ADDIS ABABA UNIVERSITY

ADDIS ABABA INSTITUTE OF TECHNOLOGY

SCHOOL OF ELECTRICAL AND COMPUTER ENGINEERING

Study on Impacts of Distributed Generation Integration in Medium Voltage Radial Distribution system

(Case Study: Sebeta-I Substation)

A Thesis Submitted to the School of Graduate Studies of Addis Ababa University in Partial Fulfillment of the Requirements for the Degree of Masters of Science in Electrical Engineering (Electrical Power Stream)

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Declaration

I declare that this thesis is my original work, and the work described in this thesis has not been previously presented for fulfillment of a degree in this or any other university, and all sources and materials used for the thesis have been acknowledged.

All examiners' comments are duly incorporated.

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Place: Addis Ababa

This thesis has been submitted for examination with my approval as a university advisor.

Dr. Getachew Bekele __________________________________

Advisor's Name Signature

Acknowledgment

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Abstract

The mission of every electric company is to transmit, distribute and supply electricity in reliable and efficient manner. However in comparison to the part of the power system supplying energy (the large generating units and the transmission grid), the distribution system, feeding load, is very extensive and has high R/X ratio causing more power loss, poor voltage stability and large voltage drop in the network which results with voltage magnitude at the customer terminal out of permissible limit. On the other hand, increasing power demands has led to the existing aging power system operation becoming more challenging from the points of security, reliability, efficiency and quality of the electric power supply.

To catch up with and possibly overtake these issues, integration of distributed generation into the distribution system is one possible solution. Integrating distributed generation into the system at a proper place with a proper size makes the grid capable to distribute and supply electricity in reliable and efficient manner with improvement of several technical parameters. The purpose of this study is to investigate the impact of distributed generation integration on a radial distribution system. The feeder SEB-12 of Sebeta-I Substation of medium voltage radial distribution system which having 44 buses is taken as a case study area to determine the impact of distributed generation integration on a radial distribution network. The feeder was selected due to its highest power interruption frequency and long duration power outage during the two year recorded data. The impacts of DG integration on total power loss, voltage profile, voltage stability, loading of line segment, fault level, and protection coordination of the distribution system were investigated.

Modelling of the case study distribution network is simulated using DIgSILENT PowerFactory 15.1.7 simulation package. The results of base case balanced and positive sequence load flow analysis at steady state condition indicated that the feeder has total power loss of 1.91 MW and 2.07 MVAR with the terminal voltage magnitude at the majority of the buses being out of acceptable limit. The minimum node voltage magnitude of 0.832 p.u. (12.479 kV) is found at bus 18 which is far out of allowable voltage range of 1±5%. To reduce the total power loss of the network, and improve voltage profile of the system to within allowable range, distributed generator is integrated to the network at a proper place with a proper size. In this thesis sizing and sitting of DG was performed based on analytical method and load flow analysis respectively. The proper size of DG was found to be 12.098MW with the proper place at bus 14. The results of simulation after the integration of DG revealed that the total real and reactive power loss is reduced to 0.30 MW and 0.28 MVAR with the total loss reduction of 84.29% and 86.47% respectively, while all node voltages had improved to within permissible limit of 1±5%.

In general, the impact of DG integration on total power loss, voltage profile, loading of line segment and voltage stability of the system are positive while there are some negative impacts such as increase in fault level and miss-coordination of protection devices.

Key Words: Distributed generation, DG proper location, DG proper size, Technical parameters, Technical constraints, Loss reduction, DIgSILENT PowerFactory.

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List of Acronyms

AC	Alternating Current
ADW1	Addis West one
ADW2	Addis West two
ANSI	American National Standards Institute
BAT	Best Available Technology
C.C.C	Current Carrying Capacity
CCGT	Combined Cycle Gas Turbine
CHP	Combine Heat and Power
CIGRE	International Council for Large Electric Systems
CT	Current Transformer
DC-AC	Direct Current to Alternating Current
DC-DC	Direct Current to Direct Current
DESS	Distributed Energy Storage System
DG	Distributed Generation
DIgSILENT	DIgital SImuLation of Electrical NeTwork
DT	Definite Time
EEP	Ethiopian Electric Power
EEU	Ethiopian Electric Utility
EF	Earth Fault
EMT	Electromagnetic Transient
FC	Fuel Cell
HV	High Voltage
ICS	Inter Connected System
IDMT	Inverse Definite Minimum Time
IEEE	Institute of Electrical and Electronics Engineering
IGBT	Insulated Gate Bipolar Transistor
KA	Kilo Ampere
KV	Kilo Volt
KW	Kilo Watt
KWh	Kilo Watthour
LG	Line to Ground
LTC	Load Tap Changer
LV	Low Voltage
MV	Medium Voltage

MVA	Mega Volt Ampere
MVAR	Mega Volt Ampere Reactive
MW	Mega Watt
OL	Over Load
OP	Operational
p.u.	Per Unit
PCC	Point of Common Coupling
PEM	Proton Exchange Membrane
PEMFC	Proton Exchange Membrane Fuel Cell
ph	phase
POC	Point of Connection
PS	Plug Setting
PSM	Plug Setting Multiplier
PV	Photo Voltaic
R/X	Resistance to reactance ratio
SC	Short Circuit
SCR	Silicon Controlled Rectifier
SEB-I	Sebeta Substation-I
SEB-I-A	Sebeta Substation -I-A
SEB-I-B	Sebeta Substation-I-B
SEB-I-C	Sebeta Substation-I-C
SOFC	Solid Oxide Fuel Cell
TD	Time Dial
TSM	Time Setting Multiplier
UF	Under Frequency
WDG	With Distributed Generator
WODG	With Out Distributed Generator

Chapter One
Introduction

1.1 Background of the Study

Continued economic growth and fulfillment of high standards in human life depends on reliable and affordable access to electricity. To meet these issues the way the electricity is generated, transmitted and delivered must be upgraded. Utilities are continuously planning the expansion of their existing electrical networks in order to meet the load growth and to properly supply their consumers with efficient and reliable power supply. An important phenomenon in this regard for further future electric power generation is distributed generation, which is also known as embedded generation, dispersed generation or decentralised generation. Distributed generation (DG) may come from a variety of source and technologies. Distributed generations (DGs) from renewable sources, like wind, solar and biomass are often called as "Green energy". In addition to this, DG includes micro turbines, gas turbines, diesel engines, fuel cells, stirling engines and internal combustion reciprocating engines [1].

In heavily loaded distribution network, the load current drawn from the source would increase. This may lead to an increase in voltage drop and system losses. The performance of distribution system becomes inefficient due to the reduction in voltage magnitude and increase in distribution losses. With this regard, changing environment of power systems design and operation has necessitated the need to consider active distribution network by incorporating distributed generator (DG) unit [2].

Nowadays electricity networks are in the era of major transition from stable passive distribution networks with unidirectional electricity transportation to active distribution networks with bidirectional electricity transportation. Distribution networks without any DG units are passive since the electrical power is supplied by the national grid system to the customers embedded in the distribution networks. It becomes active when DG units are added to the distribution system leading to bidirectional power flows in the networks [3].

In an active distribution network the amount of energy lost in transmitting electricity is less as compared to the passive distribution network, because the electricity is generated very near the load center, perhaps even in the same building. Active distribution network has several advantages like reduced line losses, voltage profile improvement, reduced emission of pollutants, increased overall efficiency, improved power quality and relieved transmission and distribution congestion. Hence, utilities and distribution companies need tools for proper planning and operation of *active distribution networks*.

In order to achieve the desired performance in DG resources such as minimizing power losses, improve the voltage profile, the reliability and power quality parameters of the electric grid, suitable placement and sizing of this DG units is required. There are two methods for sitting and sizing of DG in the distribution network. The first method is traditional based such as optimal power flow (OPF), sensitive factor and repetitive load flows (reload flow). In the second method, the artificial intelligent (AI) is used to apply with DG placement and sizing like Ant Colony Algorithm (ACO), Genetic Algorithm (GA), Tabu Search (TS), Differential Evolution (DE) and Particle Swarm Optimization (PSO).

In this thesis, an analytical method was used to determine proper size of DG with the help of MATLAB program, and the proper location for DG placement was identified by load flow analysis with injection of DG at each bus with corresponding size found at each bus by considering total power loss reduction and voltage profile improvement. The load flow analysis of the sample network was simulated in the DIgSILENT PowerFactory 15.1.7 software package. The DG is considered to be located in the primary distribution system and the objective of the DG placement is to reduce the total power losses and improve the voltage profile of the system.

1.2 Statements of the Problem

Nowadays, demand for electrical energy is growing fast and one of the main tasks for electricity utility company is to generate electricity from distributed energy sources (DG) in order to make the grid to have the ample capacity to transmit, distribute and supply electricity in reliable and efficient manner. Consequently, in order to achieve a benefit from distributed generation (DG) integration, proper planning of these resources is important. Integrating distributed generation into the system at a proper place with a proper size makes the grid capable of distribute and supply electricity in reliable and efficient manner with improvement of several technical parameters such as network power loss, voltage profile, loading of line segment and power reliability.

However the great challenges for a power system planners are integrating these distributed energy resources at a proper place with appropriate size. Improper placement and sizing of distributed generators (DG) may reduce the positive impacts gained from the DG integration with the dominant negative impacts, and on account of this the electric utility companies have no willingness to promote the distributed generation (DG) implementation in power distribution sector.

In response to these challenges, this study intends to determine the impact of DG integration on network technical parameters by conceiving the proper placement and size of DG with the objective of line loss reduction and voltage profile improvement.

1.3 Thesis objectives

1.3.1 General Objective

The main objective of the thesis is to investigate the impacts of distributed generation integration on radial distribution system by taking into account the proper placement and sizing of DG.

1.3.2 Specific Objectives

The specific objectives of the thesis are:

- ✓ Identification of the base case distribution feeder from the rest of the feeders based on their power interruption vulnerability
- ✓ Development of the base case distribution feeder model with the help of DIgSILENT PowerFactory 15.1.7 simulation software package
- ✓ Determination of base case total power loss and voltage profile of the selected feeder by using load flow analysis at steady state operating condition
- ✓ Determining the proper site and size of distributed generator (DG) for the selected distribution feeder
- ✓ Cost estimation of the determined DG size
- ✓ Investigating the impacts that different configurations and penetration levels of DG may have on different parameters of the distribution system during steady state and dynamic conditons

1.4 Methodology and Techniques

The methods and techniques used to investigate the impact of distributed generation integration on distribution system are as follows:

Data collection: Important information and data of the case study distribution substation have been collected from Ethiopian Electric Power (EEP) and Ethiopian Electric Utility (EEU).

Literature Review: Reviewing of different literatures to gain knowledge on back ground of the study area and make incite on state of the art technology in distributed generation. **Development of the base case network model:** The base case network model was developed with the help of DIGSILENT PowerFactory 15.1.7 Software.

Sizing and Sitting of DG: Sizing of DG was performed by using analytical method with the help of MATLAB and sitting was followed with help of load flow analysis.

Performance analysis, testing and data validation: The simulation results were validated by several case studies through the following scenarios:

Load flow analysis (pre-fault conditions) - which is used to investigate the potential impact of distributed generation (DG) unit on network parameters particularly to check the total power loss, voltage profile pattern and loading of line segments (possible over-loading problems).

Load flow analysis (During fault) – this intends to determine the impact of DG integration on short circuit level, system protection, and whether the system remains stable or not after distributed generation installation during several disturbances.

1.5 Scope and Limitation of the Thesis

The scope and limitations of this thesis are as follows:

- Only the major technical impacts of distributed generation integration on distribution system has covered in this thesis
- The DG technologies has been limited to Synchronous Generator which is standard models available in DIgSILENT PowerFactory 15.1.7 without considering their detail design
- Protection of DG during disturbance such as islanding problems and automatic disconnection and reconnection of DG are beyond the scope of this thesis

1.6 Organizations of the Thesis

This thesis is organized as follows:

Chapter one deals with a brief introduction of the thesis background, problem statement, description of methodology and techniques used in the thesis and the thesis outline.

Chapter two gives the details of the theoretical background and review of different literatures related to the study.

Chapter three describes distributed generation integration issue and distribution system protection by considering the presence of DG.

Chapter four covers modeling and simulation of the case study distribution system in parallel with discussion of the results found.

Chapter five gives conclusion and recommendation of the thesis as well as the further work expected to be done in the future.

Chapter Two

Theoretical Background and Review of Different Literatures

2.1 Introduction

The majority of power systems topology is taken for granted as a radial system, which means power flows from source to load or from generation to consumers. However, with the presence of distributed generation technology, this paradigm has changed and the power source is not only from centralized sources but also from another source such as distributed generation, thus power flow from the central source to the distributed generation or vice versa.

This chapter focused on review of different literatures related to the impact of DG integration on a distribution system in order to compare and contrast the legacy distribution system with the active distribution system. Furthermore, the critical review of the distributed generation concepts and technology, their environmental impacts and the contribution of DG technology to modernize the old distribution system which is involved under this chapter.

2.2 Distributed Generation Concepts and Technology

Distributed generation is not a new concept because originally, all energy was produced and consumed at or near the process that required it [4]. As cited in this literature a fireplace, wood stove, and candle are all forms of "distributed" – small scale, demand-sited – energy. So is a pocket watch, alarm clock, or car battery. However, the key to today's energy revolution involves turning the old centralized generation system (from large power plants hundreds or thousands of miles away to a "heat engine" in the building) towards the generation of electrical energy near the load center to gain several technical and economic benefits.

2.2.1 Concept of Distributed Generation

Distributed generation (or DG) generally refers to small-scale (typically 1 kW – 50 MW) electric power generators that produce electricity at a site close to customers or that are tied to an electric distribution system. Distributed generators include, but are not limited to synchronous generators, induction generators, reciprocating engines, micro turbines (combustion turbines that run on high-energy fossil fuels such as oil, propane, natural gas, gasoline or diesel), combustion gas turbines, fuel cells, solar photovoltaic, and wind turbines [5]. Distributed Generation (DG) also called as site generation, dispersed generation, embedded generation, decentralized generation, decentralized energy or distributed energy, generates electricity from the many small energy sources [6].

Conventional power stations, such as coal-fired, gas and nuclear powered plants, as well as hydroelectric dams and large-scale solar power stations, are centralized and often require electricity to be transmitted over long distances. Electricity is delivered to the customers using a large passive distribution infrastructure, which involves high voltage (HV), medium voltage (MV) and low voltage (LV) networks. In these system, networks are designed to operate radially. The power flows only in one direction; from upper voltage levels down-to customers situated along the radial feeders. In this process, there are three stages to be passed through before the power reaching the final user, i.e. generation, transmission and distribution (see figure 2.1).

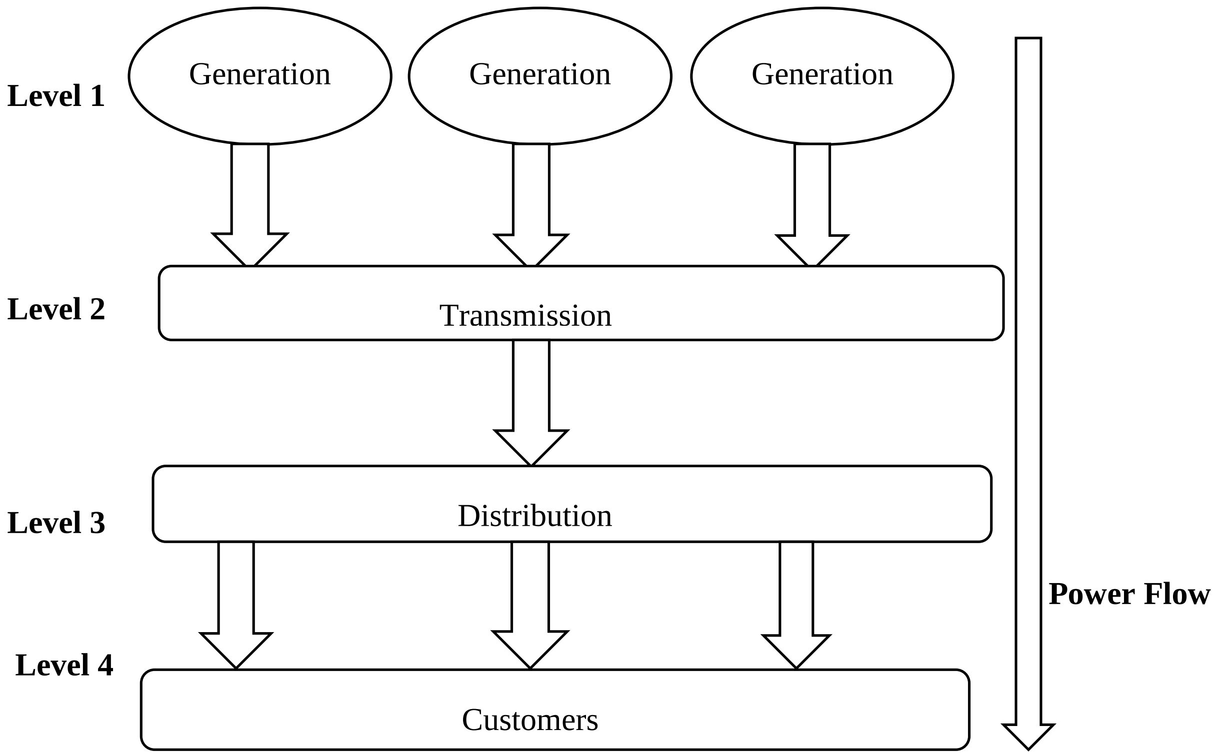


Figure 2. 1 Power flow before the integration of distributed generation

In the first stage the electricity is generated in large generation plants, located in non-populated areas away from the load center. Second stage is accomplished with the support of various equipments such transformers, overhead transmission lines and underground cables. The last stage is the distribution, 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 [7].

By contrast, distribute generation (DG) systems are decentralized, modular and more flexible technologies, which are located close to the load they serve. These systems can comprise multiple generation and storage components. In this instance they are referred to as Hybrid power systems.

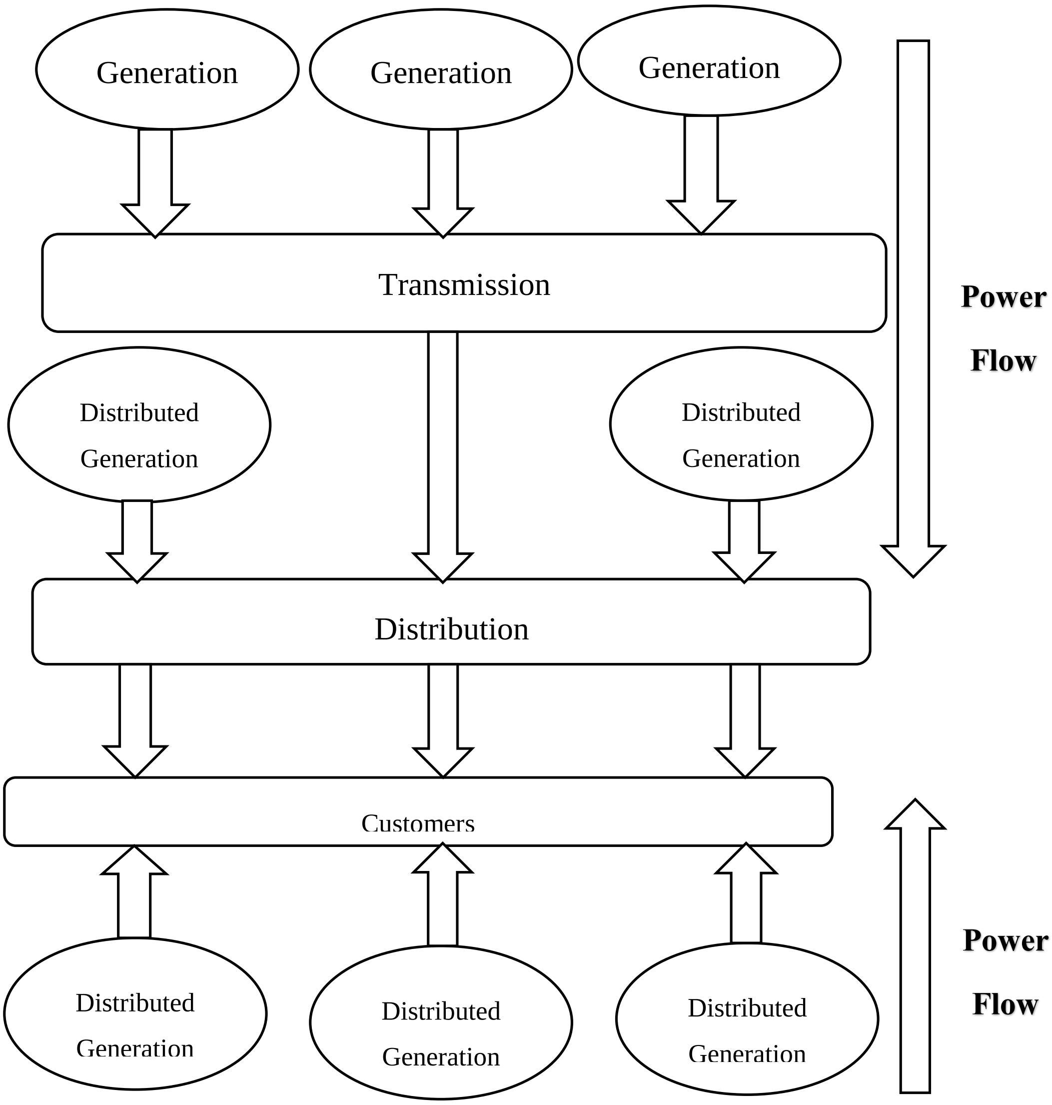


Figure 2. 2 Power flow after the integration of distributed generation

Distributed generation (DG) systems typically use renewable energy sources, including small hydro, biomass, biogas, solar power, wind power, and geothermal power, and increasingly play an important role for the electric power distribution system. A grid-connected device for electricity storage can also be classified as a DG system, and is often called a distributed energy storage system (DESS) [4].

These new technologies allow the electricity to be generated in small sized plants at the distribution level and at the customer side. Moreover, the increasing use of renewable sources in order to reduce the environmental impact of power generation leads to the development and application of this new electrical energy supply schemes. In this new conception, the generation is not exclusive to level 1. Hence some of the energy-demand is supplied by the centralized generation and another part is produced by *distributed generation*. The electricity is going to be produced closer to the customers (see figure 2.2).

2.2.2 Definition of Distributed Generation

Distributed Generation is a concept of small-scale electric power generation that is operated and installed near to the customer's site and used to support the increased energy-demand. Usually, it is connected via power electronic converter or other power electronic devices to the distribution system [4]. There is not a common accepted definition of DG as the concept involves many technologies and applications. Different terms and definitions are used related to DG in different literature. For example, Anglo-American countries often use the term 'embedded generation', North-American countries use the term 'dispersed generation', and Europe and parts of Asia, uses the term 'decentralised generation' [8].

The definitions of DG which are derived in terms of capacities of the DG units generating at the site of connection is given below [8].

1. The electric power research Institute defined DG as generation from a few kilowatts up to 50MW,
2. According to the Gas Research Institute, DG is in between 25KW and 25MW,
3. Preston and Rastler defined as 'ranging the size from a few kilowatts to over 100 MW',
4. Cardell defined DG as generation between 500KW and 1MW,
5. The international conference on Large High Voltage Electric Systems (CIGRE) defined DG as 'smaller than 50-100MW'.

However, this definition is not compulsory as there are no universal agreements on the distributed generation definition. The main objective of distributed generation is getting the electricity from point of generation close to the point of consumer. Therefore in this thesis, the following definition is used [5]:

Distributed generation is considered as the installation and operation of electric power generation units connected directly to the distribution network or connected to the network on the customer site of the meter in order to provide a source of active electric power which is small enough compared with the centralized power plants.

The motivation for using this definition is that the connection of generation units to the transmission network is done traditionally by the industry. The central idea of distributed generation, however, is to locate generation close to the load, hence on the distribution network or on the customer side of the meter.

2.2.3 Classification of Distributed Generation

DGs can be classified based on different criteria. Among these, the two main criteria for DGs classifications are based on capacity or output power rating and the type of technology involved in the power generation.

The classifications of DGs based on capacity or output power rating is as shown in Table 2.1.

Table 2. 1 Classification of DG based on power rating

Class	Power Range
Micro Distributed Generation	~ 1W – 5KW
Small Distributed Generation	5kW – 5MW
Medium Distributed Generation	5MW – 50MW
Large Distributed Generation	50MW – 300MW

Another basis for classification of DGs is the type of technology involved in the power generation. Therefore, distributed generation technologies can be categorised as renewable and non-renewable as depicted in Table 2.2.

Table 2. 2 Classification of DG based on technology

Renewables DG	Non-renewables DG
Solar	Internal Combustion Engines (ICE)
Wind	Combined Cycle
Geothermal	Combustion Turbine
Ocean	Microturbine
	Fuel Cell

Distributed generation technologies could also be grouped according to their dispatchability namely dispatchable and non-dispatchable [4]. This is because one of the primary elements in a distributed generation management system is the dispatch strategy: the aspect of control strategy that pertains to the sources and destinations of energy flows. The key difference between the two categories is the controllability of electric power. The dispatchable resources, in general, have the energy stored, and could therefore be called upon at any given time to produce power. This implies that dispatchable units such as conventional generator sets, fuel cells, and microturbines, can be controlled by a central intelligence and relied on to generate according to the needs of the power system. The non-dispatchable resources, on the other hand, inherently do not have any control of the input energy for later use when needed. This means that non-dispatchable technologies generate not as a function of power system needs, but rather as a function of intermittent availability of their energy source. From the foregoing it can adduced that while non-renewable DG technologies are dispatchable the renewable DG technologies consist of dispatchable and non-dispatchable resources. Hydroelectric, biomass and geothermal are dispatchable resources, whereas, wind, solar and tidal waves would be classified as non-dispatchable resources – most or common renewable energy systems are non-dispatchable.

Different authors still classify DG as inverter based DG and rotating machine DG [7]. 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 has to be converted first to DC and then back to AC with the nominal parameters through the rectifier.

2.2.4 Distributed Generation Environmental Impacts

Often DG technologies are described as more environmental friendly than centralised generation. Keen public awareness of the environmental impacts of electric power generation and efforts to mitigate climate change are crucial to DG renaissance. For instance, fossil fuelled power plants produce sulphur oxides, particulate matter, and nitrogen oxides [5]. Of the former, sulphur dioxide accounts for about 95% and is a by-product of the combustion of coal or oil. The sulphur content of coal varies from 0.3 to 5%. According to these authors, it should be noted that although sulphur does not accumulate in the air it does so in the soil.

Unfortunately some distributed generation technologies could, if fully deployed, significantly contribute to present environmental problems. Therefore, the technologies that can be used for distributed generation cannot be described in general as environmental friendly. But regarding the main current environmental issue, the increased greenhouse effect, all DG technologies lead to significantly lower emissions than coal-based technologies [4]. On the contrary, in the case of the so-called "zero emission" generation systems, though direct emission due to combustion is zero, indirect emissions linked to construction, maintenance and dismantling have to be considered. This is the case with nuclear power plants, windmills, photovoltaic generators, hydroelectric power plants and power plants using biomass.

Ackermann *et al*. (2001) consider indirect emissions as emissions that occur during the manufacturing of the power unit and the exploration and transport of the energy resources and maintain that the emissions from typical DG technologies are significantly lower than those from coal power stations. They have also noted that combined cycle gas turbines (CCGT) and large hydro units, too, have significantly lower SO2 and CO2 emissions than coal power stations. In their view biomass is seen as being CO2 neutral, as the amount of CO2 emitted into the atmosphere when biomass is burnt is equal to the amount of CO2 absorbed during its growth. According to them NOx (nitrogen oxides) emissions of combustion of bio-fuels were reported to be 20 - 40% lower than that of fossil fuel plants, and SO2 emissions were reported to be insignificant. Also battery storage as well as fuel cells has no direct emissions besides the emissions occurring during the manufacturing process. However, the fuel mix used for the production of the electricity stored in the batteries must be considered in the calculations of the indirect emissions of battery storage. Furthermore, in the case of fuel cells, the indirect emissions also depend on the energy mix that is required to produce hydrogen, as hydrogen cannot be easily exploited in the same way as conventional fossil fuels.

Additional environmental benefits, resulting from e.g. the reduction of transmission line losses, achieved by proper siting in terms of location and unit size, could further improve the environmental balance of DG. Apart from that, some argued that a large amount of DG might force the large units to operate below their optimum efficiency, which will lead to an increase in emissions per produced kWh. Other aspects, which make an environmental comparison very difficult are different perceptions regarding the risk of nuclear power stations or regarding the visual impact, noise impact and land requirements of wind turbines, for example.

Therefore, the technologies that can be used for distributed generation cannot be described in general as environmental friendly. But regarding the main current environmental issue, the increased greenhouse effect, all DG technologies lead to significantly lower emissions than coal-based technologies.

2.2.5 Distributed Generation Technology

The liberalisation of electricity markets and environmental policy has increased the use of distributed generation units for a range of applications, such as standalone, peak load shaving and remote applications. These units can be classified into two different categories [9]:

1. Distributed generation based generation, including micro turbines, photovoltaic, fuel cells, wind turbines and biomass.
2. Distributed generation based storage, including flywheels, battery, super capacitor and superconducting coil system.

All of these technologies are currently being used and are gaining popularity. Some of the different types of distributed generation are discussed in the subsequent section.

2.2.5.1 Photo Voltaic Systems

Photovoltaics (PV) (“photo” meaning “light” and “voltaic” referring to electricity) is the direct conversion of sunlight into an electrical potential (a photovoltage) that can be used to provide electric power. The photo voltaic effect is the electrical potential developed between two dissimilar materials when their common junction is illuminated with radiation of photons. The photo voltaic cell, thus, converts light directly into electricity [10]. A material or device that is capable of converting the energy contained in photons of light into an electrical voltage and current is said to be photovoltaic [4]. Therefore, the photo voltaic effect is the process by which an electric potential difference (voltage) is created in a material exposed to light (electromagnetic radiation), which then leads to the flow of electric current (NERC, 2010). This process is directly related to the photo electric effect, but distinct from it in that in the case of the photo electric effect electrons are ejected from the material surface upon being exposed to high enough frequency (energy) light, whereas in the photo voltaic effect the generated electrons are transferred across a material junction (e.g., PN junction in a photo-diode) resulting in the buildup of a voltage between two electrodes and the flow of direct current electricity. In other words, the energy supply for a solar cell is photons coming from the sun. A photon with short enough wavelength and high enough energy can cause an electron in a photovoltaic material to break free of the atom that holds it. If a nearby electric field is provided, those electrons can be swept toward a metallic contact where they can emerge as an electric current.

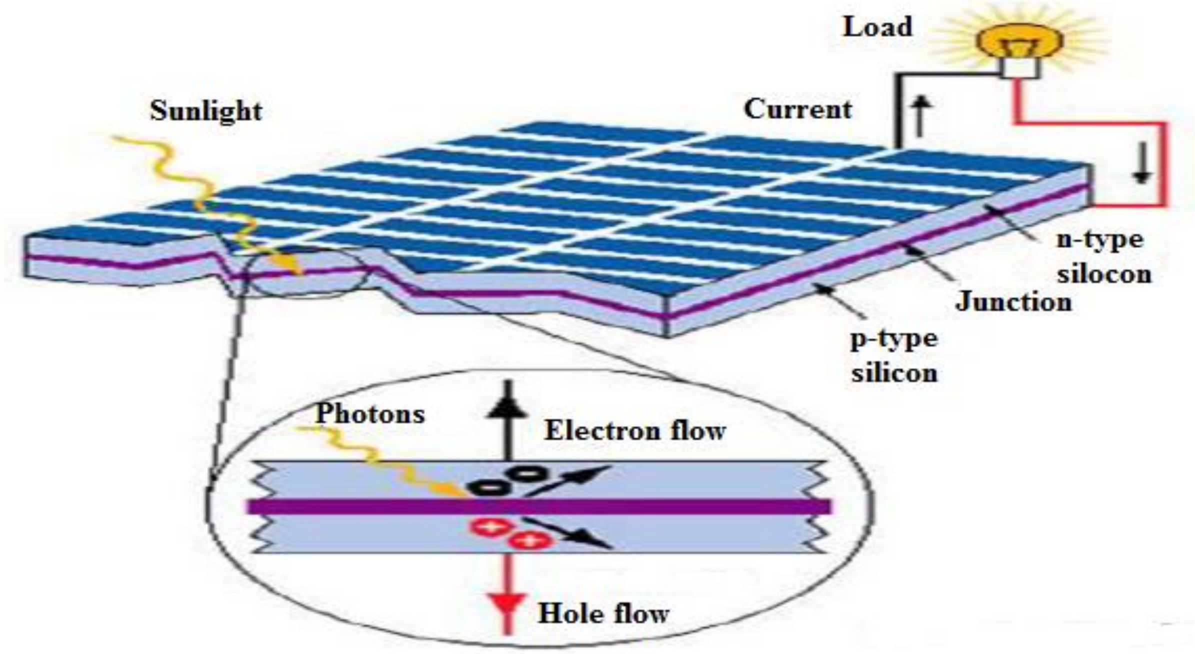
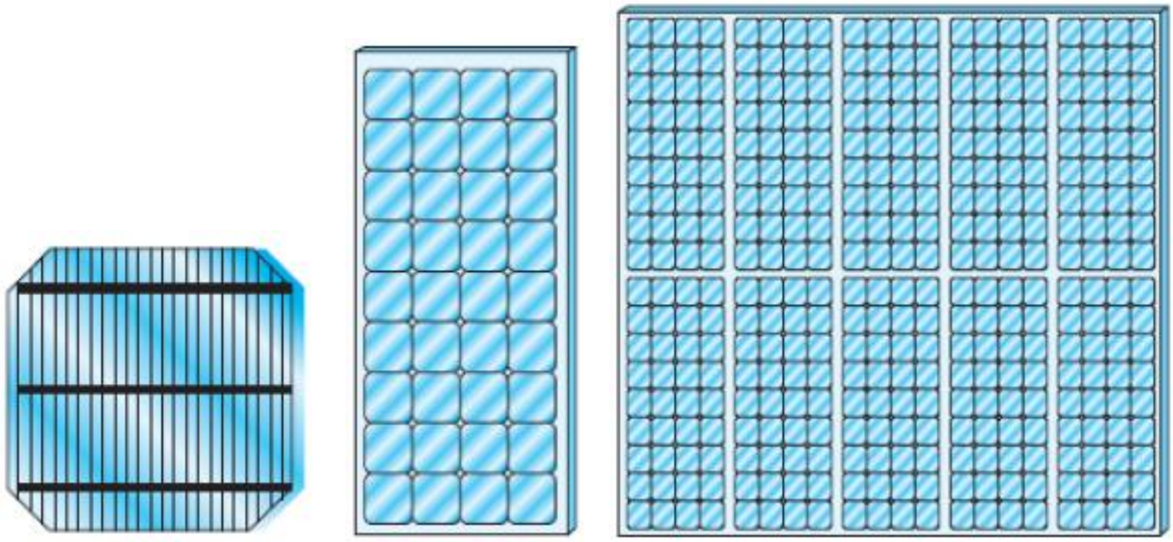


Figure 2. 3 Schematic diagram of a photovoltaic system

Photovoltaic energy conversion is the direct production of electrical energy in the form of current and voltage from electromagnetic (i.e., light, including infrared, visible, and ultraviolet) energy. A solar cell (PV cell) is a large-area semiconductor diode (Figure 2.4 a). It consists of a *p-n* junction created by an impurity addition (doping) into the semiconductor crystal (consisting of four covalent bonds to the neighboring atoms for the most commonly used silicon solar cells) [10]. The solar cell described above is the basic building block of the PV power system. Typically, it is a few square inches in size and produces about one watt of power. For obtaining high power, numerous such cells are connected in series and parallel circuits on a panel (module) area of several square feet (Figure 2.4 b). The solar array or panel is defined as a group of several modules electrically connected in series-parallel combinations to generate the required current and voltage. Figure 2.4 (c) shows the actual construction of a module in a frame that can be mounted on a structure.



a) Cell **b)** Module **c)** Array

Figure 2. 4 Distinction between cells, modules, and arrays

As stated above, the basic elements of a PV system are the modules that are usually series-parallel connected and is usually called a PV string. But several components are needed to construct a grid connected PV system to perform the power generation and conversion functions.

If the voltage of the PV string is always higher than the peak voltage of the grid the PV converter does not require a step-up stage [4]. In this case higher efficiency can be obtained because a single stage full-bridge converter can be used. Otherwise, a DC-DC boost converter or a transformer must be added for voltage amplification but it reduces efficiency. However, energy storage devices can be included in order to store the energy produced in case of grid support connection [10]. A three-phase inverter performs the power conversion of the array output power into AC power suitable for injection into the grid. Pulse width modulation control is one of the techniques used to shape the magnitude and phase of the inverter output voltage.

2.2.5.2 Wind Turbine

Wind energy relies, indirectly, on the energy of the sun. A small proportion of the solar radiation received by the Earth is converted into kinetic energy, the main cause of which is the imbalance between the net outgoing radiation at high latitudes and the net incoming radiation at low latitudes [4]. The Earth's rotation, geographic features and temperature gradients affect the location and nature of the resulting winds [10]. The use of wind energy requires that the kinetic energy of moving air be converted to useful energy. As a result, the economics of using wind for electricity supply are highly sensitive to local wind conditions and the ability of wind turbines to reliably extract energy over a wide range of typical wind speeds.

Over recent years, there have been dramatic improvements in wind energy technologies, and wind turbine generation has developed rapidly as a competitive and effective source of distributed generation. Wind energy can be exploited in many parts of the world, but is the most cost-effective in windy climates, where average wind speeds exceed 6.5 m/s [11].

The wind farm is composed of several wind turbines which have basic electrical components: an aerodynamic rotor, a mechanical transmission system, an electric generator, a control system, limited reactive power compensation and a step-up transformer as shown in Fig. 2.5.

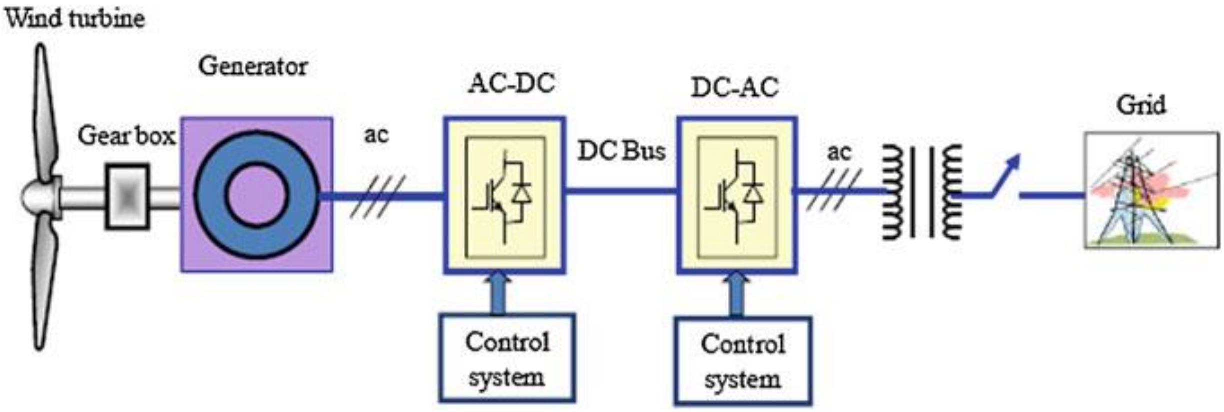


Figure 2. 5 Grid Connected wind Energy system

The generator is used for converting the mechanical power obtained from the wind turbine to electrical power. A wind turbine comprises rotor/blades for conversion of wind energy into rotational shaft energy, a nacelle with drive train that contains the generator and gear box, a tower that supports the rotor and drive train and the necessary electric equipment for connection to the grid. The majority of wind turbines offered today is of the three bladed upwind horizontal axis type and installations intended to connect at the PCC at medium or high voltage of the network [11].

In consideration of speed wind energy systems are either fixed or variable while the coupling between the mechanical and electrical parts could be with or without a gear-box. Nowadays, induction generators are widely used in wind turbine and a variable speed generator is the preferred option in newer wind turbine installations [9].

2.2.5.3 Microturbine

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 [7]. This product makes the turbine to rotate, which at the same time, impulses the generator and the compressor. In the most commonly used design the compressor and turbine are mounted above the same shaft as the electric generator as shown in figure 2.6.

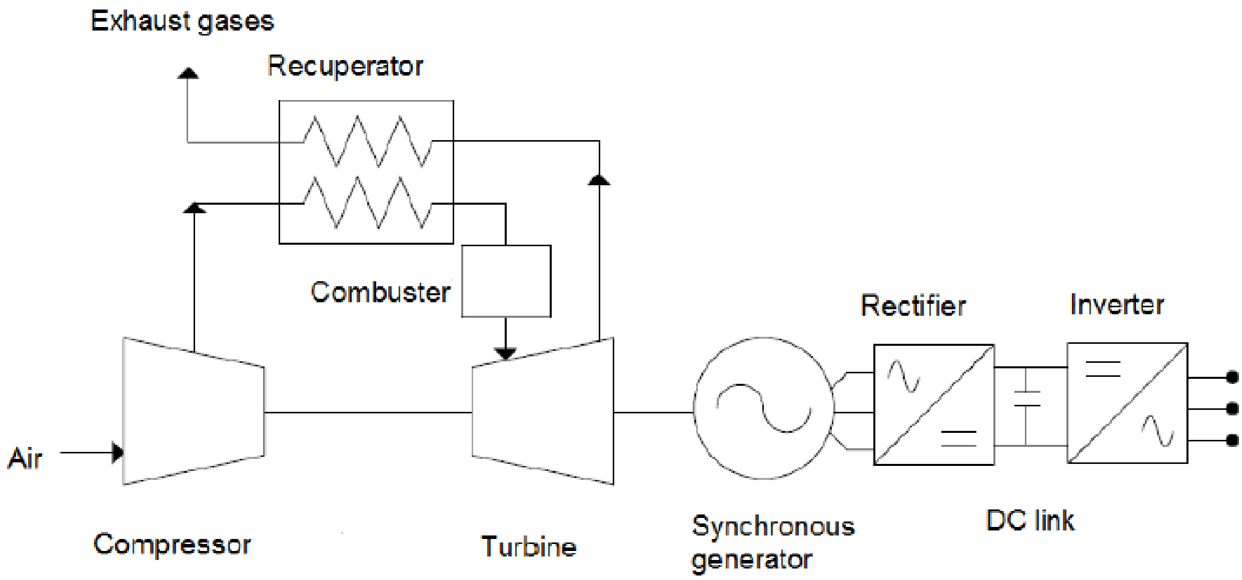


Figure 2. 6 Schematic diagram of a micro-turbine

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

2.2.5.4 Fuel Cells

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 [12]. 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 [13].

