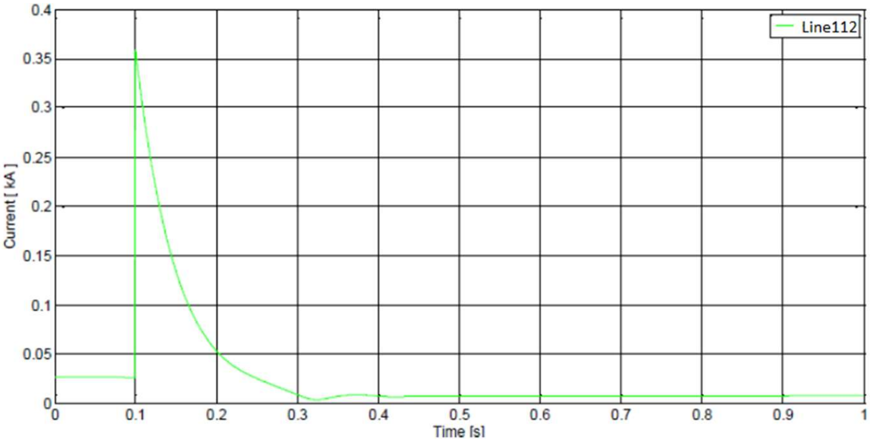


Figure 4. 12: Short Circuit Current Seen in Line112

Figure (4.12) shows the instantaneous pickup currents for each line of the distribution system when the transmission grid is disconnected, and three phase short circuits are simulated in Line112 close to Bus 02, Line23 close to Bus 03, Line34 near to Bus 04, and so on. At the relays instantaneous pickup time (*50ms*) the fault currents are approximately the same and almost negligible for all lines. Therefore, selectivity between relays cannot be attained.

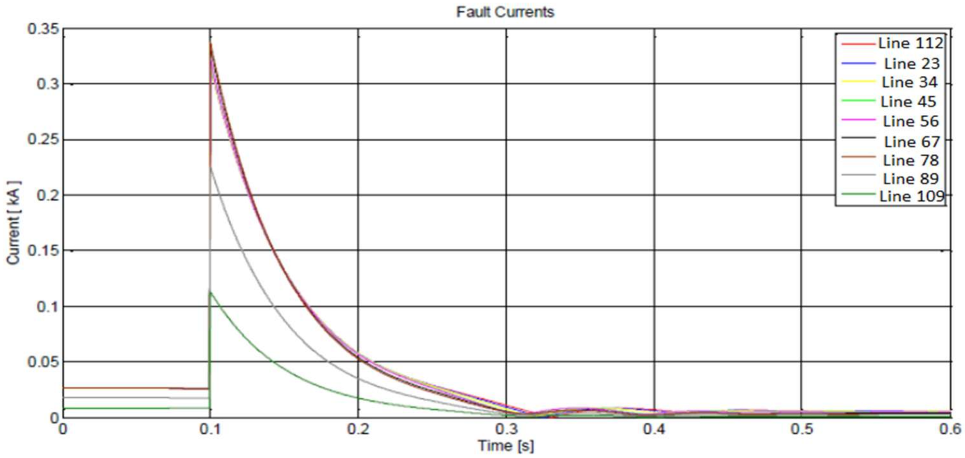


Figure 4. 13: Fault Currents seen by Relays R211, R32, R43, R54, R65, R76, R87, R98 And R910 for Three Phase Faults in each Line of the Test System

In addition, in Figure (4.13), the fault currents seen by all the relays are shown. It can be noticed that all relays sense the same fault current and that is almost zero.

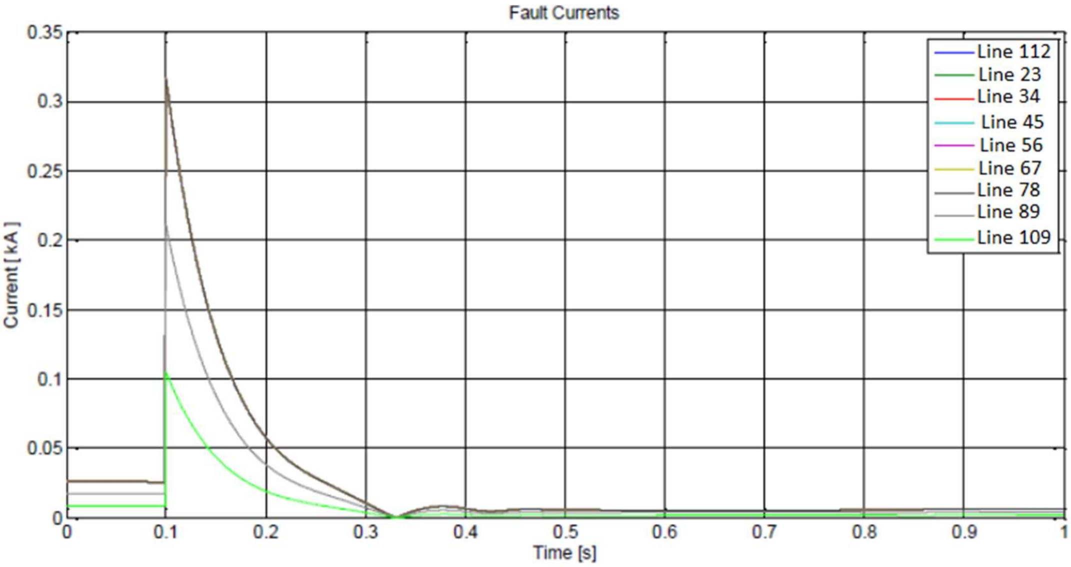


Figure 4. 14: Fault Currents Seen by the Relays R211, R32, R43, R54, R65, R76, R87, R98 and R910 for a Fault in Line112 Near to Bus 02

The currents seen by these relays are almost negligible because of the fault current contribution from the synchronous generators (Distributed Generations).

Thereby, relays R112, R32, R43, R54, R65, R76, R87, R98 and R109 will see almost no-fault current coming from the DGs and coordination between them cannot be attained. If the currents seen by the relays and the instantaneous pickup currents sensed are considered as not dangerous for any equipment in the distribution system, relays R112, R32, R43, R54, R65, R76, R87, R98 and R109 may be removed from Figure (4.9) Hence, the faulted part of the distribution system will be disconnected, and fault will be supplied by the DGs only. However, DGs cannot sustain fault current, and they are tripped by their own protection. The part upstream the fault would have been lost anyways as the DGs cannot sustain the new islanded part. Hence by avoiding these extra relays for backward protection, hardly any compromise has been made.

4.4 Adaptive protection

For conventional power systems, generation is largely based on synchronous generators, therefore, short circuit capacity, fault current contributions from the synchronous generators and the associated relay settings (Pickup, TMS, and CTI) can be easily determined. The desired protection coordination can also be easily achieved using single-stage characteristics, i.e., either inverse characteristics or definite time characteristics. However, due to the dynamic characteristics of micro generators, short circuit contribution is largely varying due to intermittent RESs and power electronics inverter interfacing. Moreover, mode of operation, i.e., grid-connected or islanded will also largely affect the short circuit contributions, for example, the short circuit current contribution in the grid-connected mode will be very high due to the large short circuit capacity of the grid, and is very small in the islanded mode due to limited short circuit capacity of the interfacing inverters. Also, the DG size, its location, fault type, and direction of the fault results in varying fault current contribution in the micro generators. Therefore, single-stage settings are not feasible for microgrid operation. Alternatively in this scheme, we have employed dual-stage settings to deal with the varying short circuit contributions and to maintain the desired coordination among upstream and downstream relays. The Figure (4.15). Shows the characteristics curve for the dual setting of DOCR, where stage 1 corresponds to the IEC 60255 standard inverse time relays characteristics [34] and is used for protection against short circuits and overloads, i.e., pickup time is inversely proportional to the fault current. The pick-up time of stage 1 is set according to (1) based on the line loading determined through the power flow analysis, while its time characteristics are set according to the ratio of fault current seen by the relay and maximum fault current as shown in (2).

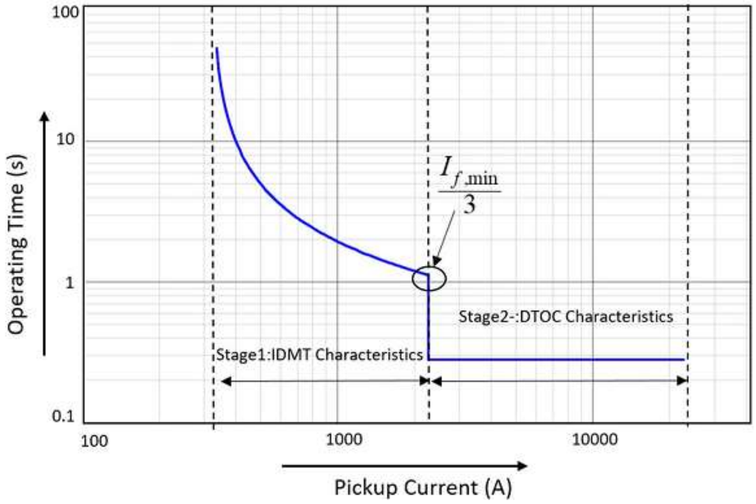


Figure 4. 15: Dual-Stage Settings of DOCR [34]

The tripping logic for the dual-stage DOCR is shown in figure 4.16, where the combination of DTOC (IEEE/ANSI-50), and DOCR (IEEE ANSI-67) is coordinated through OR and AND gates.

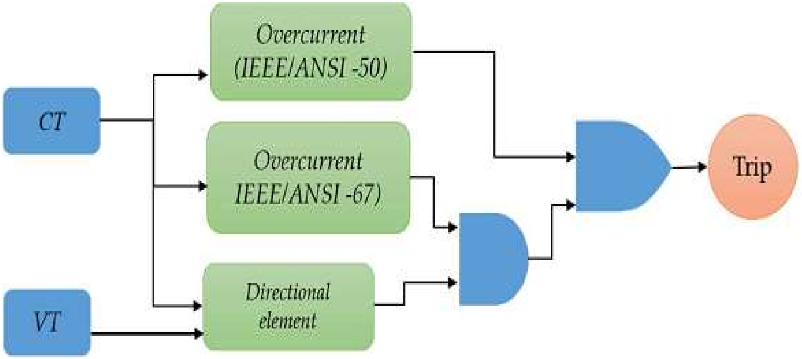


Figure 4. 16: Trip Logic for Dual-Stage DOCR [34]

The relay current transformer (CT) and voltage transformer (VT) measures current and voltages according to the predefined turn ratio settings, and the directional element decides the direction of the fault to be observed, either in the forward or in the reverse direction, based on whether it's a forward relay or reverse relay in the network.

