OPTIMAL ALLOCATION OF DISTRIBUTED GENERATION IN DISTRIBUTION SYSTEMS

by

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Approval Signatures

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Dedication

To my Dear father and beloved mother…

Without whom, this work would have never been accomplished

Abstract

The integration of distributed generation (DG) to the power grid has increased in recent years due to their techno-economic benefits for utilities and consumers. The downside of these DG units is that they introduce several challenges to the utilities. One of the critical challenges faced by the utilities from such units is their effect on the protection system settings, location, and coordination. For designing the protection system, fault analysis is carried on the system without considering any DG units. Once the DG units are installed, all previous settings must be updated, since the addition of these units affects the pickup current settings of the protection relays, coordination between the primary and the secondary relays, and even the direction of the fault current. Failing to consider the DG effect on the protection system may lead to serious equipment damage or system failure costing the utility a huge financial setback. Moreover, DG units have many economic and technical effects that must be taken into consideration such as power loss, voltage profile, and thermal overloading. This work proposes a new method for DG allocation in the distribution system through genetic algorithm. The main objective of this work is to optimally allocate DG units to minimize the overall operating costs of the system while taking into consideration its intermittency and the protection system aspects. Simulation results have been developed on a typical distribution system. The optimally allocated DG units resulted in a reduction by 10 % in the overall system costs while upgrading the protection system to withstand the new configuration over the planning horizon.

Keywords: ***Distribution generation; genetic algorithms; renewable resources; smart grids.***

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List of Abbreviations

CB	Circuit breaker
CLR	Current Limiting Reactor
CS	Current Source Inverter
CT	Current Transformer
CTI	Coordination Time Interval
DG	Distributed Generator
FCM	Fault Current Management
IBDG	Inverter Based Distributed Generation
MPR	Microgrid Protection Relay
NR	Newton-Raphson
OCR	Over Current Relays
PE	Power Electronics
PF	Power Factor
PV	Photovoltaic
PVDG	Photovoltaic Distributed Generation
SDG	Synchronous Distributed Generation
SFCL	Superconducting Fault Current Limiter
TD	Transmission and Distribution
VSI	Voltage Source Inverter
WT	Wind Turbine
WTG	Wind Turbine Generator

Chapter 1. Introduction

The current scheme and operation of electricity generation is dominated by centralized power plants where high voltage power is transmitted over long distances via transmission lines feeding substations, which steps down the voltage for distribution to feed the consumer located anywhere from tens to hundreds of kilometers away from the original generation unit/power plants. Massive power loss takes place in the process of transmission and distribution (TAD) as a result of the lengthy TAD lines. Most of the power loss occurs in the distribution network due to its high currents and low voltages as the relationship between current and power losses is directly proportional and exponential in nature.

Distributed generation (DG) refers to distributed energy sources that are usually installed on the distribution network, which brings the generation unit closer to the consumer side. The original purpose of installing DG units, which is also one of the reasons they came into existence, is to overcome the disadvantages of the widely used centralized power generation. The IEEE defines DG as "the generation of electricity by facilities that are sufficiently smaller than central generation plants as to allow the interconnection at nearly any point on a power system" [1]. As such, DG generally refers to small-scale generators that produce a fraction of the power that a power plant can; typically, the rated power generation for a distributed generation unit is several kilowatts to tens of megawatts. These DG units can be stand-alone or integrated into an existing grid at the distribution level [2].

The addition of distributed generators to power grids in the past years has changed the way a power system is viewed; from a traditional centralized structure into a more decentralized and deregulated structure with many sectors focusing on delivering power to the consumers with flexibility and reliability. Distributed generation units are gaining considerable interest from utility investors, both institutional and private, since the units add a layer of flexibility in power generation. Despite the increasing use of these types of generation units, whether its synchronous based or inverter based (wind and solar) in power systems, the idea of DG is not yet defined nor universally accepted [3]. However, the research in this area mainly focuses on some common aspects regarding these generation units such as power rating, size, location, type and technologies revolving around their operation.

The main reason for the growing number of DG units in power systems is their capability to provide operational benefits for both the utilities and consumers by enhancing the power quality. Some of the main advantages for installing DG units in a power system are [4] :

- Reduction in transmission and distribution power losses.
- Reduction in transmission and distribution expansion and upgrades.
- Improvement of voltage profiles.
- Improvement of power quality.
- Environmental benefits.
- Improvement of load shaving.
- Increase in system reliability.