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

Because hydrogen and oxygen gases are electrochemically converted into water, fuel cells have many advantages over heat 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 increases, 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.

Fuel Cell does not burn hydrogen and there are no moving parts during operations, thus fewer losses and low emissions. Unlike other distributed generation, fuel cell (FC) efficiency is higher than 60%, which is considered to be double that of conventional power generations [9].

There are many types of fuel cells, but they all consist of an anode, a cathode, and an electrolyte that allows positively charged hydrogen ions (protons) to move between the two sides of the fuel cell [12]. The anode and cathode contain catalysts that cause the fuel to undergo oxidation reactions that generate positively charged hydrogen ions and electrons. The hydrogen ions are drawn through the electrolyte after the reaction. At the same time, electrons are drawn from the anode to the cathode through an external circuit, producing direct current electricity. At the cathode, hydrogen ions, electrons, and oxygen react to form water. As the main difference among fuel cell types is the electrolyte, fuel cells are classified by the type of electrolyte they use and by the difference in startup time ranging from 1 second for proton exchange membrane fuel cells (PEM fuel cells, or PEMFC) to 10 minutes for solid oxide fuel cells (SOFC). Individual fuel cells produce relatively small electrical potentials, about 0.7 volts, so cells are "stacked", or placed in series, to create sufficient voltage to meet an application's requirements. In addition to electricity, fuel cells produce water, heat and, depending on the fuel source, very small amounts of nitrogen dioxide and other emissions. The energy efficiency of a fuel cell is generally between 40–60%, or up to 85% efficient in cogeneration if waste heat is captured for use.

A single fuel cell consists of an electrolyte sandwiched between two electrodes, an anode and a cathode. Bipolar plates on either side of the cell help distribute gases and serve as current collectors (See Figure 2.7). In a Polymer Electrolyte Membrane (PEM) fuel cell, which is widely regarded as the most promising for light-duty transportation, hydrogen gas flows through channels to the anode, where a catalyst causes the hydrogen molecules to separate into protons and electrons. The membrane allows only the protons to pass through it. While the protons are conducted through the membrane to the other side of the cell, the stream of negatively-charged electrons follows an external circuit to the cathode. This flow of electrons is electricity that can be used to do work, such as power a motor [14].

On the other side of the cell, oxygen gas, typically drawn from the outside air, flows through channels to the cathode. When the electrons return from doing work, they react with oxygen and the hydrogen protons (which have moved through the membrane) at the cathode to form water. This union is an exothermic reaction, generating heat that can be used outside the fuel cell.

The power produced by a fuel cell depends on several factors, including the fuel cell type, size, temperature at which it operates, and pressure at which gases are supplied. A single fuel cell produces approximately one volt or less-barely enough electricity for even the smallest applications. To increase the amount of electricity generated, individual fuel cells are combined in series to form a stack. (The term "fuel cell" is often used to refer to the entire stack, as well as to the individual cell.) Depending on the application, a fuel cell stack may contain only a few or as many as hundreds of individual cells layered together. This "scalability" makes fuel cells ideal for a wide variety of applications, from laptop computers (50-100 Watts) to homes (1-5kW), vehicles (50-125 kW), and central power generation (1-200 MW or more).

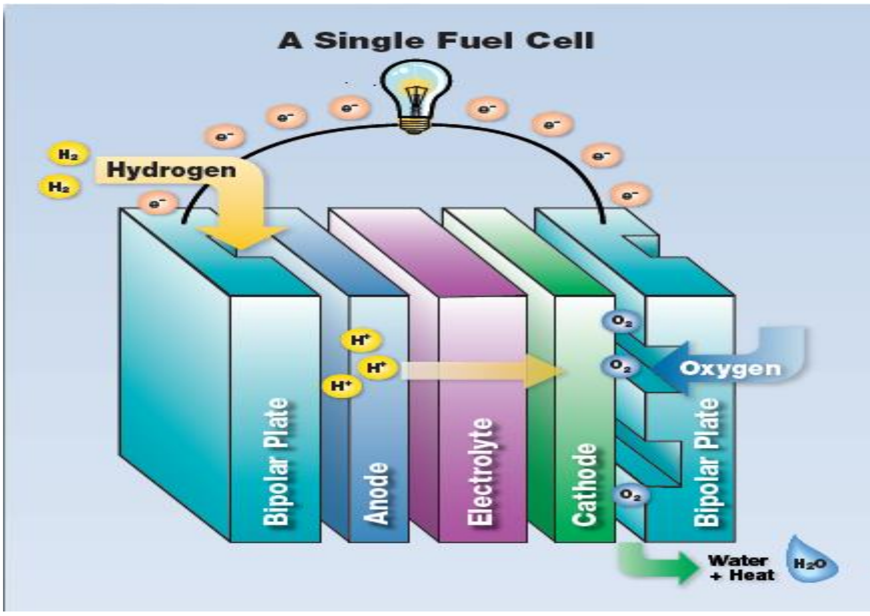


Figure 2. 7 Schematic diagram of a fuel cell

In general, all fuel cells have the same basic configuration - an electrolyte and two electrodes. But there are different types of fuel cells, classified primarily by the kind of electrolyte used. The electrolyte determines the kind of chemical reactions that take place in the fuel cell, the temperature range of operation, and other factors that determine its most suitable applications.

2.2.5.5 Induction and Synchronous Generators

Induction and synchronous generators are electrical machines which convert mechanical energy into electrical energy then dispatched to the network or loads. Induction generators produce electrical power when their shaft is rotated faster than the synchronous frequency driven by a certain prime mover (turbine, engine). The flux direction in the rotor is changed as well as the direction of the active currents, allowing the machine to provide power to the load or network to which it is connected. The power factor of the induction generator is load dependent and with an electronic controller its speed can be allowed to vary with the speed of the wind. The cost and performance of such a system is generally more attractive than the alternative systems using a synchronous generator [7].

The induction generator needs reactive power to build up the magnetic field, taking it from the mains. Therefore, the operation of the asynchronous machine is normally not possible without the corresponding three-phase mains. In that case, reactive sources such as capacitor banks would be required, making the reactive power for the generator and the load accessible at the respective locations. Hence, induction generators cannot be easily used as a backup generation unit, for instance during islanded operation [7].

The synchronous generator operates at a specific synchronous speed and hence is a constant-speed generator. In contrast with the induction generator, whose operation involves a lagging power factor, the synchronous generator has variable power factor characteristic and therefore is suitable for power factor correction applications. A generator connected to a very large (infinite bus) electrical system will have little or no effect on its frequency and voltage, as well as, its rotor speed and terminal voltage will be governed by the grid.

Normally, a change in the field excitation will cause a change in the operating power factor, whilst a change in mechanical power input will change the corresponding electrical power output. Thus, when a synchronous generator operates on infinite busbars, over-excitation will cause the generator to provide power at lagging power factor and during under-excitation the generator will deliver power at leading power factor. Thus, synchronous generator is a source or sink of reactive power. Nowadays, synchronous generators are also employed in distribution generator systems, in thermal, hydro, or wind power plants. Normally, they do not take part in the system frequency control as they are operated as constant power sources when they are connected in low voltage level. These generators can be of different ratings starting from kW range up to few MW ratings.

2.3 Impacts of Distributed generation Integration on Distribution System

The operation of distribution systems originally radial and designed to operate without any generation on the distribution system, and power flow is unidirectional. The introduction of DG in 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 [7].

Generally, impacts of penetration of DG can be classified into four main categories, namely *technical, commercial, environmental and regulatory* impacts [15].

2.3.1 Technical Impact of DG

There are some technical impacts of DG, among that power loss, voltage regulation, fault level, system stability and protection device coordination.

2.3.1.1 Impact of DG on Power Losses

One of the major impacts of distributed generation is on the power losses in a feeder. Locating the DG units is an important criterion that has to be analyzed to be able to achieve a better reliability of the system with reduced losses.

According to [16], locating DG units to minimize losses is similar to 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 in order to reduce the losses. For instance, if feeders have high losses, adding a number of small capacity 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 [16]. For example, the feeder capacity may be limited as overhead lines and cables have thermal characteristic that cannot be exceeded.

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 [7].

2.3.1.2 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 and size [17].

The installation of DG units along the power distribution feeders may cause overvoltage due to too much injection of active and reactive power. For instance, a small DG system sharing a common distribution transformer with several loads may raise the voltage on the secondary side, which is sufficient to cause high voltage at these customers [8]. This can happen if the location of the distribution transformer is at a point on the feeder where the primary voltage is near or above the fixed limits; for instance, ANSI (American National Standards Institute) upper limit +126 volts on a 120 volt base.

During normal operation conditions, without DG, voltage received at the load terminals is lower than the voltage at the primary of the transformer. The connection of DG can cause a reverse power flow, maybe even raising the voltage somewhat, and the voltage received at the customer´s site could be higher than on the primary side of the distribution transformer.

For any small scale DG unit (< 10MW) the impact on the feeder primary is negligible. Nonetheless, if the aggregate capacity increases until critical thresholds, then voltage regulation analysis is necessary to make sure that the feeder voltage will be fixed within suitable limits [7].

2.3.1.3 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 [16].

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 2.8 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 [16].

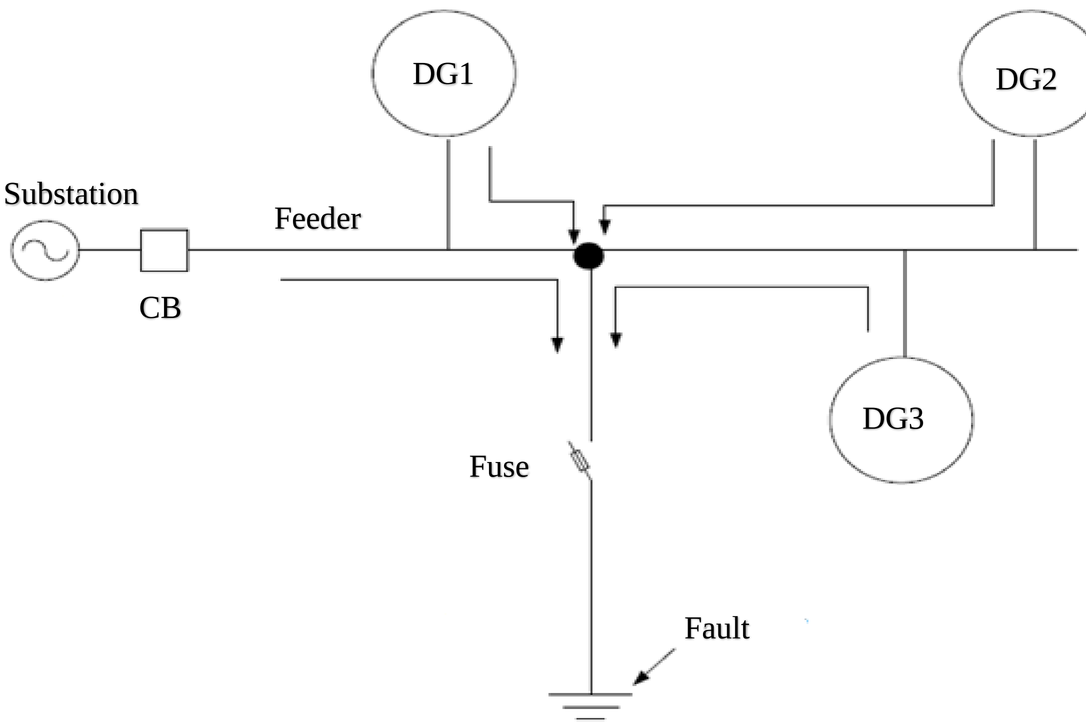


Figure 2. 8 Fault contributions due to DG units

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 [18].

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 [19].

2.3.1.4 Impact of DG on Voltage Stability

Voltage stability refers to the ability of a power system to maintain steady-state voltage at all buses in the system after being subjected to a disturbance. Voltage stability is classified into steady-state and dynamic involving small and large disturbances respectively. It is also classified into steady state and transient voltage instability, according to the time spectrum of the occurrence of the phenomena. Voltage stability concerns stable load operation, and acceptable voltage levels all over the system buses. A power system is said to have entered a state of voltage instability when a disturbance causes a progressive and uncontrollable decline in voltage [4].

Under critical loading conditions in certain industrial areas, radial distribution system experiences sudden voltage collapse due to low value of voltage stability index at most of its nodes . Voltage stability analysis often requires examination of lots of system states and many contingency scenarios. For this reason the approach based on steady state analysis is more feasible, and it can also provide global insight of the voltage reactive power problems.

The voltage stability phenomenon has been well recognized in distribution systems. The high R/X ratio of the radial distribution lines results in large voltage drops, low voltage stability and power losses so that, the radial distribution system is one of the power systems, which may suffer from voltage instability. Moreover, voltage instability of radial distribution systems has been well recognised and understood for decades and was often referred to as load instability [20].

In general, the inability of the system to supply the required demand leads to voltage instability (voltage collapse) [4].

Integration of DG renders a group of advantages, such as, economical, environmental and technical. The location and size of DG has the main effect on voltage stability of the system. Due to considerable costs, the DGs must be allocated suitably with optimal size to improve the system performance such as to reduce the system loss, improve the voltage profile while maintaining the system stability [20]. The problem of DG planning has recently received much attention by power system researchers. The effect of DG capacity and location on voltage stability analysis of radial distribution system is investigated in this paper.

2.3.2 Commercial Impact of DG

Active management of distribution networks can enable significant increases in the amount of DG that can be connected to the existing networks. Although the cost associated with the operation of active distribution networks is still to be identified, it is expected that the benefits are likely to considerably outweigh the cost of its implementation. In order to support the development of active distribution networks and extract corresponding benefits associated with connecting increased amount of DG, new commercial arrangements need to be developed.

Generally, three approaches are possible [15]:

- To establish a market mechanism outside government regulations for the development of active networks that would create a commercial environment. Distribution companies charge for providing active management services to the generators. Clearly, this could be used as a basis for bilateral negotiations between the local company and the generator whenever the net benefit from active management exists.
- To recover, cost of implementation of active management through the price controls mechanism (increasing the amount of recoverable capital and operating expenditure associated with active management). Recovery of cost could be achieved through increased charges for the use of the networks (distributed generators benefiting from either active management and/or demand customers).
- Establishing an incentive scheme that would reward companies for connecting DG, which one is recently developed in the UK [5]. With a suitable design of the scheme,

we can achieve development of active distribution networks for such incentive scheme. These types of scheme could be funded from increased charges imposed on generators and/or demand customers.

2.3.3 Environmental Impact of DG

After so many years of discussions and negotiations about sustainable development, the world‘s climate and its biodiversity are still deteriorating [21]. Environmental issues are prime concern for any countries due to increasing global warming and its negative impact over human being. Due to global warming our weather has changed and it becoming disaster for human life. Often DG technologies are described as more environmental friendly than centralised generation. Keen public awareness of the environmental impacts of electric power generation and efforts to mitigate climate change are crucial to DG renaissance.

Unfortunately some distributed generation technologies could, if fully deployed, significantly contribute to present environmental problems. Therefore, the technologies that can be used for distributed generation cannot be described in general as environmental friendly. But regarding the main current environmental issue, the increased greenhouse effect, all DG technologies lead to significantly lower emissions than coal-based technologies [4]. On the contrary, in the case of the so-called “zero emission” generation systems, though direct emission due to combustion is zero, indirect emissions linked to construction, maintenance and dismantling have to be considered. This is the case with nuclear power plants, windmills, photovoltaic generators, hydroelectric power plants and power plants using biomass.

From the fuel utilisation point of view, smaller distributed generation plants generally are less efficient than larger central plants of the same type. Only when operating in a CHP mode, they may conserve primary energy compared to the separate generation of electricity and heat in best available technology (BAT)-electric-power plants and high-efficiency boilers *[8]*.

2.3.4 Regulatory Impact of DG

In the absence of a clear policy and associated regulatory instruments on the treatment of DG, it is very unlikely that this type of generation is going to thrive. The reasons for this are partly historical and related to the way distribution networks have been developed and operated as passive networks. In order to foster the required changes, there is a clear need to develop and articulate appropriate policies that support the integration of DG into distribution networks [15].

Chapter Three

Distributed Generation Integration Issue and Distribution system Protection

3.1 Introduction

This chapter covers the distributed generation integration issue such as proper placement and sizing methodology of DG and protection of distribution system. The protection of distribution system without and with consideration of distributed generation integration (DG) is involved. The overview of some of the distribution system protection devices and the detailed design of the over current protective relays are included in this topic.

3.2 DG Placement and Sizing

Installing DG on distribution networks has many different impacts on the parameters of these networks. These impacts can be positive and negative. The positive impacts of installing DG resources includes improving the voltage profile, reducing the power loss, decreasing the requirements of installing new transmission lines, and deferring the necessity of improving the capacity of substations [22]. On the other hand, the main adverse impact of installing DG is the increase in the short-circuit level of the network.

Distributed generations (DGs) are only beneficial if their installations are carried out according to the appropriate plans. Studies show that if the capacity and location of DGs are not identified appropriately, not only are the network parameters are not improved, but they are also deteriorated [23]. Hence, two of the most important factors of DG plans are identifying the capacity and the location of these resources.

The place and capacity of DGs can be decided according to the improvement of one or more parameters in order to increase the efficiency and decrease the adverse effects of installing them. However, siting and sizing of DGs with the aim of improving a single parameter enhances the considered parameter significantly, but may have a negative impact on the other parameters of the network. On the other hand, siting and sizing DGs with the purpose of enhancing some of the parameters of the network will result in the improvement of the considered parameters. Considering the impacts of different parameters is an important issue, while having a multiobjective siting and sizing [23].

To find the appropriate place and capacity of DG resources different technical parameters in the distribution network must be identified. Therefore, an objective function is formulated that includes the most important parameters of the network. In this thesis the considered parameters include the total power loss of the network and voltage profile of the distribution system.

3.2.1 Identification of Size of DG

An analytical method is used to minimize the losses associated with the absolute value of branch currents by appropriately placing DG units [3] [24]. The problem of DG unit placement consists of determining the size, location and number of DG units to be installed in a distribution system such that maximum benefits are achieved while operational constraints at different loading levels are satisfied. The total power loss in a distribution system having 'N' number of branches is given by

$$P_{Loss} = \sum_{i=1}^{N} I_i^2 R_i \qquad (3.1)$$

Where,

Ii is the branch current magnitude which can be obtained from load flow study and Ri is the line segment resistance. The branch current has two components, active component Ia and reactive component Ir.

$$I_{ai} = I_i \cos\varphi \qquad (3.2)$$

$$I_{ri} = I_i \sin\varphi \qquad (3.3)$$

The total losses associated with these two components can be written as

$$P_{Loss} = \sum_{i=1}^{N} I_{ai}^2 R_i + \sum_{i=1}^{N} I_{ri}^2 R_i \qquad (3.4)$$

For a radial distribution system having N number of branches, if DG unit is placed at bus 'm' and 'β' be a set of branches connected between the source and DG unit, then 'β' consists of branches β1, β2, β3, …………, βm. The DG at unity power factor supplies real component of current I_{DG} and for radial distribution network it affects only the active component of current of branch set 'β'. The current of other branches is not affected by the DG unit even if the net effect reduces the overall branch currents if DG unit is placed at proper place with proper size. The new active component of current is

$$I_{ai}^{WDG} = I_{ai} + I_{DG} \qquad (3.5)$$

Where,

Iai is the active component of current of ***ith*** branch in the original system obtained from the load flow solution as in equation 3.2, by considering the average power factor of the distribution system. The $\mathbf{P_{Loss}}$ is associated with the active component of branch currents in the compensated distribution system. For a DG unit placed at node 'm', the system losses are given as,

$$P_{LOSS} = \sum_{i=1}^{m} (I_{ai} + I_{DG})^2 R_i + \sum_{i=m+1}^{N} I_{ai}^2 R_i + \sum_{i=1}^{N} I_{ri}^2 R_i \tag{3.6}$$

Subtracting equation 3.4 from equation 3.6, loss reduction due to the introduction of DG unit at node 'm' is obtained as provided below.

$$\Delta P_{LOSS} = -2 I_{DG} \sum_{i=1}^{m} I_{ai} R_i - {I_{DG}}^2 \sum_{i=1}^{m} R_i \tag{3.7}$$

The idea is to place a DG unit with a proper size and location such that the system loss reduction is maximized. For the system loss reduction to be maximum when the DG unit is be placed at node 'm', the derivative of equation 3.7 with respect to I_{DG} must be zero. Hence,

$$\frac{\partial (\Delta P_{LOSS})_m}{\partial I_{DG}} = 0 \tag{3.8}$$

Rearranging of equation 3.8, the DG current during the maximum loss reduction is given as,

$$I_{DG}(i) = -\frac{\sum_{i=1}^{m} I_{ai} R_i}{\sum_{i=1}^{m} R_i} = -\frac{\sum_{i \in \beta} I_{ai} R_i}{\sum_{i \in \beta} R_i} \tag{3.9}$$

Assuming no significant change in node voltage with DG unit placed at ***ith*** node, the proper size of DG that can be generated is given as,

$$P_{DG(i)} = I_{DG(i)} V_{ref} \tag{3.10}$$

A computer program is written in MATLAB 15 m-file to find the proper size of DG at each buses. Any size of DG other than $P_{DG(i)}$ placed at bus i, will lead to higher loss.

3.2.2 Identification of Location of DG

For proper location, first the proper sizes of DG at various locations have been calculated using equations 3.9 and 3.10, and the total power losses and voltage profile of the system is identified with the proper sizes of DG for each case by using load flow study with help of DIgSILENT

PowerFactory 15.1.7 simulation package. For each case load flow analysis the total power loss and voltage profile of the system is determined and the result is stored to proceed to the next step. The case with minimum total power losses and all terminal voltages are within allowable limit is selected as the optimal location for DG placement [25]. Based on this method, one can avoid exhaustive computation and save time.

Computational Procedure

1. Run the distribution load flow using DIgSILENT PowerFactory 15.1.7 simulation software to determine total active and reactive power losses, branch currents and voltage profile at each bus,
2. Determine the DG capacity at each node of the system, except source bus, by using equations 3.9 and 3.10 with the help of MATLAB m-file programming language,
3. Place the DG capacity found in step 2 at each node, one at a time and observe the total real and reactive power loss and the voltage profile at each bus for each case,
4. Store the place of DG corresponding to minimum loss with good voltage profile obtained from each case load flow analysis,
5. Compare the total power loss and voltage profile of the system for each case load flow study
6. The node at which losses are minimum and gives best voltage profile is considered to be the proper location for DG placement with the corresponding size as the proper size at that node.

3.2.3 Constraints

Constraints are an issue of great importance in optimization procedures. Indeed, an optimal answer is an answer that satisfies all of the constraints of the optimization problem. In this paper, the following technical constraints are considered while siting and sizing of DG.

3.2.3.1 Constraint of the 'Voltage of the Buses'

The variation range of all of the distribution buses voltage should be within a specified limit.

$$V_{min} < V_i^{WDG} < V_{max} \qquad (3.11)$$

In this thesis, the ±5% of the nominal voltage is considered. The nominal voltage of all the buses is assumed to be 15 kV.

3.2.3.2 The Size of the 'DG capacities'

The maximum of the produced active power of the DG units must not exceed the load demand of the network plus total real power loss.

$$P_{DG} \leq P_{load} + P_{loss} \quad (3.12)$$

3.2.3.3 The constraint of 'the minimum power factor of the DG units'

Synchronous generators are capable of producing active and reactive power, simultaneously. Since electrical companies are more interested in operating in the upper power factors, this constraint should be considered while sizing and siting. The mentioned constraint is defined as follows:

$$0.8 \leq PF_{DG} \quad (3.13)$$

In this paper, the power factor of DG are assumed to be 0.85.

3.2.3.4 Constraint of the 'loading of line segments'

Installing DG units should not increase the loading of line segments more than their allowable range. Otherwise, the electrical companies have to replace the overloaded line segments by large size conductor.

$$Line_{Loading} \leq 100\% \quad (3.14)$$

Constraints can be divided into soft and hard constraints. Hard constraints are those in which violating them is not permitted and soft constraints are those that can be violated to some extent To prevent any changes in the distribution network as a result of installing DG, all of the considered constraints of this thesis are assumed to be hard.

3.3 Protection in Distribution System

Connections of the renewable (distributed) generation to the power system may be made at the usage voltage level, at the utility distribution system level, or at the utility transmission level. Where the connection is made depends on the location and size of the generation plant. Rules will vary slightly by jurisdiction, but are generally similar from one location to another. Connections at the usage level and on the distribution system level are smaller installations and are also known as "distributed generation" because the generation is dispersed and intermingled with the connected loads [26].

If there is a risk of operation as an unintended island, the utility may require additional protective equipment such as communications equipment to facilitate transfer trip. Such means are avoided if possible because of the increase of the system cost, but may be required for the safe operation of the distribution system.

3.3.1 Over Current Protection Devices

The main characteristics of protective devices presently used by utilities to protect radial distribution systems are presented below.

3.3.1.1 Circuit Breakers – Overcurrent Relays

A circuit breaker is an automatic interrupting device which is capable of breaking and reclosing a circuit under all possible conditions, and based up on arc extinguishing methods can be classified as (oil, air, SF6,vacuum) circuit breakers [27].

The performance of a breaker during an opening operation is governed by the characteristics of the overcurrent relay. Concerning the relay operating characteristics, over-current relays may be classified into three major groups: definite current, definite time, and inverse time.

i) 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 Fig. 3.1:

Figure 3. 1 Definite current characteristic of over-current relays

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 neighbouring site of the fault [7].

ii) 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 [7]. 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.

Figure 3. 2 Definite time/current or definite time characteristic of over-current relays

This relay allow setting of two independent parameters, the pickup setting and the time dial setting. The pickup setting define the current value necessary to operate the relay and the time dial sets the exact timing of the relay operation. In Figure 3.2, the characteristic curve of a definite time relay is shown [7].

ii) 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. These relays are classified based on their characteristic curves, which define the speed of operation as inverse, very inverse or extremely inverse. Their defining curve shape is shown in Figure 3.3**.**

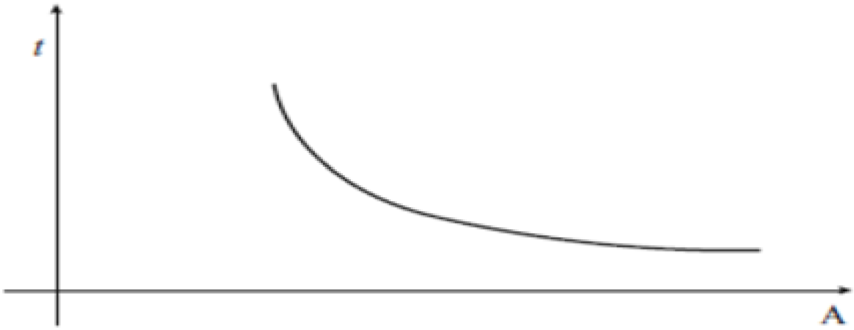


Figure 3. 3 Inverse time/ current characteristic of over-current relays

3.3.1.2 Reclosers

A recloser is a device with the ability to detect phase and phase-to-ground overcurrent conditions, to interrupt the circuit if the overcurrent persists after a predetermined time, and then to automatically reclose to re-energise the line. If the fault that originated the operation still exists, then the recloser will stay open after a preset number of operations, thus isolating the faulted section from the rest of the system. In an overhead distribution system between 75 to 95 per cent of the faults are of a temporary in nature and last, at the most, for a few cycles or seconds. Thus, the recloser, with its opening/closing characteristic, prevents a distribution circuit being left out of service for temporary faults. Typically, reclosers are designed to have up to three open-close operations and, after these, a final open operation to lock out the sequence. One further closing operation by manual means is usually allowed. The counting mechanisms register operations of the phase or ground-fault units which can also be initiated by externally controlled devices when appropriate communication means are available [28].

The operating time/current characteristic curves of reclosers normally incorporate two curves, one fast and one delayed. The first one, known as fast or instantaneous, is mainly used to save lateral fuses under temporary fault conditions. The second curve is known as slow or time-delay, and its main purpose is to delay recloser tripping, and allow fuses to blow under permanent fault conditions [18].

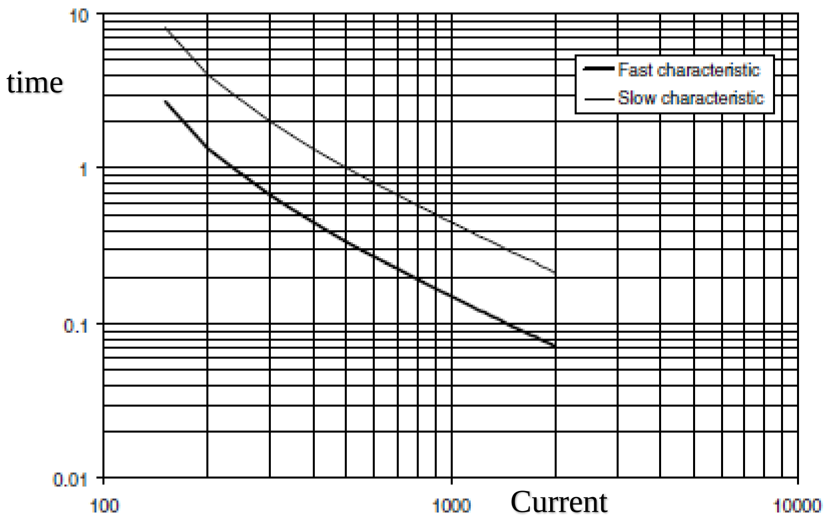


Figure 3. 4 Recloser tripping characteristics

3.3.1.3 Fuse

A fuse is a short piece of metal, inserted in the circuit, which melts when excessive current flows through it and thus breaks the circuit. Fuse is the simplest current interrupting device for protection against excessive currents. Since the invention of first fuse by Edison, several improvements have been made and now-a-days, a variety of fuses are available. Some fuses also incorporate means for extinguishing the arc that appears when the fuse element melts. In general, fuses may be classified into (i) Low voltages fuses (ii) High voltage fuses.

It is a usual practice to provide isolating switches in series with fuses where it is necessary to permit fuses to be replaced or rewired with safety. If such means of isolation are not available, the fuses must be so shielded as to protect the user against accidental contact with the live metal when the fuse carrier is being inserted or removed.

A fuse model, irrespectively of the group to be represented, has to duplicate the following stages [18]: current sensing, arc initiation, arc interruption, current interruption. The melting period, during which temperature rises, begins with the fault and finishes when the fuse melts; during this stage the current flows without limitation. The melting mechanism of a fuse depends on the magnitude and the duration of the current, as well as on the electrical properties of the fuse. This characteristic is shown in the so-called time-current curve provided by manufacturers.

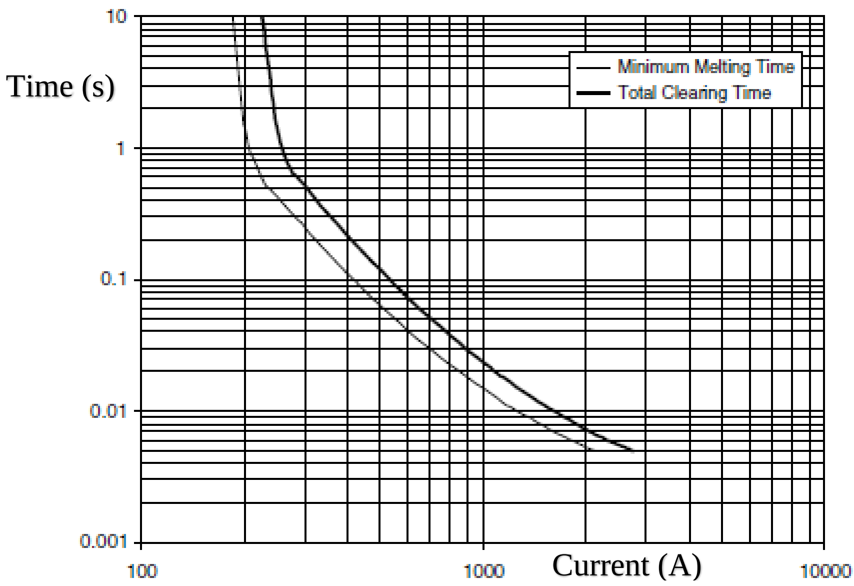


Figure 3. 5 Extreme time-current characteristics of a fuse

3.3.1.4 Sectionalizers

A sectionalizer is a device that automatically isolates faulted sections of a distribution circuit once an upstream breaker or recloser has interrupted the fault current and is usually installed downstream of a recloser. Since sectionalizers have no capacity to break fault current, they must be used with a back-up device that has fault current breaking capacity. Sectionalizers count the number of operations of the recloser during fault conditions. After a preselected number of recloser openings, and while the recloser is open, the sectionalizer opens and isolates the faulty section of line. This permits the recloser to close and re-establish supplies to those areas free of faults. If the fault is temporary, the operating mechanism of the sectionalizer is reset [28].

A sectionalizer does not have a current/time operating characteristic, and can be used between two protective devices whose operating curves are very close and where an additional step in coordination is not practicable. Sectionalizers can be used in place of fuses or between a reclosing device and a fuse.

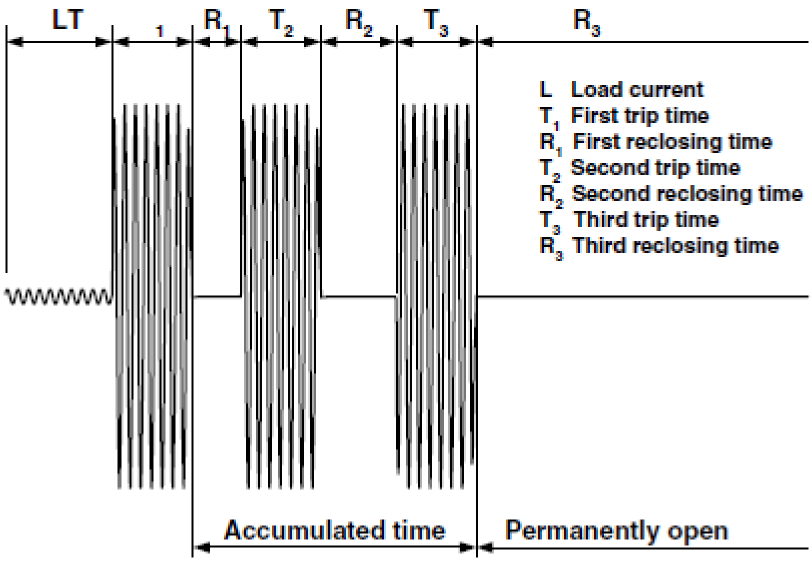


Figure 3. 6 Sectionalizer performance

3.3.2 Protection of Distribution Systems in the Presence of DG

Distribution-level protection is based on a time-overcurrent design. Such design includes selection of equipment and settings, placement of equipment, and coordination of devices to clear faults with as little impact on customers as possible. One of the main priorities is to prevent further damage to utility equipment. Secondary goals are reliability and power quality. Distribution protection is not designed to have backup, although there must be overlap between protective devices: an upstream device should operate for a fault if the downstream protector fails [18].

Although over current protection is simple and works very well with radial networks, it possesses several characteristics that have to be accounted for when selecting the appropriate protective devices [19]:

- ✓ Any distribution protective device has an associated maximum distance (also known as reach) for which the device works. For large distribution networks, in which the longest distance from a load node to the substation can be several dozens of kilometers, it is impossible to protect the whole network from the substation. Therefore, several protective devices have to be installed along the network.
- ✓ A highly reliable performance of a distribution network can be achieved by installing different types of protective devices. The coordination between protective devices is another important aspect, and this is particularly difficult in distribution networks given the number of different protective devices (breaker-relay sets, reclosers, fuses,

sectionalizers). This coordination is not easy and not always possible. In addition, it can be altered by the presence of distributed generators.

- ✓ There are some transients, such as transformer inrush and cold load pickup, which can appear during system energization. The currents associated to these transients can be of the same order that the pickup current of many distribution protective devices. This aspect has to be considered when selecting the time-current characteristic of those devices that can be affected.

DG penetration at the distribution level may have positive and adverse impacts. For DG to have a positive benefit, it must be at least suitably coordinated with the system operating philosophy and feeder design. The connection of DG unit raises few challenges related with protection system.

3.3.2.1 Islanding

Islanding is a major interconnection issue. Islanding is a situation where one or more generators (or group of distributed generators) continues to energize a portion of the utility system that has been separated from the main utility system and operate separately from the rest of the utility system. Although DG may successfully operate in island if there is a balance between load and generation, islanded operation is not generally allowed for some major reasons [18]:

1. The utility needs to restore the outaged circuits and this is complicated by having islanded generators with utility loads. Since automatic reclosing is generally used to restore power to customers, having islanded generators complicates both automatic and manual switching, which requires synchronizing the generator
2. Power quality generally cannot be maintained by the islanded generators within an acceptable level, and this can result in damage to the customer equipment.
3. Personnel security is another reason, since maintenance and reparation crews may think that there is no voltage when in fact some generation is still active and running in islanded mode.

The formation of an unintentional island is a problem for the utility company. Moreover, islanding only can be supported if the generator(s) can self-excited and maintain the load in the islanded area. This separation could be due to operation of an upstream breaker, fuse, or automatic sectionalizing switch.

The most common means to prevent islanding is to use *voltage and frequency relays* on the generator to trip whenever either of these two parameters migrate outside a selected window. This form of islanding protection is known as passive protection. It prevents islanding in most cases because when a section of the distribution system and one or more generators separate together, the output of the generator will not match the load on the island. For synchronous or induction generators, the voltage and frequency will drift, which will trip the relays in a short time. Typically the relays are set to a tight frequency range of perhaps ±1 Hz or even ±0.5 Hz. Voltage relays have a bit wider window to allow for typical voltage regulation excursions on the circuit (±5 to 10% is typical) [29].

3.3.2.2 Mal-trip and Fail-to-trip due to Impact of DG

The introduction of DG in the radial configuration causes a number of problems with the protective device coordination. For example in the traditional system, when using over current protection, it is possible to assume that the fault current only flows in one direction, whilst, this is not always true if there are DG embedded in the network. The feeder-protective relays are usually simple overcurrent relays and often with an automatic reclosing relay. With the addition of distributed generation on the feeders, several problems can occur: the new generation source will increase the available short-circuit current on the power system, reach of existing relays may be affected, current flow from unexpected directions may cause misoperation of existing relays and unintended islanding operation may occur [26].

The protection systems can fail to operate in two different ways: by unnecessarily removing a non-faulted component **(**mal-trip**)**; or by not removing a faulted component **(**fail-to-trip). A mal-trip is the case in which one of the protection devices trips instead of the other. This tripping occurs due to one protective device detecting the fault while it is outside of its protection zone and trips before the required tripping device. In contrast, fail to trip occurs for downstream faults. In this case the fault current is principally formed by the current originated from the DG unit. Consequently, the fault current through the over current protection device can be below the setting for which it was designed and the protection remains passive, hence the faulty feeder will not be disconnected [7].

Consider the distribution substation shown in Figure 3.7 with the distributed generation DG1 installed on one of the feeders [26]. For a fault anywhere on the distribution system, the additional generation provides additional fault current that may result in existing equipment on the power system being subjected to faults in excess of their ability to interrupt. For example, for the fault at location F1, the fuse must interrupt not only the fault current from the substation bus, but also the additional fault current supplied from the DG1 source. If the fuse had been selected based on the fault current contribution from the substation alone, it may be inadequately rated for the total fault current when the DG1 contribution is included. As a result, it may be necessary to replace the fuse with a device having higher ratings before allowing the DG1 to be brought on line. All other equipments must be similarly evaluated.

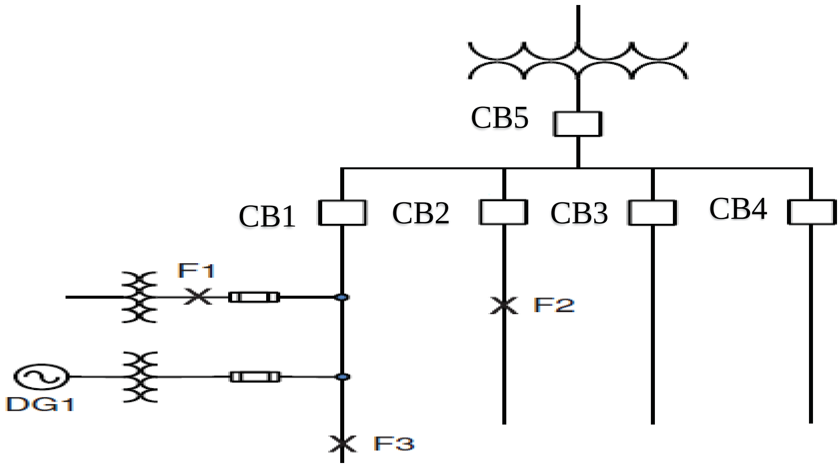


Figure 3. 7 Mal trip and fail to trip

For the fault at location F2 in Figure 3.7, the generator DG1 will also contribute fault current. In addition to the possibility of exceeding the fault-interrupting capacity of the circuit breakers, the back-feed of fault current may result in unnecessary trip (mal-trip) of the feeder circuit breaker CB1 if the current contribution from DG1 exceeds the trip setting of the feeder overcurrent relays. For a fault at location F3, the DG will contribute fault current, and the infeed from the DG source may result in a reduced fault contribution from the substation bus. Thus, the ability of the feeder relays to detect this fault may be reduced (protection blinding).