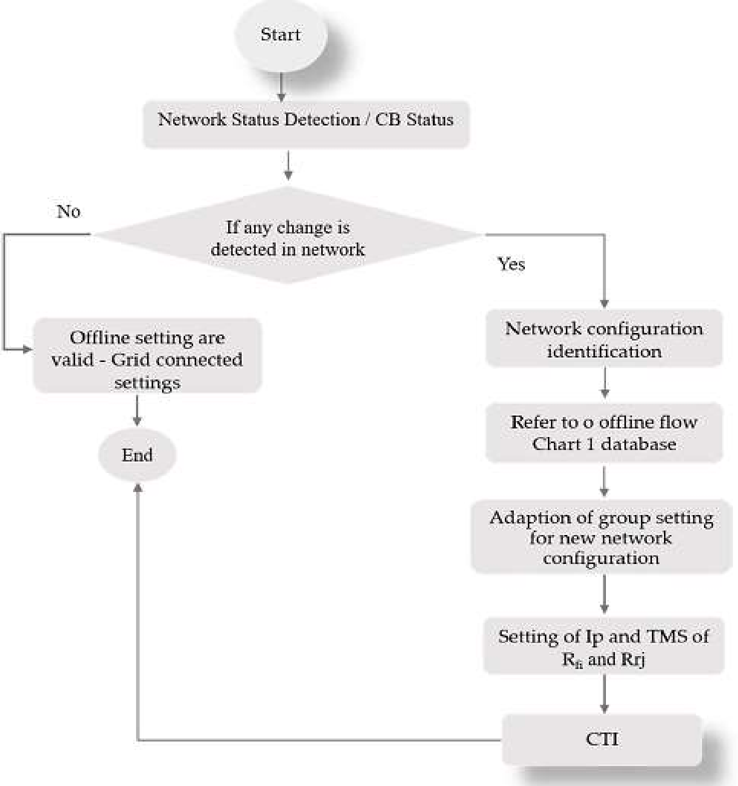


Figure 4. 17: Adaptive Algorithm for the Overcurrent Protection of N-Bus Microgrid [34]

4.4.1 Simulation Model and Results

To validate the proposed methodology, the protection scheme presented above is implemented on the modified 9-bus model and simulated in DigSilent Power Factory 15.1 2016. The model consists of two DGs, 9 buses, seven general types of loads, and relates to the utility grid at PCC (Point of common coupling).

In the previous section, the offline calculations, and dual-stage settings for DOCR for the overcurrent protection of 9-bus microgrid model have been computed. These settings have been stored in intelligent central protection unit (ICPU), adapts the respective settings based on the network configuration and incident scenario. Consequently, various scenarios have been evaluated after the application of the fault. Since the three-phase bolted fault is the most severe in the AC power system, therefore, the comparative simulations have been performed under the application of three-phase faults. The result section starts with the demonstration of the utility of two-stage settings over static single-stage settings. As discussed in the design section, two-stage settings allow us to achieve a lower tripping time, while maintaining the coordination among the neighboring relays.

It has been demonstrated that the proposed scheme has the capability to dynamically configure the settings of its relays based on the changing network conditions. The operation of the scheme is demonstrated in grid-connected, islanded, and variable distributed generation scenarios have been demonstrated. The up gradation of DOCR settings in the proposed scheme allows us to reduce the tripping times of the relays, thereby reduce the associated high current hazards in the system. Moreover, the proposed scheme also maintains the desired coordination for backup relaying applications.

The master substation computer periodically checks the status of DGs connected to bus 2 and 9 to detect the current mode, and selects the correct settings saved on digital relays that could have up to six groups of settings.

The communications with the microprocessor relays and DGs could be through GSM using communication module that are connected to the main substation computer.

In case of communication failure due to any unexpected circumstances a default group of settings must be set to maintain minimum reliability of protection scheme. The group settings number (5) is assigned to communication failure mode.

Only 5 settings are stored in the relays while the rest group is spare.

Setting 1: mode I no DG

Setting 2: mode II DG at bus 2

Setting 3: mode III DG at bus 9

Setting 4: mode IV DGs at buses 2 and 9

Setting 5: communication failure

Setting 6: spare

Fig. 4.18 shows the proposed adaptive protection scheme

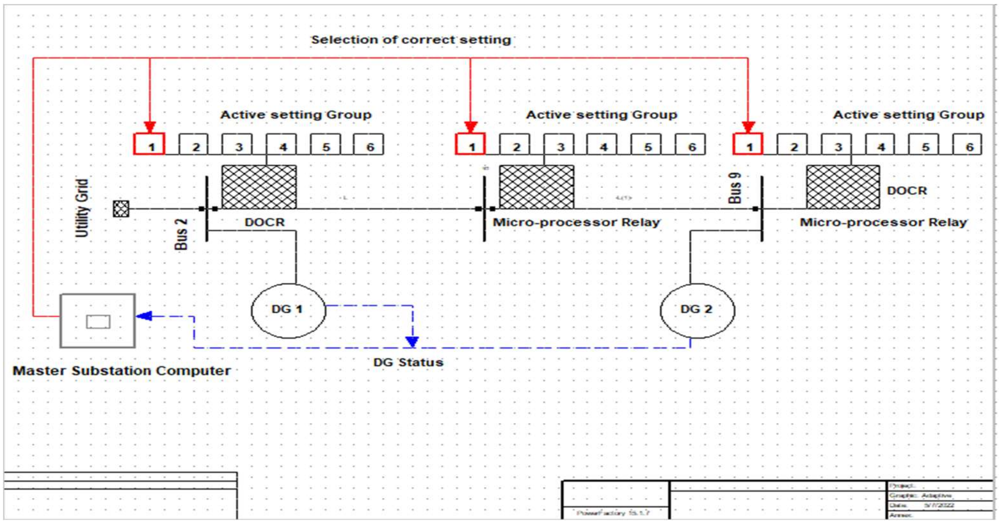


Figure 4. 18:Proposed Adaptive Protection Scheme

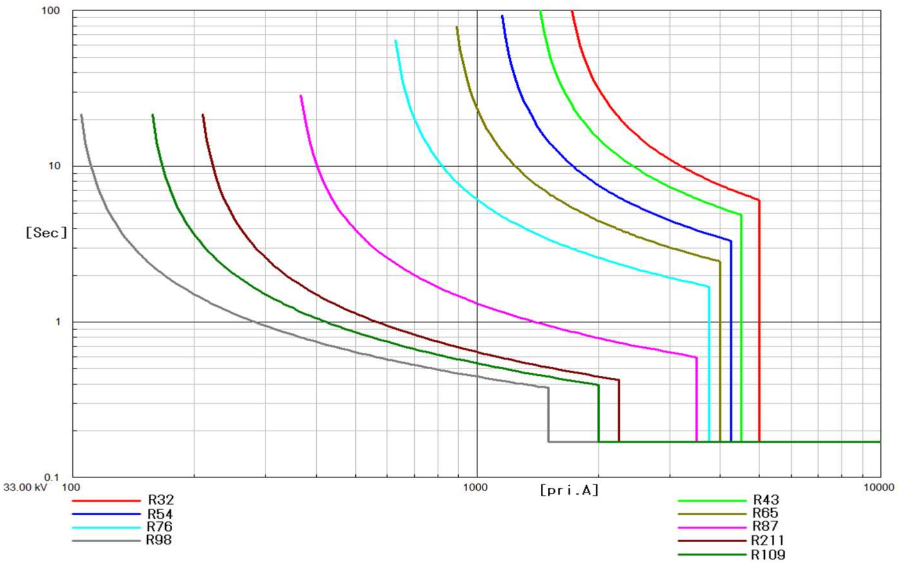


Figure 4. 19: Time Over-Current Characteristics of Relays Rr32, Rr43, Rr54, Rr65, Rr76, Rr87, Rr98, Rr211 and Rr109 for Adaptive protection

A three-phase fault, with a resistance of *0.05Ω,* is simulated in Line109 close to Bus 9, when the DG is connected to the system and the fault current reversely flow to Bus 10. The relay´s time over-current characteristics are as in Figure (4.19). Figure (4.20) shows the breaker status. It can be appreciated from the figure that the fault is cleared by opening the breaker for R109, *150ms* after the fault, due to the activation of instantaneous pickup.

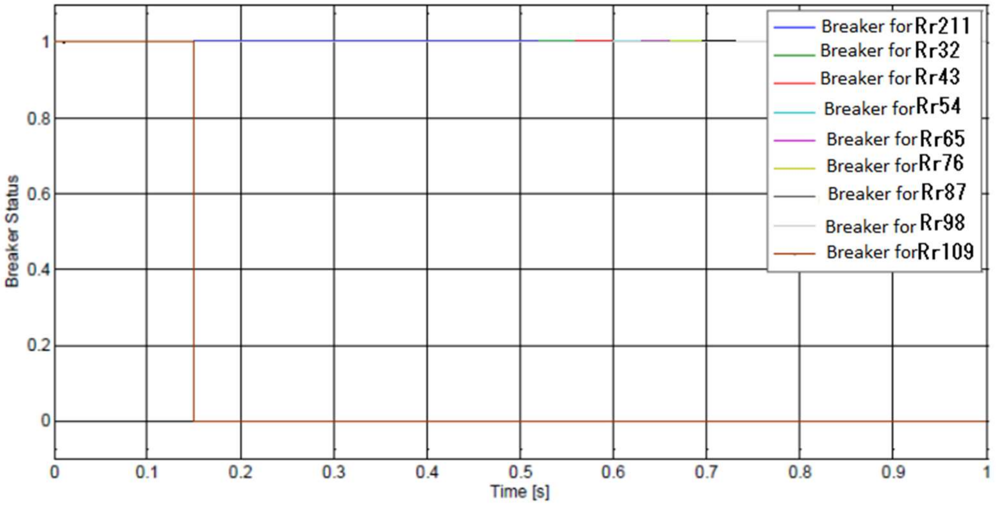


Figure 4. 20: Status of Circuit Breaker for A Three-Phase Fault in Line109 for Adaptive protection When Relays Are Setting According to Fig. 4.19

4.5. Calculation of Reliability Indices and Benchmark

The reliability indices are used to indicate the status of the system. if the system has high reliability indices, it can be concluded that the system has reliability issues. Reliability indices are calculated to show general reliability characteristics of distribution system.