The downside of DG, when integrated into the power grid, is that the DG units increase the complexity of the system from the control, operation, design, planning and protection point of view. The allocation of the DG is such a critical matter that any misplacement of the generation units may cause a huge voltage drop or an overvoltage on certain points of the system, which may cause the system to shut down or even damage the equipment devices. Hence, protection of the system and all devices connected to the grid is very important [5, 6]. Moreover, due to the varying types of DG and different technologies, many forms of DG produce a DC voltage or a variable AC voltage. Therefore, power electronics (PE) interfaces are required to connect those DG units to the grid and keep them synchronized [7]. However, the most critical issue of DG installation in power systems is during the occurrence of a fault, when the additional current contributed from the DG will violate the original setting of the protection system and, in some cases, even violate the direction of the fault current, making the system vulnerable to equipment damage or a system blackout. This thesis introduces a method for distributed generation planning, taking into consideration protection equipment's location, cost, and scheme, keeping the system and equipment safe in case a fault occurs.

1.1. Overview

Protective devices installed in the power system are designed based on all types of fault analysis performed in the original system without considering any connected DG. In this way, the analysis for the fault is done considering the utility generation units, which are usually a centralized power operation, causing the current to be unidirectional. The protection designer calculates the fault currents from all types of faults that may occur on the system, which includes a line-to-ground, line-to-line, and line-to-line-to-ground faults. When DG units are integrated into the power system, they will contribute to the fault current in both the magnitude and making the fault current bidirectional depending on the placement of the DG. Hence, the fault current passing through the protective devices is altered from the values in the grid without DG that the devices were originally designed to accommodate. Depending on the type, generation rating and location of the DG units, this may affect the magnitude and direction of the fault current going through the protection devices, causing false tripping of the protective relay and altering the operation time between the primary and secondary relays. All these problems reduce the reliability of protection devices and, thus, the reliability of the power system.

From the previous discussion, it is a necessity to study and research the planning of DG in parallel with their protection requirements and schemes. The main focus is to find a solution that helps the utilities to install and integrate the DG unit, assisting investors to achieve the highest efficiency from an operational and economical point of view while keeping the system and its equipment safe in case of faults, thus increasing reliability. Flexible operation is obtained when it is possible to install a high number of DG units in the system, though the utilities usually set a maximum power generation capacity for certain areas since they fear the negative effects mentioned previously.

Many studies have been carried out to address the protection problems associated with DG. The main protection problem discussed and researched in literature is the increase in fault current going through the protective devices when DG units are installed in the system. Some researchers have proposed the replacement of the existing protective devices with new ones designed for the new configuration of the power system after the installation of DG units. The main disadvantage of this solution is that every time a new generation unit is added to the system, the old configuration is no longer valid, which is why an update to the configuration is required every time a generation unit is added. Moreover, some of the solutions proposed by those researches involve using adaptive protection devices which allow the protection devices to communicate with each other, changing the settings and configuration of the installed protection devices depending on the power injected by the generation unit at a specific time. Another set of literature review tries to minimize the contribution of the DG units fault current. These solutions are based on the ability of the power electronics devices to limit the current that is injected into the power grid in case of a fault, reducing the DG contribution to the fault current and benefiting from the fast operation of the semiconductor devices switching time.

In the planning of distributed generation, three types of generation are dominantly used by the industry, which are wind turbines, photovoltaic panels, and synchronous generators. Each one of these generation units has its own technologies, varying in size, operation, and characteristics. Wind turbines (WT) usually produce a variable frequency AC voltage at the output terminal, whereas the photovoltaic (PV) sources produce DC voltages at the output terminals; thus, both technologies require a power electronic system/interface to allow them to be connected to the active utility grid [8]. The main advantage of PE based generation units, including PV and WT, is that the PE interface has a current limiting characteristic built into the interface of the switching semiconductors, which limits the fault current while the generation unit is injecting power to the grid. The current injected from PE based generators usually varies between 100% to 300% of the rated current, whereas the fault current injected is highly affected by the technology, building blocks and the control strategy of the inverter-based distributed generator (IBDG) [9]. Another type of distributed generation that is widely used is synchronous generators. They are commonly used to convert mechanical power outputs of steam and gas turbines into electric power injected into the grid. These types of generation units have a higher fault current contribution since they lack the power electronics building scheme, depending on the technology used, the fault current contribution of these types of generation units is between 600% to 1000% of its rated current. It is a certainty that each technology has its advantages and disadvantages in regard to its contribution to the magnitude of fault currents. However, all types of DG share a critical disadvantage, which is the altering of the fault current direction. In conventional power grids, if a fault occurs, the fault current is usually unidirectional, though with the presence of DG, the fault currents may flow in a bi-directional manner regardless of the type of generation unit.