3.3.2.3 Impact of DG on Reach of Protection Devices

The other impact of the presence of DG in the distribution network is a reduction of reach protective devices. If a large generation unit or several small ones are connected to the distribution network, the fault current seen by the feeder protection relay may be reduced, which can lead to improper operation for the over current relays. When the DG is embedded in the network (figure 3.8), its contribution to the fault current $\mathbf{I_k}$ reduces the current seen by the feeder relay $\mathbf{I_1}$. If the unit is larger, the fault current injected will be higher, as well as, if the unit is located near to the grid, higher $\mathbf{I_1}$ will be seen, as the impedance of the line will be lower. Therefore, it can be also concluded that the impact increases with the size of the unit and the distance between the feeder and the DG system [26]. This is the failure of the protection devices to cover its designed protective distance, as the DG causes a decrease in the sensitivity of these protection devices, thus decreasing the distance protected.

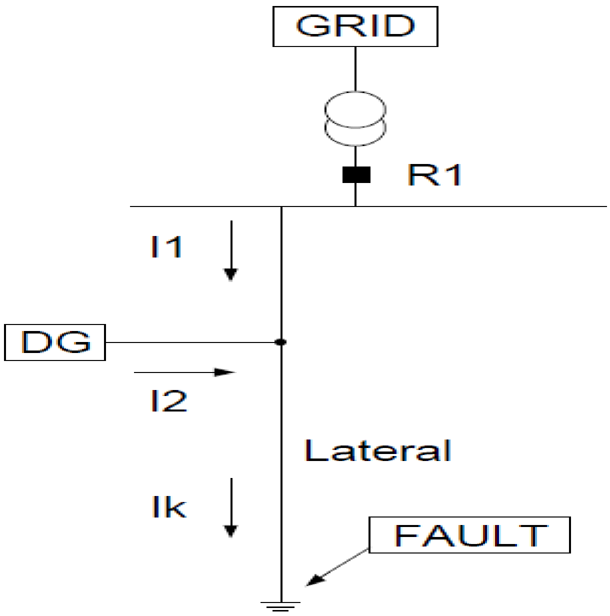


Figure 3. 8 Reduction of reach of protective devices

The relay ***R1*** is set up to cover the whole line, but the presence of the DG will cause a change in the apparent impedance of the line which causes a miss-estimation of ***R1***. When the fault is at the end of the line the impedance of the line will be higher and ***R1*** will not be able to sense the fault due to the less fault current from the grid.

3.3.3 Over Current Protection Relay Coordination

For reliability and security of power supply in distribution system, the network should be protected. Overcurrent protection is the predominant protection method used for distribution feeders. Over current relays are used in the protection of distribution circuits. Overcurrent relay is a sensing relay which operates when the current exceeds a predetermined value. Over current relays use time current characteristics in their operations. It is widely documented that in radial networks, selectivity of fault protection is achieved through time-current coordination of over-current relays. This is because for a particular fault, all the relays connected in the radial feeder see the fault current but are made to operate at different times. The coordination is based on the fact that the relay closest to the fault (primary relay) sees the largest fault current than those farther away (backup relays) [26]. Selection of different time current characteristics in the relay settings is the means of realising coordination.

The coordination of the protective relay is done during the process of system design based on the short circuit current level. It is the process of determining the sequence of relay operation for various faults in power system so that the faulted section is cleared in minimum time. For the proper relay coordination it is necessary to determine two crucial relay settings. These are:

- Pickup or plug setting (tap setting)
- Time dial or time multiplier setting

Plug setting (PS) or current setting for each relay is determined by two parameters; the minimum and the maximum fault current. The minimum and maximum fault current is determined from load flow analysis. In the coordination problem of over current relays, the objective is to determine the time setting multiplier (TSM) and plug setting multiplier (PSM) of each relay, so that the overall operating time of the primary relays is minimized properly. In order to determine current transformer (CT) ratio, the cable nominal current must be identified. Here the DIgSILENT 15.1.7 PowerFactory allows 80% of maximum load current (cable rated current) as a cable loading limit. Therefore, this requires a current transformer (CT) whose ratio produces 1A secondary current for the maximum load (primary current):

$$\text{CT ratio} = \frac{\text{Cable rated current} * 80\%}{\text{CT secondary current}} = \frac{N_1}{N_2} \tag{3.15}$$

Where,

N_1 = Primary winding of current transformer

N_2 = Secondary winding of current transformer

The minimum value of current (minimum fault current) for which the relay must operate should be at least 1.5 times pickup, but not very much more [4].

$$I_{pprim} = \frac{I_{fminprim}}{1.5} \tag{3.16}$$

$$I_{psec} = I_{pprim} * \frac{N_2}{N_1} * PS \tag{3.17}$$

$$I_{fmaxsec} = I_{fmax} * \frac{N_2}{N_1} \tag{3.18}$$

$$PSM = \frac{I_{fmaxsec}}{I_{psec}} = \frac{\text{Measured current of secondary CT}}{\text{Pick up current}} \tag{3.19}$$

Where,

I_{pprim} = Primary pick up current

$I_{fminprim}$ = Minimum primary fault current

I_{psec} = Secondary pick up current

$I_{fmaxsec}$ = Maximum secondary fault current

I_{fmax} = Maximum fault current

The three methods used for a correct relay coordination are discrimination by time, discrimination by current and discrimination both by current and time. The time setting multiplier (time dial) can be found as

$$t = \frac{0.14 * TD}{(PSM)^{0.02} - 1} \tag{3.20}$$

$$TD = \frac{t((PSM)^{0.02} - 1)}{0.14} \tag{3.21}$$

Where,

t = Operation time of the relay

TD = Time dial

Chapter Four

Modeling, Simulation Studies and Results Analysis

4.1 Introduction

In this chapter modeling and simulation of the case study distribution system by using DIgSILENT PowerFactory 15.1.7 simulation software was performed. Furthermore, the impact of DG integration on technical parameters of distribution system, when installed in radial distribution system with proper sizing and placement, has been investigated in detail.

4.2 Modeling of Case Study Distribution System

Sebeta-I substation located in Southern of Addis Ababa at Kara Kore was selected as a case study area. As it is common to connect the substation to the interconnected system (ICS), *Sebeta-I substation* has been supplied from main grid that is an interconnected system. The substation is supplied from Gilgel-Gibe I, Gefersa substation, Sebeta-II substation by two lines and Kality-I at 230kV. These five 230kV incoming lines are connected to the same double bus bars at Sebeta-I substation to which three auto transformers of capacity 125MVA, 230/132kV are connected. Currently, the substation is connected to the neighboring substation system through 132kV outgoing line such as Kality-I, Gefersa substation, Addis West (two lines ADW1 & ADW2). There is another one three winding transformer of capacity 25/25/10MVA, 132/45/15kV, which feed Gedja substation with 45kV line. The one line diagram of the overall substation modeled with DIgSILENT PowerFactory 15.1.7 software is shown in figure 4.1.

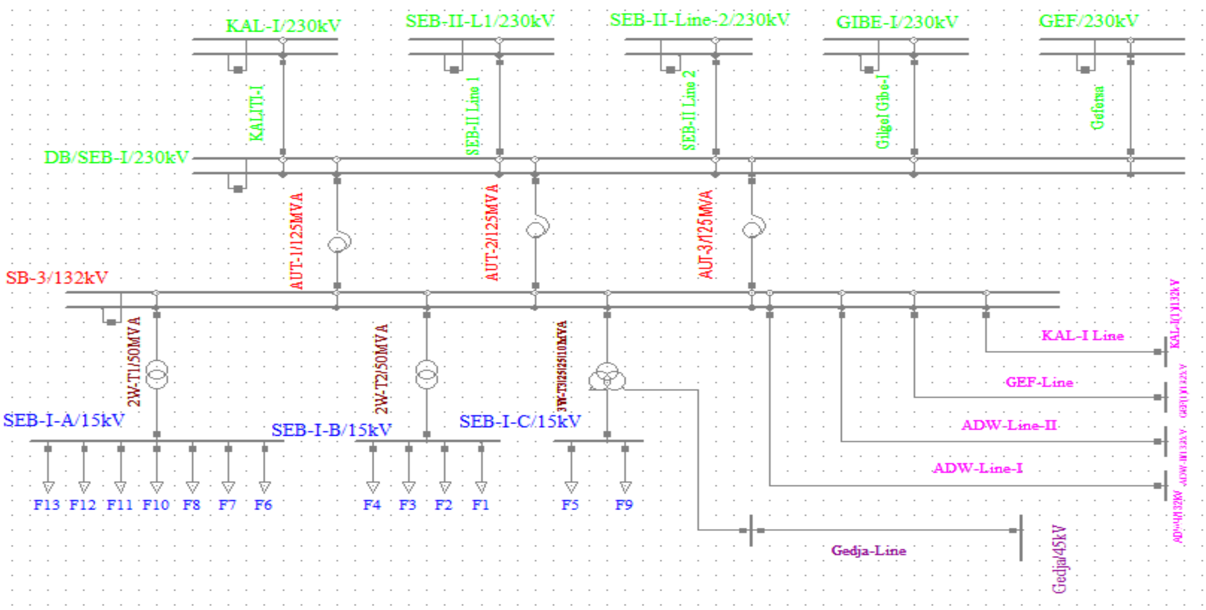


Figure 4. 1 Overview of single line diagram of Sebeta-I substation

The information for the total number of transformers and their capacity found in Sebeta-I substation is summarized in table 4.1.

Table 4. 1 Transformer data of Sebeta-I substation

Substation	Transformer Qnt.	Voltage Level(kV)	Capacity(MVA)	Total Capacity (MVA)
SEB-I	3	230/132	125	3*125=375
	2	132/15	50	2*50=100
	1	132/45/15	25/25/10	25/10

Presently, Sebeta-I Substation has 13 feeders of 15kV lines which supply power to 15/0.4kV transformers which feed different consumers such as residential, commercial and industrial. The whole distribution system has an average power factor of 0.85. To limit the scope of the study the single line diagram of figure 4.1 is reduced to that of figure 4.2 which shows only the two transformers of capacity 50MVA, 132/15 kV which supply power to the eleven feeders of SEB-I-A and SEB-I-B and, one three winding transformer of capacity 25/25/10 MVA, 132/45/15 kV which supply power to Gedja substation and two feeders of SEB-I-C by 45 kV and 15 kV line respectively (see figure 4.2).

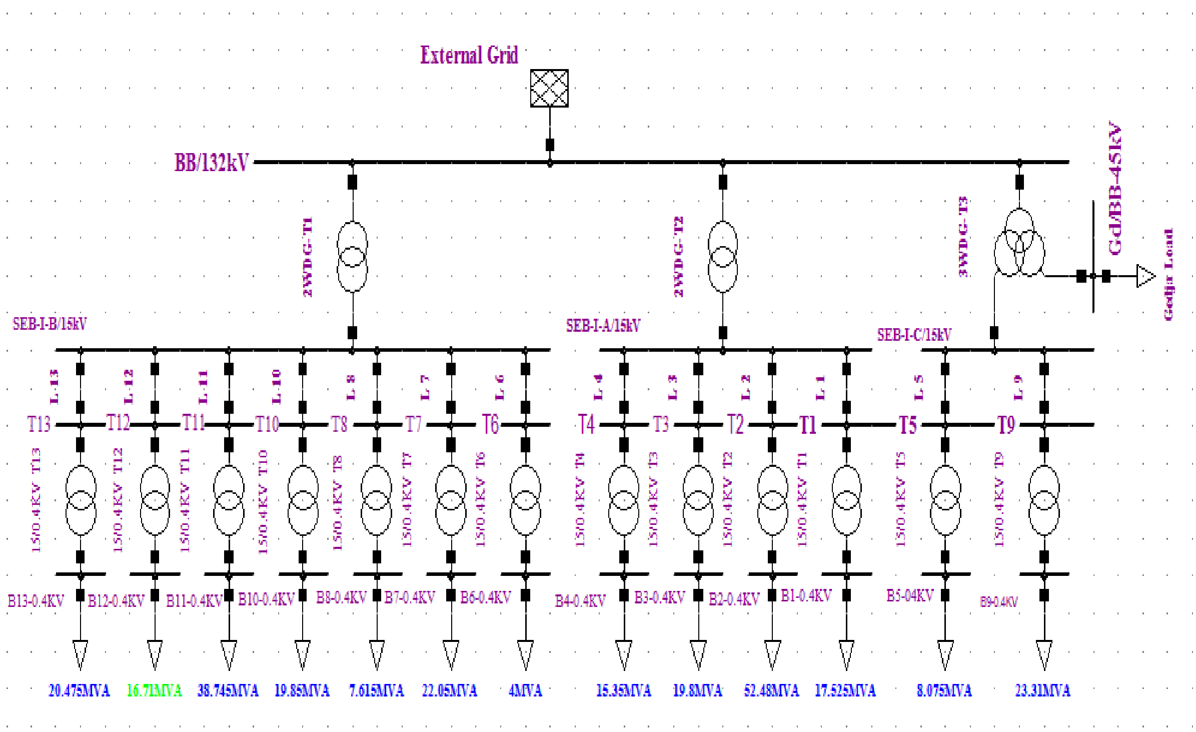


Figure 4. 2 Single line diagram of the 13 feeders of Sebeta-I substation

The general information of the 13 feeders of Sebeta-I substation indicating the total number of transformers with their aggregate capacity on each feeder, cable type and cable capacity is shown in table 4.2.

Table 4. 2 General data of the 13 feeders of Sebeta-I substation

Feeder Name	Number of transformers	Total Capacity (MVA)	Cable type	Cable C.C.C (KA)	Cable Capacity (MW)
SEB-1	57	17.525	Al	0.836	19.5
SEB-2	170	52.48	Al	0.836	19.5
SEB-3	82	19.8	Al	0.836	19.5
SEB-4	64	15.35	Al	0.386	19.5
SEB-5	8	8.075	Cu	0.367	8.6
SEB-6	2	4	Al	0.455	10.6
SEB-7	70	22.05	Cu	0.325	7.6
SEB-8	8	7.615	Cu	0.325	7.6
SEB-9	74	23.31	Cu	0.532	12.4
SEB-10	77	19.85	Al	0.1064	24.9
SEB-11	123	38.745	Al	0.1064	24.9
SEB-12	69	16.71	Al	0.1064	24.9
SEB-13	65	20.475	Al	0.1064	24.9

In order to limit further the scope the study area, one feeder of Sebeta-I substation is selected as a case study network among the total 13 feeders of the substation based on their vulnerability to frequent power interruption and long duration outage of a feeder. Among the 13 feeders of the substation, a feeder which has more frequent power interruption with long duration outage of the feeder is preferred as a base case study network. Therefore, the two year data indicating average yearly power interruption with their causative agent is shown in tables 4.3 and 4.4.

Table 4. 3 Major causes of power interruption in Sebeta-I substation (01/09/2015-31/08/2016)

Feeder Name	Causes of Power Interruption						Total Duration (HRs)
	OP	SC	EF	UF	OL	Total	
	Freq.(Int/Yr)	Freq.(Int/Yr)	Freq.(Int/Yr)	Freq.(Int/Yr)	Freq.(Int/Yr)	Freq.(Int/Yr)	
SEB-1	127	47	69	8	6	257	210.49
SEB-2	191	119	279	17	1	607	617.3
SEB-3	104	73	144	27	8	356	424.25
SEB-4	153	75	151	37	10	426	528.36
SEB-5	61	7	15	0	13	96	262.39
SEB-6	77	17	42	0	1	137	214.94
SEB-7	169	145	169	1	9	493	565.74
SEB-8	47	11	31	0	0	89	100.32
SEB-9	102	115	50	0	2	269	385.01
SEB-10	202	38	130	0	1	371	559.76
SEB-11	219	82	114	13	5	433	525.09
SEB-12	208	234	233	1	33	**709**	**755.52**
SEB-13	198	105	200	0	2	505	484.03

Table 4. 4 Major Causes of Power Interruption in Sebeta-I substation (01/09/2016-31/08/2017)

Feeder Name	Causes of Power Interruption						Total Duration (HRs)
	OP	SC	EF	UF	OL	Total	
	Freq.(Int/Yr)	Freq.(Int/Yr)	Freq.(Int/Yr)	Freq.(Int/Yr)	Freq.(Int/Yr)	Freq.(Int/Yr)	
SEB-1	102	33	57	0	4	196	554.62
SEB-2	133	189	199	0	22	543	405.65
SEB-3	103	50	176	0	2	331	252.37
SEB-4	133	60	161	20	41	415	1053.58
SEB-5	57	25	52	5	10	149	214.27
SEB-6	94	24	70	1	8	197	247.57
SEB-7	174	100	83	10	21	388	372.75
SEB-8	62	14	62	0	8	146	261.06
SEB-9	74	58	50	0	7	189	194.64
SEB-10	131	48	120	1	24	324	435.83
SEB-11	144	100	201	22	21	488	410.36
SEB-12	175	133	185	1	53	**547**	**1149.27**
SEB-13	175	97	174	0	9	455	351.17

The two year data of power interruption in Sebeta-I substation summarized in tables 4.3 and 4.4 is shown graphically in figures 4.3 and 4.4 which depict the total duration and frequency of power interruption per year for each feeder.

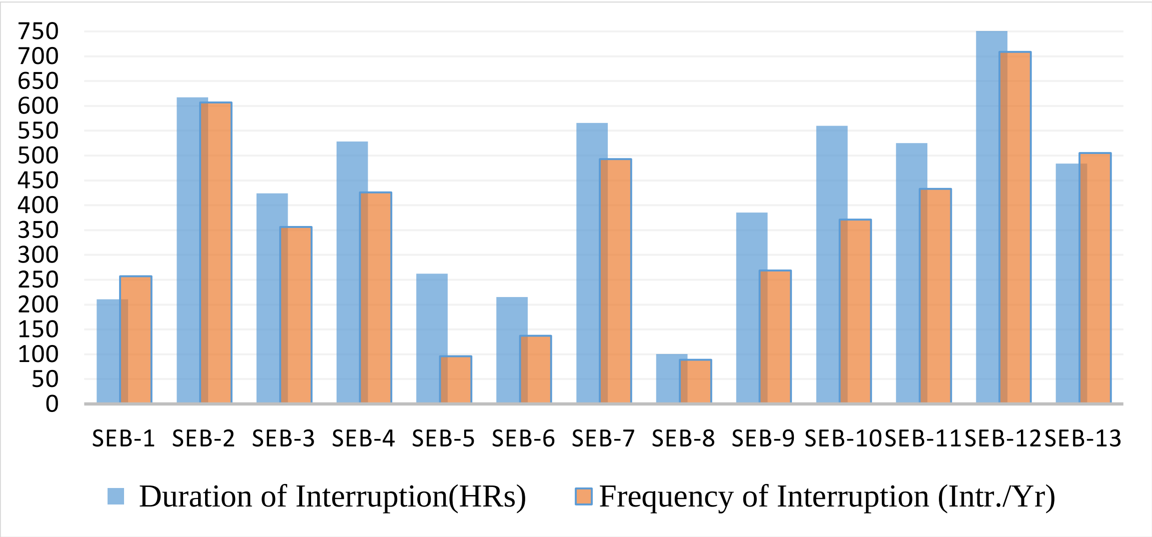


Figure 4. 3 Sebeta-I Substation feeder outage duration and failure occurrence in (01/09/2015-31/08/2016)

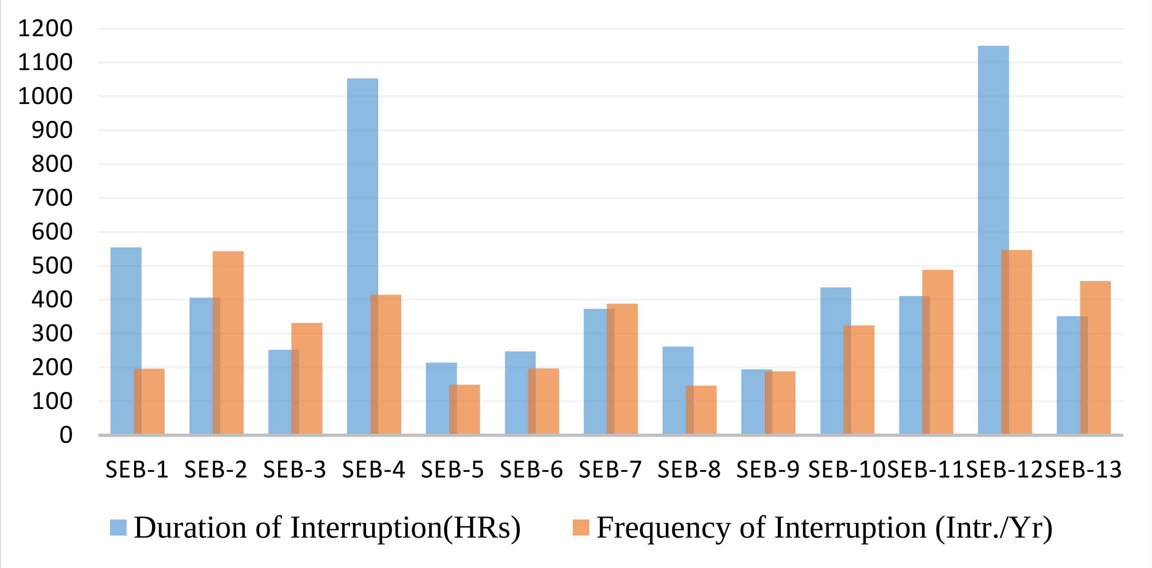


Figure 4. 4 Sebeta-I Substation feeder outage duration and failure occurrence in (01/09/2016-31/08/2017)

As it is evident from the power interruption frequency and duration of interruption of the two year data, out of the 13 feeders in Sebeta-I substation, SEB-12 has the highest frequency of power interruption with a very long duration of power interruption, and the highest number of over loading of the feeder during the two years of recorded data. Hence to limit further the scope of the study, the feeder SEB-12 of Sebeta-I substation was chosen for DG integration in order to examine the impact of DG integration on technical parameters of the radial distribution system. The single line diagram of SEB-12 modeled by using DIgSILENT PowerFactory 15.1.7 simulation software is shown in figure 4.5.

4.2.1 Line parameters of the Feeder SEB-12 of Sebeta-I substation

Table 4. 5 Line parameters of SEB-12

Code of Conductor	R (Ω/km)	X (Ω/km)	I_{Sc} (kA)	I_{Rated} (KA)	Type of Conductor
AAC95	0.578	0.36	4.3	0.381	OH Bare
XLPE AAAC95	0.307	0.34	8.1	1.012	OH XLPE Covered
UG Al 240mm^2	0.122	0.103	19.2	1.012	UG cable

Where,

R: Positive sequence resistance of conductor (Ω/km) **I_{sc} (kA)**: short circuit capability

X: positive sequence reactance of conductor (Ω/km) **I_{Rated} (kA)**: Thermal Limit

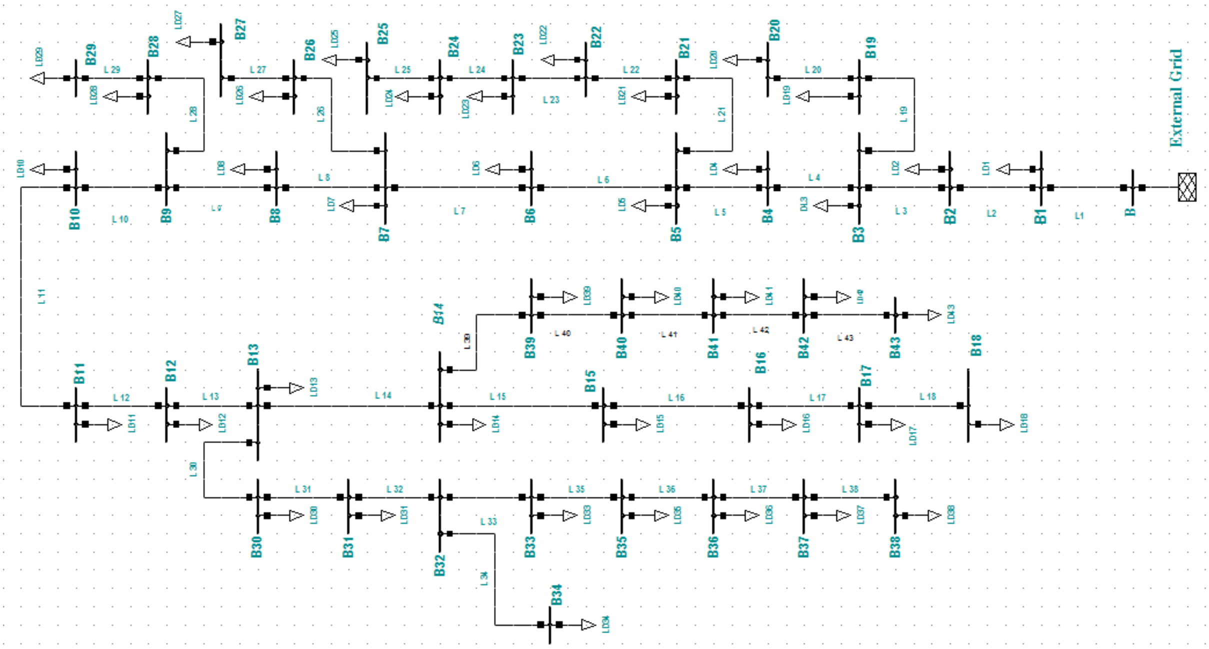


Figure 4. 5 Single line diagram of the feeder SEB-12 of Sebeta-I substation

4.2.2 Base Case Total power loss of the Feeder

The total power loss of the feeder SEB-12 of Sebeta-I substation during the base case balanced and positive sequence load flow analysis was found to be 1.91MW and 2.07MVAR as indicated in the screenshot of load flow simulation by using DIgSILENT PowerFactory 15.1.7 software (see figure 4.6). In figure 4.7 the total real and reactive power loss of the feeder before DG integration is clearly illustrated.

```
|                    |                                                             |  DIgSILENT   | Project:                     |
|                    |                                                             | PowerFactory |------------------------------
|                    |                                                             |   15.1.7     | Date:  9/13/2018             |

| Load Flow Calculation                        Complete System Report: Substations, Voltage Profiles, Grid Interchange |

|    AC Load Flow, balanced, positive sequence                |    Automatic Model Adaptation for Convergence          No    |
|    Automatic Tap Adjust of Transformers          No         |    Max. Acceptable Load Flow Error for                       |
|    Consider Reactive Power Limits                No         |      Nodes                                             1.00 kVA  |
|                                                             |      Model Equations                                  0.10 %    |

| Total System Summary                              | Study Case: Study Case              | Annex:                     / 12 |

|          Generation   Motor    Load    Compen-  External                    Inter Area    Total    Load     Noload        |
|                       Load             sation   Infeed                        Flow       Losses   Losses   Losses        |
|             [MW]/     [MW]/    [MW]/   [MW]/    [MW]/                        [MW]/       [MW]/    [MW]/    [MW]/         |
|            [Mvar]    [Mvar]   [Mvar]  [Mvar]   [Mvar]                       [Mvar]      [Mvar]   [Mvar]   [Mvar]         |

| \Freeware Sys\Feeder_12\Network Model\Network Data\Grid 5                                                                |
|              0.00      0.00    15.87    0.00    17.78                        0.00        1.91     1.91     0.00         |
|              0.00      0.00     5.22    0.00     7.29                        0.00        2.07     2.07     0.00         |

| Total:                                                                                                                   |
|              0.00      0.00    15.87    0.00    17.78                                    1.91     1.91     0.00         |
|              0.00      0.00     5.22    0.00     7.29                                    2.07     2.07     0.00         |
```

Figure 4. 6 Total power loss during base case simulation

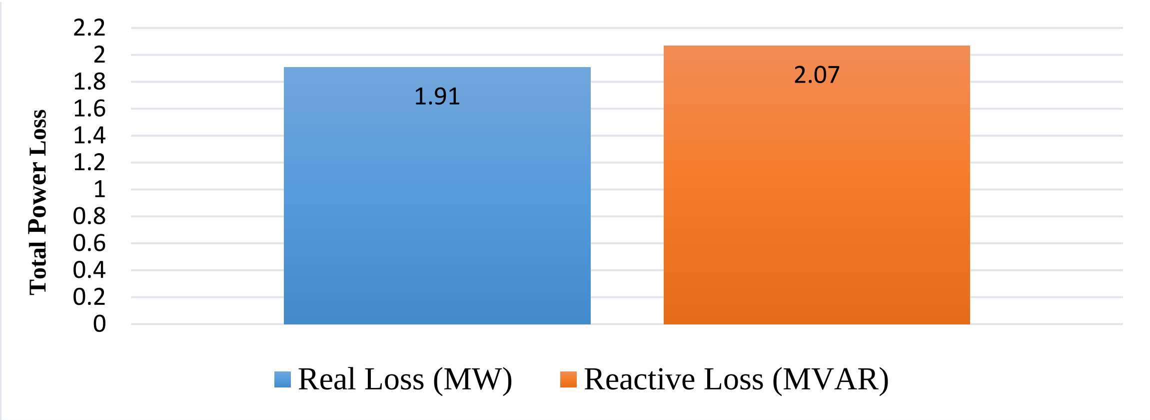


Figure 4. 7 Total power loss of SEB-12 of Sebeta-I before DG integration

4.2.3 Base Case Voltage profile of the Feeder

The base case load flow analysis shows that the majority of the bus voltage of the feeder is out of allowable limit which is indicated by blue color that is less than 0.95 p.u. as shown in figure 4.8. The acceptable voltage limit in DIgSILENT PowerFactory 15.1.7 simulation package is ±5% of the nominal voltage of the system. Figure 4.9 depicts that the most of the bus voltages are out of permissible limit with the minimum voltage occur at bus 18 which was 0.832 p.u. Hence, the feeder has poor voltage profile which indicates that the additional means of voltage profile improvement is required.

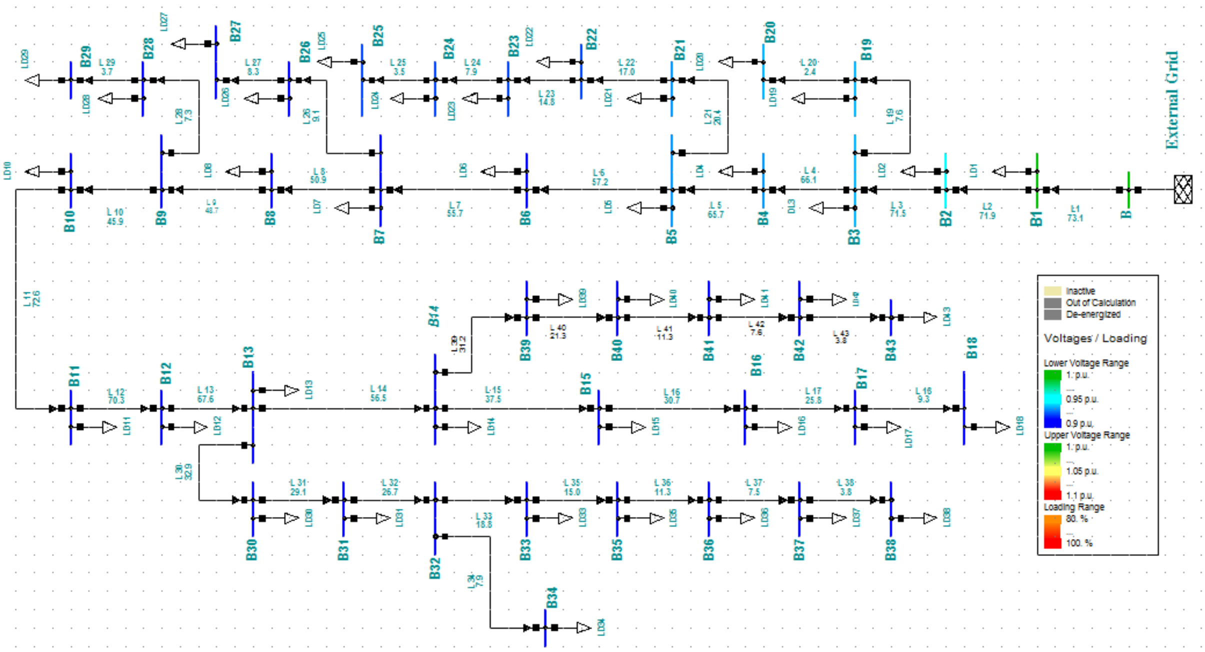


Figure 4. 8 Single line diagram of SEB-12 of Sebeta-I substation showing majority of bus voltages are out of permissible limit (blue colour) before DG injection

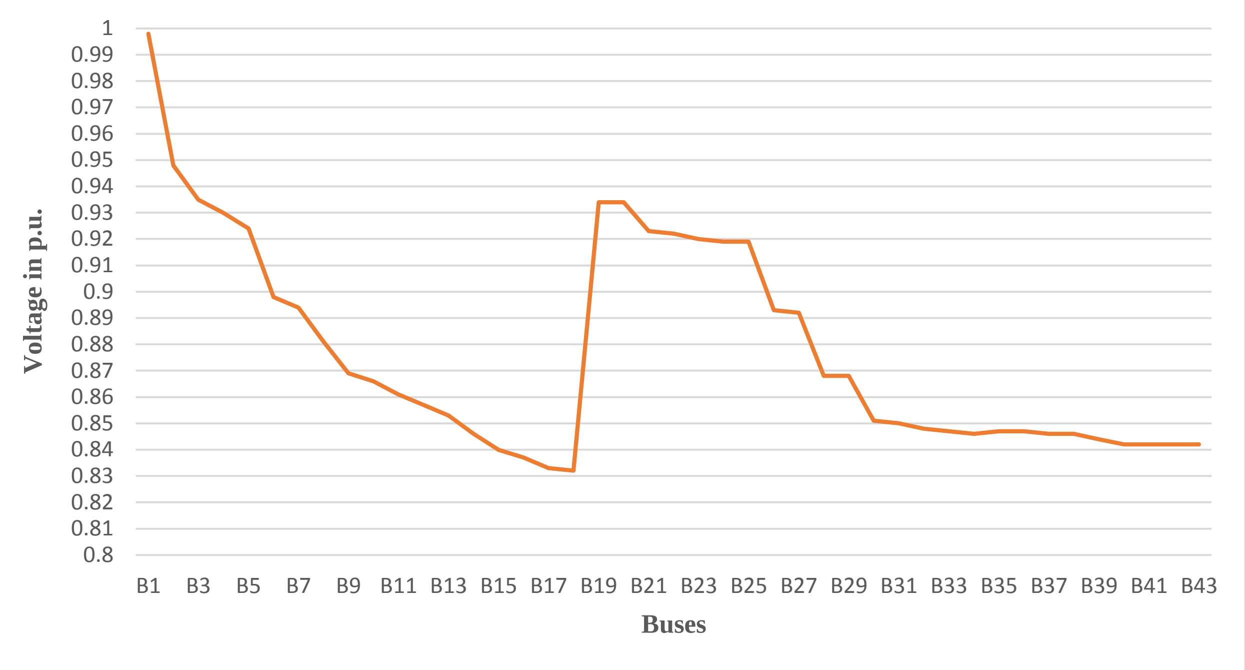


Figure 4. 9 Base case voltage profile of SEB-12 of Sebeta-I substation before DG integration

4.3 Selection of DG units

The distributed generators selected for this study case was a synchronous generator which is available in DIgSILENT PowerFactory 15.1.7 software that can be used in thermal, hydro, or wind power plants. The DG is modelled as a Turbo Series 1 of IEC909/IEC60909 Machine Type and the excitation system control mode is constant power factor. Power factor control mode is aimed at maximising the active power production. Also it exempts the DG from participating in the system frequency control. In consequence, unitary power factor operation is adopted. The loads are general load types modelled as constant impedance and therefore do not contribute to the fault level.

4.4 Sizing and placement of DG units

The size of distributed generators must not exceed the capacity of the feeder which is 18 MW. Therefore the size of DG units selected for the case study had been medium size DG not exceeding 18 MW. The size of DG unit was found by using equations (3.9) and (3.10) at each bus with the help of MATLAB software by writing the program in MATLAB m-file programming language. The size of DG unit found at each bus is shown in figure 4.10.

The total power losses the feeder after DG integration at each bus was identified for each case by using load flow study with the help of DIgSILENT PowerFactory 15.1.7 simulation package.

The total power loss of the feeder was found by placing the size of DG unit found in figure 4.10 at each bus.

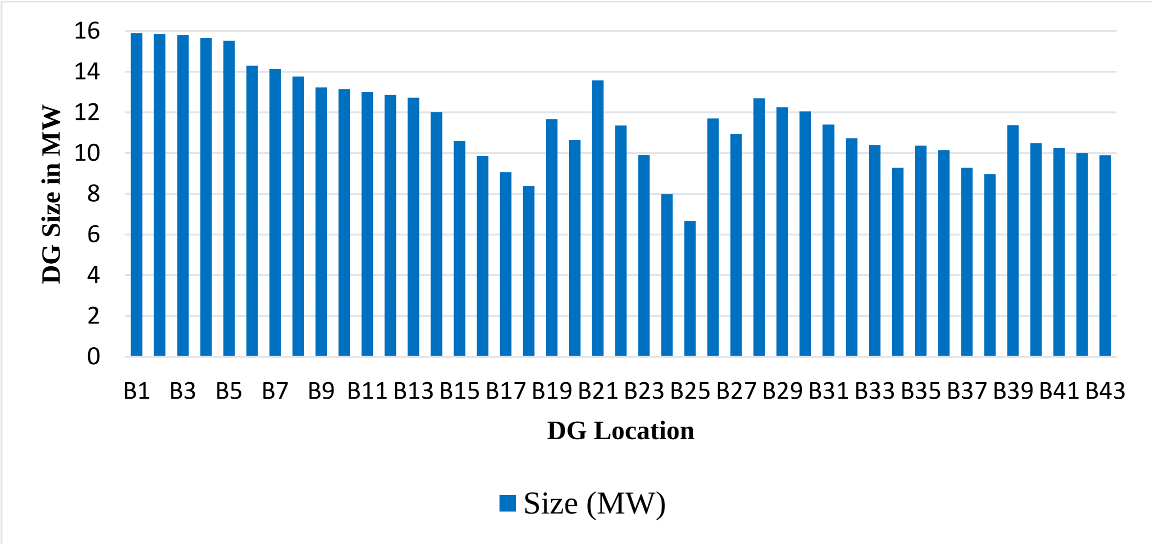


Figure 4. 10 The size of DG unit at each bus

The total power loss of the feeder for each case study was compared, and the bus at which the total losses were minimum, which means the maximum total loss reduction of the feeder had been found, and all bus voltages were within acceptable value that is greater than 0.95 p.u. was considered to be the proper location for DG placement. Then the proper capacity of DG is corresponding to optimum location.

For each study case, the total real and reactive power loss when DG unit of corresponding size was placed at each bus is illustrated in figure 4.11. The balanced and positive sequence load flow analysis for each case reveals that the minimum total real and reactive power loss was found at bus 14 which was determined to be 0.30 MW and 0.28 MVAR respectively with all bus voltages were within acceptable range when DG size of 12.098 MW was placed at this bus (see figure 4.14). The minimum bus voltage which was 0.832 p.u. had been improved to 0.950 p.u. in this case.

The highest percentage of real and reactive power loss reduction was found to be 84.29% and 86.47% respectively which occur when DG size of 12.098MW was placed at bus 14 as shown in figure 4.12. Therefore, the proper size of DG unit which gives the maximum power loss reduction with all terminal voltages became within allowable limit was found to be 12.098 MW with the optimal place at bus 14.

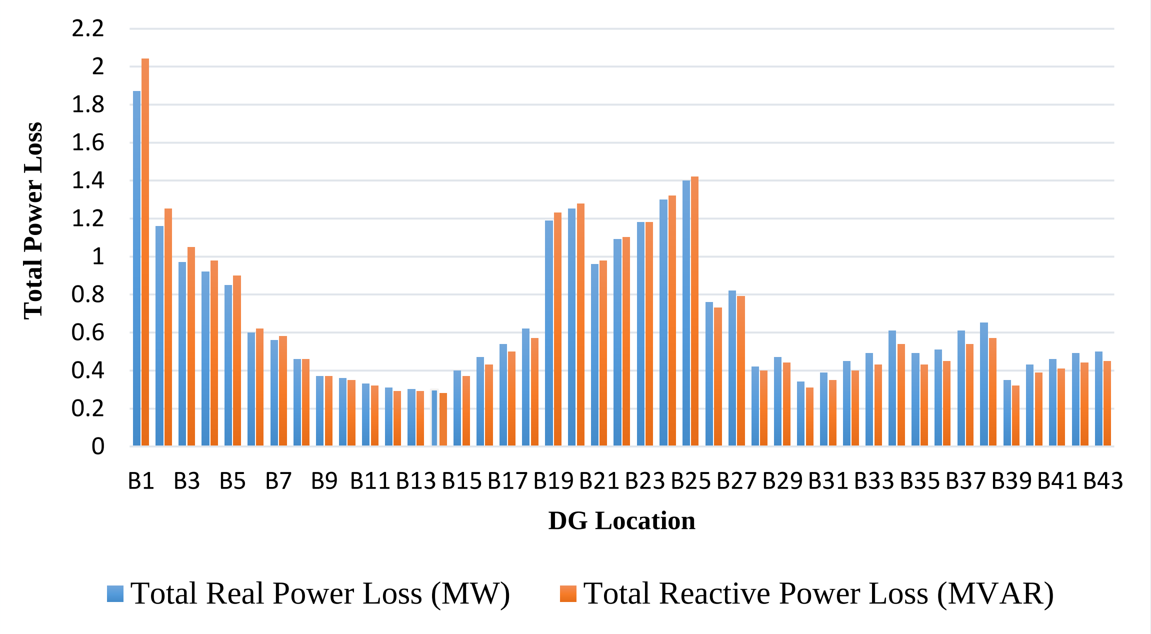


Figure 4. 11 Total power loss when DG unit is placed at each bus with corresponding size

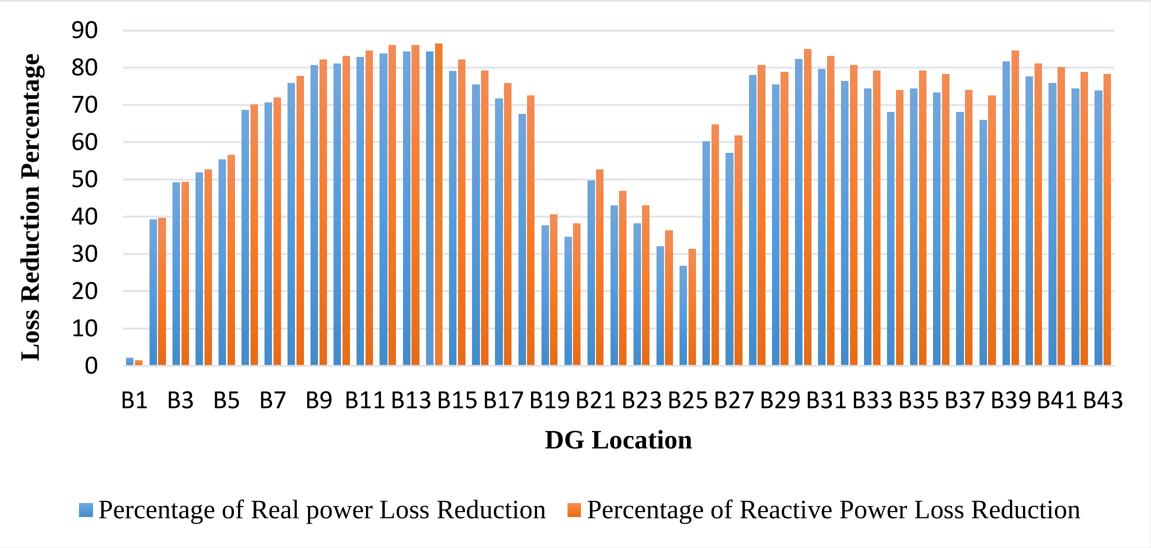


Figure 4. 12 Percentage of total power loss reduction in each case of DG injection

From figure 4.13, it is observed that with proper size and site of DG injection, all the terminal voltages were within allowable range as indicated in green colour that is all terminal voltages were above 0.95 p.u. Figure 4.14 depicts the total real and reactive power loss of the feeder after the integration of DG by performing balanced and positive sequence load flow analysis during steady state with the help of DIgSILENT PowerFactory 15.1.7 simulation software.