In this section reliability indices are calculated for feeder 10. There are different types of reliability indices, but in this section common reliability indices are used to determine the reliability based on interruption frequency and duration such as, SAIFI and SAIDI. These indices are calculated using the following equations: -

$$SAIFI = \frac{Total\ number\ of\ customer\ interruption}{Total\ number\ of\ customer\ served} = \frac{(\sum N_i)}{N_T}$$

Where: -Ni - Number of interrupted customers for each interruption event during reporting period, NT - Total number of customers served for the area being indexed, i - An interruption event

$$SAIDI = \frac{Customer\ interruption\ duration}{Total\ number\ of\ customer\ served} = \frac{\sum ri \times Ni}{N_T}$$

Where: -Ni - Number of interrupted customers for each interruption event during reporting period, NT - Total number of customers served for the area being indexed, ri- Restoration time for each interruption event during reported period and i- An interruption event

The existing system feeder 10 SAIFI and SAIDI is 184.5 interruptions per customer of year and 249.64 respectively. The data obtained has only sustained interruptions in frequency and duration because of that only sustained interruption are considered. SAIDI and SAIFI are the best-known reliability measures.

Reliability benchmarks are needed to compare if the system has reliability issue or to compare with the standard. The main purpose of reliability standard benchmarks are used to identify or asses minimum or average performance of distribution network. There are different recommended values of reliability standards. According to benchmarking report on the quality of electricity supply, the reliability indices values of five countries are shown in Table 4.6. These countries give high emphasis to power quality and reliability. The three basic reliability indices, SAIDI, SAIFI and ASIA for each country are shown in the table. The higher number of reliability indices indicate the lower reliability performance that is high interruption frequency and duration. A lower reliability index shows the better reliability performance and lower interruption duration and frequency. Comparing Hawassa distribution system specifically feeder 10 with the benchmark it has lower reliability performance, even it has lower reliability performance than the standard benchmark of Ethiopia.

Table 4. 6 Standard Benchmark of different countries [37]

Country	SAIDI	SAIFI	ASAI
Austria	1.2	0.9	99.97
Denmark	0.4	0.5	99.98
France	1.03	1.0	99.97

Germany	0.383	0.5	99.99
Italy	0.967	2.2	99.99
Netherlands	0.55	0.3	99.97
Spain	1.733	2.2	99.96
UK	1.5	0.8	99.96
Ethiopia	25	20	99.425

After the interconnection of distributed generation (DG) to the Hawassa distribution system specifically to feeder10 and after applying of adaptive protections coordination to the specific feeder and the reliability indexes are found around on Ethiopian benchmark.

$$SAIFI = \frac{(\sum N_i)}{N_T} = \frac{20350}{1{,}032}$$

$$SAIFI = 19.71899 \text{ interruptions per customer of year}$$

$$SAIDI = \frac{\sum ri \times Ni}{N_T} = \frac{1.25 \ \times 20350}{1032}$$

$$SAIDI = 24.64874 \text{ hours per customer of year}$$

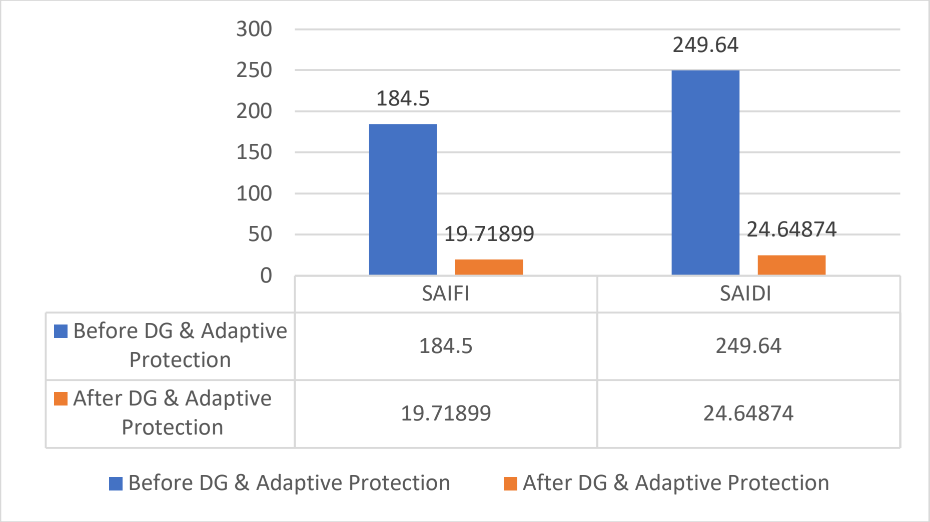


Figure 4. 21: Reliability Indices comparison before & after applying DG & Adaptive protection coordination

4.6. Impact of DG on Voltage Stability of the Radial Distribution System

Voltage stability is classified into steady-state and dynamic involving small and large disturbances respectively. To be investigated here are steady-state voltage stability pertaining to load increase and faults - large disturbances.

4.6.1. Loading Margin (Stability Margin) of the System

Small disturbance (or small signal) stability pertaining to load increment is studied under steady state conditions. This is because the voltage profile improvement from DG integration does not imply unlimited loading to avoid the system’s failure to sustain the load. In general, the inability of the system to supply the required demand leads to voltage instability (voltage collapse). Voltage stability is usually represented by Power-Voltage curve and at the point of voltage collapse the voltage drops rapidly with an increase of the load demand and consequently, the load flow simulation fails to converge beyond this limit. Power-Voltage curves have been traditionally used as graphical tools for studying voltage stability in electric power systems.

Voltage stability analysis in DIgSILENT PowerFactory 15.1 software is performed by selecting the buses and the loads that are of interest, choosing the Execute DSL scripts and the selection of PV-Curve. The resulting graphs are automatically displayed. Prior to voltage stability analysis the loads have unity scaling factors but DIgSILENT PowerFactory 15.1 performs voltage stability analysis by gradually increasing the load, while keeping the power factor constant, of the preselected buses until they reach the power transfer limit.

Making the voltage stability analysis for gradual increment of load, the Power-Voltage curve of the developed model without DG is as shown in Figure 4.21. For all the loads down steam of DG which was 3.3MW, the maximum or total load before voltage collapse was determined to be 5.024MW. Therefore, the loading margin to voltage collapse, for a current operating point, the total increment of load in a specified pattern of load increase that would cause a voltage collapse became 1.724 MW.

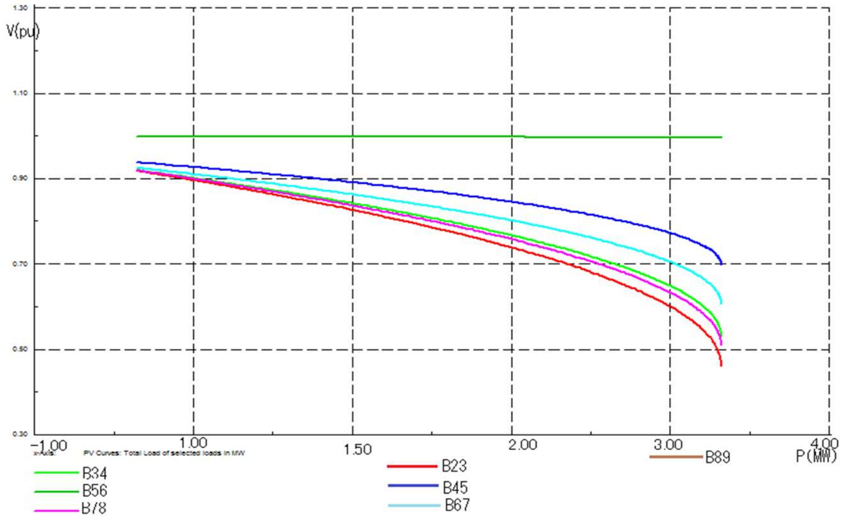


Figure 4. 22 : Power-Voltage Curve without DG injection (Bus 56 and Bus 89 overlaped each other)

To investigate the impact of DG integration, the voltage stability analysis was made after DG integration and, the Power-Voltage curve when the DG injects 1.8618MW resulting to a maximum load of 5.024 MW before voltage collapse is shown in figure 4.21. Now the loading margin to voltage collapse, for a current operating point, the total increment of load in a specified pattern of load increase that would cause a voltage collapse during DG injection had been found to be 1.724 MW. This implies the enhancement of loading margin when DG integrated into distribution system with proper sizing and placement. Finally, the overall impact of a DG unit on voltage stability during gradual increment of load is positive. This is due to the improved voltage profiles as well as decreased reactive power losses.

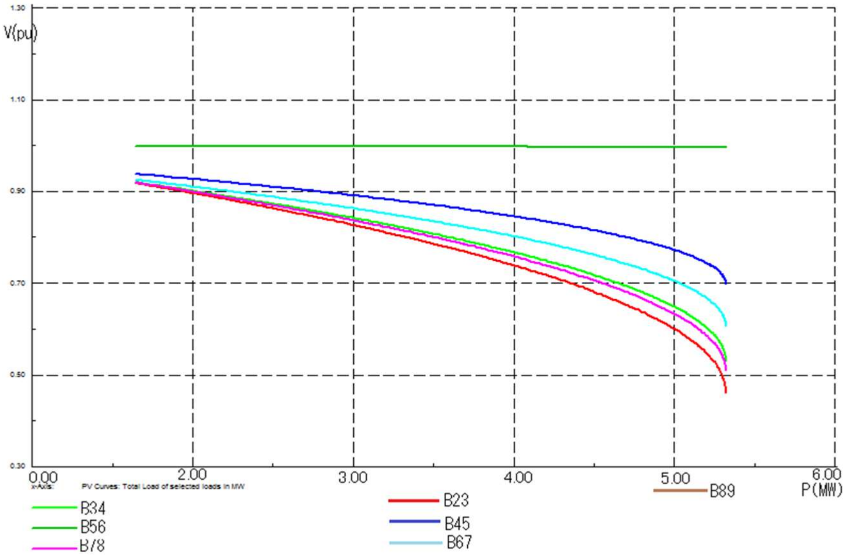


Figure 4. 23: Power-Voltage Curve after DG injection (Bus 56 and Bus 89 overlaped each other)

4.6.2. Transient Stability of the System

Voltage instability due to faults is a transient stability problem which is large disturbance voltage stability-studied under dynamic conditions. In principle, transient stability problems might occur in distribution networks with DG. The electromagnetic transient (EMT) Simulation of DIgSILENT PowerFactory 15.1 had been utilities in investigating three phase short circuits. The electromagnetic transient (EMT) simulation involves the definition of variables and events. In this case the variables are phase short circuit currents and their corresponding voltages. The short circuit and its clearing time on the selected busbars are the events.