1.2. Research Objectives

The objective of the proposed thesis focuses on developing a planning algorithm to find the optimal size, location and type of DG units that would maximize the investor, developer or even the utility's benefits while minimizing the investment costs associated with DG planning over a project's lifetime. The study's main contribution to DG planning is that it takes into consideration the protection upgrades needed for installing these DG units, which is usually ignored by most researchers. Therefore, the main objective of the thesis can be summarized as

- Develop a comprehensive fault analysis technique to the distribution network for both synchronous and inverter-based DG.
- Develop a planning algorithm for DG allocation, including the protection system requirements and the uncertainty associated with renewable DG.
- Extend the planning approach to be dynamic, where multi-year decisions are developed utilizing Genetic Algorithm.

1.3. Thesis Organization

The remainder of the thesis is organized as follows:

Chapter 2 presents literature review prior to this research, a study on the effects of different technologies of DG on the power system and the effect of DG type and location in the fault current seen by protective devices. Chapter 3 presents background on power flow analysis methods. Chapter 4 presents the methodology of DG planning and protection, the formulation for the power flow, fault current analysis in presence of IBDG in a system and the models used in the study. Chapter 5 provides simulation results/discussion, the concluding remarks and future work.

Chapter 2. Background and Literature Review

2.1. DG Allocation

The DG allocation problem in distribution networks has been addressed and studied by many researchers. In [10], a multi-objective optimization technique is used, and the formulation is carried out to find the optimal location and size of a DG in an existing distribution network using a genetic algorithm. However, the study did not consider renewable resources-based DG.

The authors in [11] used an analytical method to solve the DG size and location problem on a radial distribution system with uniformly distributed load. The analytical method named by the author as the “2/3 rule” suggests installing DG units of 2/3 the capacity of incoming generation at 2/3 of the distribution line length. This technique is not effective for nonuniformly distributed or different load levels. Another problem not addressed by the study is the physical constraints for placing the DG at 2/3 of the line length. Similar analytical methods are carried out through other studies in [12] [13]. In [12], a single DG unit with fixed generation is used to investigate the effect of a single or multi-DG unit’s installation on the power loss and network performance index. The authors also proposed a new approximation formula to reduce the iterations needed for the required solution. In [13], a DG allocation problem was presented for both meshed and radial systems. The proposed method that tackled this problem was based on an exact loss formula applied to the power system to allocate a single DG unit in a meshed or radial system.

The planning study proposed in [14] focuses on optimal sizing and allocation of DG units in a radial distribution system to achieve minimum load supply costs. The technique adopted in the study was evolutionary programming. The results show a significant reduction in power cost because of decreasing the power loss caused by the addition of DG. In [15], the authors proposed a solution to the distribution expansion planning problem by considering the use of DG on the distribution level network rather than transmission network, thus avoiding the upgrades required for installing DG units in the transmission network, such as feeders, line upgrades, and substation upgrades. The study used particle swarm optimization, taking into consideration the economic and operational costs. The study results showed that the installation of DG units in the distribution network has more positive effects on the power system than installing it on the transmission line.

A genetic algorithm (GA) technique was used in [16] to solve a multi-objective optimization to find the near optimal sizes and location of DG units within a distribution-level network. The main objective was to minimize the power loss of the distribution-level system with varying loads. The authors modeled the load in time segments based on hours, comparing the results of the time-based load to the fixed-load approach, proving that the load modeling greatly affects the optimal location and size of DG planning. The distribution planning study carried out in [13] included four types of DG with different power factors. The study presents an analytical expression of finding the optimal size of those four different DG units with different power factors that can minimize the power losses in the distribution network. The proposed work investigates the improvement of DG planning research if DG units are not limited by type. Four types of DG technologies were considered in the study: type 1, real power injection, type 2, capable of P and Q injection, type 3, capable of injecting Q and type 4, capable of P injection and Q consumption. The study concluded that the operation power factor of the DG heavily affects the allocation results.

In [17] and [18], the authors used GA to find the optimal location for a mix of solar, wind and biomass DG units within a distribution network, aiming to minimize system losses through an annual time frame. The authors modeled the uncertainty of wind-based DG and solar-based DG in the study. The results of the study achieved a significant reduction in power loss for all possible operating conditions without violating any constraints. It is worth noting that the authors used the cost of energy as a fixed value, which is not the case in power systems as the cost of energy varies from hour to hour throughout the year. A planning integration problem for wind-based DG was presented in [19] for a distribution network. The objective was to maximize wind-based DG capacity in distribution networks while keeping the voltage from violating the constraints through voltage control of the DG unit and reconfigurations of feeder’s coordination. A particle swarm optimization technique was adopted and employed to solve the problem. The study did not take into consideration the load fluctuation in load.