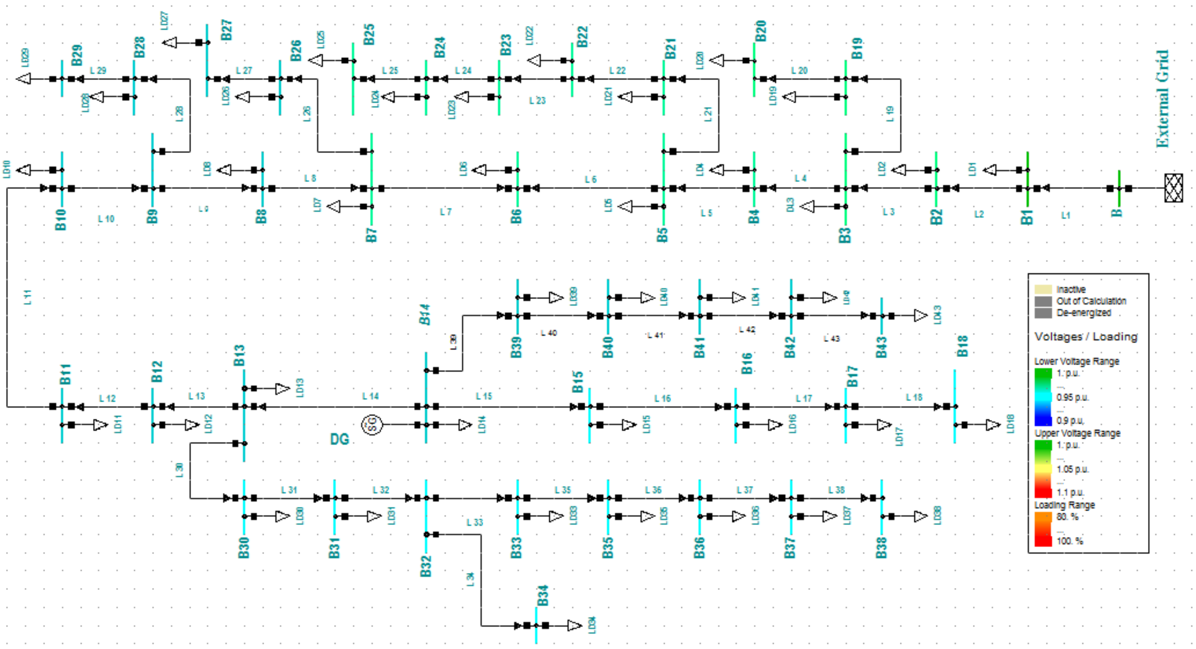


Figure 4. 13 Single line diagram of SEB-12 of Sebeta-I substation showing voltage profile at all buses after DG injection

```
-------------------------------------------------------------------------------------------------------
|                  |                                                          |  DIgSILENT  | Project:              |
|                  |                                                          | PowerFactory |------------------------
|                  |                                                          |   15.1.7    | Date:  9/14/2018      |
-------------------------------------------------------------------------------------------------------

-------------------------------------------------------------------------------------------------------
| Load Flow Calculation                          Complete System Report: Substations, Voltage Profiles, Grid Interchange |
-------------------------------------------------------------------------------------------------------
|    AC Load Flow, balanced, positive sequence          |  Automatic Model Adaptation for Convergence     No       |
|    Automatic Tap Adjust of Transformers         No    |  Max. Acceptable Load Flow Error for                     |
|    Consider Reactive Power Limits               No    |     Nodes                                  1.00 kVA      |
|                                                       |     Model Equations                        0.10 %        |
-------------------------------------------------------------------------------------------------------

-------------------------------------------------------------------------------------------------------
| Total System Summary                         | Study Case: Study Case           | Annex:              / 12 |
-------------------------------------------------------------------------------------------------------
|      Generation  Motor    Load    Compen-  External           Inter Area   Total    Load    Noload   |
|                  Load             sation   Infeed               Flow      Losses   Losses  Losses   |
|         [MW]/    [MW]/    [MW]/    [MW]/    [MW]/               [MW]/     [MW]/    [MW]/   [MW]/    |
|        [Mvar]   [Mvar]   [Mvar]   [Mvar]   [Mvar]              [Mvar]    [Mvar]   [Mvar]  [Mvar]    |
-------------------------------------------------------------------------------------------------------
| \Freeware Sys\Feeder_12\Network Model\Network Data\Grid 5                                            |
|         12.00     0.00    15.87     0.00     4.17                0.00      0.30     0.30    0.00     |
|          0.00     0.00     5.22     0.00     5.50                0.00      0.28     0.28    0.00     |
-------------------------------------------------------------------------------------------------------
| Total:                                                                                               |
|         12.00     0.00    15.87     0.00     4.17                          0.30     0.30    0.00     |
|          0.00     0.00     5.22     0.00     5.50                          0.28     0.28    0.00     |
-------------------------------------------------------------------------------------------------------
```

Figure 4. 14 Total power loss of the feeder SEB-12 after DG integration

4.5 Cost Estimation of DG Installation

After the determination of DG site 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 into its detailed technology. 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 is given the consideration. The following table shows the emission level and cost of various DG technologies [30].

Table 4. 6 Emission and Cost levels of different DGs

Technology	Emission Level	Cost
PV	No	Moderate
Fuel cell	Low	High
Wind turbine	No harmful emissions	Moderate
Diesel generator	High emission	Low
Microturbine	Low	Moderate

Even though, the PV systems and wind turbines are free energy sources with low cost and low emission level it is not conformable to implement in Sebeta-I substation due unsuitability of installation site since the substation is located in center of the city. Hence, to estimate the cost of DG size of 12.098 MW, the DG technologies selected in this thesis was Microturbine owing to their low emission level and average limited cost. Microturbines are used in distributed generation applications due to their flexibility in connection methods, their ability to be stacked in parallel to serve larger loads, their ability to provide stable and reliable power, and their low emissions level. Microturbines are well suited to be used in CHP applications because the exhaust heat can either be recovered in a heat recovery boiler, or the hot exhaust gases can be used directly [31].

The basic microturbine package consists of the microturbine and power electronics. The total plant cost consists of total equipment cost plus installation labor and materials (including site work), engineering, project management (including licensing, insurance, commissioning and startup), and financial carrying costs during a typical 3-month construction period [32].

The following table illustrates the equipment and installation cost of various sized microturbines [32].

Table 4. 7 Equipments and Installation costs of Microturbine

Description	System					
	1	2	3	4	5	6
Generator Capacity						
Nominal capacity (kW)	30	65	200	250	333	1000
Net capacity (kW)	28	61	190	240	320	950
Equipment costs						
Gen set package	$53,100	$112,900	$359,300	$441,200	$566,400	$1,188,600
Heat recovery	$13,500	$0	$0	$0	$0	$275,000
Fuel gas compression	$8,700	$16,400	$42,600	$0	$0	$164,000
Interconnection	$0	$0	$0	$0	$0	$0
Total equipment cost	$75,300	$129,300	$401,900	$441,200	$566,400	$1,627,600
$/kW	$2,689	$2,120	$2,120	$1,840	$1,770	$1,710
Installation costs						
Labor/materials	$22,600	$28,400	$80,400	$83,800	$101,900	$293,000
Project & construction Mgmt.	$9,000	$15,500	$48,200	$52,900	$68,000	$195,300
Engineering and fees	$9,000	$15,500	$48,200	$52,900	$68,000	$195,300
Project contingency	$3,800	$6,500	$20,100	$22,100	$28,300	$81,400
Financing (int. during const.)	$700	$1,200	$3,700	$4,100	$5,100	$14,800
Total other costs	$45,100	$67,100	$196,400	$211,400	$259,900	$747,300
$/kW	$1,611	$1,100	$1,035	$881	$812	$787
Total installed cost ($)	$120,400	$196,400	$598,500	$652,600	$826,300	$2,374,900
$/kW	$4,300	$3,220	$3,150	$2,720	$2,580	$2,500

From table 4.7 it is observed that the installed capital costs range from $3,220 to $2,500 per kW and decline with increasing capacity. Here, the microturbine of 1000 kW was selected to estimate the cost of DG capacity of 12.098 MW. The generators should be integrated to provide the modular packages of 12 MW unit comprised of twelve 1000 kW. Table 4.8 gives the cost estimation of 12.098 MW of DG capacity.

Table 4. 8 Cost of 12.098 MW DG

Generator Type	Capacity (MW)	Cost ($/kW)	Total Cost ($)
Microturbine	12.098	2,500	30,245,000
Cost of Installation in Ethiopian Birr			831,737,500 ETB

Table 4.8 gives the installation cost of 12.098 MW DG. Accordingly, assuming the microturbine with capacity of 1MW which has a total installation cost of 2,500 $/kW, the total cost of 12.098 MW DG was found to be $30,245,000 or 831.7375 million ETB.

4.6 Impacts of DG Integration on Radial Distribution System

Then after the designation of the size and site of DG unit, the load flow study has been performed with the help of DIgSILENT PowerFactory 15.1.7 software in order to show the impact of DG integration on a radial distribution system with selected size and site.

4.6.1 Impact of DG on Total Power Losses of the Radial Distribution System

During the base case load flow analysis at steady state condition, the total real and reactive power loss was determined as 1.91 MW and 2.07 MVAR respectively. In order to reduce the total power losses of the system, the integration of DG unit at proper site with proper size is significant. To get the best benefit from DG integration, sizing and sitting of distributed generation should be made with a great care otherwise the negative impact of DG may dominate.

Here the proper size and site of DG had been determined. The steady state balanced and positive sequence load flow analysis indicated that the total real and reactive power loss was reduced to 0.3 MW and 0.28 MVAR respectively after the integration of DG units with selected size and site. The comparison of total power loss before and after DG integration is shown in figure 4.15 which depicts a major significant improvement of total power losses reduction.

Here in comparison to the base case total power loss with total power loss after DG integration, the integration of DG makes a great reduction of total power losses in the system. The percentage of reduction of total real and reactive power loss had been found to be 84.29% and 86.47% respectively as shown in figure 4.16. Therefore, the impact of DG integration on total power losses is positive if DG unit is integrated with proper size and site.

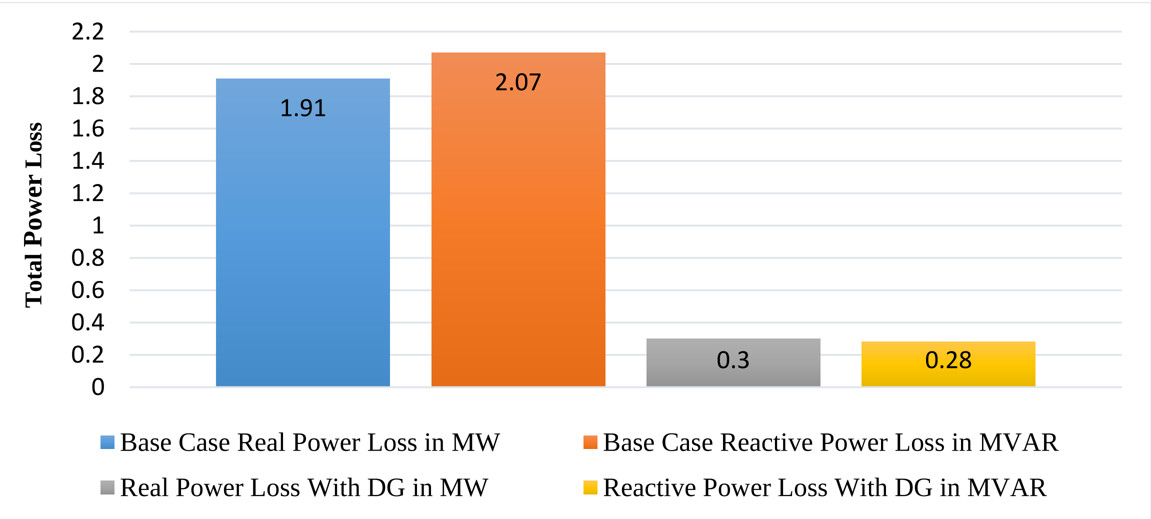


Figure 4. 15 Comparison of total power loss before and after DG integration

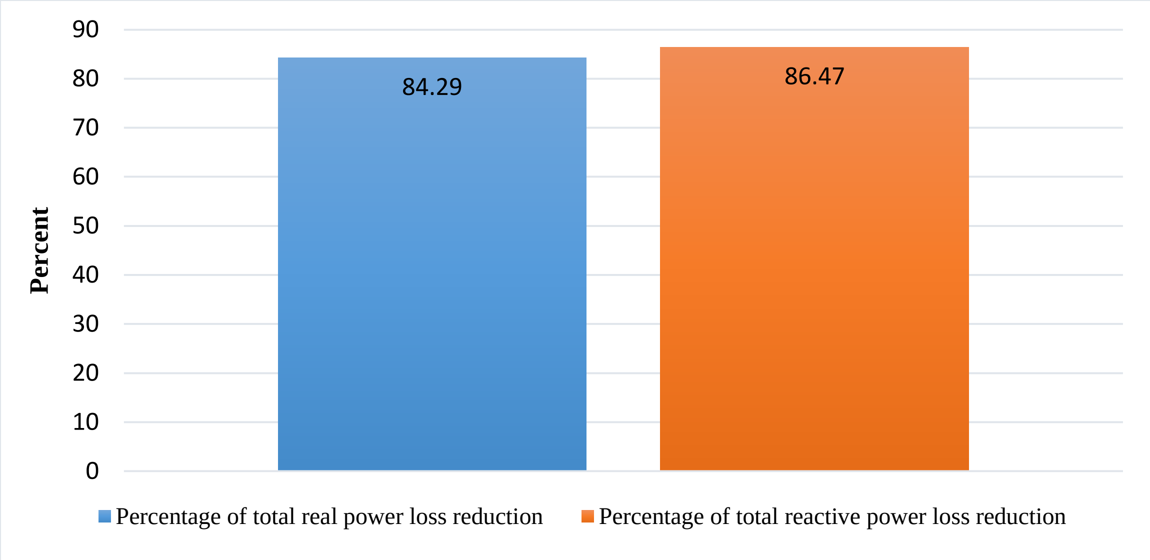


Figure 4. 16 Total real and reactive power loss reduction in percentage

4.6.2 Impact of DG on Voltage Profile of the Radial Distribution System

The voltage level of distribution systems by requirement must be kept within a specific range which is well defined in international standards and the common range is 1 ± 5% p.u. This range is the default in DIgSILENT PowerFactory 15.1.7 for the steady-state bus voltages.

The investigation of the possible effects of DG on the voltage profile along the feeder entails, firstly, ascertaining the feeder voltage profile in the absence of a DG - base case scenario. This necessitated the execution of a balanced and positive sequence load flow simulation of the distribution model. The result indicated that after the integration of DG the voltages at all buses were within permissible limit. The screenshot of the network model depicting the steady state load flow analysis with the voltages at all buses were within acceptable range is shown in figure 4.17. The green colour indicates that the voltage at that bus is within allowable range that is above 0.95 p.u. Figure 4.18 shows what voltage profile of the system resembles graphically after integration of DG. As it is clearly observed from the figure, all the terminal voltages are above 0.95 p.u. During the base case load flow analysis, the minimum voltage magnitude which occur at bus 18 had been determined to be 0.832 p.u, then now improved to 0.950 p.u.

Generally, the impact of distributed generation (DG) integration on a voltage profile of the radial distribution system is positive by taking into account the proper sizing and sitting of the unit.

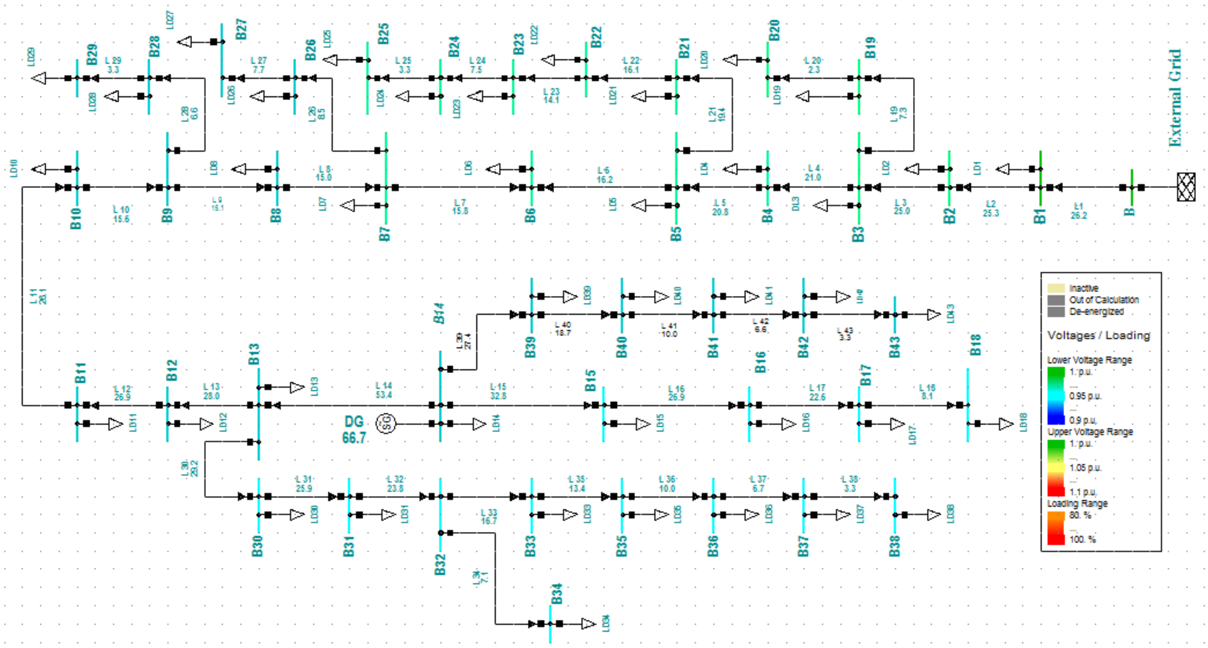


Figure 4. 17 Single line diagram of SEB-12 of Sebeta-I substation showing all voltage profile at all buses within permissible limit (green colour) after DG injection

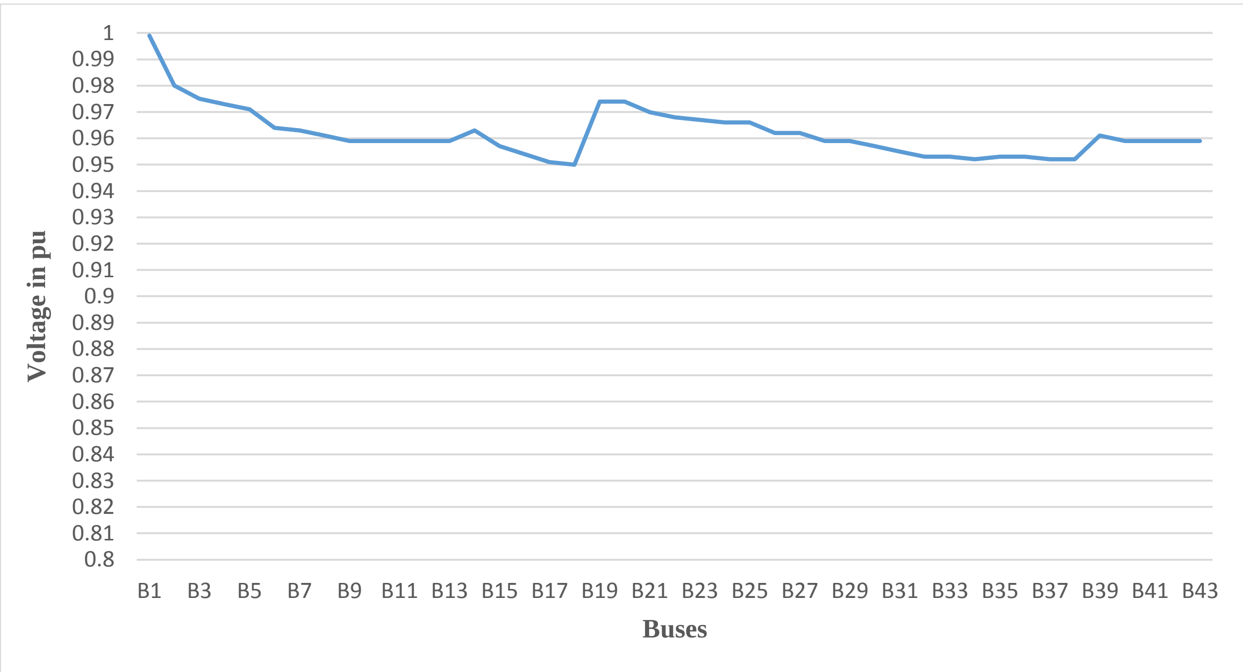


Figure 4. 18 Voltage profile of SEB-12 of Sebeta-I after DG integration

In order to clearly indicate the improvement of voltage profile the system, the base case voltage profile was compared with the voltage profile of the system after DG integration. The comparison of voltage profile during base case scenario and after DG integration is shown in figure 4.19 which entail a great improvement of the voltage profile at all buses of the system.

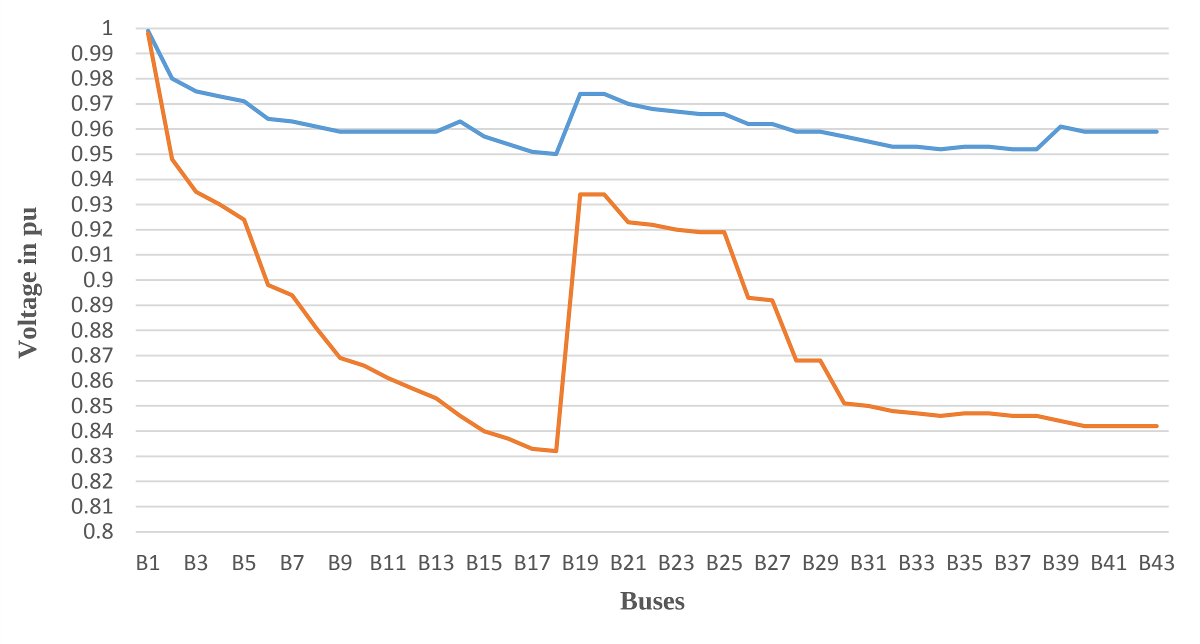


Figure 4. 19 Comparison of voltage profile of SEB-12 of Sebeta-I substation before and after DG integration

4.6.3 Impact of DG on Loading of Line Segment

Load flow analysis is necessary to obtain how much the voltages, currents, and power (active and reactive) are flowing in the power system network under steady state conditions. It also provides power losses in the system, the voltage profile and the percentage loading of line segment and generator. Here to investigate the impact of DG on loading of line segments, the base case load flow analysis was made on case study radial distribution system modeled in DIgSILENT PowerFactory 15.1.7 software and the simulation result revealed the improvement of loading of line segment after the integration of DG unit. The percentage of loading of line was observed from the result box of DIgSILENT PowerFactory 15.1.7 software for each line segment of the system separately. From table 4.9 it is ascertained that the impact of DG on loading of line segment is positive.

Table 4. 9 Percentage loading of line segment before and after DG injection

Line	Line loading % WODG	Line loading % WDG	Line	Line loading % WODG	Line loading % WDG
L1	73.1	26.2	L23	14.8	14.1
L2	71.9	25.2	L24	7.9	7.5
L3	71.5	24.9	L25	3.5	3.3
L4	66.1	21	L26	9.1	8.5
L5	65.7	20.7	L27	8.3	7.7

L6	57.2	16.2	L28	7.3	6.6
L7	55.7	15.8	L29	3.7	3.3
L8	50.9	15	L30	32.9	29.2
L9	48.7	15.1	L31	29.1	25.9
L10	45.9	15.6	L32	26.7	23.8
L11	72.6	26.1	L33	18.8	16.7
L12	70.3	26.9	L34	7.9	7.1
L13	67.6	28	L35	15	13.4
L14	56.5	53.5	L36	11.3	10
L15	37.5	32.8	L37	7.5	6.7
L16	30.7	26.9	L38	3.8	3.3
L17	25.8	22.6	L39	31.2	27.4
L18	9.3	8.1	L40	21.3	18.7
L19	7.6	7.3	L41	11.3	10
L20	2.4	2.3	L42	7.6	6.6
L21	20.4	19.4	L43	3.8	3.3
L22	17	16.1			

Where,

WODG: With Out Distributed Generator **WDG**: With Distributed Generator

4.6.4 Impact of DG on Fault Level of the System

Identification of the maximum fault current that will flow in the network under faulted conditions is the essence of short circuit studies prior to DG integration.

From literature the two types of fault level conditions that should be studied are:

Single phase to ground faults - because they have highest rate of occurrence in distribution networks.

Three phase faults - because of their severity (they produce maximum fault currents).

To determine the impact of DG integration on fault level of the system, the short-circuit load flow analysis was performed in two case scenarios that is the short circuit simulation before and after DG injection. The short circuit simulation was made at all the buses before and after DG injection, and the impact of DG on short circuit level was examined. The short circuit method in this work is according to IEC60909 using a constant voltage factor which makes the fault level independent of the load.

From the short-circuit load flow analysis made on case study network model, it is seen that, in both three phase and single line to ground faults, there was some increment of fault level at each bus. Therefore, in general the impact of DG on short circuit level of the system is negative as it is shown in table 4.10 for three phase fault and table 4.11 for single phase to ground (LG) fault.

Table 4. 10 Short circuit level before and after DG injection during three phase faults

Bus No	3Φ-Fault Level WODG (MVA)	3Φ-SC- WODG (KA)	3Φ-Fault Level WDG (MVA)	3Φ-SC-WDG (KA)
B1	5275.8	203.063	5327.4	205.054
B2	351.8	13.542	408.3	15.716
B3	278.7	10.727	337.4	12.986
B4	258.3	9.943	317.9	12.237
B5	226.7	9.109	297.7	11.459
B6	166.1	6.392	233.7	8.993
B7	157.9	6.79	226.8	8.73
B8	136.5	5.256	209.7	8.073
B9	120.4	4.633	198.3	7.634
B10	117.2	4.51	196.3	7.556
B11	111.8	4.303	193.1	7.433
B12	107.2	4.124	190.6	7.337
B13	103	3.966	188.7	7.262
B14	94.5	3.637	182.6	7.03
B15	82.3	3.168	145.8	5.612
B16	76.1	2.928	128.5	4.946
B17	69.4	2.67	111.3	4.285
B18	64.6	2.487	100	3.8
B19	217.6	8.374	252.7	9.726
B20	201.6	7.761	231.7	8.916
B21	211	8.123	259.1	9.972
B22	179.8	6.921	214.1	8.24
B23	158.5	6.102	184.8	7.113
B24	129.5	4.986	146.7	5.647
B25	109.7	4.224	121.9	4.691
B26	135.3	5.208	184.3	7.093
B27	127.3	4.9	170	6.542
B28	116.5	4.485	188.9	7.269
B29	113.4	4.363	181.3	6.977
B30	97.7	3.762	173.4	6.672
B31	92.7	3.567	159.2	6.129
B32	87.2	3.356	144.7	5.569
B33	84.6	3.256	138.1	5.315
B34	76.9	2.961	119.5	4.601
B35	84.4	3.248	137.5	5.293

B36	82.8	3.186	133.5	5.14
B37	76.5	2.946	118.6	4.565
B38	74.3	2.859	113.5	4.367
B39	89.5	3.44	167.1	6.43
B40	82.8	3.186	147.1	5.662
B41	81.2	3.124	142.6	5.487
B42	79.4	3.055	137.5	5.292
B43	78.7	3.03	135.7	5.223

Table 4. 11 Short circuit level before and after DG injection during single line to ground faults

Bus No	1**Φ**-Fault Level WODG (MVA)	1**Φ**-SC-WODG (KA)	1**Φ**-Fault Level WDG (MVA)	1**Φ**-SC-WDG (KA)
B1	669.8	77.338	689.3	79.593
B2	73.6	8.503	92.2	10.651
B3	58.9	6.8	78.6	9.077
B4	54.7	6.321	74.9	8.652
B5	50.3	5.807	71.1	8.214
B6	35.6	4.113	60.5	6.982
B7	33.9	3.917	59.6	6.884
B8	29.4	3.396	58.3	6.733
B9	26	3	59	6.808
B10	25.3	2.921	59.4	6.857
B11	24.2	2.79	60.4	6.978
B12	23.2	2.675	61.8	7.133
B13	22.3	2.574	63.4	7.323
B14	20.8	2.401	66	7.618
B15	18.6	2.146	48.7	5.62
B16	17.4	2.01	41.6	4.798
B17	16.1	1.86	35	4.041
B18	15.2	1.752	30.9	3.568
B19	48.4	5.586	61	7.043
B20	45.5	5.251	56.5	6.519
B21	45.9	5.304	62.8	7.248
B22	40.4	4.66	52.8	6.101
B23	36.4	4.199	46.2	5.337
B24	30.7	3.541	37.4	4.317
B25	26.6	3.067	31.5	3.633
B26	30	3.46	48.5	5.63
B27	28.5	3.291	44.8	5.176
B28	25.3	2.923	55.7	6.436
B29	24.8	2.859	53.2	6.145
B30	21.4	2.468	56.8	6.562
B31	20.5	2.364	51.1	5.9
B32	19.2	2.223	44.3	5.112

B33	18.8	2.169	41.9	4.844
B34	17.4	2.007	35.6	4.116
B35	18.7	2.164	41.7	4.82
B36	18.5	2.131	40.4	4.661
B37	17.3	1.998	35.3	4.08
B38	16.9	1.95	33.6	3.884
B39	19.9	2.297	58.2	6.725
B40	18.7	2.155	49.2	5.684
B41	18.4	2.121	47.3	5.461
B42	18	2.082	45.2	5.217
B43	17.9	2.068	44.4	5.132

Where,

WODG: With Out Distributed Generator **WDG**: With Distributed Generator

4.6.5 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.

4.6.5.1 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 P-V 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. P-V curves have been traditionally used as graphical tools for studying voltage stability in electric power systems.

Voltage stability analysis in DIgSILENT PowerFactory 15.1.7 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 15.1.7 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 increament of load, the P-V curve of the developed model without DG is as shown in Figure 4.20. For all the loads down steam of DG which was 5.71425 MW, the maximum or total load before voltage collapse was determined to be 15.299904 MW. 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 9.58564 MW.

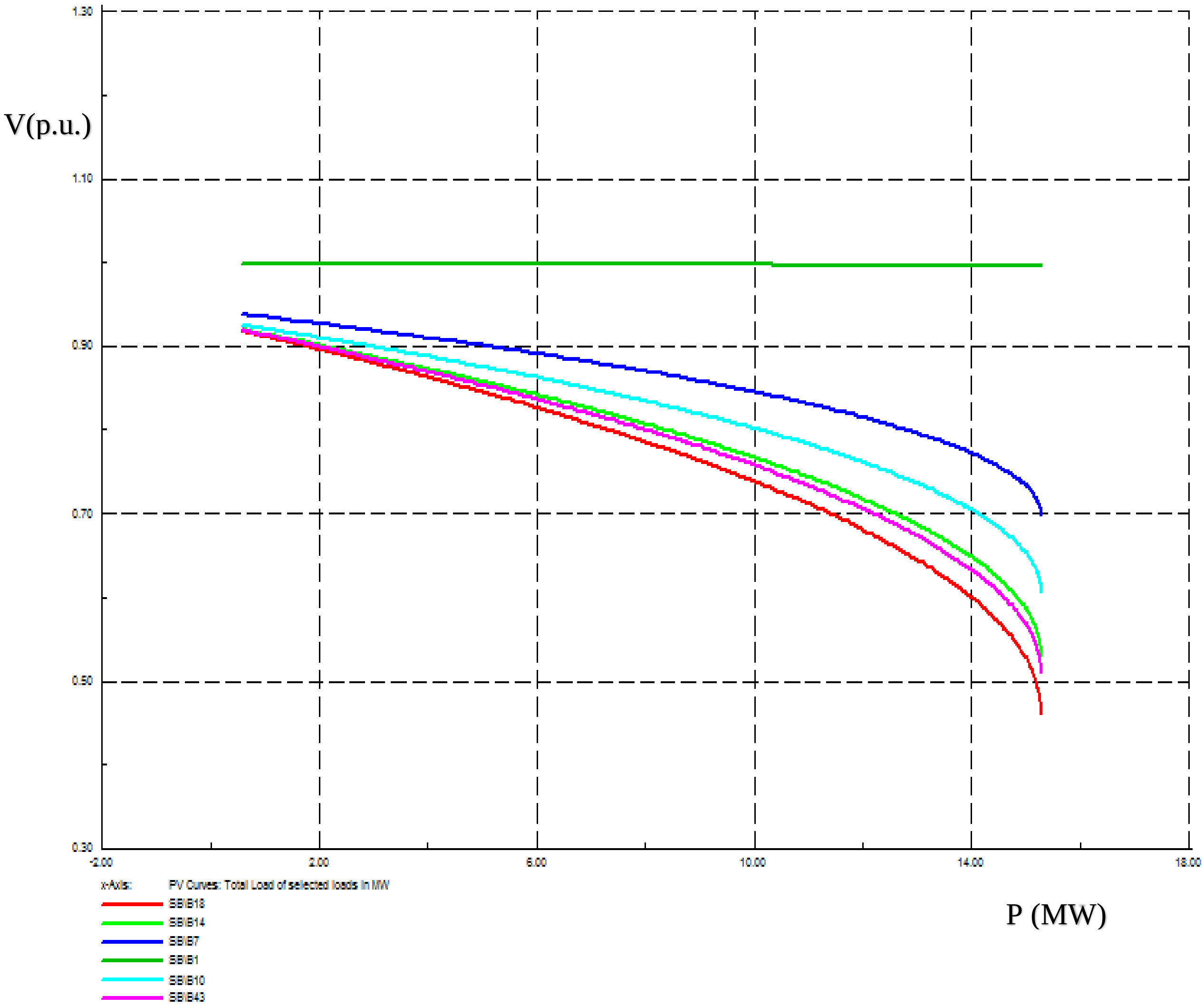


Figure 4. 20 P-V Curve without DG injection

To investigate the impact of DG integration, the voltage stability analysis was made after DG integration and, the P-V curve when the DG injects 12.098 MW resulting to a maximum load of 23.098713 MW before voltage collapse is shown in figure 4.20. 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 17.384463 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 increament of load is positive. This is due to the improved voltage profiles as well as decreased reactive power losses.

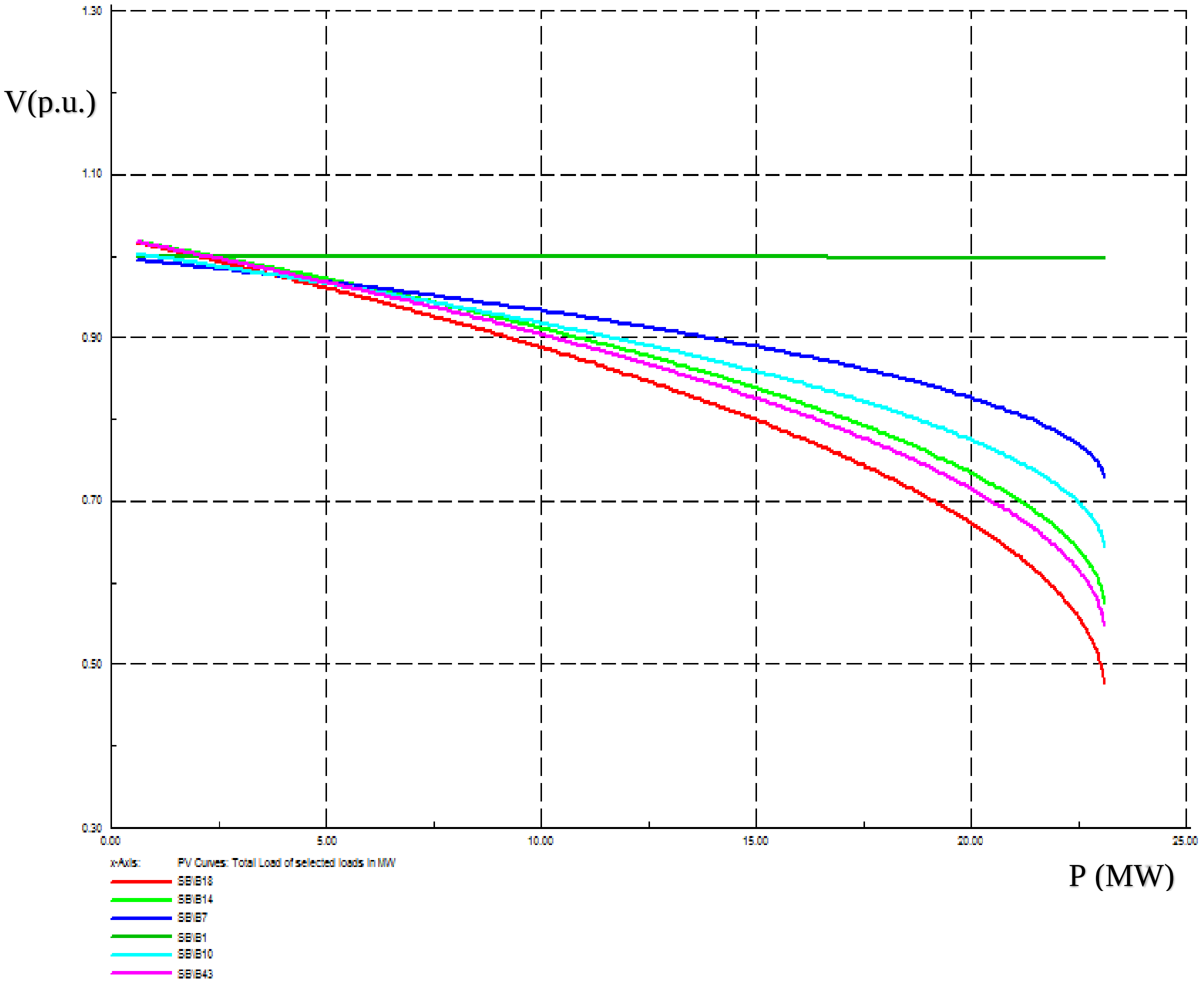


Figure 4. 21 P-V Curve after DG injection

4.6.5.2 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 15.1.7 had been utililised in investigating single phase and 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 and single phase to ground 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, and single phase to ground short circuit introduced at 0.3s and cleared at 0.4s.

The three buses were selected to study the transient stability of the system. Bus 14 at the point of connection (POC) of DG was selected and one bus from upstream of DG that is bus 7 and one bus from downstream of DG that is bus 18 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 all the three buses. This implies that synchronous generators have the most distinct impact on fault currents.

Besides, from the result of the simulation, the system regain 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.