To investigate the transient stability of the developed model, self-clearing three-phase short circuits were simulated. The simulation absolute run time is 0.5s with the three-phase short circuit introduced at 0.1s and cleared at 0.2s.

The two buses were selected to study the transient stability of the system. Bus 2 at the point of connection (POC) of DG was selected and one bus from downstream of DG that is bus 6 were selected to study the transient stability of the system before and after DG integration. The simulation results or plots are shown below for all case scenarios. The simulation output revealed that the only disturbance is the increment of short circuit level during DG injection which is evident at two buses. This implies that synchronous generators have the most distinct impact on fault currents.

Besides, from the result of the simulation, the system regains its original voltage wave form after the clearance of fault before and after DG injection. Therefore, it can be concluded as the impact of DG on transient stability of the system is positive except some increment of fault currents by considering its appropriate place with appropriate capacity.

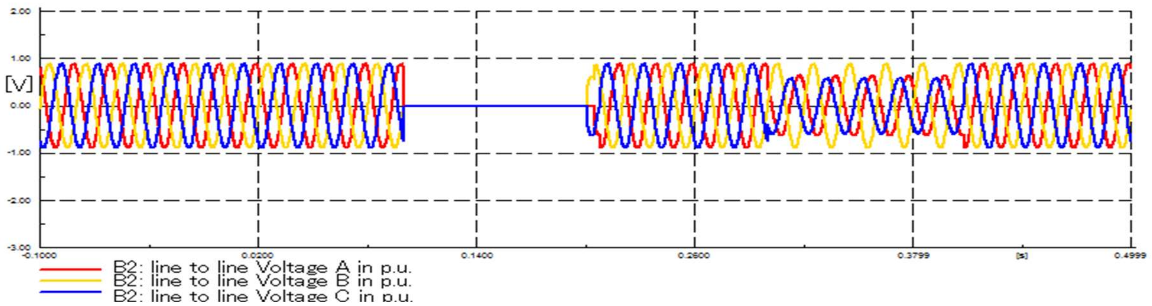


Figure 4. 24: Voltage and current wave form during 3phase fault at bus 2 without DG

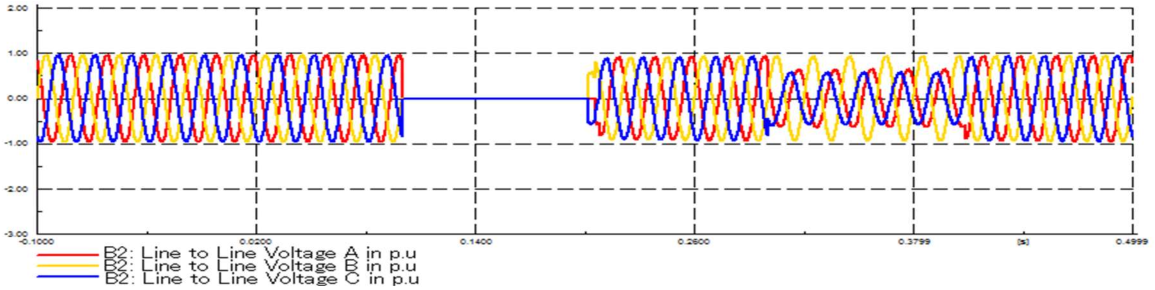


Figure 4. 25: Voltage and current wave form during 3phase fault at bus 2 with DG

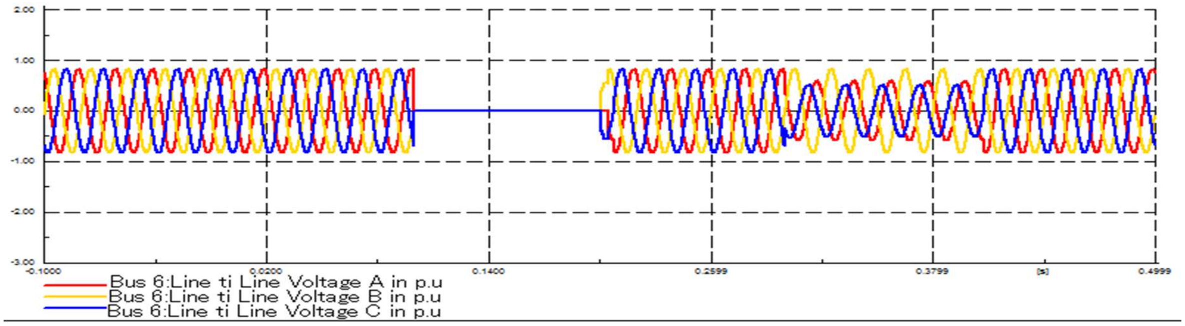


Figure 4. 26: Voltage and current wave form during 3phasefault at bus 6 without DG

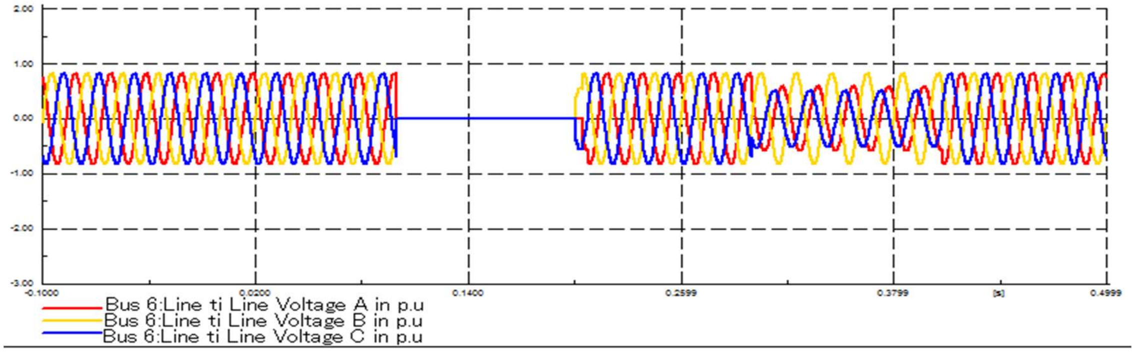


Figure 4. 27: Voltage and current wave form during 3phase fault at bus 6 with DG

4.7. Economic Analysis

4.7.1 Cost Estimation of DG Installation

After the determination of DG location and size, cost estimation of the obtained DG size has followed. The DG type was assigned simply for cost estimation of the determined DG size without entering its detailed technology.

Therefore, to estimate the cost of DGs size of 0.95MW and 0.9118MW, the DG technology selected in this study was PV due to no emission level and moderate cost.

Solar Panel Brand	Peak Power watts	Price per watt	Total cost	Poly Mono Thin film	Module efficiency	Country of Manufacture
Sunpower Maxeon 6-440	440	$0.875	$350	M	22.8%	Singapore
Qcells 325-watt Mono Half-cell Black frame	325	$0.50	$162.50	M	19.05%	USA
Peimar SG310M-BF	310	$0.52	$160	M	19.05%	Italy
LONGI LR4-60HPB-350M	350	$0.54	$188	M	19.20%	Malaysia
Trina Solar TSM-310-DD05H.05(II)	310	$0.54	$168	M	18.70%	China
Trina Solar TSM-325-DD05H.05(II)	325	$0.56	$182	M	19.10%	China
Tiger NEO -480	480	$0.882	$423.36	M	22.2%	China
Canadian 395-watt silver Frame Bifacial Module	395	$0.63	$250.29	M	18.54%	Italy
Astronergy CHSM6612M-370 solar Panel	370	$0.69	$270	M	19.10%	Germany
REC 355A Black Alpha	355	$0.73	$258	M	20.30%	Singapore
Sharp ND-250Qcs	250	$1.1	$275	Poly	15.3%	USA
Canadiansolar CS6R-MS	440	$0.865	$380.6	M	22.5%	China

Table 4. 7: Power Rating and Cost of Various Module Types

As shown in the above Table 4.6 Equipment cost of various types of PV module with their efficiency and Manufactured country are stated. The performance of PV module stated according to their maximum power output. Based on cost, output power and efficiency Sun-power Maxeon 6-440 solar Panel is selected for this study and its output power is 440watt.

PV Generator Sizing

Calculating Wattage of the Solar Panels for DG-1

$$Wattage(W) = \frac{Total\ Generation(Load)}{Peak\ Sunhours/day} = \frac{950000Wh/day}{3/day} = 316{,}666.7W$$

$$Wattage(W) = \frac{Daily\ Peak\ Wattage}{Sysytem\ Loasses} = \frac{316{,}66.7W}{0.8} = 395{,}832.5W$$

Calculating number of the Solar Panels for DG-1

$$Number\ of\ solar\ panels = \frac{Total\ Wattage}{Single\ panel\ Watt} = \frac{395{,}832.5W}{440W} = 876.89$$
$$\approx 877 Solar\ panels\ with\ 440\ watt\ of\ each\ panels$$

For DG-1 to generate 0.95MW photovoltaic power using 440W solar panels is need 877 solar panels and the number of solar panels was approximated to get optimal array combination to 880 panels, the cost will be come $308,000.00. The land needed to build DG-1 PV power plant is around 1,496m^2, this for PV panels deploying including over all units the total land needed around 1.7Km^2.

Calculate Wattage of the Solar Panels for DG-2

$$Wattage(W) = \frac{Total\ Generation(Load)}{Peak\ Sunhours/day} = \frac{911800Wh/day}{3/day} = 303{,}933.33W$$

$$Wattage(W) = \frac{Daily\ Peak\ Wattage}{Sysytem\ Loasses} = \frac{303{,}933.33W}{0.8} = 379{,}916.7\mathrm{W}$$

Calculating number of the Solar Panels for DG-1

$$Number\ of\ solar\ panels = \frac{Total\ Wattage}{Single\ panel\ Watt} = \frac{379{,}916.7\mathrm{W}}{440W} = 863.45$$
$$\approx 866\ Solar\ panels\ with\ 440\ watt\ of\ each\ panels$$

For DG-2 to generate 0.9118MW photovoltaic power using 440W solar panels is need 866 solar panels and the number of solar panels was approximated to get optimal array combination to 872 panels, the cost will be come $305,200.00. The land needed to build DG-2 PV power plant is around 1,482.4m^2, this for PV panels deploying including over all units the total land needed around 1.7Km^2.

Selecting the Inverter

The solar inverter is selected based on the efficiency, power quality, and lifetime of inverter; the detail specification is described below table 4.7.