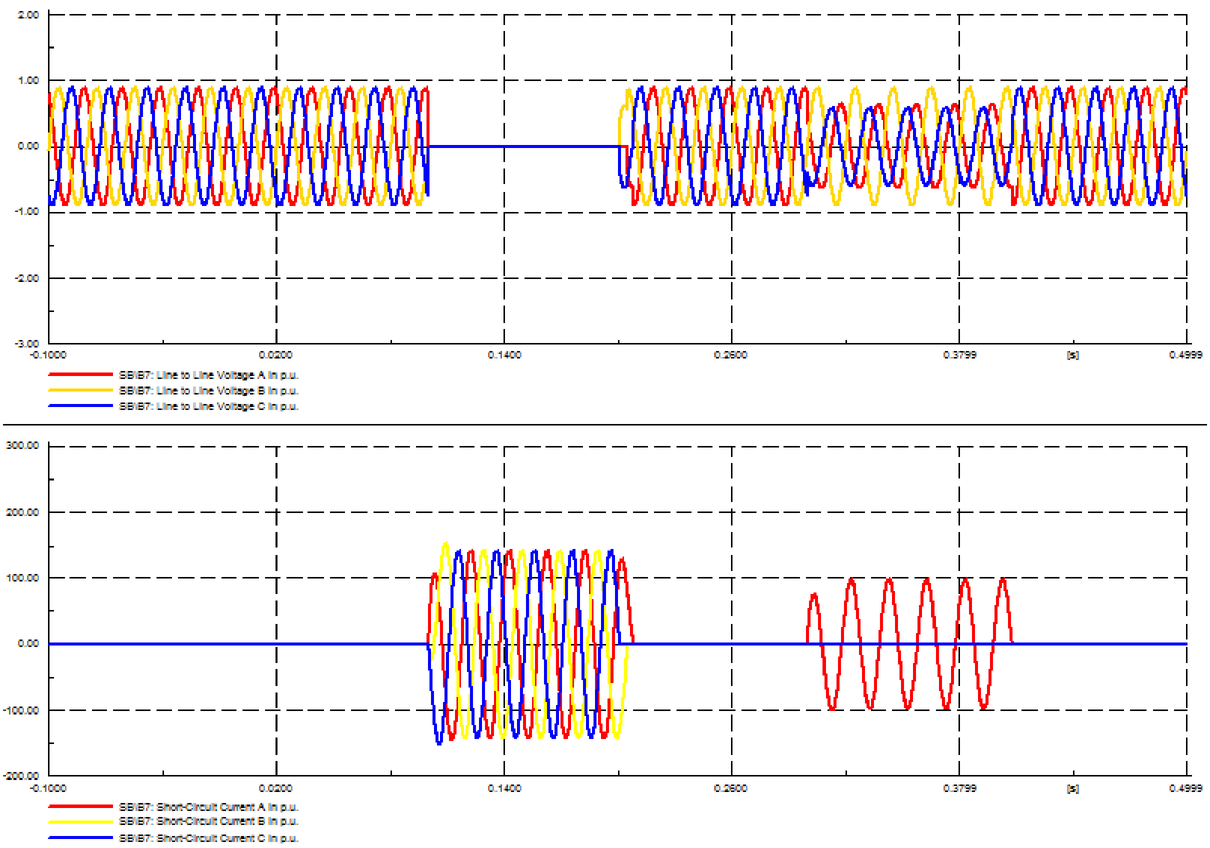


Figure 4. 22 Voltage and current wave form during 3ph and LG fault at bus 7 without DG

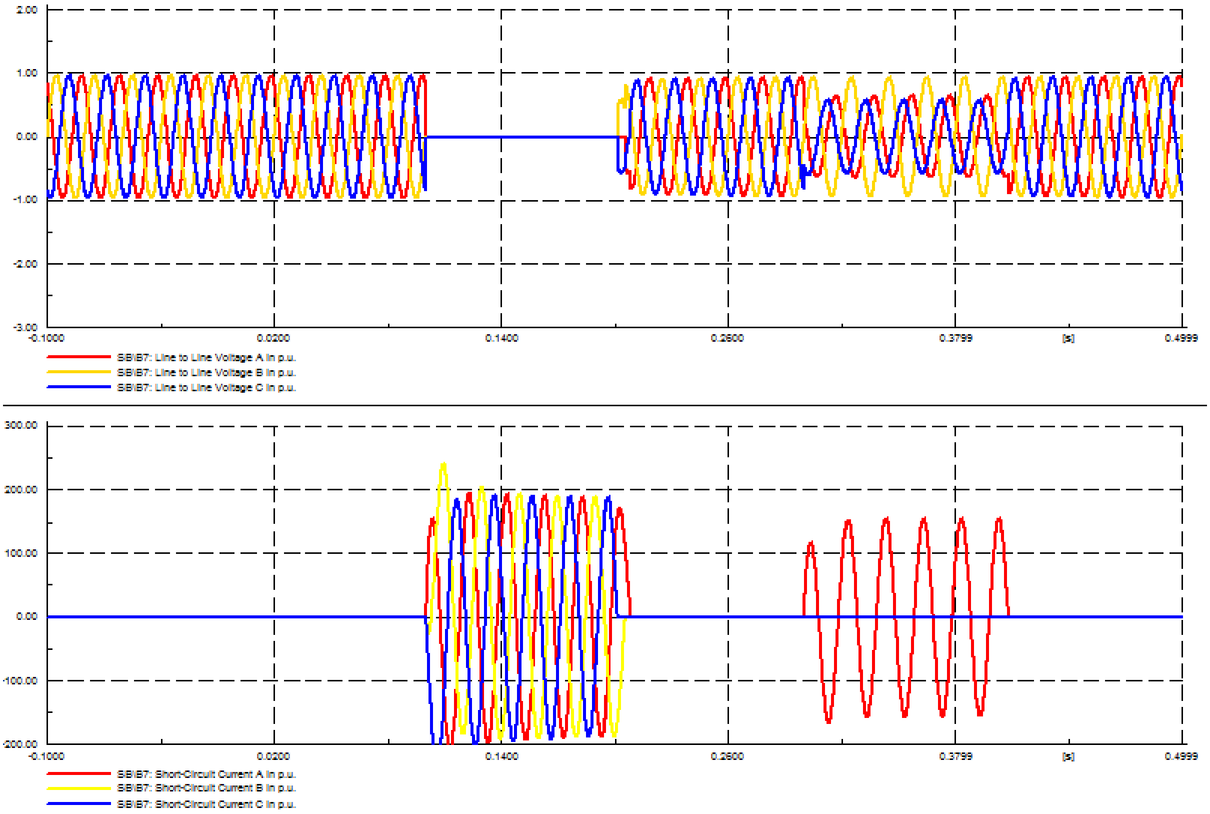


Figure 4. 23 Voltage and current wave form during 3ph and LG fault at bus 7 with DG

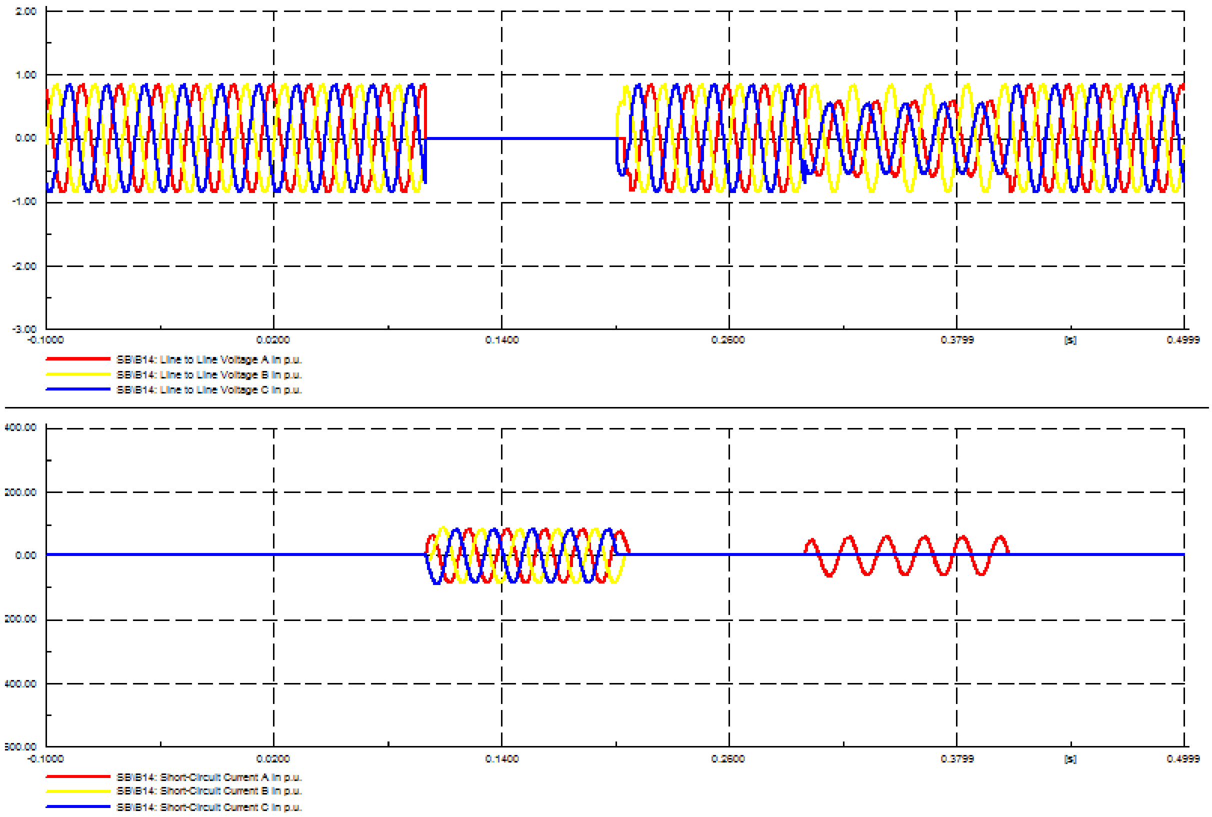


Figure 4. 24 Voltage and current wave form during 3ph and LG fault at bus 14 without DG

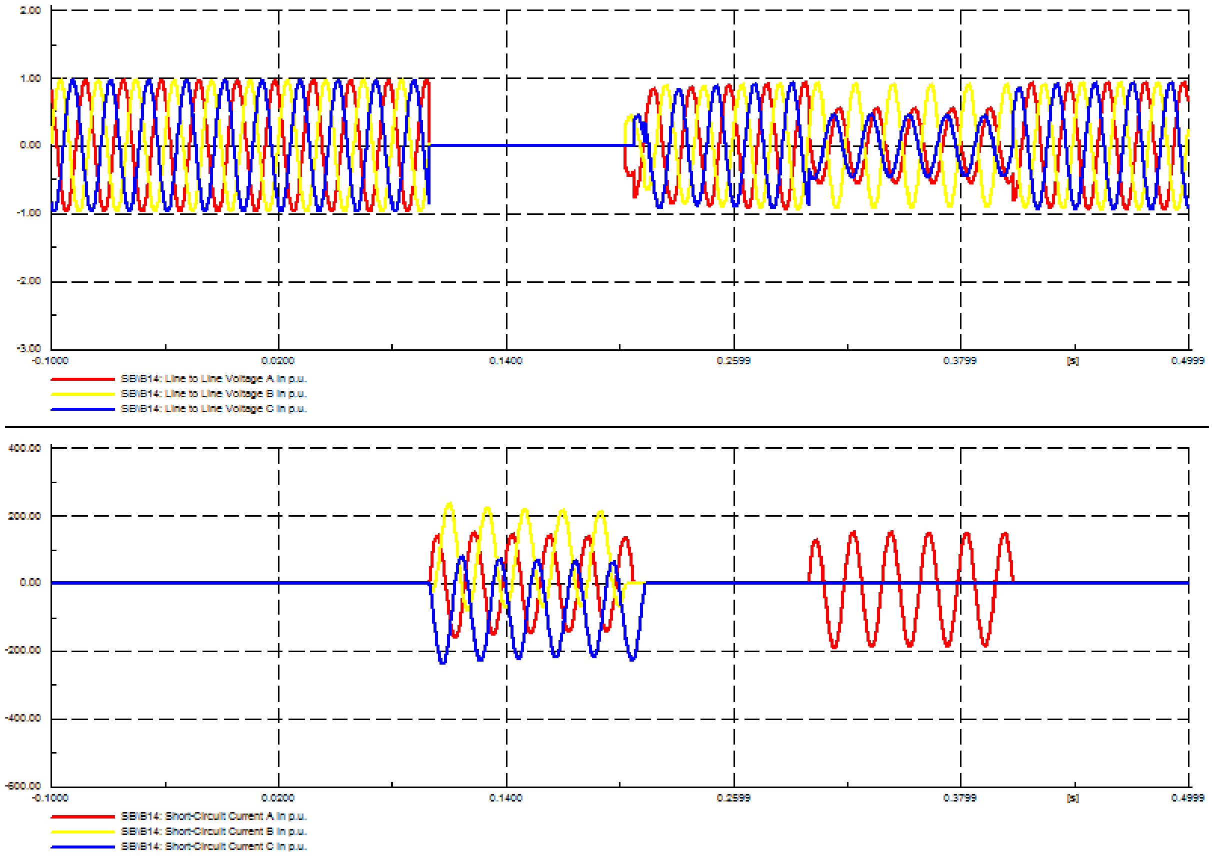


Figure 4. 25 Voltage and current wave form during 3ph and LG fault at bus 14 with DG

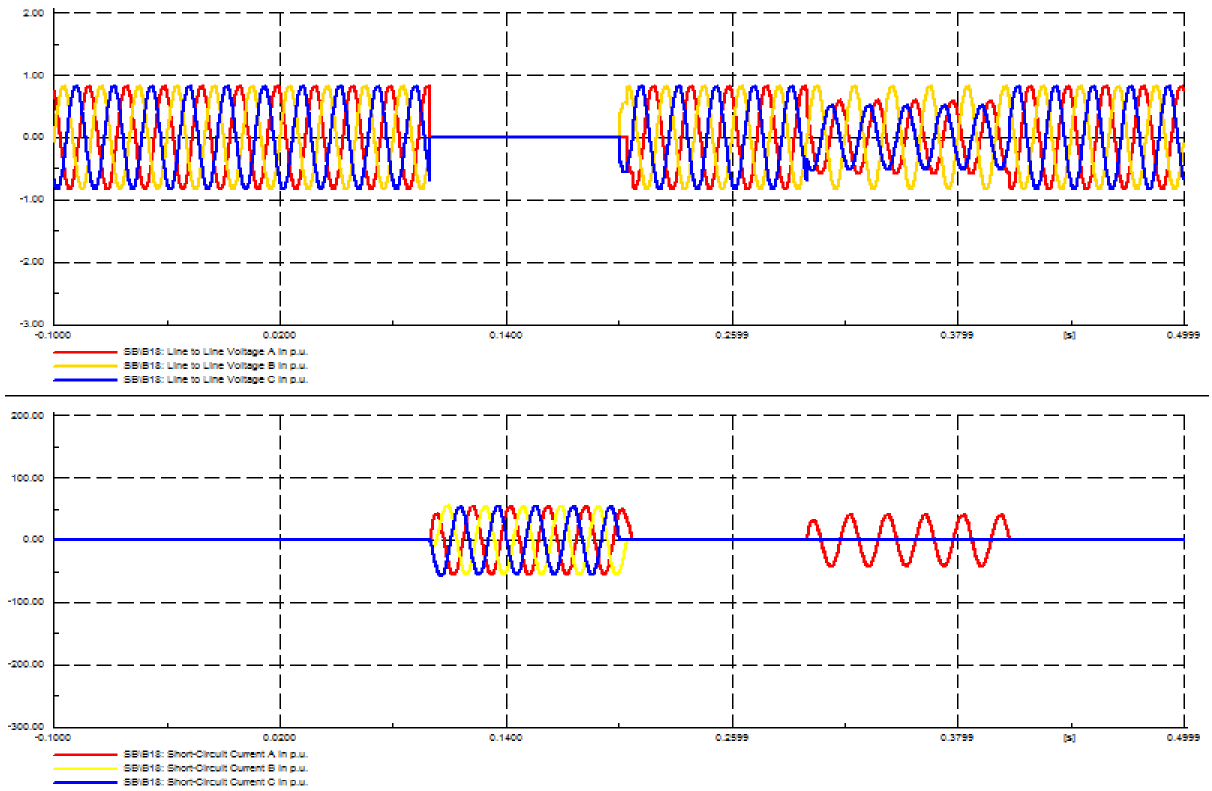


Figure 4. 26 Voltage and current wave form during 3ph and LG fault at bus 18 without DG

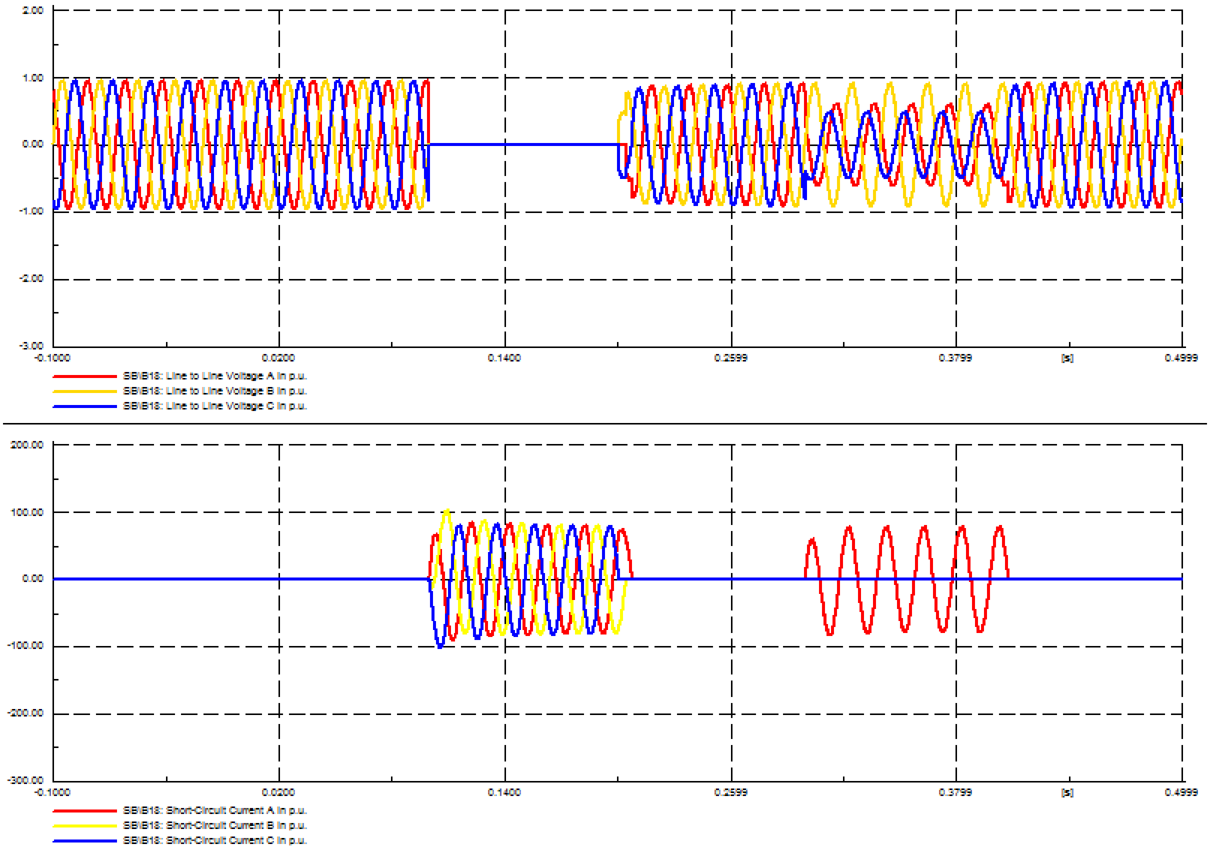


Figure 4. 27 Voltage and current wave form during 3ph and LG fault at bus 18 with DG

4.6.6 Impact of DG on Protection Devices

Investigation on some protection issues involving DG was carried out on the developed radial system model based on protection coordination. Types of over-current protective devices coordination include fuse-fuse coordination, fuse-relay coordination and relay-relay coordination. Here, to investigate the impact of DG integration on protection coordination of radial distribution system, relay-relay coordination had been chosen because the emphasis is on the feeder although the primary of the substation transformer is ideally protected with a fuse. Also DG protection or its isolation techniques are above the scope of this thesis.

The aim is to determine the impact of DG integration on coordination of over-current relays in a radial distribution network. It is widely documented that in radial networks, selectivity of fault protection is achieved through time-current coordination of over-current relays. This is because for a particular fault, all the relays connected in the radial feeder see the fault current but are made to operate at different times. The coordination is based on the fact that the relay closest to the fault (primary relay) sees the largest fault current than those farther away (backup relays). Selection of different time current characteristics in the relay settings is the means of realising coordination.

The feeder SEB-12 of Sebeta-I substation has only one relay which is found at the outlet of the feeder with CT ratio ranges from 400-800A/1A. For seek of investigation of the impact of DG integration on protection coordination of the protective devices, here seven relays were added to the utility relay and in total eight relays were used. Based on equation 3.14 the current transformer setting has been determined for the eight instrument transformers. The setting exported from the DIgSILENT power factory simulation software is as shown in table 4.12. To ensure effective protection of the feeder, eight GE Alstom KCCG142-1A overcurrent relays with inverse time characteristics are chosen from the DIgSILENT PowerFactory 15.1.7 global library. All relay models perform Inverse Definite Minimum Time (IDMT) and Definite Time (DT) or Instantaneous functions. Assuming Plug Setting (PS) of relay 14 (R14) =100% and time multiplier setting of relay 14 (TD_{14}) = 0.025, the operating time of relay 14 (R14) was determined from equation 3.18 which was found to be 0.2836763s. Taking the coordination time interval of 0.3s which is standard the operating time of relay 13 (R13) became 0.5836763s. Then the time dial of relay 13 (R13) was determined from equation 3.19. The procedure is continued in the same way up to the utility relay that is the relay Ru which its operating time was determined to be 2.3836763s.

Table 4. 12 Instrument Transformers Setting

Protection Device	Location	Branch	Manufacturer	Model	CT	Slot	Ratio (pri.A/sec.A)
Ru	SB/B	L1	Alstom	KCGG142-1A	CTU	Ct-3p	800A/1A
					CTU	Ct-Io	800A/1A
R3	SB/B3	L3	Alstom	KCGG142-1A	CT3	Ct-3p	800A/1A
					CT3	Ct-Io	800A/1A
R5	SB/B5	L5	Alstom	KCGG142-1A	CT5	Ct-3p	800A/1A
					CT5	Ct-Io	800A/1A
R7	SB/B7	L7	Alstom	KCGG142-1A	CT7	Ct-3p	800A/1A
					CT7	Ct-Io	800A/1A
R9	SB/B9	L9	Alstom	KCGG142-1A	CT9	Ct-3p	800A/1A
					CT9	Ct-Io	800A/1A
R12	SB/B12	L12	Alstom	KCGG142-1A	CT12	Ct-3p	500A/1A
					CT12	Ct-Io	500A/1A
R13	SB/B13	L13	Alstom	KCGG142-1A	CT13	Ct-3p	500A/1A
					CT13	Ct-Io	500A/1A
R14	SB/B14	L14	Alstom	KCGG142-1A	CT14	Ct-3p	400A/1A
					CT14	Ct-Io	400A/1A

Table 4. 13 Over Current relay Setting

Protection Device	Location	Branch	Manufacturer	Model	Stage (Phase)	Current [pri.A]	Current [sec.A]	Current [p.u.]	Time	Characteristic	Directional
RU	SB/B	L1	Alstom	KCGG142-1A	I>/t>	800.00	1.00	1.00	0.200	No. 1 -- SI30xDT (Standard Inverse)	None
					I>>/t>>	25600.00	32.00	32.00	0.01	Definite	None
R3	SB/B3	L 4	Alstom	KCGG142-1A	I>/t>	800.00	1.00	1.00	0.175	No. 1 -- SI30xDT (Standard Inverse)	None
					I>>/t>>	10728.00	13.41	13.41	0.01	Definite	None
R5	SB/B5	L 6	Alstom	KCGG142-1A	I>/t>	800.00	1.00	1.00	0.150	No. 1 -- SI30xDT (Standard Inverse)	None
					I>>/t>>	9112.00	11.39	11.39	0.01	Definite	None
R7	SB/B7	L 8	Alstom	KCGG142-1A	I>/t>	800.00	1.00	1.00	0.125	No. 1 -- SI30xDT (Standard Inverse)	None
					I>>/t>>	6792.00	8.49	8.49	0.01	Definite	None
R9	SB/B9	L 10	Alstom	KCGG142-1A	I>/t>	800.00	1.00	1.00	0.100	No. 1 -- SI30xDT (Standard Inverse)	None
					I>>/t>>	4632.00	5.79	5.79	0.01	Definite	None
R12	SB/B12	L 13	Alstom	KCGG142-1A	I>/t>	500.00	1.00	1.00	0.075	No. 1 -- SI30xDT (Standard Inverse)	None
					I>>/t>>	4125.00	8.25	8.25	0.01	Definite	None
R13	SB/B13	L 14	Alstom	KCGG142-1A	I>/t>	500.00	1.00	1.00	0.050	No. 1 -- SI30xDT (Standard Inverse)	None
					I>>/t>>	3965.00	7.93	7.93	0.01	Definite	None
R14	SB/B14	L 15	Alstom	KCGG142-1A	I>/t>	400.00	1.00	1.00	0.025	No. 1 -- SI30xDT (Standard Inverse)	None
					I>>/t>>	3636.00	9.09	9.09	0.01	Definite	None

Appendix D shows the operating time of all relays in each study case during three phase and single phase to ground faults. The instantaneous tripping of all the relays is assumed to be 0.01s when the fault current reaching the maximum fault current at each bus for all corresponding relays at the selected buses as shown in table 4.13.

Figure 4.28 depicts the balanced and positive sequence load flow analysis before DG injection with the location of the relays are illustrated in green. In figure 4.29 the same network was analysed with DG integrated at bus 14 with the location of over current relays are also seen in green. In both cases all the relays are not tripping as expected during steady state condition since the branch currents are below the operation currents of the relays.

However, during DG integration the reverse power flow was seen without affecting the operation of the relays at steady state condition. In case of faulty condition the integration of DG affects the operation of the relays by causing a little increment of fault current. To be noted that if distributed generator (DG) is sized and placed properly the negative impact of DG is not due to increment of fault currents rather the reverse power flow in the network causes the islanding of DG and all loads downstream of DG.

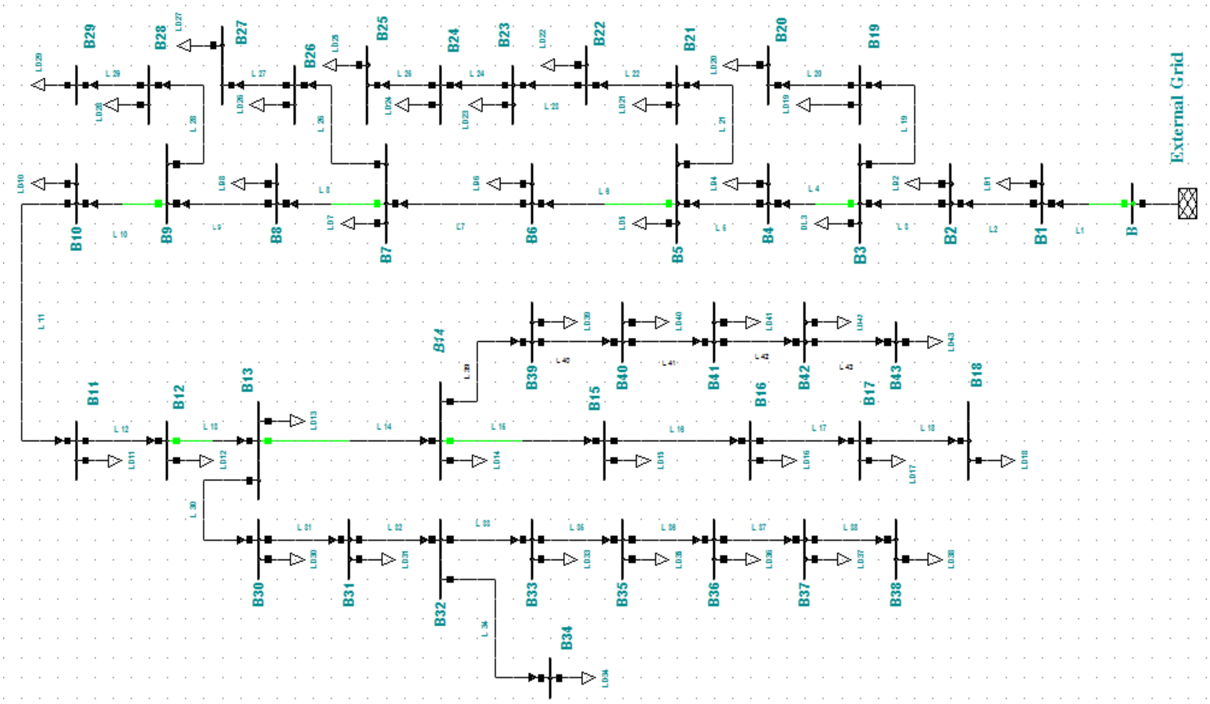


Figure 4. 28 Base case balanced and positive sequence load flow analysis with Protection coordination

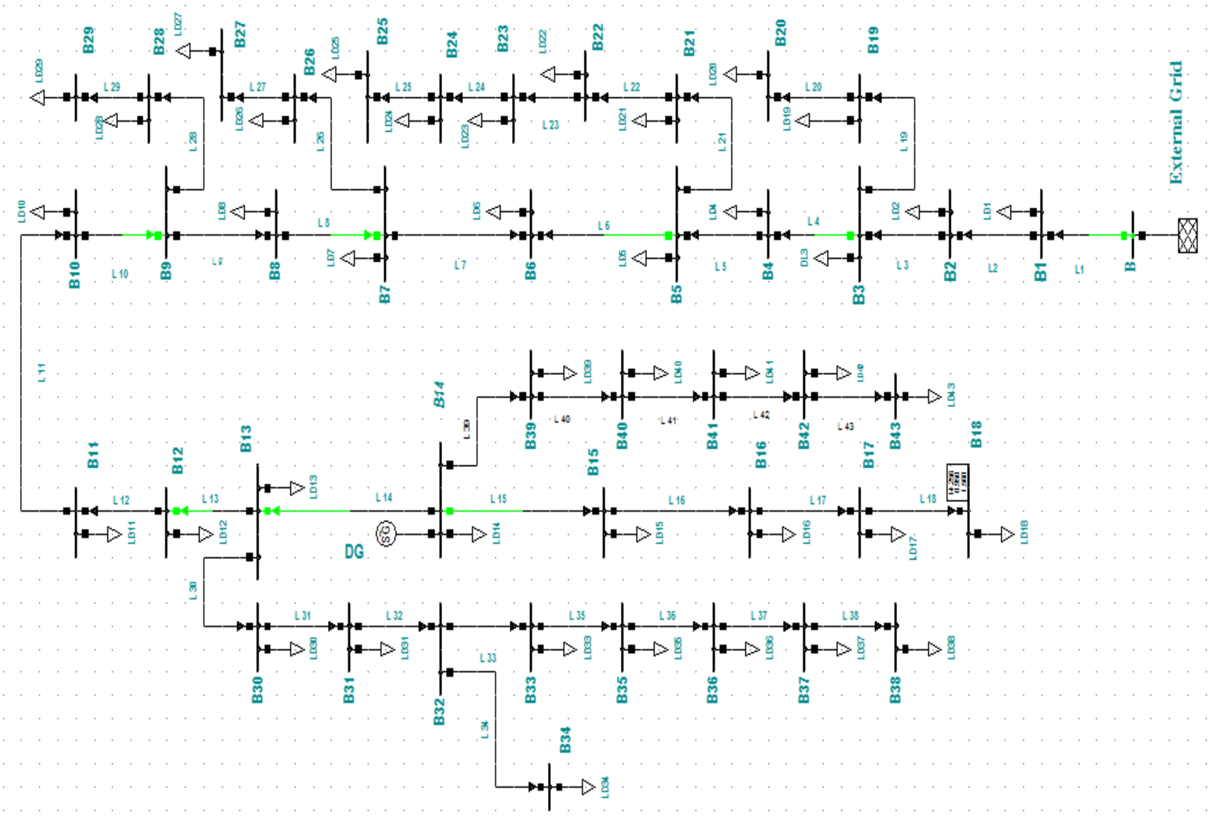


Figure 4. 29 Balanced and positive sequence load flow analysis after DG integration with Protection coordination

The time-overcurrent plot of the relays are shown in figure 4.30. All the relays perform inverse time-current characteristic and definite time with instantaneous tripping at 0.03s. The investigation of the impacts of DG on protection coordination of the relay was performed by making short circuit analysis on some selected buses. The selection of the buses was made by taking into consideration as for the fault at the buses far-off the source bus, the utility relay at the source bus see the fault and try to operate in case of failure of all the downstream relays since the utility relay Ru is set up to cover the whole line of the feeder.

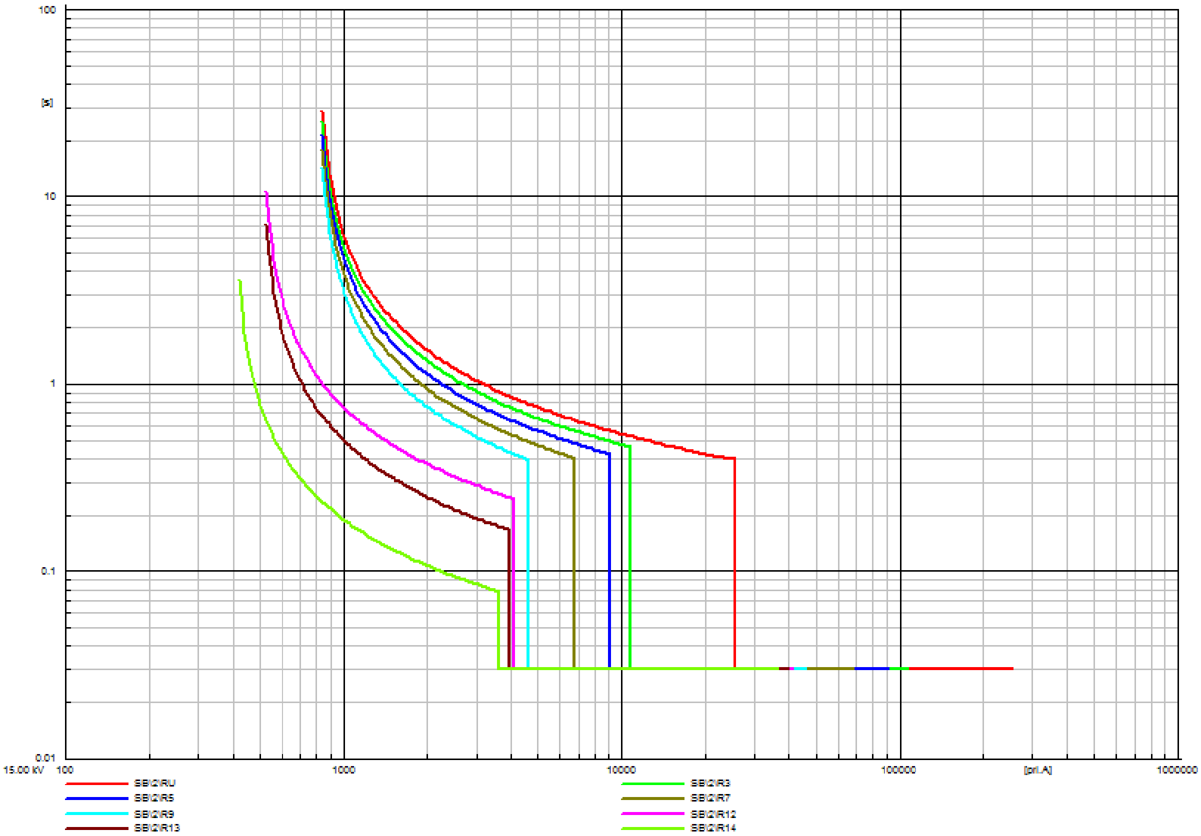


Figure 4. 30 Time-overcurrent plot of the relays

4.6.6.1 Impact of DG during Three Phase Fault Analysis

Three phase short circuit at Bus 18

Figure 4.31 shows that a three phase fault on bus 18 in the absence of DG is cleared by R14 in 0.094s. The rest of the relay performs their back up protection according to their sequence of operation for instance R13 clear the fault in 0.215s, R12 in 0.322s if R14 fail to trip and so on. But with DG connected the fault is cleared by the instantaneous element of R14 in 0.030s. However, the clearance of the fault by R13 in 0.250s leads to the islanding of DG and loads

LD_{39} through LD_{43} as shown in figure 4.32. Here, besides, the connection of DG leads to time delay (protection blinding) of all upstream relays and nuisance tripping of R14.

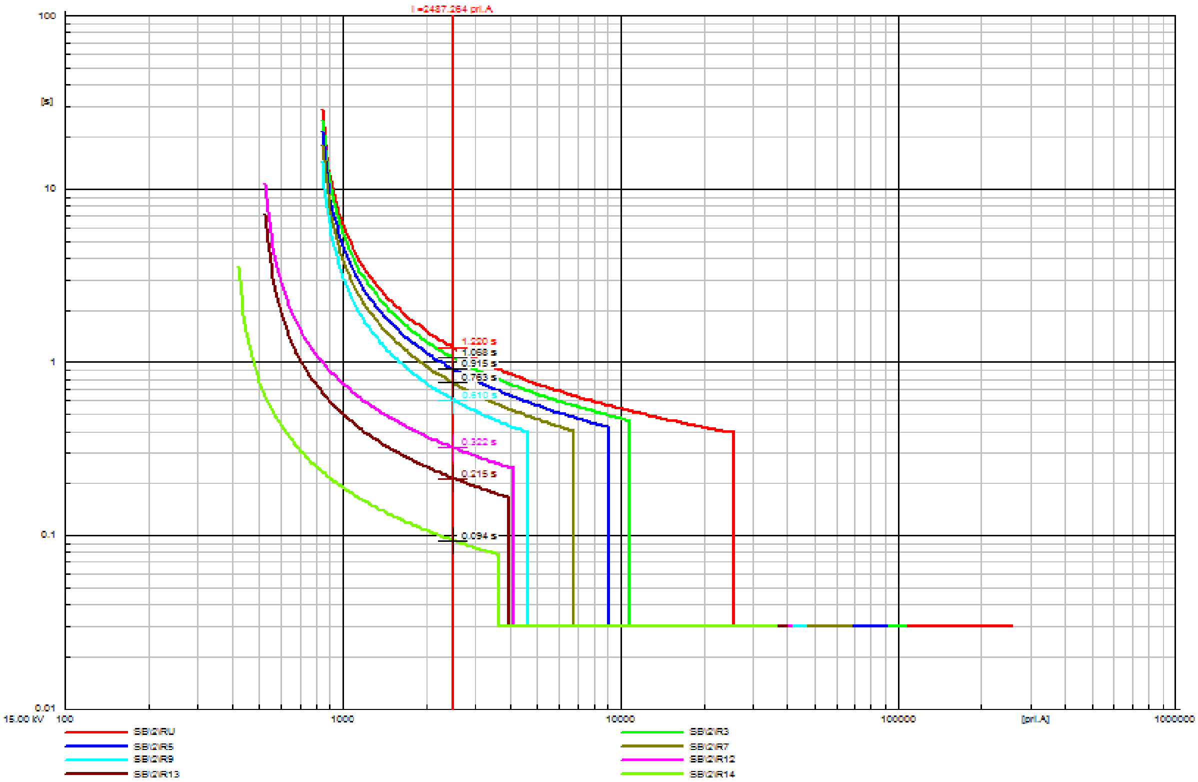


Figure 4. 31 Overcurrent relay coordination during three phase fault at bus 18 without DG

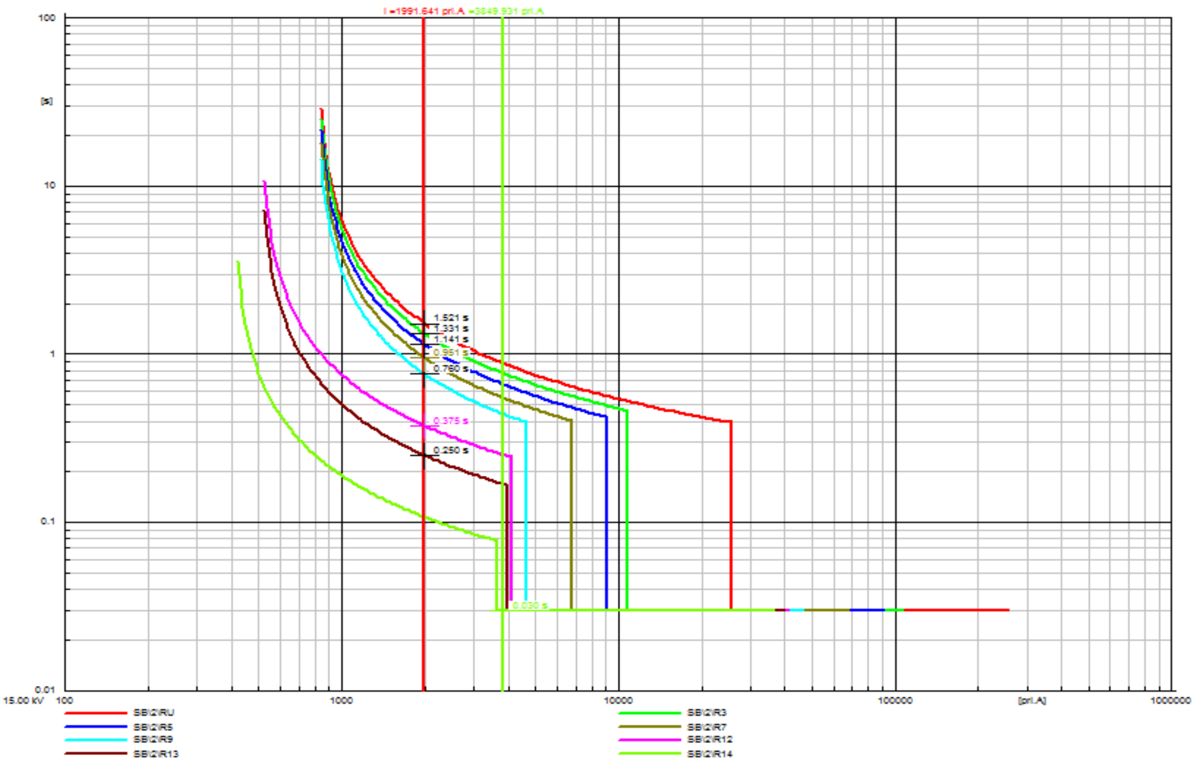


Figure 4. 32 Overcurrent relay coordination during three phase fault at bus 18 with DG

Three phase short circuit at Bus 38

For the base case – without DG – the three phase fault at bus38 is cleared within 0.296s by R12 and tripping of R9 is followed in 0.543s should R12 fail to trip as shown in Figure 4.33. All the relays upstream of R9 are also see the fault and ready to trip according to their sequence of coordination. The relays R14 and R13 are not tripping as expected. But when DG is connected R13 trips in 0.235s making islanding of DG and all loads downstream of bus 13, and R12 clear the fault in 0.331s and R9 trips in 0.634s should R12 fail to trip as depicted in figure 4.34. Again, here the protection coordination is affected with islanding problem and delay of time to operate after the integration of DG.

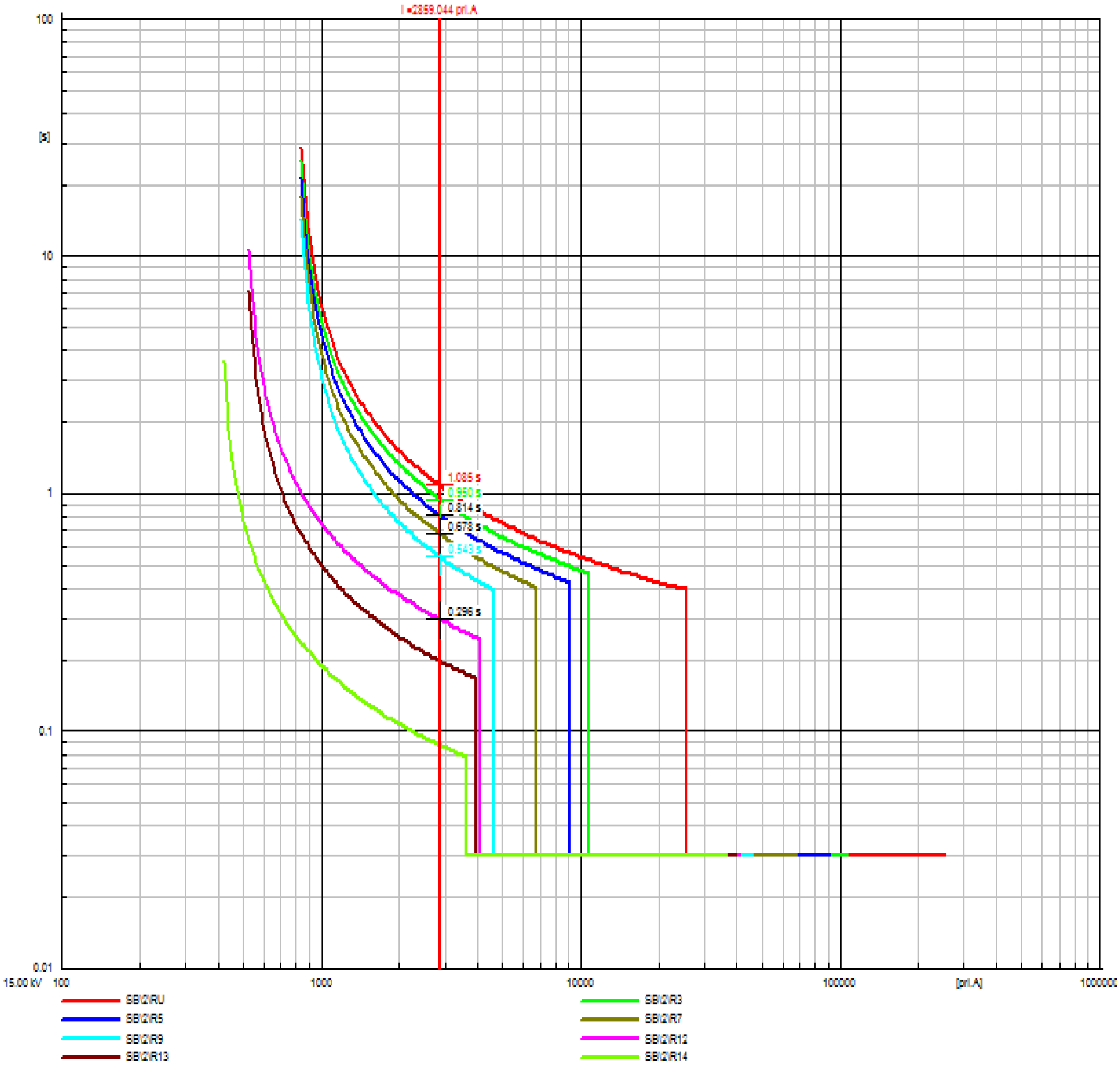


Figure 4. 33 Protection relay coordination during three phase fault at bus 38 without DG

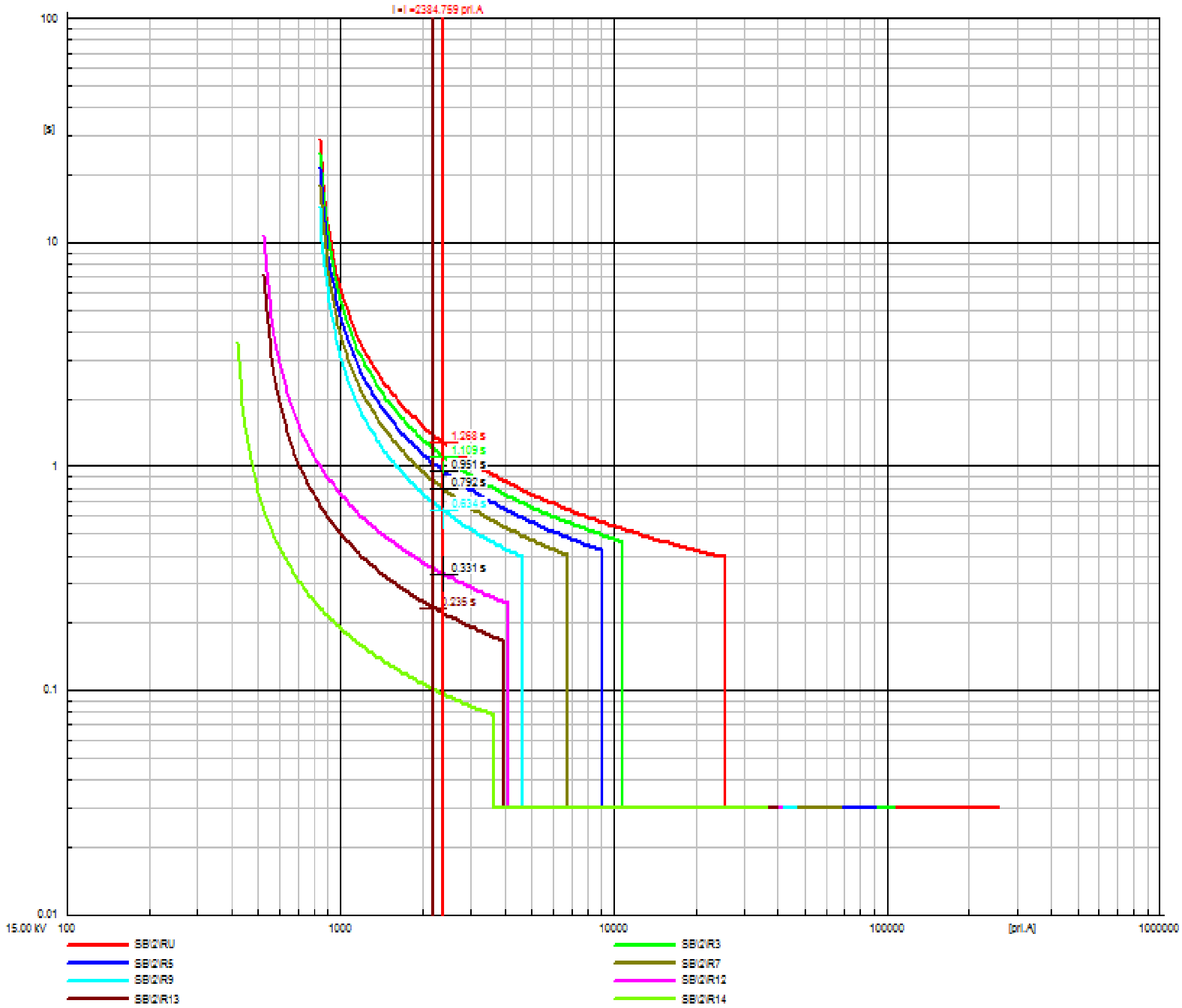


Figure 4. 34 Overcurrent relay coordination during three phase fault at bus 38 with DG

Three phase short circuit at Bus 43

According to Figure 4.35 the time for a three phase fault on the bus 43 to be cleared by R13 is 0.191s and R12 should trip in 0.286s as a backup in case of failure of R13 for the base case. All upstream relays perform their operation in their sequence as expected. But the fault clearing time becomes 0.204s and 0.306s for R13 and R12 respectively with the connection of DG (see Figure 4.36). Also in this case DG connection has negative impact on the protection coordination that is delay of time to trip (protection blinding) for all the relays except R14. Besides, tripping of R13 during DG injection makes islanding of DG and all loads downstream of bus 13. Once more the injection of DG makes the islanding problem which shows the negative impact of DG on protection coordination. To mitigate the islanding problem of DG, automatic disconnection of DG during fault is important. Here, R14 is not tripping in both cases as required.

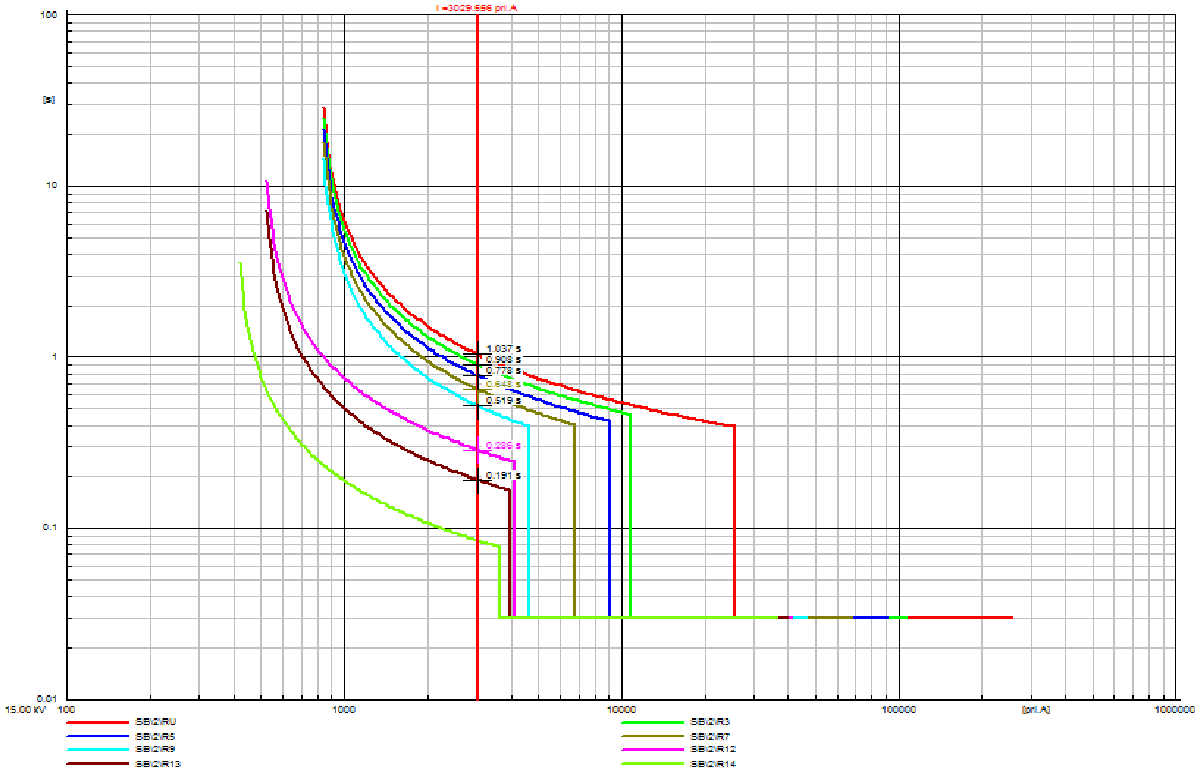


Figure 4. 35 Overcurrent relay coordination during three phase fault at bus 43 without DG

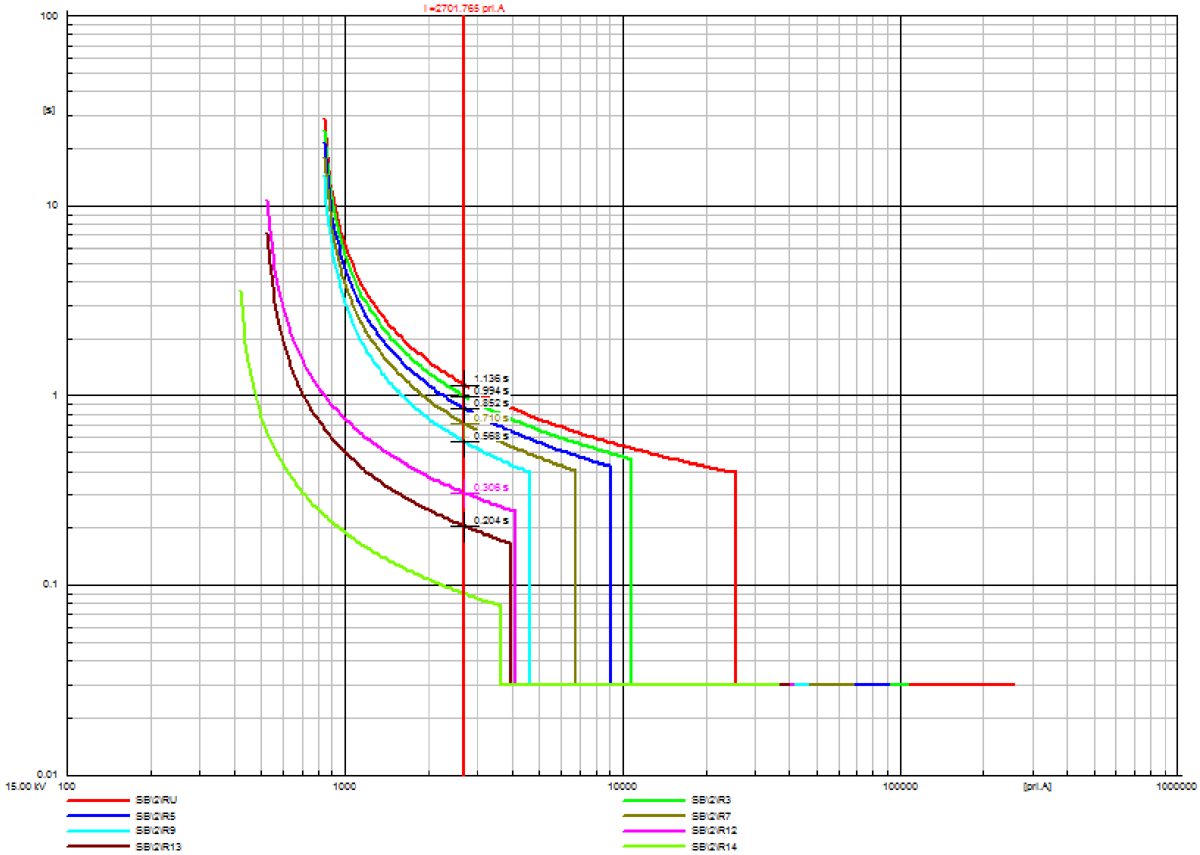


Figure 4. 36 Overcurrent relay coordination during three phase fault at bus 43 with DG

Three phase short circuit at Bus 14

Ordinarily, a three phase fault at bus 14 is cleared by R13 in 0.173s and R12 backup the protection, tripping in 0.259s if R13 fail to trip and so for all the upstream relays as contained in Figure 4.37. Figure 4.38 shows that connection of DG results to a fault clearing time of 0.173s by R13 and 0.259s by R12 and the same thing happen for the other relays as previous. Therefore, here, the presence of DG has no negative impact on protection coordination when three phase fault occur at the point of connection (POC) of DG.

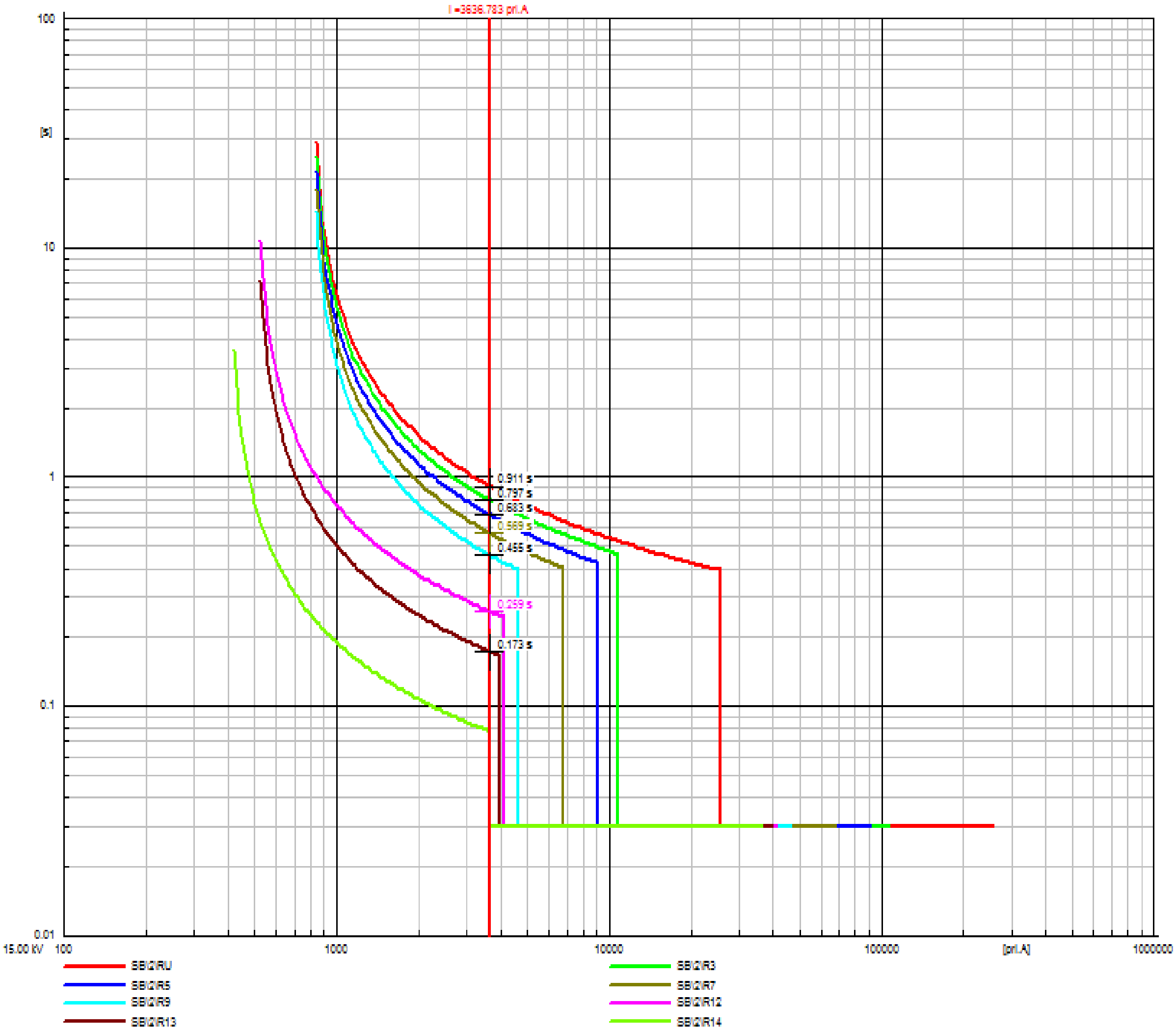


Figure 4. 37 Overcurrent relay coordination during three phase fault at bus 14 without DG

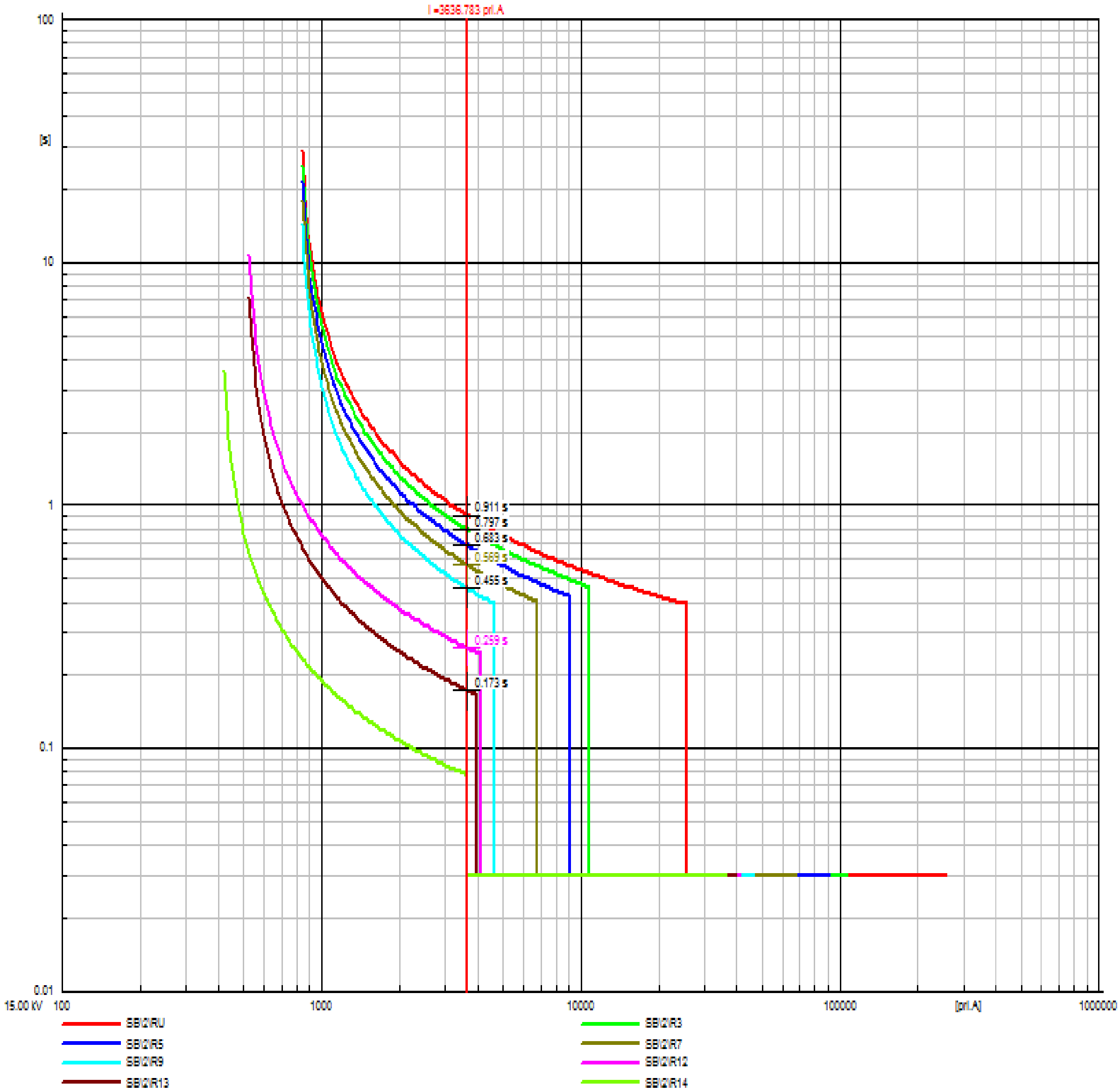


Figure 4. 38 Overcurrent relay coordination during three phase fault at bus 14 DG

Three phase short circuit at Bus 8

Here, R7 clears a three phase fault in 0.456s and R5 backup the fault clearance by tripping in 0.547s in the absence of DG as depicted in figure 4.39. With the connection of DG the fault clearing time by all the relays up stream of the fault are the same as before DG connection. However, R13, R12 and R9 clears the fault contribution due to DG (reverse power flow) in 0.191s, 0.286s and 0.518s respectively with the resultant islanding of the DG and all loads downstream of the corresponding relays as shown in figure 4.40. In this case also the DG injection causes the problem of islanding and nuisance tripping of all relays downstream of fault point.

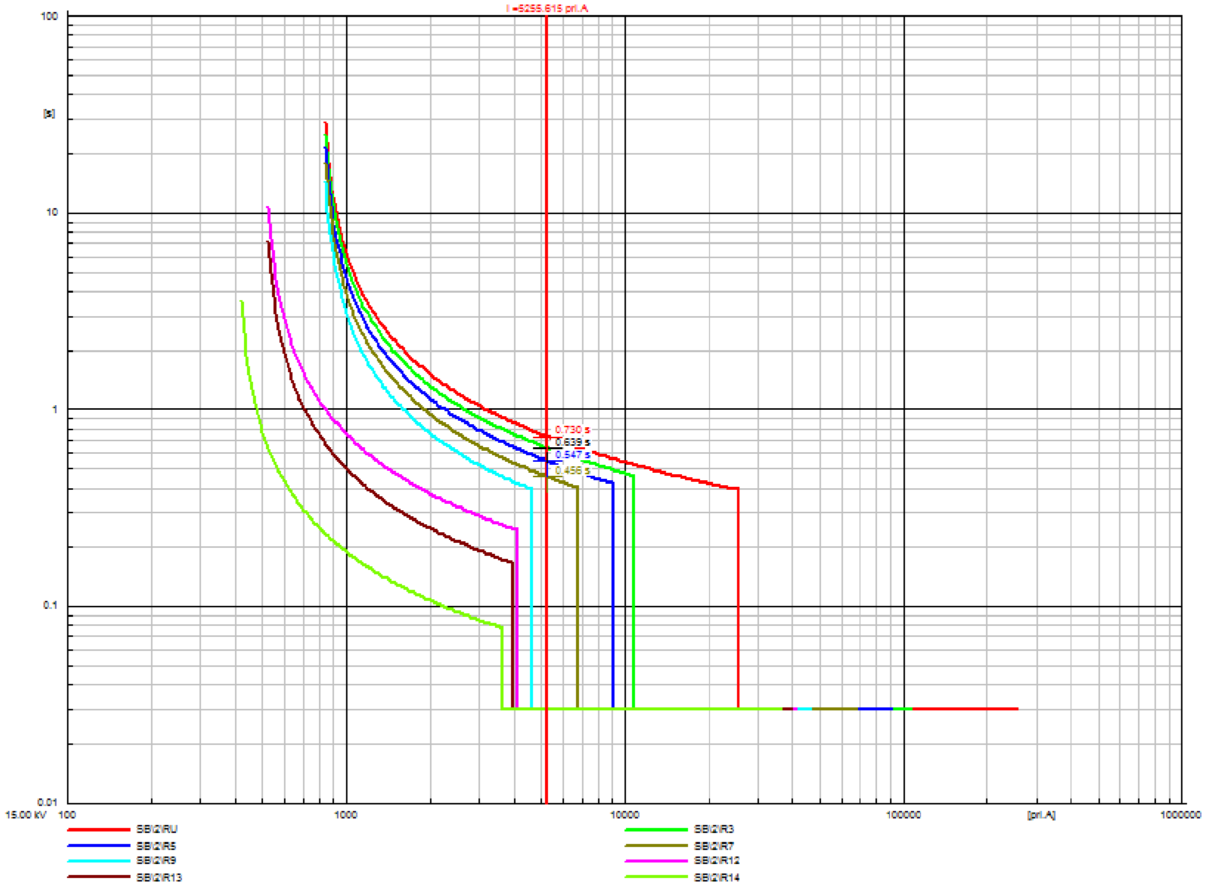


Figure 4. 39 Overcurrent relay coordination during three phase fault at bus 8 without DG

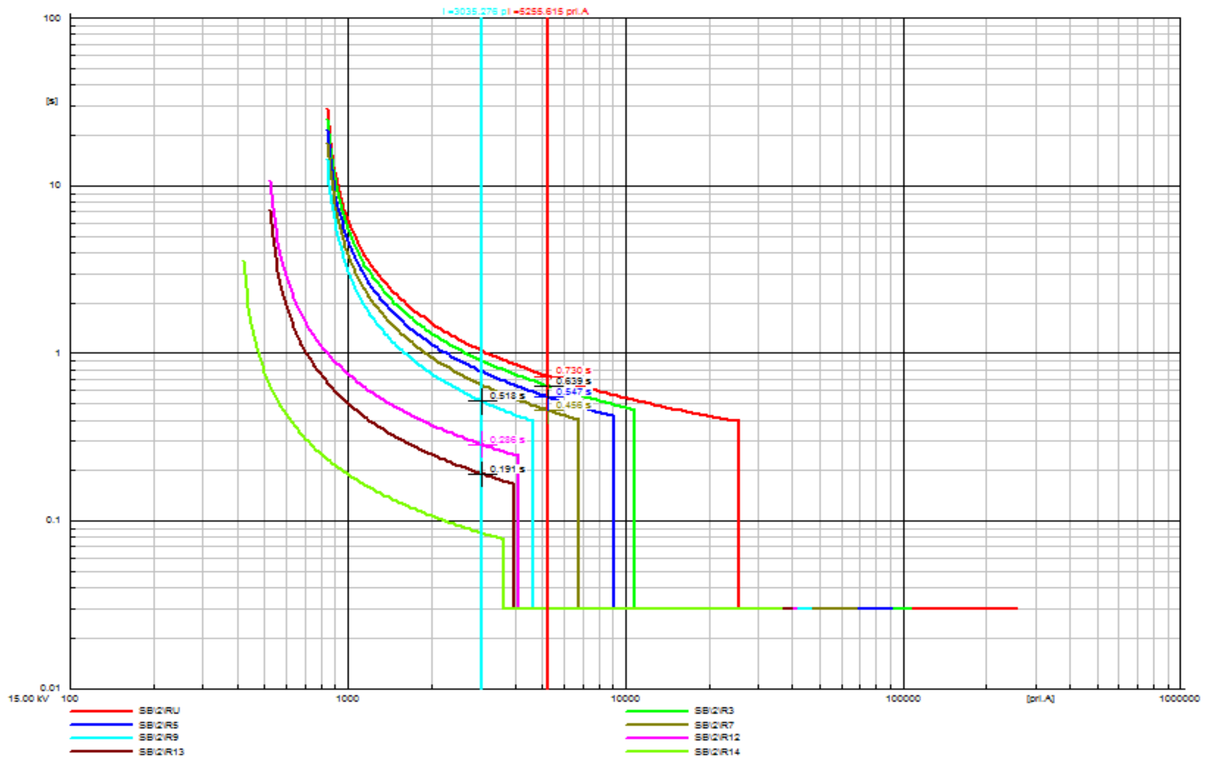


Figure 4. 40 Overcurrent relay coordination during three phase fault at bus 8 with DG

Three phase short circuit at Bus 4

A three phase fault occurring at bus 4 is cleared by R3 in 0.474s and Ru clear the fault in 0.542s in case of failure of R3 in the base case scenario as shown in figure 4.41. After DG injection the fault clearing time is also the same as before for R3 and Ru. But when DG is connected, due to reverse power flow, the occurrence of this fault causes R13, R12, R9 and R7 to isolate the DG and downstream loads – a case of islanding – in 0.218s, 0.327s, 0.623s, 0.778s and 0.934s respectively as depicted in figure 4.42. Therefore, in this case also the problem is islanding of DG and downstream loads, and nuisance tripping of relays.

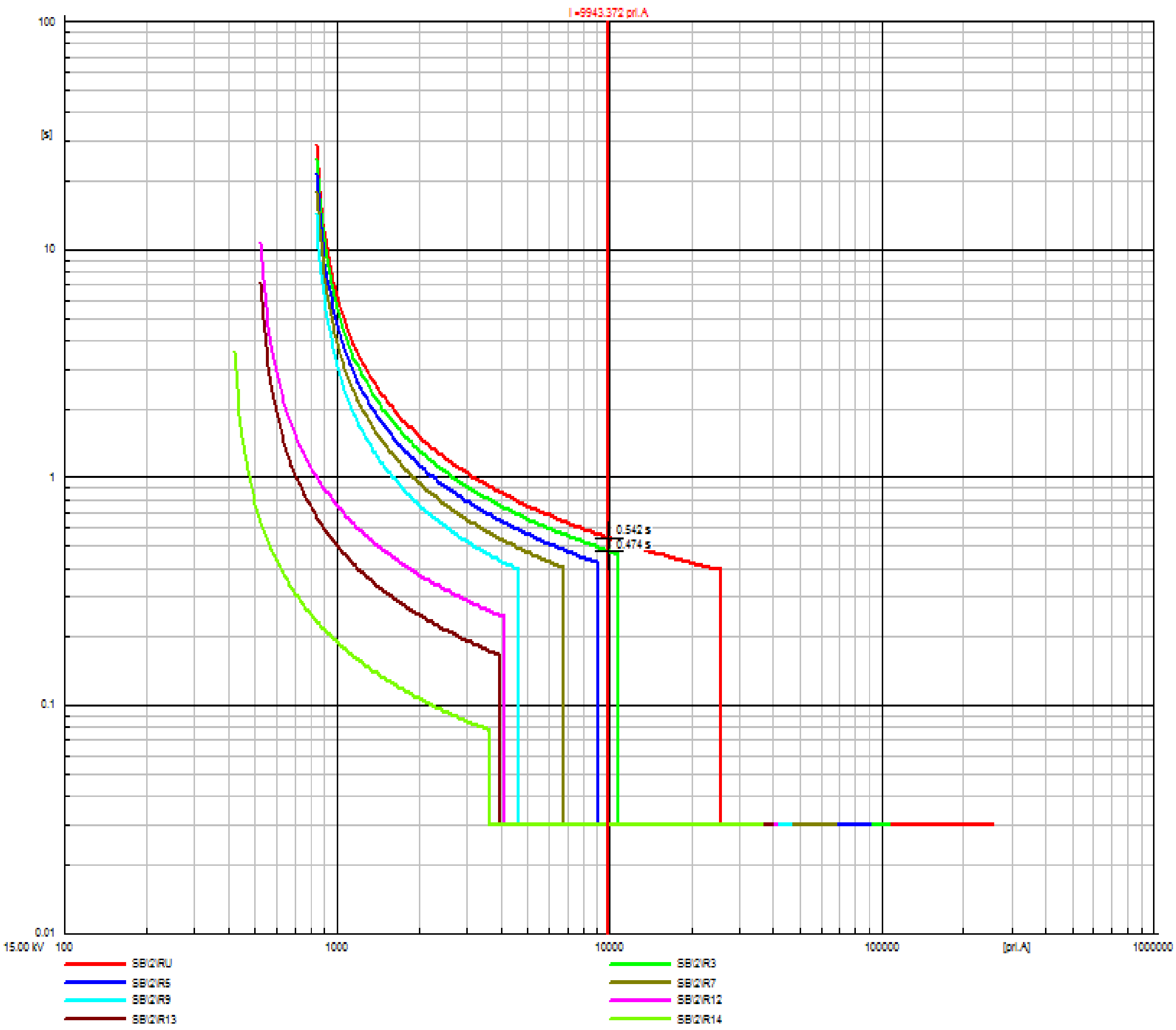


Figure 4. 41 Overcurrent relay coordination during three phase fault at bus 4 without DG

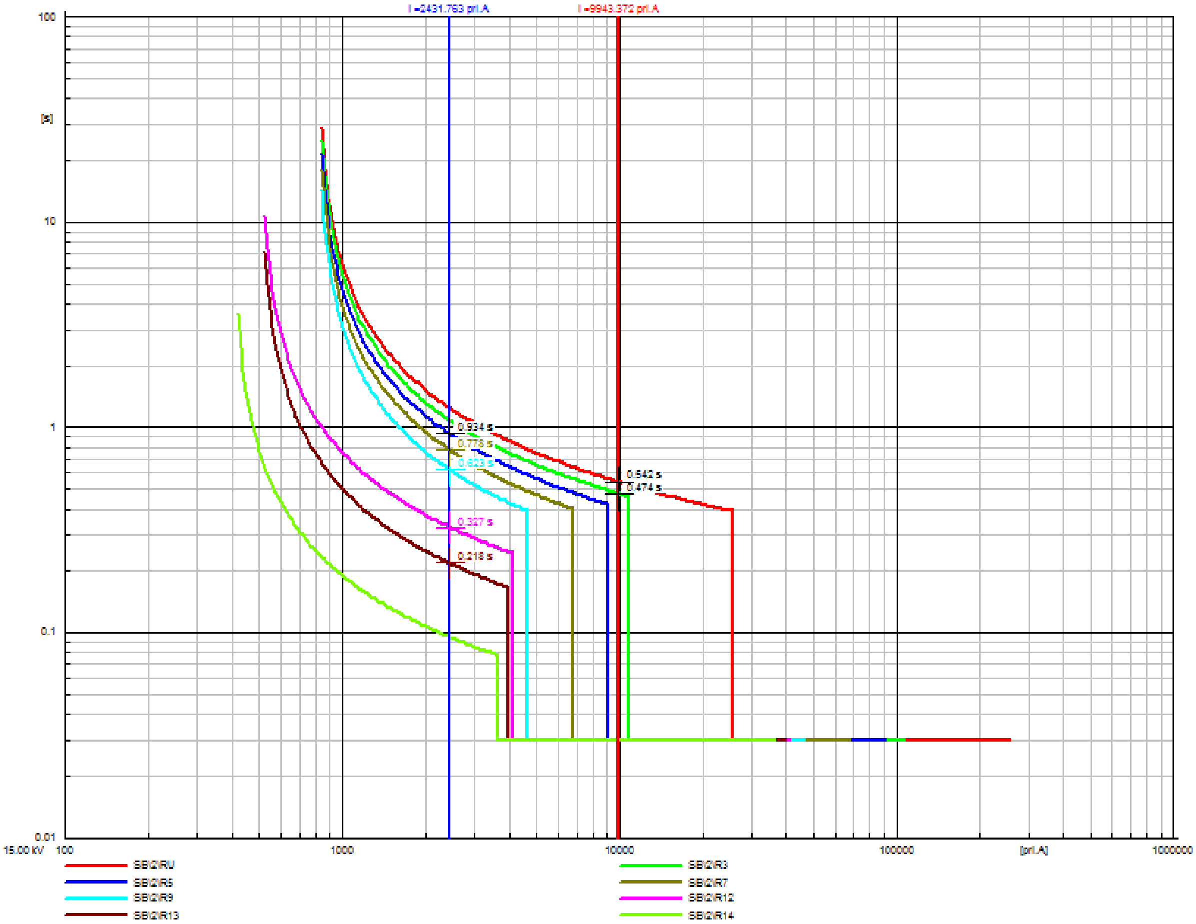


Figure 4. 42 Overcurrent relay coordination during three phase fault at bus 43 with DG

4.6.6.2 Impact of DG during Single Phase to Ground (LG) Fault.

Single phase to ground fault at Bus 18

Figure 4.43 shows that a single phase to ground fault on bus 18 in the absence of DG is cleared by R14 in 0.117s and R13 backup R14 to clear the fault in 0.276s. The rest of the relays perform their operation according to the sequence of their set up. But with DG connected the fault clearing time by R14 is reduced to 0.078s and R13 as a backup relay clears the fault in 0.331s should R14 fail to operate which causes islanding of DG and downstream loads, figure 4.44. At this location the connection of DG causes islanding problem and mal-tripping of R14. Apart from this all the relays upstream of the fault point are blinded that is delay in time to trip due to reduction in fault current caused by composite impedance of the system and DG seen from the point of fault occurrence towards the source.