Table 4. 8: Solar Inverter-ESHB 1-6KW

ESHB 1-6KW (Solar Inverter)						
Model	1K	2K	3K	4K	5K	6K
Nominal capacity (KW)	1	2	3	4	5	6
DC Voltage (VDC)	24VDC		48VDC/96VDC			
Input voltage (VAC)	220VAC±25%					
Charge current(A)	Max 20A					
Output voltage (VAC)	220VAC±2%					
Output frequency	50Hz±1%					
Output waveform	Pure sine wave					
Solar maximum input voltage(V)	48V			96V/180V		
Solar charging current(A)	30A			30A-60A		
Overcharge protected voltage(V)	30V			60V/120V		
Overcharge of recovered voltage(V)	28V			55V/110V		
Floating voltage(V)	27V			54V/108V		
Control mode	PWM					
Temperature	0 ~ 40℃					
Relative humidity	0% ~ 90%					
Running altitude	0 ~ 3,000meters					
Protections	Protect against anti-charge at night					
	Battery over charge/over discharge					
	output short-circuit, against over-current, against over-voltage					
	Overload protection					
Noise	≤45dB (Distance 1m)					

Design of the Storage Battery

The nominal battery block voltage is selected to be 48 V, which is safe when installing the battery in this study. The battery block storage capacity will be selected to cover the energy load demands for two days without the sun and electric grid. The total ampere-hour C_{BAh} is obtained as follows [60]:

$$\mathrm{BC_{Ah}} = \frac{\mathrm{E_{db}} \times \mathrm{AD}}{\mathrm{DOD} \times \eta_{\mathrm{BAh}} \times \mathrm{V_B}}$$

where E_{db} is the daily energy required from the battery (E_d/η_{inv}), DOD is the permissible depth of discharge, AD is autonomy days, η_{BAh} is the ampere hour efficiency of the battery cell, and V_B is the selected nominal DC voltage of the battery block.

Considering realistic values for these parameters represented in AD=2.25days, DOD=0.8, $\eta_{BAh} = 0.85$, and $V_B = 48V$, as well as, the ampere hour capacity is obtained as:

For DG-1, the daily average energy consumption per day is 950,000 (W-h/day)

$$Battery\ Capacity\ (Ah) = \frac{950000/0.93}{(0.8\ \times 0.85 \times 48)} \times 2.25 = \frac{1021505.38}{(32.64)} \times 2 = 62{,}592.24Ah$$

For DG-1 $62{,}592.24Ah$ Battery Capacity required for the system

For DG-2, the daily average energy consumption per day is 911,800 (W-h/day)

$$Battery\ Capacity\ (Ah) = \frac{911{,}800/0.93}{(0.8\ \times 0.85 \times 48)} \times 2 = 60{,}075.37Ah$$

For DG-2 $60{,}075.37Ah$ Battery Capacity required for the system.

The DC-coupled batteries are the most common type of battery used for solar energy storage and must be connected with a compatible grid-connected hybrid inverter to create a solar energy storage system with backup power. Several of these modular battery systems, including the low-voltage Pylontech and BYD batteries, can also be used for off-grid solar systems. For this study Sungrow SBP4K8 solar battery is selected based on the efficiency of 70% and the lifetime is ten years, and cost effectiveness.

The below table 4.8 shows the overall cost estimation of the study, the cost of equipment is based on current international market.

Table 4. 9: Installation Cost of DG

Equipment	Capacity	Unit Cost ($)	Total Cost ($)
PV Total	1.8618MW		
DG-1 PV Module	880 solar panels	350$/W	308,000.00$
DG-2 PV Module	872 Solar panels	350$/W	305,200.00$
Inverter	2MW	0.18$/W	360,000.00$
Battery	2MW	137$/KW	274,000.00$
Land	3.4Km^2		52,000$
O&M			135,000$
Trasport & Labor			34,320$
Total Cost			1,468,520.00$

4.7.2 Cost analysis and Payback Period

The cost effectiveness is determined the difference of expected interruption cost (ECOST) before and after applying the proposed method. Before the proposed method used, 697,500$/year lost due to interruption. After the proposed DG's and protection coordination implemented, the expected interruption cost (ECOST) is reduced to 69,750$/year. This indicate that, 627,750$/year is saved after using the proposed techniques.

The total capacity of distributed generation (DG) is 1.8618MW. Cost of DG including cost of PV installation cost, operation and maintenance total cost is $1,468,520.00. Total revenue loss due to interruption is distribution system is 697,500$/year. Dividing the total cost of DG with interruption cost, it will be 2.1054, this indicate the cost of DG can be paid back within around two years.

CHAPTER 5

CONCLUSION, RECOMMEDATION AND FUTURE WORK

5.1 Conclusion

With the objective of investigating the impact of DG integration on radial distribution system, the case study distribution feeder was identified based on power interruption data. The feeder 10 of Hawassa substation was selected owing to its more power interruption vulnerability compared to the rest of the feeders. The modelling and simulation of the feeder was carried out using DIgSILENT PowerFactory 15.1 simulation package. The base case simulation results indicated that the feeder encountered the total power loss of 783.95KW with major bus voltages were out of acceptable range. To reduce the total power loss of the system and enhance all node voltages to within allowable range, distributed generator was integrated into the system at a proper place with a proper size. Sitting and sizing of DG was based on HHO algorithm and accordingly the proper site and size of DG was found and determined to be at bus 2 and 30 with proper size of 0.95MW and 0.9118MW respectively. The cost estimation for the determined both DG size was carried out by taking the photovoltaic DG type. Consequently, the total cost of the 0.95MW & 0.9118MW DG installation was found to be $1,468,520.00.

However, it is well known that the current existing electricity networks, particularly distribution systems, have been designed in radial topology with centralized generation as the main power source to supply the load. Nevertheless, with the presence of distributed generation the power flow is no longer radial. This occurrence of DG has definitely created both positive and negative impacts on distribution system. To deal with these impacts, various case study projects was conducted in this thesis and the overall research scenarios were investigated on the technical impact of distributed generation on distribution system. The investigations involving a directly connected synchronous DG with proper size and site indicated that for a particular DG type the impact on total power loss, voltage profile, and voltage stability. The results of the balanced and positive sequence load flow analysis at steady state condition after DG integration pointed out that the total power loss was reduced to 86.9KW with the total loss reduction of 68.81%.

The impact of DG integration on distribution network during dynamic condition was investigated thoroughly to see the impacts of DG on voltage stability, short circuit level and protection coordination of the system. The impact of DG on system fault level and the accompanying protection issues have also been investigated and the results were analyzed by performing three phase short circuits. The results show that as the DG's size and number changes, the chance of relays miscoordination increases which requires a new setting for DOCR and new setting of relays found using HHO algorithm, one of the possible solutions to solve this issue is to use adaptive coordination. The adaptive protection scheme is applicable and works effectively for existing power distribution systems, which lately install DG to get their benefits, protection system follow the network topological changes and connectivity of DG to the system and switches between the pre-calculated setting groups based on the actual operating state of the DG using standard communication and programmable logic, this adaptive protection may increase availability of local generation and reduce outage time for the customers without a need to change existing hardware, which leads to the increase of selectivity and security of the system and the adaptive algorithm that stored on ICPU was developed by using HHO algorithm on MATLAB R2016a.

5.2 Recommendation

In this study, it has been determined that DG integration has positive impact on enhancement of grid capacity, power system loss reduction, improvement of voltage profile, reduction of loading of line segment and relieving of over loading of the network, this indicated on the thesis by reliability indices such as SAIFI and SAIDI before DG integration and adaptive protection coordination was 184.5 interruptions per customer of year and 249.64 hours per customer of year respectively, After DG integration and adaptive protection coordination the value of SAIFI and SAIDI reaches reliability index bench mark of Ethiopia 19.71899 and 24.64874 respectively and power loss reduced from 783.95KW to 86.90KW by 68.81%. So, distributed generation technology especially renewable energy-based DG options should be promoted by the power utility company not only for rural electrification but also for urban areas even as a backup. Therefore, it is recommended that the Ethiopian Electric Utility and its counterpart Ethiopian Electric Power or other stake holders like Ethiopian Electric Authority should make awareness and encouragements to the government to promote the implementation of distributed generation in distribution sector.

5.3 Future Work

Although many aspects of over-current protection of the distribution system with DG have been covered by this dissertation, several other issues are interesting for future investigation. Some of the issues that am believed interesting are,

1st integrating DG into existing distribution networks is a complex issue because data acquisition systems are not available. The installation of an information system such as the Supervisory Control and Data Acquisition (SCADA) system may help to solve many problems. The internet is already easily accessible; therefore, it could be a great chance to utilize it for the purpose of power system operation,

2nd in this study the size of the induction, as well as of the synchronous generators were considered equal for all simulations. Capacity of the DG sources may be increased to observe its impact on the short circuit levels and analyze if protection coordination can be attained,

Finally, solutions overcoming the issues with a significant presence of DG, were briefly described. These solutions could be implemented in DIgSILENT to analyze if the problems found in this study persist with the employment of another kind of system´s protection.

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APPENDIX

Appendix-A: MATLAB Code for DG Location and Sizing Using HHO

```
% Harris's hawk optimizer: In this algorithm, Harris' hawks try to catch the rabbit.
% T: maximum iterations, N: population size
clear all
clc
close all
warning('off')
 N=40;
T=100;
UB=40; LB=2;
lb=1; ub=4;
dim=2;
disp('HHO is now tackling your problem')
tic
% initialize the location and Energy of the rabbit
Rabbit_Location=zeros(1,dim);
Rabbit_Energy=inf;
di=1;
%Initialize the locations of Harris' hawks
for run=2
for i=1:di
if size(UB,1)==1
  x(:,1)=ceil(rand(N,di).*(UB-LB)+LB);
  x(:,2)=round(rand(N,di).*(ub-lb)+lb,4);
end
if size(UB,1)>1
  for i=1:di
    high=UB(i);low=LB(i);
    HIGH=ub(i);LOW=lb(i);
    x(1,i)=ceil(rand(1,N).*(high-low)+low);
    x(2,i)=round(rand(1,N).*(HIGH-LOW)+LOW,4);
  end
end
end
[f]=Get_Functions_details(x,N);
B=f;
CNVG=zeros(1,T);
t=0; % Loop counter
while t<T
  for i=1:size(x,1)
    % Check boundries
    FU=x(i,1)>UB;FL=x(i,1)<LB;x(i,1)=(x(i,1).*(~(FU+FL)))+UB.*FU+LB.*FL;
    FU=x(i,2)>ub;FL=x(i,2)<lb;x(i,2)=(x(i,2).*(~(FU+FL)))+ub.*FU+lb.*FL;
    % fitness of locations
    fitness=B(i,:);
    % Update the location of Rabbit
    if fitness<Rabbit_Energy
      Rabbit_Energy=fitness;
      Rabbit_Location=x(i,:);
    end
  end
  E1=2*(1-(t/T)); % factor to show the decreaing energy of rabbit
  % Update the location of Harris' hawks
    E0=2*rand()-1; %-1<E0<1
    Escaping_Energy=E1*(E0);  % escaping energy of rabbit
%      Escaping_Energy=0.1;
    if abs(Escaping_Energy)>=1
      %% Exploration:
      % Harris' hawks perch randomly based on 2 strategy:
      for i=1:N
      q=rand();
      rand_Hawk_index = floor(N*rand()+1);
      X_rand = x(rand_Hawk_index, :);
      if q<0.5
        % perch based on other family members
```

```
        X(i,:)=X_rand-rand()*abs(X_rand-2*rand()*x(i,:));
      elseif q>=0.5
         % perch on a random tall tree (random site inside group's home range)
        X(i,:)=(Rabbit_Location(1,:)-mean(x))-rand()*((ub-lb)*rand+lb);
      end
      end
      for i=1:N
       if X(i,1)>40|X(i,1)<2
      X(i,1)=ceil(2+38*rand);
  end
    if X(i,2)<0|X(i,2)>4
      X(i,2)=2+2*rand;
    end
     X(i,1)=round(X(i,1));
X(i,2)=round(X(i,2),4);
      end
      [f]=Get_Functions_details(X,N);
      H=f;
       for i=1:N
  if H(i,:)<B(i,:) % improved move?
          x(i,:)=X(i,:);
        end
       end
  [f]=Get_Functions_details(x,N);
   s=f;
   for i=1:size(x,1)
    % fitness of locations
    fitness=s(i,:);
    % Update the location of Rabbit
    if fitness<Rabbit_Energy
      Rabbit_Energy=fitness;
      Rabbit_Location=x(i,:);
    end
   end
    elseif abs(Escaping_Energy)<1
      %% Exploitation:
      % Attacking the rabbit using 4 strategies regarding the behavior of the rabbit
      %% phase 1: surprise pounce (seven kills)
      % surprise pounce (seven kills): multiple, short rapid dives by different
hawks
      r=rand(); % probablity of each event
      if r>=0.5 && abs(Escaping_Energy)<0.5 % Hard besiege
        for i=1:N
        X(i,:)=(Rabbit_Location)-Escaping_Energy*abs(Rabbit_Location-x(i,:));
        end
         for i=1:N
       if X(i,1)>40|X(i,1)<2
      X(i,1)=ceil(2+38*rand);
  end
    if X(i,2)<0|X(i,2)>4
      X(i,2)=2+2*rand;
    end
     X(i,1)=round(X(i,1));
X(i,2)=round(X(i,2),4);
      end
      [f]=Get_Functions_details(X,N);
      H=f;
       for i=1:N
  if H(i,:)<B(i,:) % improved move?
          x(i,:)=X(i,:);
        end
       end
  [f]=Get_Functions_details(x,N);
   s=f;
   for i=1:size(x,1)
    % fitness of locations
    fitness=s(i,:);
```

```
    % Update the location of Rabbit
    if fitness<Rabbit_Energy
      Rabbit_Energy=fitness;
      Rabbit_Location=x(i,:);
    end
   end
      end
      if r>=0.5 && abs(Escaping_Energy)>=0.5  % Soft besiege
        for i=1:N
        Jump_strength=2*(1-rand()); % random jump strength of the rabbit
        X(i,:)=(Rabbit_Location-x(i,:))-
Escaping_Energy*abs(Jump_strength*Rabbit_Location-x(i,:));
        end
      for i=1:N
       if X(i,1)>40|X(i,1)<2
      X(i,1)=ceil(2+38*rand);
  end
    if X(i,2)<0|X(i,2)>4
      X(i,2)=2+2*rand;
    end
     X(i,1)=round(X(i,1));
X(i,2)=round(X(i,2),4);
      end
      [f]=Get_Functions_details(X,N);
      H=f;
       for i=1:N
  if H(i,:)<B(i,:) % improved move?
          x(i,:)=X(i,:);
        end
       end
  [f]=Get_Functions_details(x,N);
   s=f;
   for i=1:size(x,2)
    % fitness of locations
    fitness=s(i,:);
    % Update the location of Rabbit
    if fitness<Rabbit_Energy
      Rabbit_Energy=fitness;
      Rabbit_Location=x(i,:);
    end
   end
      end
     %% phase 2: performing team rapid dives (leapfrog movements)
      %% phase 2: performing team rapid dives (leapfrog movements)
      if r<0.5 && abs(Escaping_Energy)>=0.5, % Soft besiege % rabbit try to escape
by many zigzag deceptive motions
        Jump_strength=2*(1-rand());
        for i=N
        X1=Rabbit_Location-Escaping_Energy*abs(Jump_strength*Rabbit_Location-
x(i,:));
       if X1(1,1)>40|X1(1,1)<2
      X1(1,1)=ceil(2+38*rand);
       end
    if X1(1,2)<0|X1(1,2)>4
      X1(1,2)=2+2*rand;
    end
     X1(1,1)=round(X1(1,1));
X1(1,2)=round(X1(1,2),4);
       [f]=Get_Functions_details(X1,N);
      H=f;
  if H<B(i,:) % improved move?
          x(i,:)=X1;
        else % hawks perform levy-based short rapid dives around the rabbit
            [o]=levy(dim);
    X2=Rabbit_Location-Escaping_Energy*abs(Jump_strength*Rabbit_Location-
x(i,:))+rand(1,dim).*o;
       if X2(1,1)>40|X2(1,1)<2
```

```
      X2(1,1)=ceil(2+38*rand);
       end
    if X2(1,2)<0|X2(1,2)>4
      X2(1,2)=2+2*rand;
    end
     X2(1,1)=round(X2(1,1));
X2(1,2)=round(X2(1,2),4);

      [f]=Get_Functions_details(X2,N);
      R=f;

  if R<B(i,:) % improved move?
          x(i,:)=X2;

  end
  end
       end
      end
   [f]=Get_Functions_details(x,N);
   s=f;
   for i=1:N
    % fitness of locations
    fitness=s(i,:);
    % Update the location of Rabbit
    if fitness<Rabbit_Energy
      Rabbit_Energy=fitness;
      Rabbit_Location=x(i,:);
    end
   end
    if r<0.5 && abs(Escaping_Energy)<0.5, % Hard besiege % rabbit try to escape by
many zigzag deceptive motions
 % hawks try to decrease their average location with the rabbit
          Jump_strength=2*(1-rand());
        for i=N

        X1=Rabbit_Location-Escaping_Energy*abs(Jump_strength*Rabbit_Location-
mean(x));
      if X1(1,1)>40|X1(1,1)<2
      X1(1,1)=ceil(2+38*rand);
       end
    if X1(1,2)<0|X1(1,2)>4
      X1(1,2)=2+2*rand;
    end
     X1(1,1)=round(X1(1,1));
X1(1,2)=round(X1(1,2),4)
      [f]=Get_Functions_details(X1,N);
      H=f;

  if H<B(i,:) % improved move?
          x(i,:)=X1;
        else
% Hawks perform levy-based short rapid dives around the rabbit
            [o]=levy(dim);
   X2=Rabbit_Location-Escaping_Energy*abs(Jump_strength*Rabbit_Location-
mean(x))+rand(1,dim).*o;
      if X2(1,1)>40|X2(1,1)<2
      X2(1,1)=ceil(2+38*rand);
       end
    if X2(1,2)<0|X2(1,2)>4
      X2(1,2)=2+2*rand;
    end
     X2(1,1)=round(X2(1,1));
X2(1,2)=round(X2(1,2),4);

      [f]=Get_Functions_details(X2,N);
      R=f;
```

```
  if R<B(i,:) % improved move?
         x(i,:)=X2;
  end
  end
      end
     end
  [f]=Get_Functions_details(x,N);
   s=f;
   for i=1:N
    % fitness of locations
    fitness=s(i,:);
    % Update the location of Rabbit
    if fitness<Rabbit_Energy
      Rabbit_Energy=fitness;
      Rabbit_Location=x(i,:);
    end
   end
    end

    t=t+1;
  CNVG(t)=Rabbit_Energy;
end
r=Rabbit_Energy;
R=Rabbit_Location;
if Rabbit_Energy<r
  r=Rabbit_Energy;
  R=Rabbit_Location;
end
end
r
R
toc
figure,
hold on
semilogy(CNVG,'Color','b','LineWidth',4);
title('Convergence curve')
xlabel('Iteration');
ylabel('Best fitness obtained so far');
axis tight
grid off
box on
legend('HHO')
display(['The best location of HHO is: ', num2str(R)]);
display(['The best fitness of HHO is: ', num2str(r)]);
%___________________________________
%HHO Algoritm for DG position assignment

function [f] = Get_Functions_details(x,N)
basemva=10;
accuracy=0.0001;
maxiter=1000;
%==============Load data ==================
busdata = [
1  1  1  0    0.0000   0.000  0  0  0  0  0
2  0  1  0    0.9758   0.7671 0  0  0  0  0
3  0  1  0    0.3635   0.2224 0  0  0  0  0
4  0  1  0    0.3450   0.1104 0  0  0  0  0
5  0  1  0    0.3765   0.2311 0  0  0  0  0
6  0  1  0    0.3700   0.2091 0  0  0  0  0
7  0  1  0    0.2649   0.1982 0  0  0  0  0
8  0  1  0    0.1607   0.1250 0  0  0  0  0
9  0  1  0    0.2413   0.1240 0  0  0  0  0
10  0  1  0    0.3675   0.1370 0  0  0  0  0
11  0  1  0    0.3807   0.0384 0  0  0  0  0
12  0  1  0    0.4000   0.1854 0  0  0  0  0
13  0  1  0    0.3110   0.2590 0  0  0  0  0
14  0  1  0    0.3842   0.2465 0  0  0  0  0
```

```
15 0  1  0    0.2400    0.1127 0  0  0  0  0
16 0  1  0    0.2669    0.1822 0  0  0  0  0
17 0  1  0    0.6332    0.4218 0  0  0  0  0
18 0  1  0    0.2603    0.1600 0  0  0  0  0
19 0  1  0    0.3649    0.2186 0  0  0  0  0
20 0  1  0    0.4453    0.2243 0  0  0  0  0
21 0  1  0    0.5447    0.4132 0  0  0  0  0
22 0  1  0    0.2644    0.1022 0  0  0  0  0
23 0  1  0    0.2669    0.1246 0  0  0  0  0
24 0  1  0    0.5525    0.2888 0  0  0  0  0
25 0  1  0    0.3900    0.1340 0  0  0  0  0
26 0  1  0    0.1755    0.0933 0  0  0  0  0
27 0  1  0    0.2503    0.1132 0  0  0  0  0
28 0  1  0    0.2100    0.1260 0  0  0  0  0
29 0  1  0    0.6758    0.2494 0  0  0  0  0
30 0  1  0    0.3713    0.1455 0  0  0  0  0
31 0  1  0    0.3503    0.1241 0  0  0  0  0
32 0  1  0    0.2669    0.1046 0  0  0  0  0
33 0  1  0    0.2530    0.0838 0  0  0  0  0
34 0  1  0    0.1159    0.0346 0  0  0  0  0
35 0  1  0    0.3842    0.1476 0  0  0  0  0
36 0  1  0    0.4913    0.2300 0  0  0  0  0
37 0  1  0    0.1950    0.1580 0  0  0  0  0
38 0  1  0    0.9605    0.6476 0  0  0  0  0
39 0  1  0    0.1700    0.0976 0  0  0  0  0
40 0  1  0    0.4882    0.2310 0  0  0  0  0];
a=sum(busdata(:,1))
%% branch data
% fbus  tbus  r x  b  rateA  rateB  rateC  ratio  angle  status angmin angmax
linedata= [1.0000  2.0000  0.0288  0.0131     0  1.0000
   2.0000  3.0000  0.0187  0.0142     0  1.0000
   3.0000  4.0000  0.0287  0.0250     0  1.0000
   4.0000  5.0000  0.0356  0.0244     0  1.0000
   5.0000  6.0000  0.0142  0.0273     0  1.0000
   6.0000  7.0000  0.0246  0.0287     0  1.0000
   7.0000  8.0000  0.0382  0.0297     0  1.0000
   8.0000  9.0000  0.0267  0.0242     0  1.0000
   9.0000 10.0000  0.0231  0.0211     0  1.0000
   3.0000 11.0000  0.0173  0.0154     0  1.0000
  11.0000 12.0000  0.0250  0.0233     0  1.0000
  12.0000 13.0000  0.0146  0.0258     0  1.0000
  13.0000 14.0000  0.0155  0.0053     0  1.0000
  14.0000 15.0000  0.0360  0.0121     0  1.0000
  15.0000 16.0000  0.0120  0.0100     0  1.0000
  16.0000 17.0000  0.0218  0.0110     0  1.0000
  17.0000 18.0000  0.0180  0.0111     0  1.0000
  18.0000 19.0000  0.0160  0.0111     0  1.0000
  19.0000 20.0000  0.0160  0.0116     0  1.0000
  20.0000 21.0000  0.0068  0.012     0  1.0000
  21.0000 22.0000  0.0155  0.012     0  1.0000
  3.0000  23.0000  0.0355  0.023     0  1.0000
  23.0000 24.0000  0.0218  0.056     0  1.0000
  24.0000 25.0000  0.0360  0.012     0  1.0000
  25.0000 26.0000  0.028  0.0286     0  1.0000
  26.0000 27.0000  0.039  0.015     0  1.0000
  27.0000 28.0000  0.029  0.023     0  1.0000
  28.0000 29.0000  0.0291  0.025     0  1.0000
  29.0000 30.0000  0.0390  0.0023     0  1.0000
  30.0000 31.0000  0.0179  0.0074     0  1.0000
  31.0000 32.0000  0.0285  0.0273     0  1.0000
  32.0000 33.0000  0.0196  0.0143     0  1.0000
  23.0000 34.0000  0.0430  0.0039     0  1.0000
  34.0000 35.0000  0.0456  0.0287     0  1.0000
  35.0000 36.0000  0.0252  0.0155     0  1.0000
  22.0000 37.0000  0.0376  0.0225     0  1.0000
  37.0000 38.0000  0.0223  0.065     0  1.0000
  38.0000 39.0000  0.0193  0.0065     0  1.0000
```

```
  39.0000  40.0000   0.0279   0.0104      0   1.0000];
%% Before DG Installation
busp=10*busdata(:,5);
sump=sum(busp);
% number of OF
LFYBUS;
LFNEWTON
BUSOUT
bloss
Cost_P_loss_before=8760*733*PL;
PL1=PL;
Pg1=Pg(1);
R=linedata(:,3);
X=linedata(:,4);
Z1=sqrt(R.^2+X.^2);
 for h=1:size(x,1)
     basemva=10; accuracy=0.001; maxiter=1000;
     %=============Load data ==============
   busdata = [
1  1  1  0    0.0000    0.000  0  0  0  0  0
2  0  1  0    0.9758    0.7671 0  0  0  0  0
3  0  1  0    0.3635    0.2224 0  0  0  0  0
4  0  1  0    0.3450    0.1104 0  0  0  0  0
5  0  1  0    0.3765    0.2311 0  0  0  0  0
6  0  1  0    0.3700    0.2091 0  0  0  0  0
7  0  1  0    0.2649    0.1982 0  0  0  0  0
8  0  1  0    0.1607    0.1250 0  0  0  0  0
9  0  1  0    0.2413    0.1240 0  0  0  0  0
10 0  1  0    0.3675    0.1370 0  0  0  0  0
11 0  1  0    0.3807    0.0384 0  0  0  0  0
12 0  1  0    0.4000    0.1854 0  0  0  0  0
13 0  1  0    0.3110    0.2590 0  0  0  0  0
14 0  1  0    0.3842    0.2465 0  0  0  0  0
15 0  1  0    0.2400    0.1127 0  0  0  0  0
16 0  1  0    0.2669    0.1822 0  0  0  0  0
17 0  1  0    0.6332    0.4218 0  0  0  0  0
18 0  1  0    0.2603    0.1600 0  0  0  0  0
19 0  1  0    0.3649    0.2186 0  0  0  0  0
20 0  1  0    0.4453    0.2243 0  0  0  0  0
21 0  1  0    0.5447    0.4132 0  0  0  0  0
22 0  1  0    0.2644    0.1022 0  0  0  0  0
23 0  1  0    0.2669    0.1246 0  0  0  0  0
24 0  1  0    0.5525    0.2888 0  0  0  0  0
25 0  1  0    0.3900    0.1340 0  0  0  0  0
26 0  1  0    0.1755    0.0933 0  0  0  0  0
27 0  1  0    0.2503    0.1132 0  0  0  0  0
28 0  1  0    0.2100    0.1260 0  0  0  0  0
29 0  1  0    0.6758    0.2494 0  0  0  0  0
30 0  1  0    0.3713    0.1455 0  0  0  0  0
31 0  1  0    0.3503    0.1241 0  0  0  0  0
32 0  1  0    0.2669    0.1046 0  0  0  0  0
33 0  1  0    0.2530    0.0838 0  0  0  0  0
34 0  1  0    0.1159    0.0346 0  0  0  0  0
35 0  1  0    0.3842    0.1476 0  0  0  0  0
36 0  1  0    0.4913    0.2300 0  0  0  0  0
37 0  1  0    0.1950    0.1580 0  0  0  0  0
38 0  1  0    0.9605    0.6476 0  0  0  0  0
39 0  1  0    0.1700    0.0976 0  0  0  0  0
40 0  1  0    0.4882    0.2310 0  0  0  0  0];
%% branch data
%  fbus   tbus   r  x  b  rateA  rateB  rateC  ratio  angle  status angmin angmax
linedata= [1.0000   2.0000   0.0288   0.0131      0   1.0000
   2.0000   3.0000   0.0187   0.0142      0   1.0000
   3.0000   4.0000   0.0287   0.0250      0   1.0000
   4.0000   5.0000   0.0356   0.0244      0   1.0000
   5.0000   6.0000   0.0142   0.0273      0   1.0000
   6.0000   7.0000   0.0246   0.0287      0   1.0000
```

```
   7.0000   8.0000  0.0382  0.0297     0  1.0000
   8.0000   9.0000  0.0267  0.0242     0  1.0000
   9.0000  10.0000  0.0231  0.0211     0  1.0000
   3.0000  11.0000  0.0173  0.0154     0  1.0000
  11.0000  12.0000  0.0250  0.0233     0  1.0000
  12.0000  13.0000  0.0146  0.0258     0  1.0000
  13.0000  14.0000  0.0155  0.0053     0  1.0000
  14.0000  15.0000  0.0360  0.0121     0  1.0000
  15.0000  16.0000  0.0120  0.0100     0  1.0000
  16.0000  17.0000  0.0218  0.0110     0  1.0000
  17.0000  18.0000  0.0180  0.0111     0  1.0000
  18.0000  19.0000  0.0160  0.0111     0  1.0000
  19.0000  20.0000  0.0160  0.0116     0  1.0000
  20.0000  21.0000  0.0068  0.012     0  1.0000
  21.0000  22.0000  0.0155  0.012     0  1.0000
  3.0000  23.0000  0.0355  0.023     0  1.0000
  23.0000  24.0000  0.0218  0.056     0  1.0000
  24.0000  25.0000  0.0360  0.012     0  1.0000
  25.0000  26.0000  0.028  0.0286     0  1.0000
  26.0000  27.0000  0.039  0.015     0  1.0000
  27.0000  28.0000  0.029  0.023     0  1.0000
  28.0000  29.0000  0.0291  0.025     0  1.0000
  29.0000  30.0000  0.0390  0.0023     0  1.0000
  30.0000  31.0000  0.0179  0.0074     0  1.0000
  31.0000  32.0000  0.0285  0.0273     0  1.0000
  32.0000  33.0000  0.0196  0.0143     0  1.0000
  23.0000  34.0000  0.0430  0.0039     0  1.0000
  34.0000  35.0000  0.0456  0.0287     0  1.0000
  35.0000  36.0000  0.0252  0.0155     0  1.0000
  22.0000  37.0000  0.0376  0.0225     0  1.0000
  37.0000  38.0000  0.0223  0.065     0  1.0000
  38.0000  39.0000  0.0193  0.0065     0  1.0000
  39.0000  40.0000  0.0279  0.0104     0  1.0000];
     busdata(x(h,1),7)=x(h,2);
     busdata(1,7)=0;
     LFYBUS;
LFNEWTON2
BUSOUT
bloss2
Cost_P_loss_after=8760*733*PL2;
PL3=PL2;
Pg1=Pg(1);
R=linedata(:,3);
X=linedata(:,4);
Z1=sqrt(R.^2+X.^2);
% Vm(h,:)
for n=1:nbus
   VPI(n)= (Vm(n)- 1.0)^2;
  end
VP(h,1)=sum(VPI);
f(h,1)=PL3/PL;
 end
  f ;
```