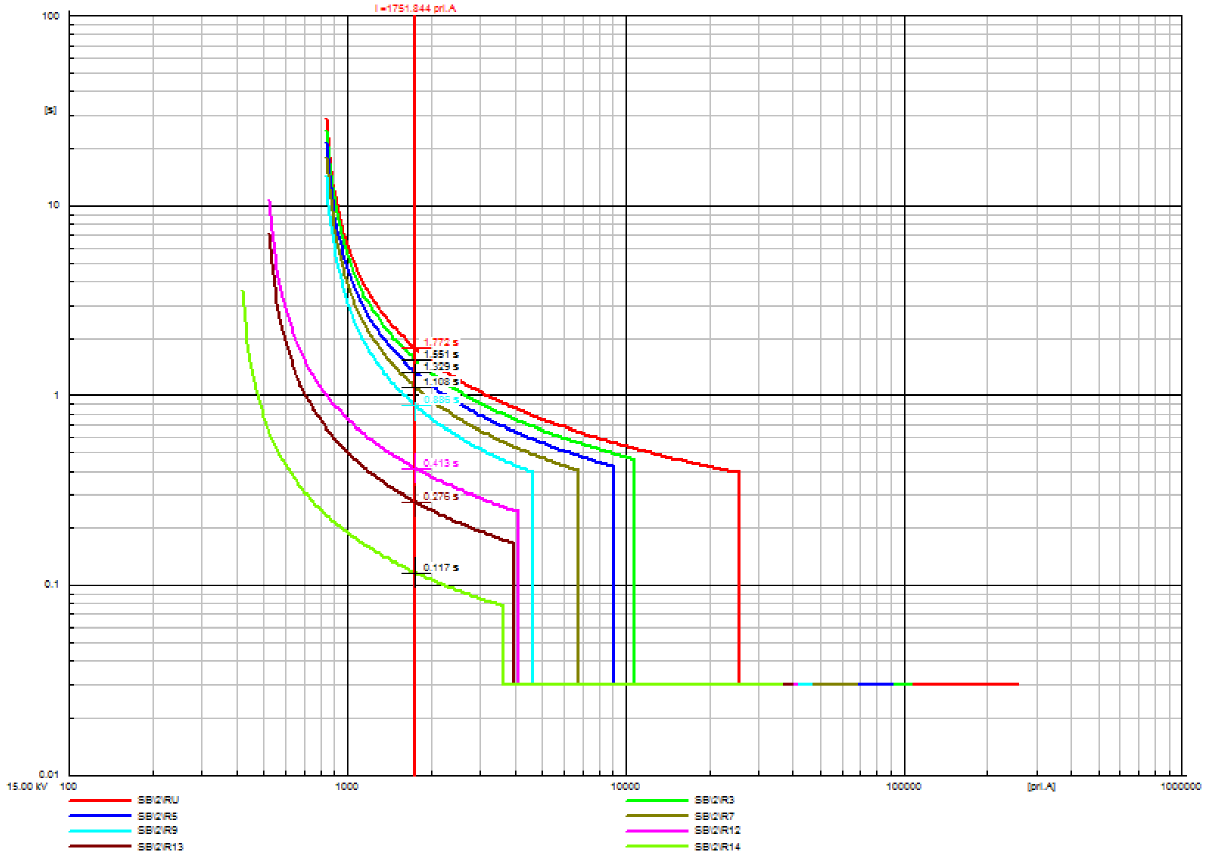


Figure 4. 43 Overcurrent relay coordination during single phase fault at bus 18 without DG

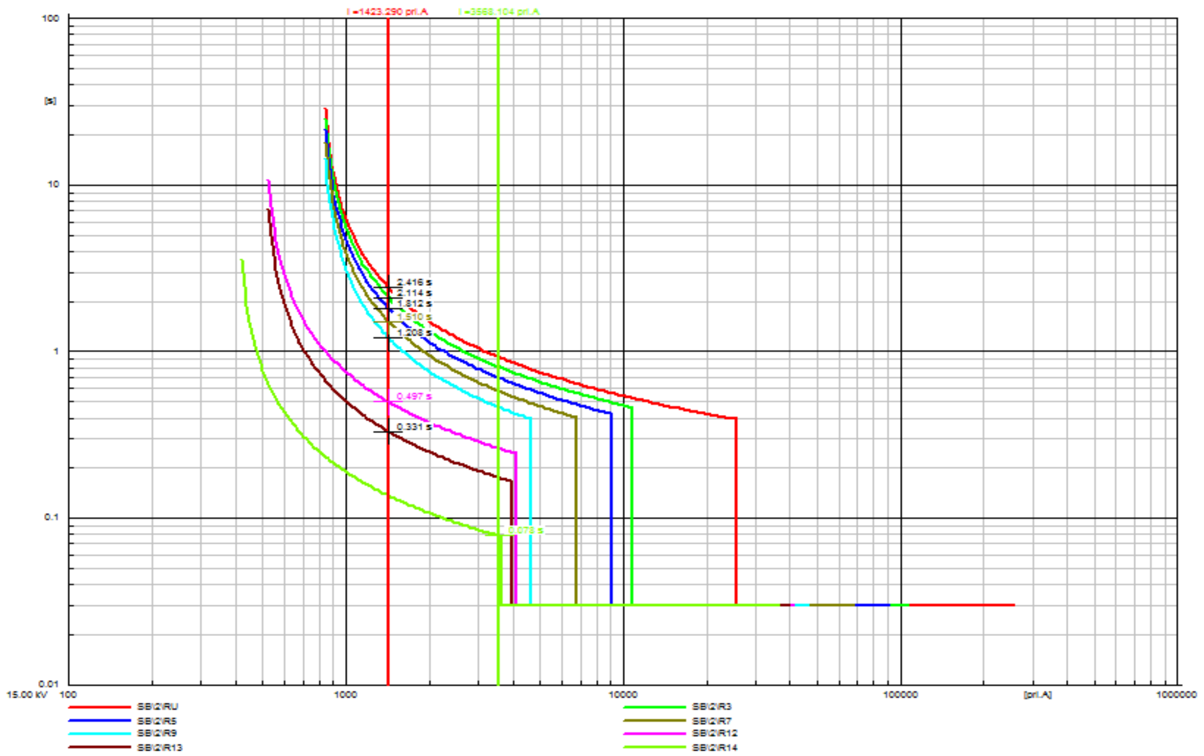


Figure 4. 44 Overcurrent relay coordination during single phase fault at bus 18 with DG

Single phase to ground fault at Bus 38

For the base case – without DG – an earth fault at bus 38 is cleared within 0.381s by R12 and R9 clear the fault in 0.771s in case of failure of R12 and all the relays that follow will trip keeping the sequence of their operation as shown in Figure 4.45. The fault is cleared in 0.428s by R12 followed by R9 in 0.936s should R12 fail to trip which implies protection blinding that is delay in time to trip when DG is connected as shown in Figure 4.46. As well R13 trips in 0.224s making islanding of DG and all loads downstream of DG. In general the integration of DG causes islanding, protection blinding and nuisance tripping problems at this fault location.

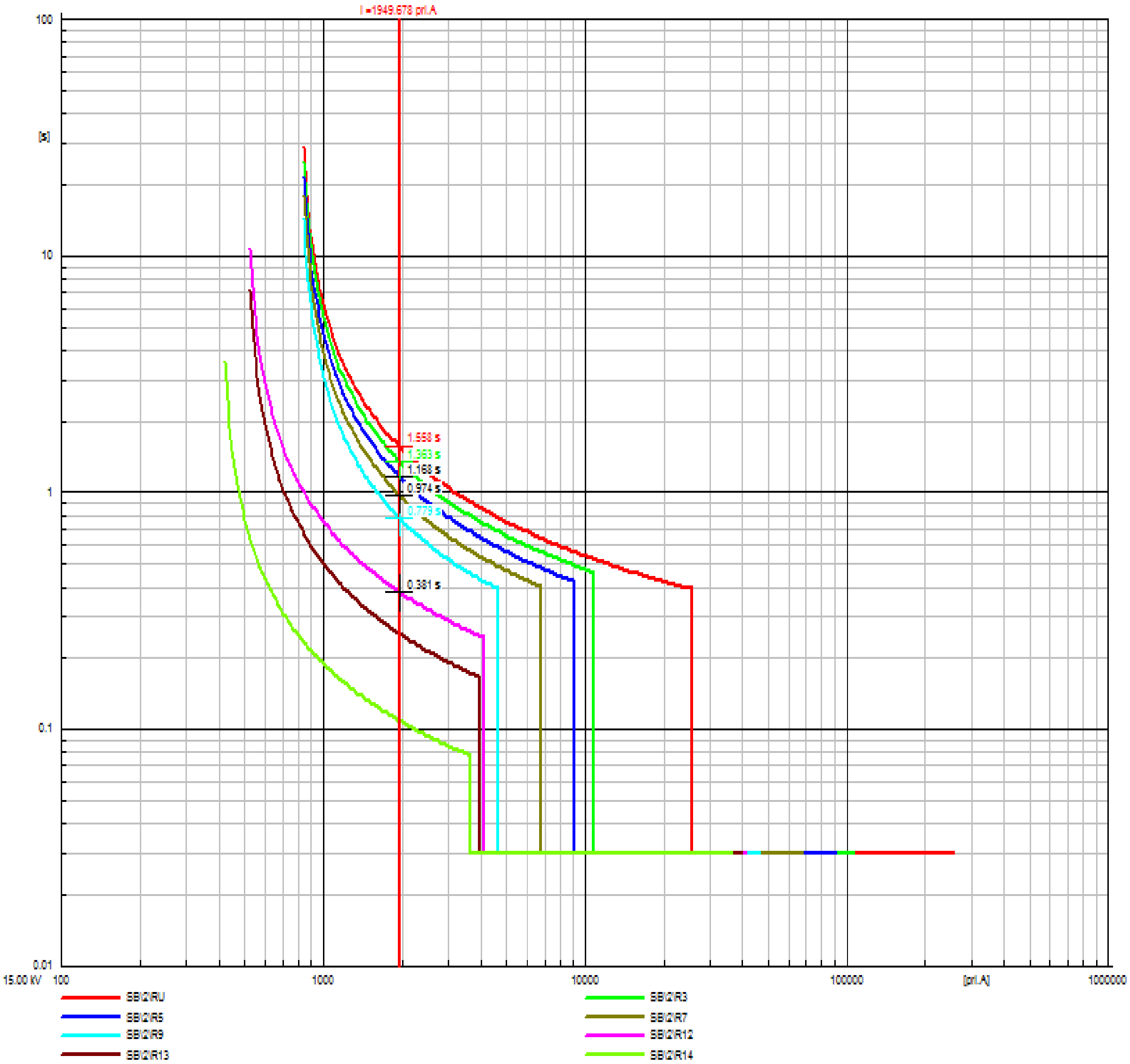


Figure 4. 45 Overcurrent relay coordination during single phase fault at bus 38 without DG

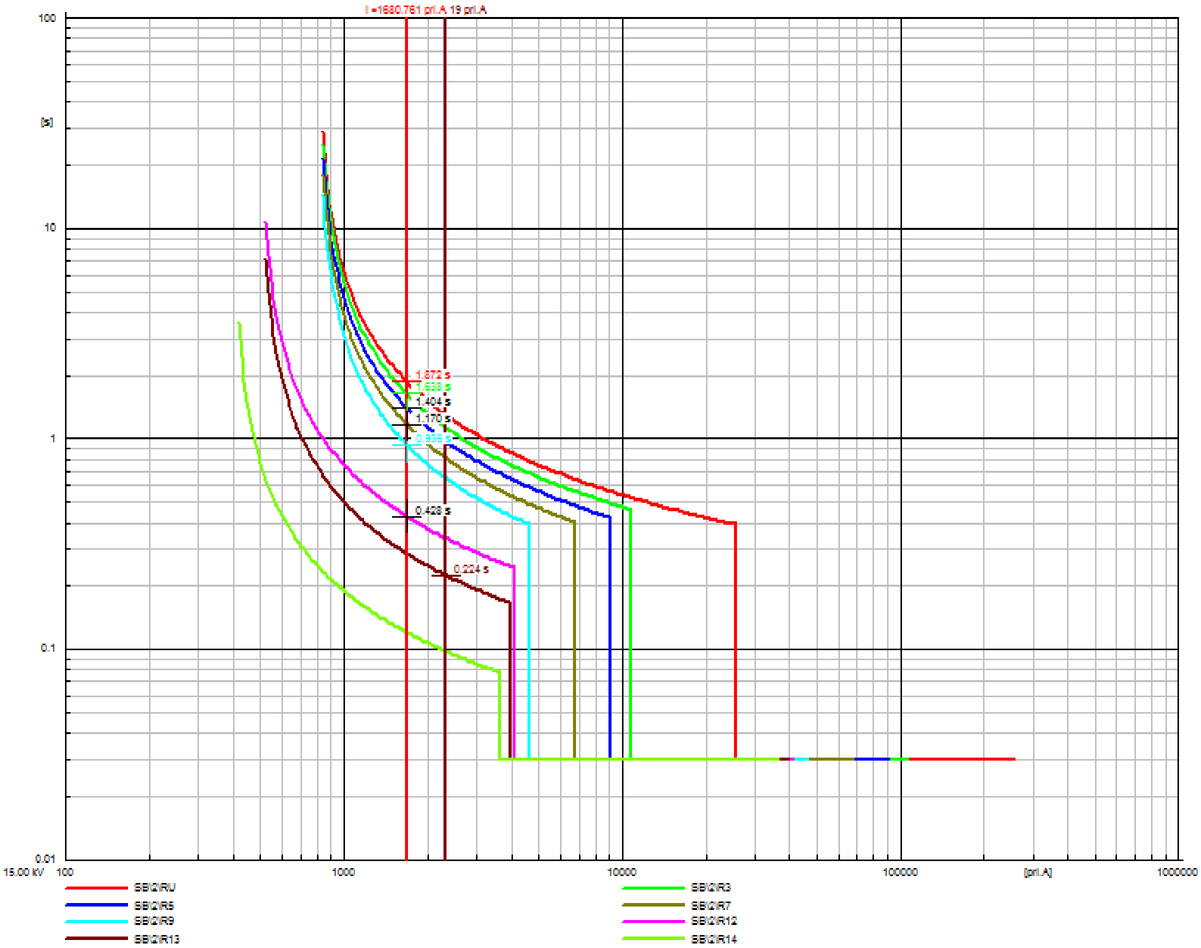


Figure 4. 46 Overcurrent relay coordination during single phase fault at bus 38 with DG

Single phase to ground fault at bus 43

Figure 4.47 illustrates that an earth fault on bus 43 is cleared in 0.243s through with R13 and R12 clear the fault in 0.365s as backup and so for all the upstream relays in the base case. But the fault clearing time becomes 0.245s for R13 and 0.367s for R12 with some increment of fault clearing time due to reduction of fault current at this point (see Figure 4.48). Besides tripping of R13 in 0.245s makes the islanding of DG and all loads downstream of bus 13. In conclusion the integration of DG causes islanding and protection blinding problems at this fault location.

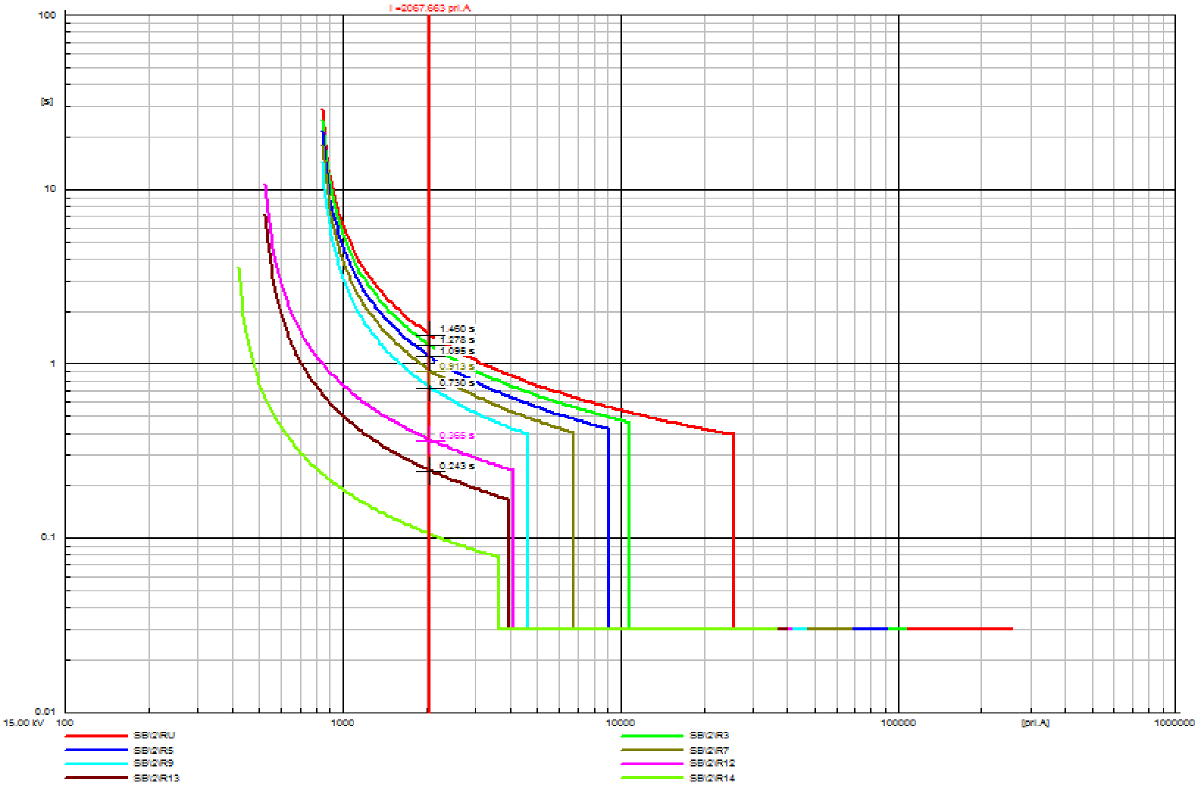


Figure 4. 47 Overcurrent relay coordination during single phase fault at bus 43 without DG

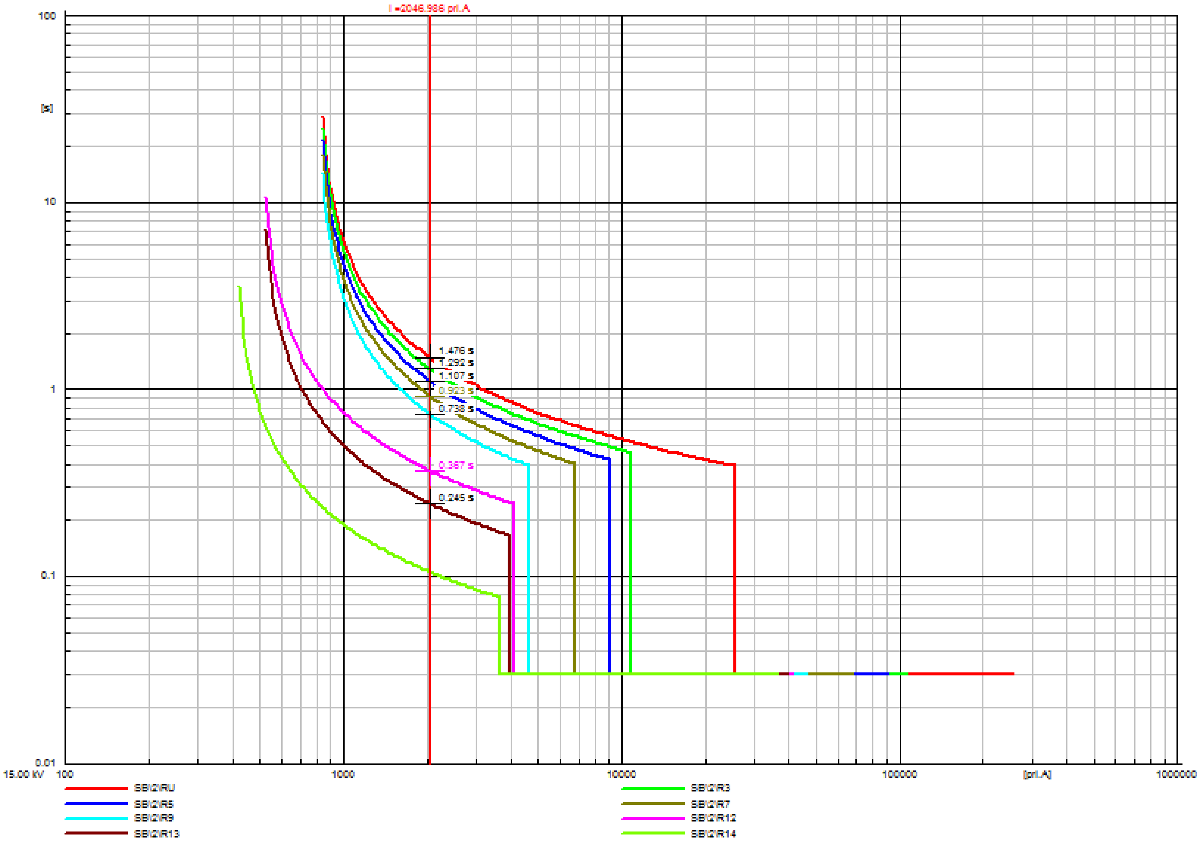


Figure 4. 48 Overcurrent relay coordination during single phase fault at bus 18 with DG

Single phase to ground at bus 14

In the base case a three phase fault at bus 14 is cleared by R13 in 0.220s and R12 clear the fault in 0.329s should R13 fail to trip as shown in Figure 4.49. The fault clearing time become 0.191s and 0.286s by R13 and R12 respectively when DG connected as shown in figure 4.50. Here the connection of DG create islanding of DG and all loads downstream of bus13 in case R13 trips in 0.220s, and nuisance tripping happen to all relays excluding R14 which is not tripping in both cases as expected.

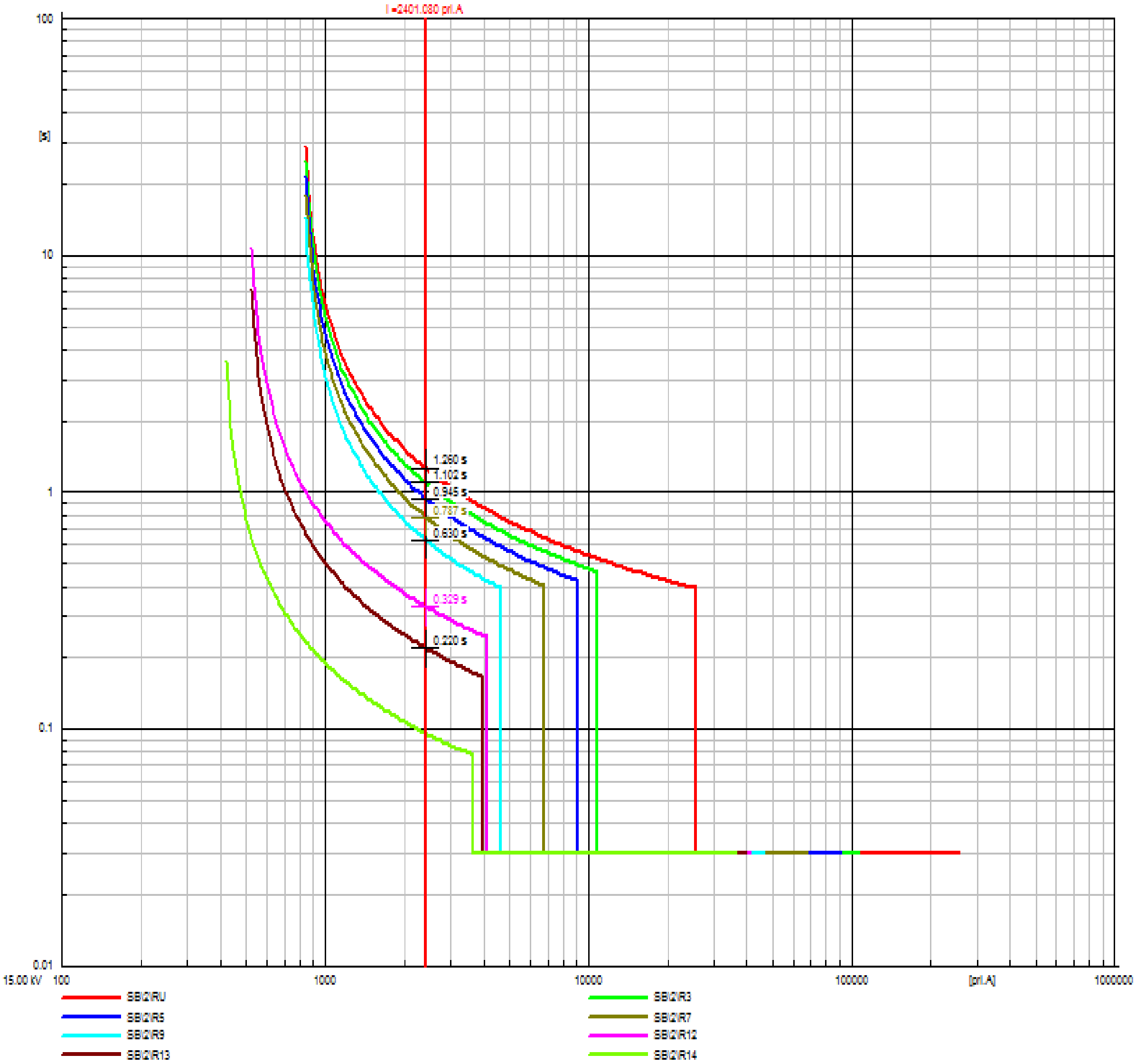


Figure 4. 49 Overcurrent relay coordination during single phase fault at bus 14 without DG

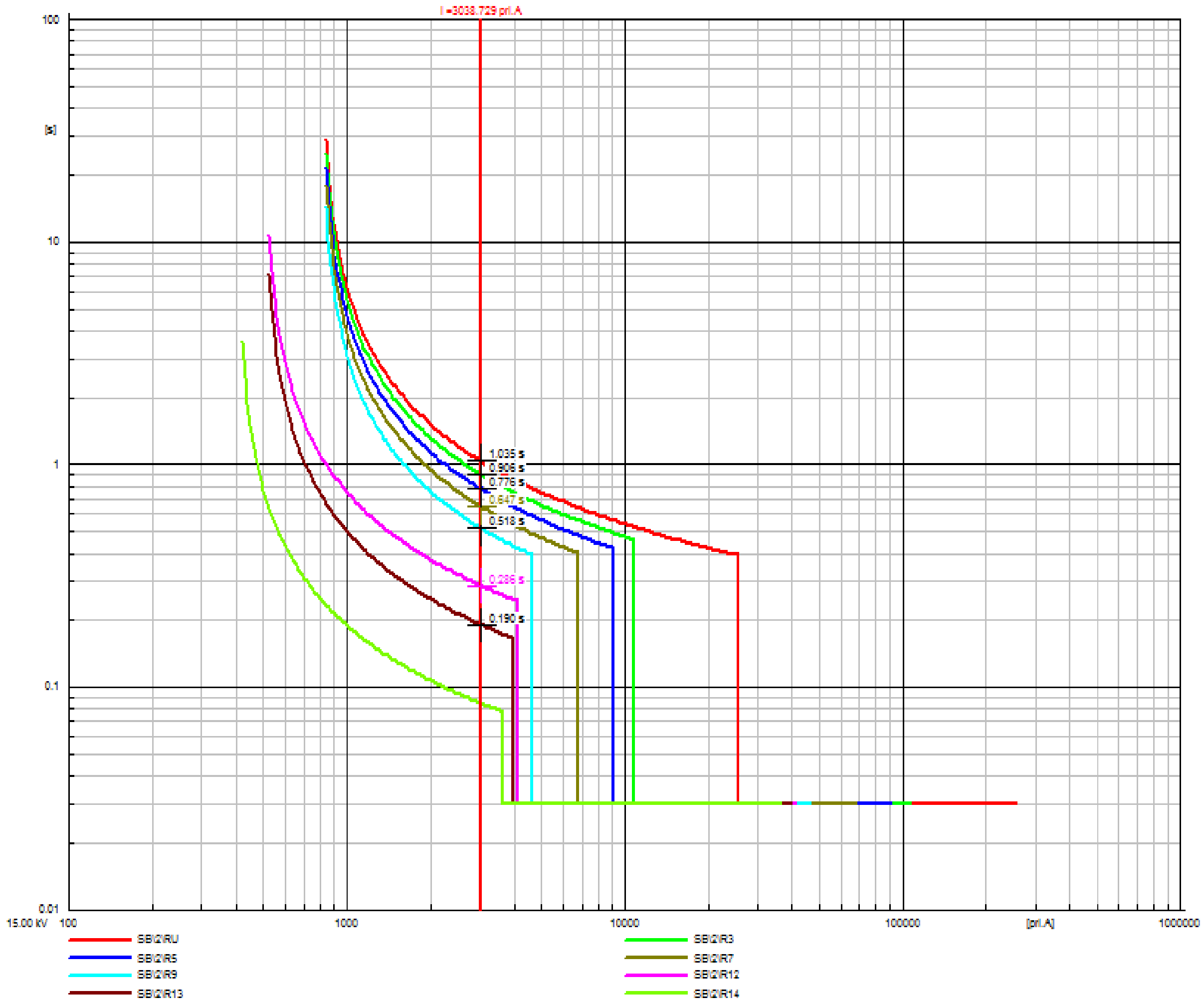


Figure 4. 50 Overcurrent relay coordination during single phase fault at bus 14 with DG

Single phase to ground fault at bus 8

Figure 4.51 shows that R7 clears a single phase to ground fault on the bus 8 in 0.597s and R5 trips to clear the fault in 0.716s in case of R7 fail to trip when no DG is connected. The other upstream relays that is R3 and Ru trips in 0.835s and 0.955s respectively as backup protection. However, during DG injection, DG and all loads downstream of the corresponding relay are islanded by R13 in 0.190s and so for R12 and R9 tripping in 0.285s and 0.516s respectively, but the fault is cleared by R7 in 0.553s and should R7 fail to trip R5, R3 and Ru trips in 0.664s, 0.774s and 0.885 sequentially as backup protection according to their sequence of operation (see Figure 4.52).

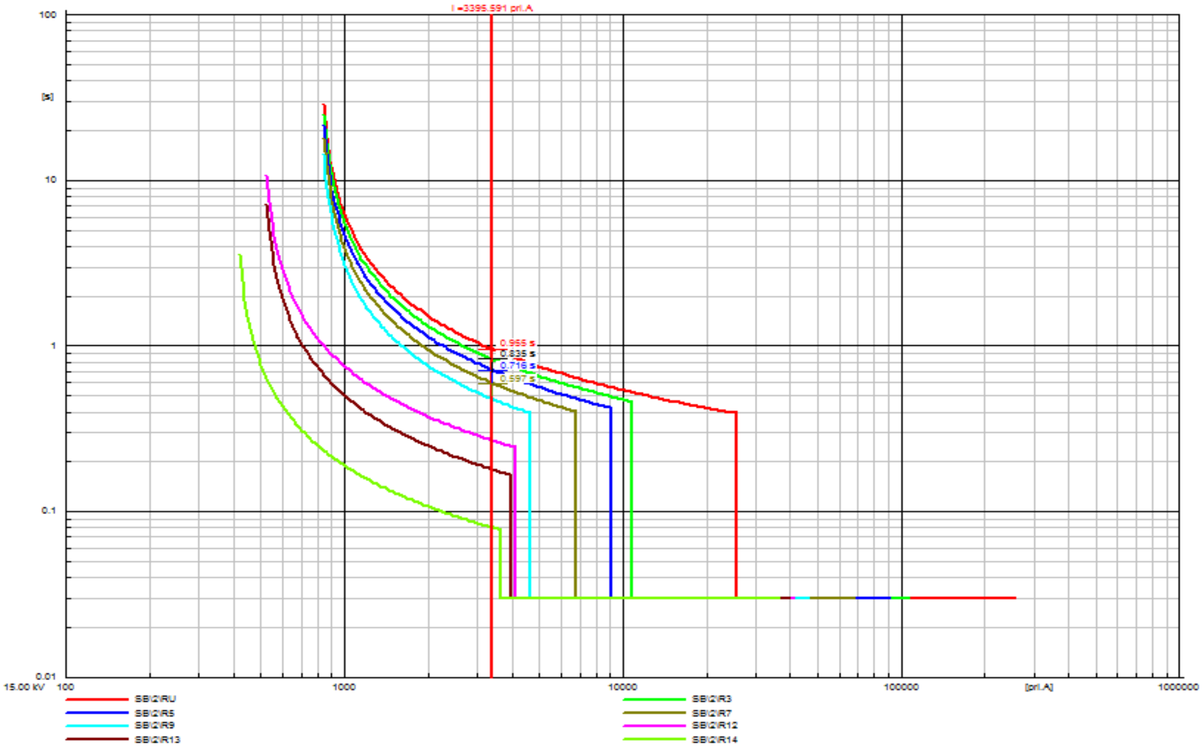


Figure 4. 51 Overcurrent relay coordination during single phase fault at bus 8 without DG

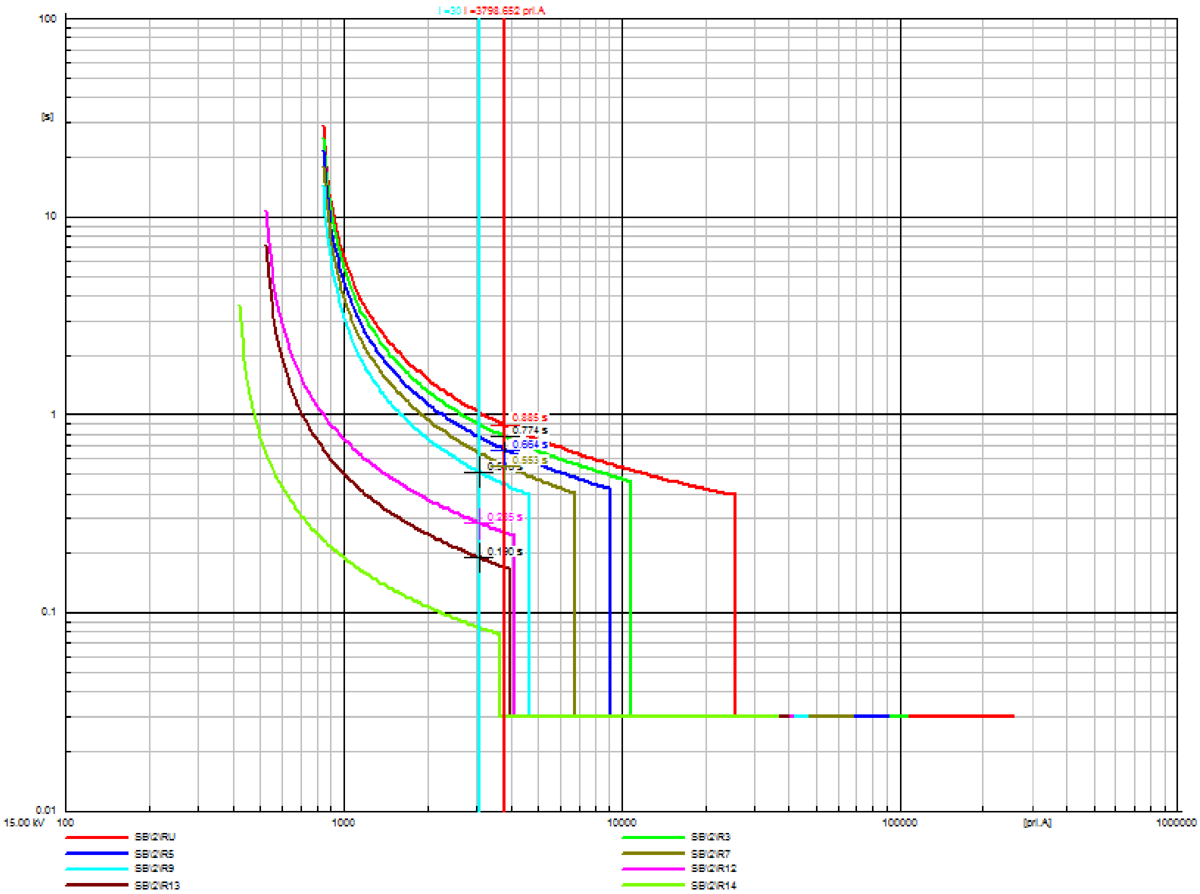


Figure 4. 52 Overcurrent relay coordination during single phase fault at bus 8 with DG

Single phase to ground fault at bus 4

Figure 4.53 shows that without any DG connected, an earth fault at bus 4 is cleared by R3 in 0.580s and Ru trips in 0.663s in case R3 fail to trip. An earth fault on bus 4 with DG connected results to a combination of nuisance tripping and islanding problems as shown in figure 4.54. While R13 isolates DG and all the downstream loads in 0.241s, R3 clears the fault in 0.580s followed by Ru in case of failure of R3. Undoubtedly, the protection coordination is impinged upon by the presence of the DG at this location.

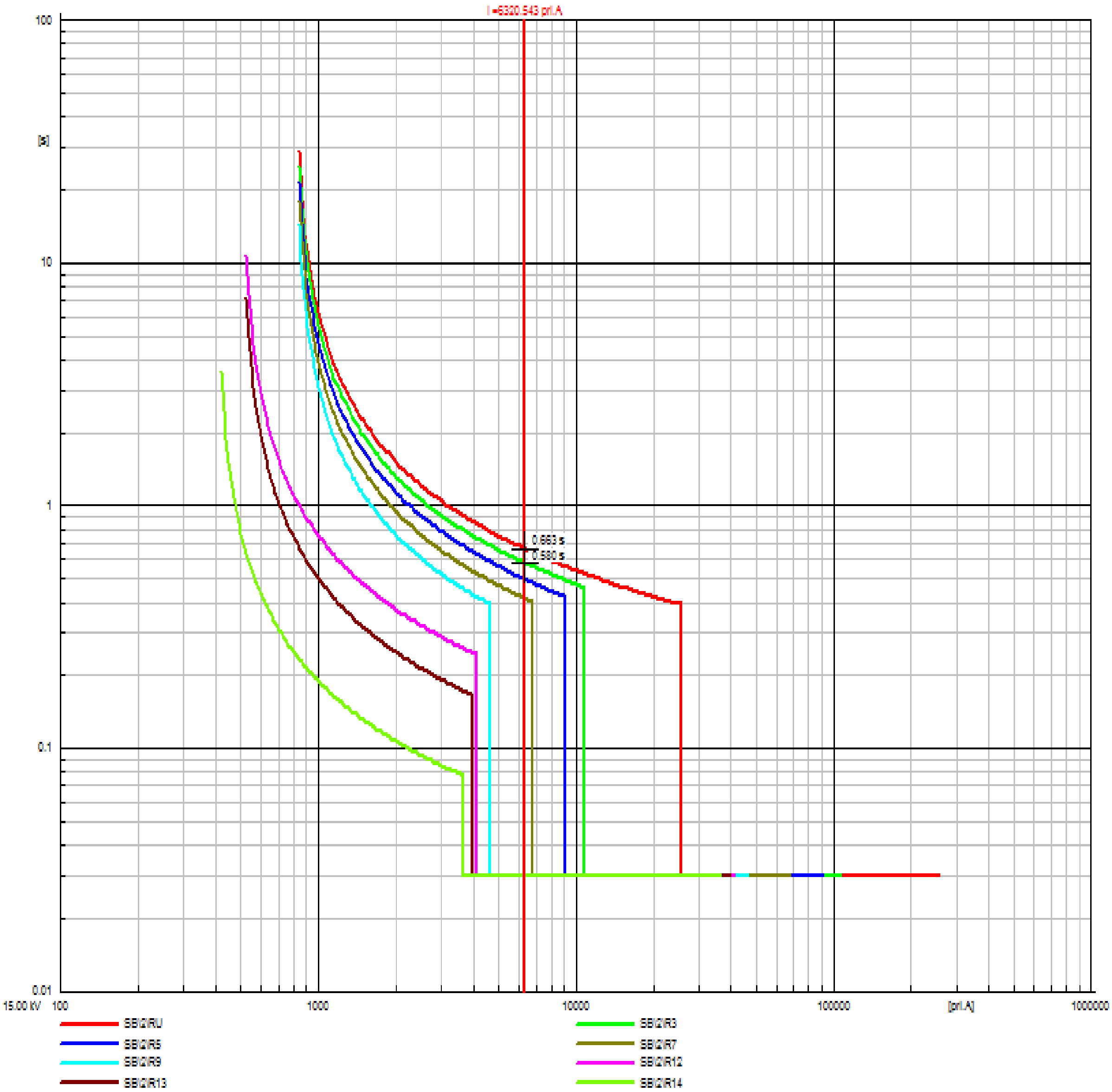


Figure 4. 53 Overcurrent relay coordination during single phase fault at bus 4 without DG

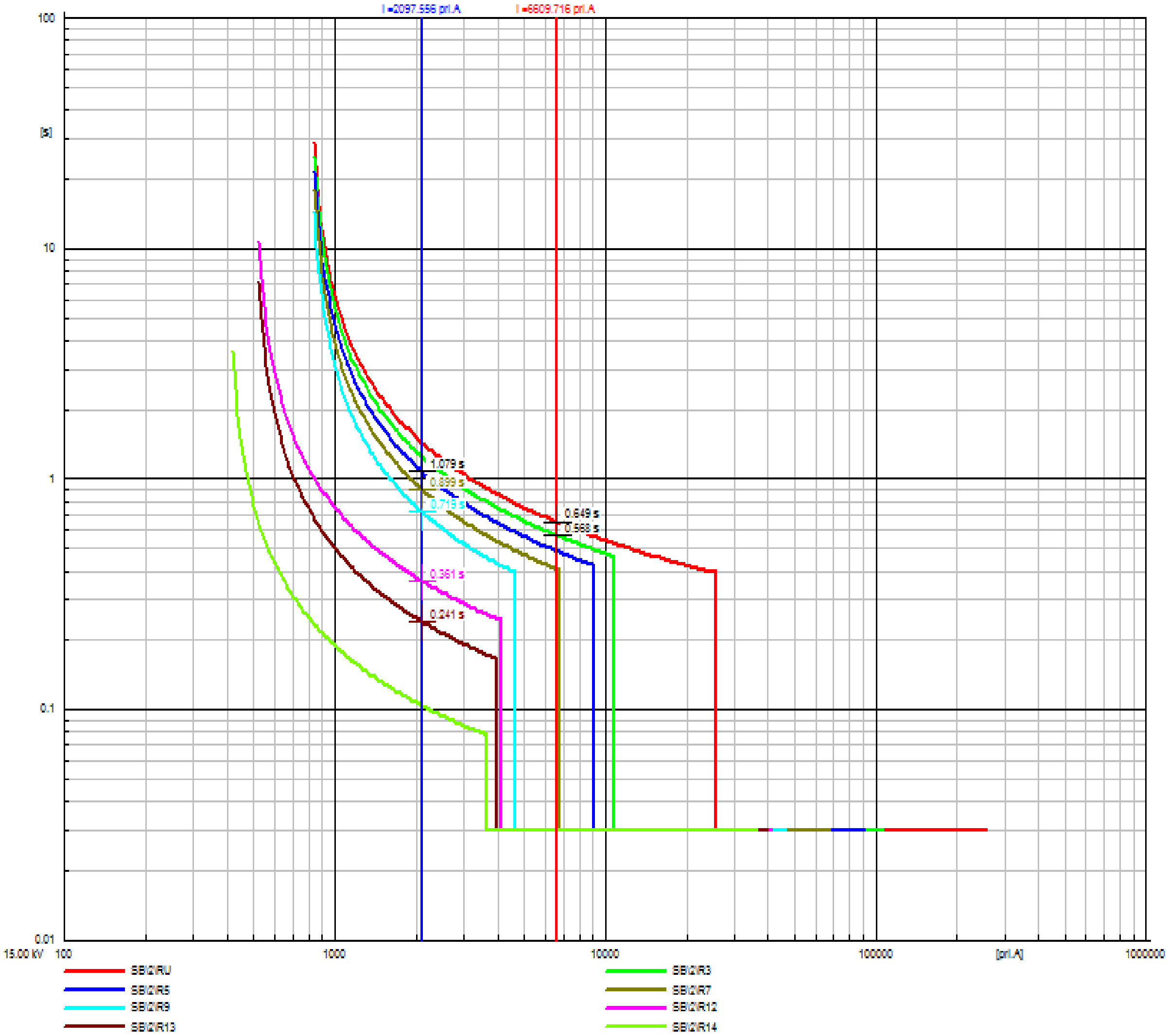


Figure 4. 54 Overcurrent relay coordination during single phase fault at bus 4 with DG

Chapter Five
Conclusions, Recommenditions and Further Work

5.1 Conclusions

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 SEB-12 of Sebeta-I 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 15.1.7 simulation package. The base case simulation results indicated that the feeder encountered the total real and reactive power loss of 1.91 MW and 2.07 MVAR respectively with major bus voltages were out of acceptable range. In order to reduce the total real and reactive 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 analytical method and load flow analysis respectively, and accordingly the proper site and size of DG was found and determined to be at bus 14 with proper size of 12.098 MW. The cost estimation for the determined DG size was carried out by taking the microturbine DG type as an example. Consequently, the total cost of the 12.098 MW DG installation was found to be $30,245,000.