Appendix B: Adaptive Protection Coordination HHO Algorithm

```
ns=0; ng=0; Vm=0; delta=0; yload=0; deltad=0;
nbus = length(busdata(:,1));
for k=1:nbus
  n=busdata(k,1);
  kb(n)=busdata(k,2); Vm(n)=busdata(k,3); delta(n)=busdata(k, 4);
  Pd(n)=busdata(k,5); Qd(n)=busdata(k,6); Pg(n)=busdata(k,7); Qg(n) = busdata(k,8);
  Qmin(n)=busdata(k, 9); Qmax(n)=busdata(k, 10);
  Qsh(n)=busdata(k, 11);
  if Vm(n) <= 0  Vm(n) = 1.0; V(n) = 1 + j*0;
  else delta(n) = pi/180*delta(n);
    V(n) = Vm(n)*(cos(delta(n)) + j*sin(delta(n)));
    P(n)=(Pg(n)-Pd(n))/basemva;
    Q(n)=(Qg(n)-Qd(n)+ Qsh(n))/basemva;
    S(n) = P(n) + j*Q(n);
```

```
  end
end
for k=1:nbus
  if kb(k) == 1, ns = ns+1; else, end
  if kb(k) == 2 ng = ng+1; else, end
  ngs(k) = ng;
  nss(k) = ns;
end
Ym=abs(Ybus); t = angle(Ybus);
m=2*nbus-ng-2*ns;
maxerror = 1; converge=1;
iter = 0;
% Start of iterations
clear A  DC  J DX
while maxerror >= accuracy & iter <= maxiter % Test for max. power mismatch
  for i=1:m
    for k=1:m
      A(i,k)=0;    %Initializing Jacobian matrix
    end, end
  iter = iter+1;
  for n=1:nbus
    nn=n-nss(n);
    lm=nbus+n-ngs(n)-nss(n)-ns;
    J11=0; J22=0; J33=0; J44=0;
    for i=1:nbr
      if nl(i) == n | nr(i) == n
        if nl(i) == n,  l = nr(i); end
        if nr(i) == n,  l = nl(i); end
        J11=J11+ Vm(n)*Vm(l)*Ym(n,l)*sin(t(n,l)- delta(n) + delta(l));
        J33=J33+ Vm(n)*Vm(l)*Ym(n,l)*cos(t(n,l)- delta(n) + delta(l));
        III(n)= abs(Ym(n,l))*sqrt(Vm(n)^2+Vm(l)^2-2*Vm(n)*Vm(l)*cos(delta(n) +
delta(l)));
        if kb(n)~=1
          J22=J22+ Vm(l)*Ym(n,l)*cos(t(n,l)- delta(n) + delta(l));
          J44=J44+ Vm(l)*Ym(n,l)*sin(t(n,l)- delta(n) + delta(l));
        else, end
        if kb(n) ~= 1  & kb(l) ~=1
          lk = nbus+l-ngs(l)-nss(l)-ns;
          ll = l -nss(l);
          % off diagonalelements of J1
          A(nn, ll) =-Vm(n)*Vm(l)*Ym(n,l)*sin(t(n,l)- delta(n) + delta(l));
          if kb(l) == 0  % off diagonal elements of J2
            A(nn, lk) =Vm(n)*Ym(n,l)*cos(t(n,l)- delta(n) + delta(l));end
          if kb(n) == 0  % off diagonal elements of J3
            A(lm, ll) =-Vm(n)*Vm(l)*Ym(n,l)*cos(t(n,l)- delta(n)+delta(l)); end
          if kb(n) == 0 & kb(l) == 0  % off diagonal elements of  J4
            A(lm, lk) =-Vm(n)*Ym(n,l)*sin(t(n,l)- delta(n) + delta(l));end
        else end
      else , end
    end
    Pk = Vm(n)^2*Ym(n,n)*cos(t(n,n))+J33;
    Qk = -Vm(n)^2*Ym(n,n)*sin(t(n,n))-J11;
    if kb(n) == 1 P(n)=Pk; Q(n) = Qk; end  % Swing bus P
    if kb(n) == 2  Q(n)=Qk;
      if Qmax(n) ~= 0
        Qgc = Q(n)*basemva + Qd(n) - Qsh(n);
        if iter <= 7          % Between the 2th & 6th iterations
          if iter > 2         % the Mvar of generator buses are
            if Qgc  < Qmin(n),     % tested. If not within limits Vm(n)
              Vm(n) = Vm(n) + 0.01;   % is changed in steps of 0.01 pu to
            elseif Qgc  > Qmax(n),  % bring the generator Mvar within
              Vm(n) = Vm(n) - 0.01;end % the specified limits.
          else, end
        else,end
      else,end
    end
    if kb(n) ~= 1
      A(nn,nn) = J11; %diagonal elements of J1
      DC(nn) = P(n)-Pk;
    end
    if kb(n) == 0
      A(nn,lm) = 2*Vm(n)*Ym(n,n)*cos(t(n,n))+J22; %diagonal elements of J2
      A(lm,nn)= J33;     %diagonal elements of J3
      A(lm,lm) =-2*Vm(n)*Ym(n,n)*sin(t(n,n))-J44; %diagonal of elements of J4
```

```
      DC(lm) = Q(n)-Qk;
    end
  end
  DX=A\DC';
  for n=1:nbus
    nn=n-nss(n);
    lm=nbus+n-ngs(n)-nss(n)-ns;
    if kb(n) ~= 1
      delta(n) = delta(n)+DX(nn); end
    if kb(n) == 0
      Vm(n)=Vm(n)+DX(lm); end
  end
  maxerror=max(abs(DC));
  if iter == maxiter & maxerror > accuracy
    fprintf('\nWARNING: Iterative solution did not converged after ')
    fprintf('%g', iter), fprintf(' iterations.\n\n')
    fprintf('Press Enter to terminate the iterations and print the results \n')
    converge = 0; pause, else, end
end
if converge ~= 1
  tech= ('              ITERATIVE SOLUTION DID NOT CONVERGE'); else,
  tech=('            Power Flow Solution by Newton-Raphson Method');
end
V = Vm.*cos(delta)+j*Vm.*sin(delta);
deltad=180/pi*delta;
i=sqrt(-1);
k=0;
for n = 1:nbus
  if kb(n) == 1
    k=k+1;
    S(n)= P(n)+j*Q(n);
    Pg(n) = P(n)*basemva + Pd(n);
    Qg(n) = Q(n)*basemva + Qd(n) - Qsh(n);
    Pgg(k)=Pg(n);
    Qgg(k)=Qg(n);   %june 97
  elseif kb(n) ==2
    k=k+1;
    S(n)=P(n)+j*Q(n);
    Qg(n) = Q(n)*basemva + Qd(n) - Qsh(n);
    Pgg(k)=Pg(n);
    Qgg(k)=Qg(n); % June 1997
  end
  yload(n) = (Pd(n)- j*Qd(n)+j*Qsh(n))/(basemva*Vm(n)^2);
end
busdata(:,3)=Vm'; busdata(:,4)=deltad';
Pgt = sum(Pg); Qgt = sum(Qg); Pdt = sum(Pd); Qdt = sum(Qd); Qsht = sum(Qsh);

%clear A DC DX  J11 J22 J33 J44 Qk delta lk ll lm
%clear A DC DX  J11 J22 J33  Qk delta lk ll lm
```

Appendix C: Load Data of the Network

Load Point	Load in KW	Load in KVAR	Load in KVA
LD1	167	13	180
LD2	165	10	175
LD3	288	21.5	309.5
LD4	95	6	101
LD5	90	10	100
LD6	12	1	13
LD7	99.25	15.75	215
LD8	89	15	104
LD9	15	2	17
LD10	99.25	5.75	105
LD11	299.25	15.75	315
LD12	299.25	15.75	375
LD13	394.25	20.75	415
LD14	299.25	15.75	315
LD15	36.75	8.25	44.5
LD16	80	12	92
LD17	296.75	68.25	365
LD18	726.75	38.25	765

LD19	475	25	500
LD20	190	10	200
LD21	299.25	15.75	315
LD22	190	10	200
LD23	598.5	31.5	630
LD24	380	20	400
LD25	299.25	15.75	315
LD26	71.25	3.75	75
LD27	693.5	36.5	730
LD28	299.25	15.75	315
LD29	99.25	15.75	215
LD30	299.25	15.75	315
LD31	190	20	210
LD32	12	3	15
LD33	299.25	15.75	315
LD34	299.25	15.75	315
LD35	299.25	15.75	315
LD36	299.25	15.75	315
LD37	299.25	15.75	315
LD38	299.25	15.75	315
LD39	788.5	41.5	830
LD40	788.5	41.5	830

Appendix D: Line Parameters of the Network (Line Data)

Name of Line	Resistance in Ω	Reactance in Ω
L1	0.0643	0.07126
L2	0.4409	0.48824
L3	0.078	0.0486
L4	0.0469	0.051952
L5	0.0506	0.07234
L6	0.298	0.33004
L7	0.0513	0.05681
L8	0.1605	0.09998
L9	0.1632	0.18071
L10	0.0378	0.04189
L11	0.0679	0.07517
L12	0.0643	0.07126
L13	0.0619	0.06858
L14	0.1917	0.11937
L15	0.3389	0.22110
L16	0.2151	0.13396
L17	0.2721	0.16949
L18	0.2263	0.14094
L19	0.2191	0.13644
L20	0.078	0.0486
L21	0.1122	0.06986
L22	0.1783	0.11103
L23	0.1605	0.09998
L24	0.3014	0.18771
L25	0.296	0.18476
L26	0.231	14386
L27	0.0928	0.07041
L28	0.0603	0.03755
L29	0.0521	0.03244
L30	0.1148	0.07147
L31	0.122	0.07601
L32	0.1471	0.09159
L33	0.4	0.04722
L34	0.3295	0.22052
L35	0.007	0.00437
L36	0.0494	0.03075
L37	0.212	0.13201
L38	0.0853	0.05317
L39	0.1286	0.08008
L40	0.1961	0.12216