However, it is well known that the current existing electricity networks, particularly distribution systems, have been designed in radial topology with centralised 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, voltage stability and loading of the line segment were positive. The results of the balanced and positive sequence load flow analysis at steady state condition after DG integration pointed out that the total real and reactive power loss was reduced to 0.30 MW and 0.28 MVAR with the total loss reduction of 84.29% and by 86.47% respectively, and all bus voltages was improved to within acceptable range with minimum voltage magnitude that was found at bus 18 with magnitude of 0.832 pu (12.479 kV) became 0.950 pu (14.256 kV).

Besides, 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. Voltage stability analysis of the system was examined by gradually increasing the load, while keeping the power factor constant, of the preselected buses until they reach the power transfer limit, and the transient stability of the system was analyzed by carrying out the self-clearing three-phase and single phase to ground short circuits analysis. In both cases the impact of DG on voltage stability of the system had been determined to be positive. Likewise, the impact of DG on system fault level and the accompanying protection issues have also been investigated and the results were analysed by performing three phase and single phase short circuits. The results of the simulation in both cases suggested that DG connection could lead to increment of fault level and protection miss-coordination in a radial distribution network. Generally, nuisance tripping, relay blinding and islanding are some of the protection issues resulting from DG integration into the distribution network.

5.2 Recommendations

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. 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 (EEU) and its counterpart Ethiopian Electric Power (EEP) or other stake holders like Ethiopian Electric Authority (EEA) should make awareness and encouragements to the government to promote the implementation of distributed generation in distribution sector.

5.3 Further Work

The current thesis used a radial distribution circuit for the model development, but future work could include improvements to fit it for ring distribution networks. As well, in this thesis work the most pronounced problems that have been found through several case study projects gives a clue to work on DG protection and deep investigation on DG interconnection methodology. Hence, the protection of distributed generator during disturbance by using smart protection devices that is automatic isolation of DG during disturbance and reconnection of DG after the clearance of disturbance will be the future work to be focused on.

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Appendices

Appendix A: Network Data

A1: Load Data of the Network

Load Point	Load in KW	Load in KVAR	Load in KVA
LD1	299.25	15.75	315
LD2	95	5	100
LD3	598.5	31.5	630
LD4	95	5	100
LD5	190	10	200
LD6	332.5	17.5	350
LD7	299.25	15.75	315
LD8	489.25	25.75	515
LD9	0	0	0
LD10	299.25	15.75	315
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	536.75	28.25	565
LD16	380	20	400
LD17	1296.75	68.25	1365
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	299.25	15.75	315
LD30	299.25	15.75	315
LD31	190	10	200

LD32	0	0	0
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
LD41	299.25	15.75	315
LD42	299.25	15.75	315
LD43	299.25	15.75	315

A2: Line Parameters of the Network (Line Data)

Name of Line	Resistance in Ω	Reactance in Ω
L1	0.0198	0.01669
L2	0.4409	0.48824
L3	0.1237	0.137202
L4	0.0469	0.051952
L5	0.0506	0.07234
L6	0.298	0.33004
L7	0.0513	0.05681
L8	0.1646	0.18231
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
L41	0.051	0.03179
L42	0.0607	0.03778
L43	0.0225	0.01399

Appendix B: MATLAB m-file program for DG sizing

```
clc;
clear;
close all;

%% Parameter Definition
N = 43;
i = (1:N);
pf = 0.85;
Vref=15;
IDG =zeros(1,N);
PDG=zeros(1,N);
size=zeros(1,N);

%% Parameter Initialization
R = zeros(1,N);
I = zeros(1,N);

%% Branch Currents Initialization
I18 = zeros(1,18);
A18 = zeros(1,18);
k = zeros(1,18);

I3 = zeros(1,3);
A3 = zeros(1,3);
I19 = zeros(1,19);
A19=zeros(1,19);
l = zeros(1,19);

I5 = zeros(1,5);
A5 = zeros(1,5);
I25 = zeros(1,25);
A25 =zeros(1,25);
m = zeros(1,25);

I7 = zeros(1,7);
A7=zeros(1,7);
I27 = zeros(1,27);
A27 = zeros(1,27);
n=zeros(1,27);

I9=zeros(1,9);
A9=zeros(1,9);
I29=zeros(1,29);
A29=zeros(1,29);
o=zeros(1,29);

I13 =zeros(1,13);
A13 =zeros(1,13);
I32=zeros(1,32);
A32=zeros(1,32);
p=zeros(1,32);

q=zeros(1,34);
r=zeros(1,33);

I38=zeros(1,38);
```

```
A38=zeros(1,38);
s=zeros(1,38);

I14=zeros(1,14);
A14=zeros(1,14);
I43=zeros(1,43);
A43=zeros(1,43);
t=zeros(1,43);

%% Input Data
R = [0.019764 0.440852 0.123721 0.0469069 0.05062848 0.2980049 0.0512997
0.1646134 0.1631705 0.0378224 0.0678777 0.0643472 ...
    0.0619219 0.1916648 0.3389392 0.2150738 0.2721224 0.226287 0.219062
0.0780301 0.1121577 0.1782575 0.1605164 0.3013866...
    0.2959996 0.2309752 0.09283996 0.0602854 0.05208936 0.1147521 0.1220447
0.1470548 0.07581627 0.3294831 0.00700964 0.04937854...
    0.2119526 0.085306 0.1285761 0.196121 0.0510374 0.06065242 0.02246686];

I = [0.720 0.718 0.707 0.629 0.625 0.519 0.514 0.515 0.423 0.465 0.451
0.437 0.420 0.276 0.143 0.117 0.098 0.035 0.029 0.008 ...
    0.078 0.065 0.056 0.030 0.013 0.035 0.031 0.028 0.014 0.125 0.111 0.102
0.072 0.030 0.057 0.043 0.029 0.014 0.119 0.081...
    0.043 0.029 0.014];

%% Implementation to Find DG Size

% Step 1
for i =1:18
    I18(i) = (I(i).*R(i))*pf;
    A18(i) =R(i);

    k(i) = sum(I18)/sum(A18);

end
K=k(:,1:18);

% Step 2
for i = 1:3
       I3(i) = (I(i).*R(i)*pf);
       A3(i) = (R(i));
end
I3;
A3;

for i=19:20
    I19(i)= (I(i).*R(i))*pf;
    A19(i)=R(i);

    l(i)=(sum(I3)+sum(I19))/(sum(A3)+sum(A19));
end
L=l(:,19:20);

% Step 3
 for i = 1:5
    I5(i) = I(i).*R(i)*pf;
    A5(i) = R(i);
 end
I5;
```

```
A5;

for i = 21:25
    I25(i) = I(i).*R(i)*pf;
    A25(i) = R(i);

   m(i) = (sum(I5)+sum(I25))/(sum(A5)+sum(A25));
end
  M=m(:,21:25);


% Step 4
for i = 1:7
    I7(i) = I(i).*R(i)*pf;
    A7(i) = R(i);
end
I7;
A7;

for i=26:27
    I27(i) = I(i).*R(i)*pf;
    A27(i) = R(i);

    n(i) = (sum(I7)+sum(I27))/(sum(A7)+sum(A27));
end
J=n(:,26:27);


% Step 5
for i=1:9
    I9(i)=I(i).*R(i)*pf;
    A9(i)=R(i);
end
I9;
A9;

for i=28:29
    I29(i)=I(i).*R(i)*pf;
    A29(i)=R(i);

    o(i) = (sum(I9)+sum(I29))/(sum(A9)+sum(A29));
end
O=o(:,28:29);


% Step 6
for i=1:13;
    I13(i)=I(i).*R(i)*pf;
    A13(i)=R(i);
end
I13;
A13;

for i=30:32
    I32(i)=I(i).*R(i)*pf;
    A32(i)=R(i);

    p(i)=(sum(I13)+sum(I32))/(sum(A13)+sum(A32));
```

```
end
P=p(:,30:32);

% Step 7
for i=34

   q(i)=(sum(I13)+sum(I32)+I(34)*R(34)*pf)/(sum(A13)+sum(A32)+R(34));
end
 Q=q(:,34);

% Step 8
for i=33

   r(i)=(sum(I13)+sum(I32)+I(33)*R(33)*pf)/(sum(A13)+sum(A32)+R(33));
end
W=r(:,33);

% Step 9
for i=35:38
    I38(i)=I(i).*R(i)*pf;
    A38(i)=R(i);

s(i)=(sum(I13)+sum(I32)+I(33)*R(33)+sum(I38))/(sum(A13)+sum(A32)+R(33)+sum(
A38));
end
S=s(:,35:38);

%Step 10
for i=1:14
    I14(i)=I(i).*R(i)*pf;
    A14(i)=R(i);
end
I14;
A14;

for i=39:43
    I43(i)=I(i).*R(i)*pf;
    A43(i)=R(i);

    t(i)=(sum(I14)+sum(I43))/(sum(A14)+sum(A43));
end
T=t(:,39:43);

%% OutPut DG Size
IDG =[K L M J O P W Q S T];
PDG=Vref*IDG*sqrt(3);
idg=IDG';
size=PDG';
sr=(1:N)';
OP=table(sr,size,idg);
OP(:,1:3);
OP;
```

Appendix C: Voltage Profiles of the Feeder

C1: Voltage Profiles before DG Integration

DIgSILENT PowerFactory 15.1.7 | Project: | Date: 10/6/2018

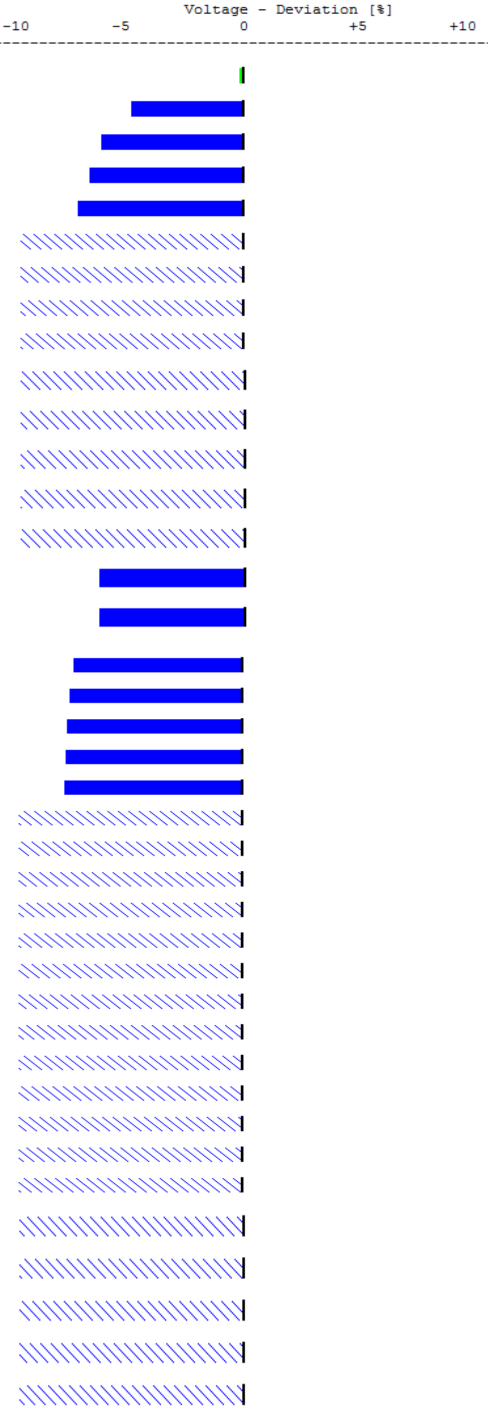
Load Flow Calculation — Complete System Report: Substations, Voltage Profiles, Grid Interchange

AC Load Flow, balanced, positive sequence		Automatic Model Adaptation for Convergence	No
Automatic Tap Adjust of Transformers	No	Max. Acceptable Load Flow Error for	
Consider Reactive Power Limits	No	Nodes	1.00 kVA
		Model Equations	0.10 %

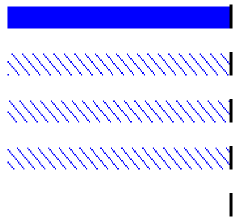
Grid: Grid 5 | System Stage: Grid 5 | Study Case: Study Case | Annex: / 8

	rtd.V [kV]	Bus - voltage [p.u.]	[kV]	[deg]
SB 1				
B1	15.00	0.998	14.97	-0.04
SB 2				
B2	15.00	0.948	14.23	-1.48
SB 3				
B3	15.00	0.935	14.02	-1.91
SB 4				
B4	15.00	0.930	13.95	-2.06
SB 5				
B5	15.00	0.924	13.86	-2.30
SB				
B13	15.00	0.853	12.80	-4.79
SB10				
B10	15.00	0.866	12.99	-4.31
SB11				
B11	15.00	0.861	12.92	-4.48
SB12				
B12	15.00	0.857	12.86	-4.64
SB14				
B14	15.00	0.846	12.69	-4.90
SB15				
B15	15.00	0.840	12.60	-5.00
SB16				
B16	15.00	0.837	12.55	-5.06
SB17				
B17	15.00	0.833	12.49	-5.12
SB18				
B18	15.00	0.832	12.48	-5.14
SB19				
B19	15.00	0.934	14.01	-1.92
SB20				
B20	15.00	0.934	14.01	-1.93
SB21				
B21	15.00	0.923	13.85	-2.32
SB22				
B22	15.00	0.922	13.82	-2.34
SB23				
B23	15.00	0.920	13.81	-2.36
SB24				
B24	15.00	0.919	13.79	-2.38
SB25				
B25	15.00	0.919	13.78	-2.39
SB26				
B26	15.00	0.893	13.39	-3.34
SB27				
B27	15.00	0.892	13.38	-3.35
SB28				
B28	15.00	0.868	13.03	-4.22
SB29				
B29	15.00	0.868	13.02	-4.22
SB30				
B30	15.00	0.851	12.77	-4.82
SB31				
B31	15.00	0.850	12.74	-4.85
SB32				
B32	15.00	0.848	12.71	-4.88
SB33				
B33	15.00	0.847	12.70	-4.89
SB34				
B34	15.00	0.846	12.69	-4.90
SB35				
B35	15.00	0.847	12.70	-4.89
SB36				
B36	15.00	0.847	12.70	-4.90
SB37				
B37	15.00	0.846	12.69	-4.91
SB38				
B38	15.00	0.846	12.68	-4.91
SB39				
B39	15.00	0.844	12.66	-4.93
SB40				
B40	15.00	0.842	12.63	-4.97
SB41				
B41	15.00	0.842	12.63	-4.97
SB42				
B42	15.00	0.842	12.62	-4.98
SB43				
B43	15.00	0.842	12.62	-4.98
SB6				

Voltage - Deviation [%]



B6	15.00	0.898	13.47	-3.17
SB7				
B7	15.00	0.894	13.40	-3.32
SB8				
B8	15.00	0.881	13.21	-3.77
SB9				
B9	15.00	0.869	13.03	-4.21
SBS				
B	15.00	1.000	15.00	0.00



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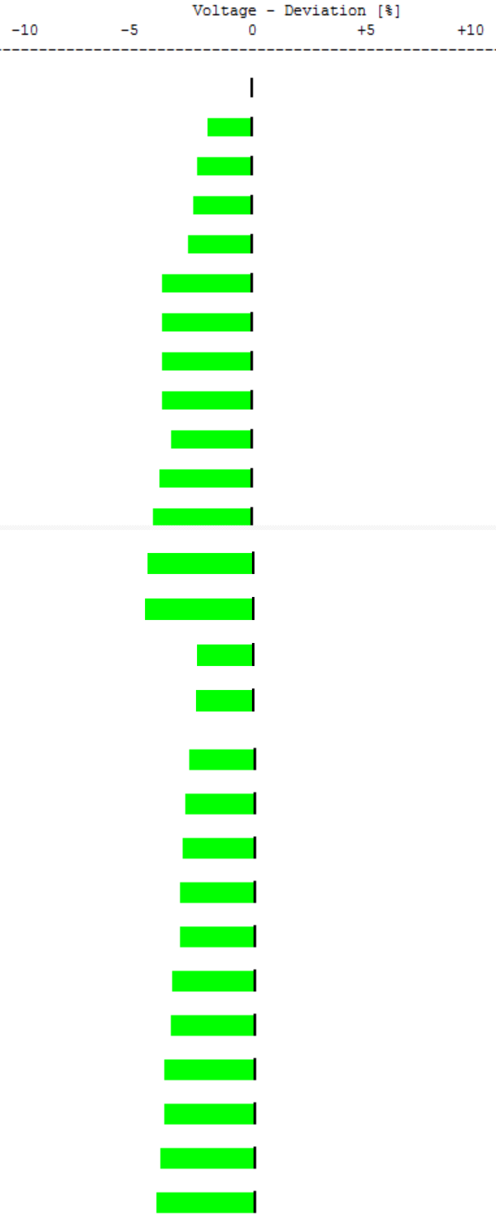
C2: Voltage Profile after DG Integration

Load Flow Calculation — Complete System Report: Substations, Voltage Profiles, Grid Interchange

AC Load Flow, balanced, positive sequence		Automatic Model Adaptation for Convergence		No
Automatic Tap Adjust of Transformers	No	Max. Acceptable Load Flow Error for		
Consider Reactive Power Limits	No	Nodes		1.00 kVA
		Model Equations		0.10 %

Grid: Grid 5 | System Stage: Grid 5 | Study Case: Study Case | Annex: / 8

	rtd.V [kV]	Bus - voltage [p.u.]	[kV]	[deg]
SB 1				
B1	15.00	0.999	14.99	0.01
SB 2				
B2	15.00	0.980	14.70	0.14
SB 3				
B3	15.00	0.975	14.62	0.18
SB 4				
B4	15.00	0.973	14.59	0.20
SB 5				
B5	15.00	0.971	14.56	0.22
SB				
B13	15.00	0.958	14.38	1.44
SB10				
B10	15.00	0.959	14.38	1.10
SB11				
B11	15.00	0.959	14.38	1.22
SB12				
B12	15.00	0.958	14.38	1.33
SB14				
B14	15.00	0.963	14.44	1.74
SB15				
B15	15.00	0.957	14.36	1.66
SB16				
B16	15.00	0.954	14.32	1.62
SB17				
B17	15.00	0.951	14.27	1.57
SB18				
B18	15.00	0.950	14.26	1.56
SB19				
B19	15.00	0.974	14.61	0.17
SB20				
B20	15.00	0.974	14.61	0.16
SB21				
B21	15.00	0.970	14.55	0.21
SB22				
B22	15.00	0.968	14.52	0.19
SB23				
B23	15.00	0.967	14.51	0.17
SB24				
B24	15.00	0.966	14.49	0.16
SB25				
B25	15.00	0.966	14.48	0.15
SB26				
B26	15.00	0.962	14.43	0.57
SB27				
B27	15.00	0.962	14.43	0.57
SB28				
B28	15.00	0.959	14.38	1.04
SB29				
B29	15.00	0.959	14.38	1.04
SB30				
B30	15.00	0.957	14.35	1.41
SB31				
B31	15.00	0.955	14.33	1.39



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|SB34
|  B34          15.00   0.952   14.28   1.35
|SB35
|  B35          15.00   0.953   14.29   1.35
|SB36
|  B36          15.00   0.952   14.29   1.35
|SB37
|  B37          15.00   0.952   14.28   1.34
|SB38
|  B38          15.00   0.952   14.27   1.34
|SB39
|  B39          15.00   0.961   14.42   1.72
|SB40
|  B40          15.00   0.959   14.39   1.69
|SB41
|  B41          15.00   0.959   14.39   1.69
|SB42
|  B42          15.00   0.959   14.38   1.68
|SB43
|  B43          15.00   0.959   14.38   1.68
|SB6
|  B6           15.00   0.964   14.46   0.53
|SB7
|  B7           15.00   0.963   14.45   0.59
|SB8
|  B8           15.00   0.961   14.41   0.81
|SB9
|  B9           15.00   0.959   14.39   1.04
|SBS
|  B            15.00   1.000   15.00   0.00
```

Appendix D: Over Current Relay Coordination Tripping Time

D1: During Three Phase Fault

Fault Point	Relays	Tripping Time (s) without DG	Tripping Time (s) With DG
Bus 18	RU	1.220	1.521
	R3	1.068	1.331
	R5	0.915	1.141
	R7	0.763	0.951
	R9	0.610	0.760
	R12	0.322	0.375
	R13	0.215	0.250
	R14	0.094	0.030
Bus 38	RU	1.085	1.268
	R3	0.950	1.109
	R5	0.814	0.951
	R7	0.678	0.792
	R9	0.543	0.634
	R12	0.296	0.331
	R13	Not trips	0.235
	R14	Not trips	Not trips

Bus 43	RU	1.037	1.136
	R3	0.908	0.994
	R5	0.778	0.852
	R7	0.648	0.710
	R9	0.519	0.568
	R12	0.286	0.306
	R13	0.191	0.204
	R14	Not trips	Not trips
Bus 14	RU	0.911	0.911
	R3	0.797	0.797
	R5	0.683	0.683
	R7	0.569	0.569
	R9	0.455	0.455
	R12	0.259	0.259
	R13	0.173	0.173
	R14	Not trips	Not trips
Bus 8	RU	0.730	0.730
	R3	0.639	0.639
	R5	0.547	0.547
	R7	0.456	0.456
	R9	Not trips	0.518
	R12	Not trips	0.286
	R13	Not trips	0.191
	R14	Not trips	Not trips
Bus 4	RU	0.542	0.542
	R3	0.474	0.474
	R5	Not trips	0.934
	R7	Not trips	0.778
	R9	Not trips	0.623
	R12	Not trips	0.327
	R13	Not trips	0.218
	R14	Not trips	Not trips

D2: During Single Phase to Ground Fault

Fault Point	Relays	Tripping Time (s) without DG	Tripping Time (s) With DG
Bus 18	RU	1.772	2.416
	R3	1.551	2.114
	R5	1.329	1.812
	R7	1.108	1.510
	R9	0.886	1.208
	R12	0.413	0.497
	R13	0.276	0.331
	R14	0.117	0.078
Bus 38	RU	1.558	1.872
	R3	1.363	1.638
	R5	1.168	1.404
	R7	0.974	1.170
	R9	0.779	0.936
	R12	0.381	0.428
	R13	Not trips	0.224
	R14	Not trips	Not trips
Bus 43	RU	1.460	1.476
	R3	1.278	1.292
	R5	1.095	1.107
	R7	0.913	0.923
	R9	0.730	0.738
	R12	0.365	0.367
	R13	0.243	0.245
	R14	Not trips	Not trips
Bus 14	RU	1.260	1.035
	R3	1.102	0.906
	R5	0.945	0.776
	R7	0787	0.647
	R9	0.630	0.518
	R12	0.329	0.286
	R13	0.220	0.190
	R14	Not trips	Not trips
Bus 8	RU	0.955	0.885

Bus 8	R3	0.835	0.774
	R5	0.716	0.664
	R7	0.597	0.553
	R9	Not trips	0.516
	R12	Not trips	0.285
	R13	Not trips	0.190
	R14	Not trips	Not trips
Bus 4	RU	0.663	0.649
	R3	0.580	0.568
	R5	Not trips	1.079
	R7	Not trips	0.899
	R9	Not trips	0.719
	R12	Not trips	0.361
	R13	Not trips	0.241
	R14	Not trips	Not trips

Appendix E: Two Year Power Interruption Data

Name of the Feeder	Month:01/09/15-31/09/15						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB-1	5	5	4	0	0	14	7.85
SEB-2	17	9	28	3	0	57	66.68
SEB-3	8	6	9	7	1	31	44.5
SEB-4	17	8	14	6	2	47	69.01
SEB-5	7	2	1	0	0	10	34.93
SEB-6	10	4	6	0	0	20	25.61
SEB-7	18	11	18	0	0	47	50.45
SEB-8	4	1	3	0	0	8	5.78
SEB-9	15	8	6	0	0	29	37.58
SEB-10	22	6	9	0	0	37	65.05
SEB-11	26	9	10	0	2	47	58.78
SEB-12	28	11	13	0	3	55	73.43
SEB-13	21	5	14	0	0	40	38.28
Name of the Feeder	Month:01/10/15-30/10/15						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	9	1	4	0	0	14	11.85

SEB -2	18	5	37	0	0	60	56.67
SEB -3	3	1	14	0	2	20	64.4
SEB -4	10	6	15	0	0	31	79.03
SEB 5	5	1	2	0	0	8	44.93
SEB 6	7	1	3	0	0	11	35.31
SEB -7	11	23	12	0	3	49	60.25
SEB -8	2		4	0	0	6	15.88
SEB -9	1	4	1	0	1	7	47.51
SEB -10	15	1	13	0	0	29	55.04
SEB -11	16	5	10	0	0	31	58.78
SEB -12	11	17	23	0	1	52	83.44
SEB -13	5	7	13	0	1	26	58.21
Name of the Feeder	Month:01/11/15-30/10/15						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	9	1	4	0	1	15	9.75
SEB -2	18	5	37	0	0	60	76.63
SEB -3	3	1	14	0	0	18	33.54
SEB -4	10	6	15	0	1	32	72.01
SEB -5	5	1	2	0	0	8	54.91
SEB -6	7	1	3	0	0	11	35.71
SEB -7	11	23	12	0	2	48	60.43
SEB -8	2	3	4	0	0	9	11.78
SEB -9	1	4	1	0	1	7	27.56
SEB -10	15	1	13	0	0	29	72.02
SEB -11	16	5	10	0	0	31	48.75
SEB -12	11	25	16	0	1	53	93.53
SEB -13	4	11	17	0	0	32	28.23
Name of the Feeder	Month:01/12/15-31/12/15						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	23	4	5	0	0	32	8.83
SEB -2	27	12	23	0	0	62	78.58
SEB -3	8	3	10	0	3	24	34.52
SEB -4	15	4	9	0	0	28	65.01
SEB -5	7		1	0	0	8	24.73
SEB -6	5	2	2	0	0	9	45.68
SEB -7	18	1	9	0	2	30	60.46
SEB -8	5	0	7	0	0	12	8.77
SEB -9	19	5	3	0	0	27	27.55
SEB -10	23	4	13	0	0	40	55.08

SEB -11	20	8	5	0	1	34	63.76
SEB -12	21	24	13	0	4	62	103.33
SEB -13	32	19	13	0	0	64	58.29
Name of the Feeder	Month:01/01/16-31/01/16						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	5	5	4	0	0	14	7.82
SEB -2	17	9	28	3	0	57	76.68
SEB -3	8	6	9	7	1	31	54.5
SEB -4	17	8	14	6	2	47	69.09
SEB -5	7	2	1	0	0	10	34.93
SEB -6	10	4	6	0	0	20	25.63
SEB -7	18	11	18	0	0	47	60.44
SEB -8	4	1	3	0	0	8	9.72
SEB -9	15	8	6	0	0	29	47.58
SEB -10	22	6	9	0	0	37	65.08
SEB -11	26	9	10	0	2	47	68.76
SEB -12	28	27	13	0	3	71	83.42
SEB -13	21	5	14	0	0	40	48.28
Name of the Feeder	Month:01/02/16-29/02/16						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC		UF	OL		
SEB -1	11	3	1	0	0	15	7.65
SEB -2	16	6	24	3	0	49	32.85
SEB -3	13	9	11	8	0	41	28.83
SEB -4	11	1	8	8	0	28	23.55
SEB -5	5	1	2	0	0	8	20.3
SEB -6	4	2	5	0	0	11	12.07
SEB -7	8	7	9	0	1	25	34.45
SEB -8	2	0	2	0	0	4	20.33
SEB -9	11	6	7	0	0	24	45.32
SEB -10	11	1	7	0	1	20	24.72
SEB -11	14	5	8	0	0	27	32.95
SEB -12	16	13	7	0	5	41	61.48
SEB -13	11	4	11	0	0	26	18.92
Name of the Feeder	Month:01/03/16-31/03/16						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	9	7	6	0	0	22	30.2
SEB -2	16	27	20	4	1	68	62.06

SEB -3	13	12	8	3	0	36	27.35
SEB -4	12	4	23	5	0	44	27.21
SEB -5	7	0	1	0	0	8	9.6
SEB -6	6	0	1	0	1	8	4
SEB -7	12	3	10	0	0	25	30.63
SEB -8	5	0	1	0	0	6	3.18
SEB -9	14	38	7	0	0	59	61.21
SEB -10	18	4	24	0	0	46	61.46
SEB -11	17	8	5	3	0	33	31.91
SEB -12	26	14	15	0	2	57	28.53
SEB -13	18	9	14	0	0	41	37.05

Name of the Feeder	Month:01/04/16-30/04/16						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	8	3	12	0	0	23	16.61
SEB -2	16	5	12	1	0	34	33.63
SEB -3	9	8	10	0	0	27	23.7
SEB -4	10	8	6	5	0	29	21.76
SEB -5	7	0	1	0	9	17	24.53
SEB -6	5	1	2	0	0	8	2.18
SEB -7	16	20	13	0	0	49	47.18
SEB -8	3	0	1	0	0	4	0.48
SEB -9	8	22	5	0	0	35	50.36
SEB -10	18	3	7	0	0	28	35.66
SEB -11	21	4	11	5	0	41	26.45
SEB -12	16	15	14	0	3	48	49.31
SEB -13	16	5	16	0	0	37	35.26

Name of the Feeder	Month:01/05/16-31/05/16						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	5	4	10	0	0	19	6.38
SEB -2	3	4	44	0	0	51	43.66
SEB -3	10	2	11	0	0	23	8.5
SEB -4	11	6	7	2	0	26	6.4
SEB -5	3	0	0	0	1	4	2.11
SEB -6	5	0	4	0	0	9	2.56
SEB -7	8	12	5	1	0	26	21.56
SEB -8	3	1	2	0	0	6	2.8
SEB -9	5	10	3	0	0	18	8.88
SEB -10	6	4	6	0	0	16	9.91
SEB -11	16	6	14	2	0	38	26.81

SEB -12	14	22	17	0	1	54	59.58
SEB -13	18	12	37	0	0	67	62.55
Name of the Feeder	Month:01/06/16-30/06/16						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	15	9	6	8	5	43	25
SEB -2	8	13	17	1	0	39	10.76
SEB -3	3	4	17	0	0	24	17.6
SEB -4	10	10	9	0	3	32	34.3
SEB -5	0	0	2	0	0	2	0.33
SEB -6	4	0	3	0	0	7	1.86
SEB -7	11	5	14	0	0	30	27.88
SEB -8	3	4	0	0	0	7	4.7
SEB -9	4	0	6	0	0	10	12.38
SEB -10	16	2	7	0	0	25	41.28
SEB -11	16	10	13	1	0	40	35.53
SEB -12	11	4	16	0	4	35	25.68
SEB -13	13	10	14	0	1	38	37.3
Name of the Feeder	Month:01/07/16-31/07/16						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	10	3	8	0	0	21	21.6
SEB -2	12	6	18	2	0	38	16.8
SEB -3	9	15	16	2	0	42	28.8
SEB -4	13	9	14	2	0	38	17.08
SEB -5	3	0	1	0	0	4	3.06
SEB -6	8	1	4	0	0	13	15.12
SEB -7	15	11	13	0	1	40	31.5
SEB -8	6	0	2	0	0	8	9.2
SEB -9	4	2	1	0	0	7	6.6
SEB -10	18	4	10	0	0	32	39.7
SEB -11	14	8	7	0	0	29	35.3
SEB -12	8	17	19	0	1	45	25.2
SEB -13	16	11	18	0	0	45	28.9
Name of the Feeder	Month:01/08/16-31/08/16						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	18	2	5	0	0	25	56.95
SEB -2	23	18	28	0	0	69	62.3
SEB -3	17	6	15	0	1	39	58.01

SEB -4	17	5	17	3	2	44	43.91
SEB -5	5	0	1	0	3	9	8.03
SEB -6	6	1	3	0	0	10	9.21
SEB -7	23	18	36	0	0	77	80.51
SEB -8	8	1	2	0	0	11	7.7
SEB -9	5	8	4	0	0	17	12.48
SEB -10	18	2	12	0	0	32	34.76
SEB -11	17	5	11	2	0	35	37.31
SEB -12	18	45	67	1	5	136	68.59
SEB -13	23	7	19	0	0	49	32.76
Name of the Feeder	Month:01/09/16-30/09/16						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	13	1	4	0	1	19	9.38
SEB -2	10	21	12	0	0	43	43.87
SEB -3	14	3	29	0	0	46	19.65
SEB -4	12	6	10	3	0	31	16.8
SEB -5	7	1	1	0	0	9	8.38
SEB -6	5	1	1	0	1	8	6.33
SEB -7	19	7	5	0	0	31	26.4
SEB -8	3	1	1	0	0	5	7.35
SEB -9	3	5	7	0	0	15	9.68
SEB -10	7	5	11	0	0	23	28.12
SEB -11	10	2	25	3	0	40	39.22
SEB -12	24	7	13	1	2	47	101.1
SEB -13	17	6	21	0	0	44	23.22
Name of the Feeder	Month:01/10/16-31/10/16						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	18	0	4	0	0	22	44.51
SEB -2	20	6	12	0	1	39	52.4
SEB -3	21	1	10	0	0	32	52.4
SEB -4	22	8	15	3	0	48	59.6
SEB -5	1	1	15	0	0	17	8.6
SEB -6	18	0	4	0	0	22	38.9
SEB -7	36	6	0	0	0	42	67.2
SEB -8	4	1	1	0	0	6	159.4
SEB -9	4	3	5	0	0	12	12.9
SEB -10	24	6	14	0	1	45	88.3
SEB -11	21	9	14	2	0	46	47.3
SEB -12	24	11	16	0	3	54	54.2
SEB -13	22	15	19	0	0	56	53.2

Name of the Feeder	Month:01/11/16-30/11/16						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	8	1	2	0	0	11	7
SEB -2	14	17	15	0	1	47	15.2
SEB -3	4	5	6	0	1	16	13.6
SEB -4	14	6	20	0	3	43	17.1
SEB -5	2	0	13	0	9	24	35.5
SEB -6	12	1	2	0	1	16	6.7
SEB -7	9	2	0	0	1	12	6.7
SEB -8	14	0	3	0	1	18	7.5
SEB -9	6	2	5	0	1	14	6.6
SEB -10	16	2	21	0	1	40	24.5
SEB -11	23	9	19	3	0	54	43.9
SEB -12	7	19	29	0	8	63	22.8
SEB -13	19	10	10	0	1	40	17.9
Name of the Feeder	Month:01/12/16-31/12/16						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	11	3	0	0	0	14	8.6
SEB -2	9	17	18	0	0	44	30.81
SEB -3	9	6	23	0	0	38	17.68
SEB -4	7	7	15	3	2	34	15.35
SEB -5	5	0	0	5	0	10	21.61
SEB -6	4	3	4	0	0	11	12.31
SEB -7	16	15	1	0	0	32	22.85
SEB -8	5	1	6	0	0	12	15.73
SEB -9	4	4	5	0	0	13	6.05
SEB -10	11	3	6	0	0	20	18.75
SEB -11	19	4	13	2	0	38	21.55
SEB -12	18	24	14	0	2	58	12.1
SEB -13	22	3	8	0	0	33	35.76
Name of the Feeder	Month:01/01/17-31/01/17						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	13	2	5	0	0	20	7.61
SEB -2	9	13	11	0	0	33	16.3
SEB -3	15	4	19	0	0	38	9.53
SEB -4	16	2	12	1	3	34	9.13
SEB -5	4	4	0	0	0	8	21.08

SEB -6	3	0	0	0	0	3	0.21
SEB -7	18	15	4	0	0	37	12.5
SEB -8	4	1	3	0	0	8	5.18
SEB -9	2	2	2	0	0	6	1.78
SEB -10	13	7	18	0	0	38	18.51
SEB -11	9	5	19	1	0	34	10.08
SEB -12	10	6	15	0	4	35	15.25
SEB -13	12	5	14	0	0	31	10.1
Name of the Feeder	Month:01/02/17-28/02/17						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	13	5	6	0	0	24	9.57
SEB -2	15	15	11	0	4	45	68.65
SEB -3	7	13	14	0	0	34	45.58
SEB -4	21	5	19	1	11	57	68.01
SEB -5	13	3	0	0	0	16	44.23
SEB -6	14	9	13	0	3	39	35.21
SEB -7	22	20	3	0	11	56	53.23
SEB -8	6	0	3	0	0	9	9.45
SEB -9	17	2	1	0	2	22	47.01
SEB -10	12	0	13	1	2	28	75.2
SEB -11	5	8	10	2	6	31	58.43
SEB -12	23	13	10	0	8	54	108.43
SEB -13	11	2	18	0	8	39	25.23
Name of the Feeder	Month:01/03/17-31/03/17						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	1	8	7	0	0	16	4.87
SEB -2	2	17	23	0	1	43	15.68
SEB -3	3	6	37	0	0	46	17.17
SEB -4	3	2	5	4	3	17	9.85
SEB -5	7	4	11	0	0	22	6.9
SEB -6	8	0	2	1	0	11	4.55
SEB -7	6	0	9	10	0	25	13.83
SEB -8	4	0	7	0	0	11	2.25
SEB -9	5	11	0	0	0	16	21.77
SEB -10	6	1	4	0	0	11	14.1
SEB -11	4	13	20	4	0	41	9.63
SEB -12	4	1	12	0	2	19	608.6
SEB -13	6	3	19	0	0	28	13.13

Name of the Feeder	Month:01/04/17-30/04/17						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	12	1	1	0	1	15	11.95
SEB -2	21	9	22	0	9	61	56.67
SEB -3	11	2	10	0	1	24	41.58
SEB -4	23	6	39	3	17	88	78.01
SEB -5	8	9	7	0	1	25	43.53
SEB -6	5	1	4	0	2	12	35.21
SEB -7	13	8	8	0	9	38	42.45
SEB -8	9	1	4	0	7	21	12.75
SEB -9	13	2	2	0	4	21	27.43
SEB -10	17	5	5	0	15	42	64.02
SEB -11	15	9	21	3	14	62	58.78
SEB -12	25	7	15	0	7	54	95.58
SEB -13	19	9	10	0	0	38	47.25
Name of the Feeder	Month:01/05/17-31/05/17						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	4	1	5	0	1	11	12.93
SEB -2	9	22	8	0	1	40	19
SEB -3	4	6	5	0	0	15	16.88
SEB -4	6	8	14	2	0	30	22.92
SEB -5	2	1	0	0	0	3	7.86
SEB -6	4	1	6	0	1	12	16.5
SEB -7	7	8	6	0	0	21	40.51
SEB -8	4	3	4	0	0	11	26.3
SEB -9	2	2	3	0	0	7	8.33
SEB -10	11	8	3	0	0	22	40.88
SEB -11	7	11	8	2	0	28	23.1
SEB -12	10	5	14	0	3	32	27.03
SEB -13	7	11	0	0	0	18	22.05
Name of the Feeder	Month:01/06/17-30/06/17						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	3	6	17	0	0	26	1.15
SEB -2	6	9	21	0	0	36	13.57
SEB -3	6	0	2	0	0	8	4.57
SEB -4	3	0	4	0	0	7	3.58
SEB -5	4	0	2	0	0	6	13.9
SEB -6	5	2	4	0	0	11	8.42

SEB -7	9	12	21	0	0	42	52
SEB -8	3	5	13	0	0	21	3.6
SEB -9	7	11	12	0	0	30	7.77
SEB -10	9	9	20	0	5	43	42.1
SEB -11	9	13	18	0	0	40	23.2
SEB -12	13	4	11	0	7	35	19.5
SEB -13	9	3	15	0	0	27	21.2
Name of the Feeder	Month:01/07/17-31/07/17						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	3	1	3	0	0	7	405.4
SEB -2	6	24	25	0	0	55	37.9
SEB -3	5	3	7	0	0	15	11.33
SEB -4	0	8	5	0	2	15	744
SEB -5	2	0	2	0	0	4	1.28
SEB -6	9	1	10	0	0	20	20.53
SEB -7	10	4	18	0	0	32	22.48
SEB -8	4	0	7	0	0	11	3.62
SEB -9	3	6	3	0	0	12	10.62
SEB -10	4	0	1	0	0	5	4.65
SEB -11	7	11	16	0	1	35	46.87
SEB -12	9	17	23	0	4	53	37.78
SEB -13	17	25	19	0	0	61	50.23
Name of the Feeder	Month: 01/08/17-31/08/17						
	Causes of Interruption					Total Interruption Frequency	Total Duration of Interruption (HRs)
	OP	SC	EF	UF	OL		
SEB -1	3	4	3	0	1	11	31.65
SEB -2	12	19	21	0	5	57	35.6
SEB -3	4	1	14	0	0	19	2.4
SEB -4	6	2	3	0	0	11	9.23
SEB -5	2	2	1	0	0	5	1.4
SEB -6	7	5	20	0	0	32	62.7
SEB -7	9	3	8	0	0	20	12.6
SEB -8	2	1	10	0	0	13	7.93
SEB -9	8	8	5	0	0	21	34.7
SEB -10	1	2	4	0	0	7	16.7
SEB -11	15	6	18	0	0	39	28.3
SEB -12	8	19	13	0	3	43	46.9
SEB -13	14	5	21	0	0	40	31.9