A planning approach for a radial distribution network was presented in [20]. The approach focuses on allocating the DG units within the distribution network with the aim to minimize the network's power loss and maximize the voltage regulation. However, the DG types considered in the study were not renewable DG; moreover, the load was fixed. A methodology presented in [21] aimed to optimize the size and location of the renewable DG within the radial distribution network. The purpose of the study is to maximize the annual system benefits. The considered benefits included reduction of transmission losses, saving or delaying system upgrades, environmental benefits and the profit of selling energy. It's worth mentioning that the methodology used did not consider the varying energy prices and used two states to model the load for maximum and minimum load only.

The planning problem presented in [22] used an analytical method integrated with an optimal power flow algorithm. The objective is to find the near optimal size and location of DG units in the radial distribution network to minimize system losses. However, the study did not consider any renewable or IBDG units in the optimization problem. In [23] and [17], the authors proposed a new discrete probabilistic generation model with all possible generation and operation conditions. The probabilistic model is reduced into one deterministic model and solved using mixed integer nonlinear programming for finding the optimal allocation and type. However, in [23], the study only considered one wind DG allocation problem, while in [17] multiple types of DG are considered.

A DG allocation problem was introduced in [24] using the Monte Carlo method. The aim of the study was to minimize energy loss. The study concluded that using the Monte Carlo simulation to solve allocation problems produces similar results as other methods yet has a significant advantage in simulation time. The paper did not consider the energy cost savings due to the reduction in losses when the DG units are installed in the distribution system. A study utilizing genetic algorithms [25] looked to solve near optimal allocations of DG in distribution systems to minimize system losses. The study utilized a genetic algorithm optimization technique and achieved better results than most other similar studies available in literature. The authors used deterministic DG models with different types and different technologies to achieve those results. A different system configuration is considered in [25] and each configuration is optimized separately. The planning study took into account only the size and location of DG units without considering a varying load while keeping the cost under a specific load fixed with some constraints on energy price, creating multiple brackets of load pricing for each load type.

In [26], a planning study proposed a new methodology for planning for micro-grid systems. Reliability and supply adequacy indices were the main consideration of designing the micro-grid planning methodology, combining both aspects to create a new index. The new tribalistic index was considered in the main objective function of the optimization problem in formulation, concluding that DG planning in a micro grid and distribution network is an overall advantage for system performance and reliability. Unlike most previous studies, in [27], the planning approach for a distribution network assumed that demand response is active by real time pricing. It optimized both renewable and non-renewable DG and added smart metering to minimize the economic cost including carbon emission costs using genetic algorithm. The added smart metering is used primarily to reduce cost rather than generate profit, meaning the consumer energy generation is less than the consumption.

In [28], a methodology was proposed to eliminate the requirement of transmission upgrades for a growing load demand by adding DG units to the distribution level network and tie-line allocation. The allocation was based on load maximization using a district bee colony algorithm. The results from the study proved that both DG and tie-line allocation achieved better results when optimized together rather than each one separately. Moreover, the proposed method showed significant improvement to the network efficiency and reliability while reducing the total system losses. Similar to [28], the author in [22] utilized a bee colony algorithm to find the near optimal location, size and power factors of DG units in order to minimize energy losses in the distribution system. Both the studies demonstrated the effectiveness of bee colony algorithms to solve DG allocation problems.

In [29], the author applied particle a swarm optimization technique to reconfigure the distribution network reactive power dispatches of DG units aiming to enhance the overall performance of the network. The methodology focused on minimizing power loss, voltage regulation, decreasing voltage violation and reducing the energy wasted from renewable resources. The results demonstrated an increase in energy saving from renewable based DG and the effectiveness of the proposed reconfirmation and power dispatch, resulting in the maximization of renewable resource capacity. The proposed planning algorithm in [30] allocates DG units in distribution networks to achieve economic benefits. A mutual understanding and agreements between the owner of the DG unit or the investors of the DG units and the distribution company is proposed to achieve the best economic benefit for both the investor and the utilities. The unpredictable nature of renewable based DG was modelled in the study, and an optimal power flow was applied to the model with DG to obtain minimum power loss and minimum energy cost.

Another study to investigate the technical as well as the economic aspects related to the growth of DG units within the whole electrical network is [31]. The load and the market price variability is modelled in the study to give accurate results. The authors utilized particle swarm optimization techniques to study the operation of the DG in an active market, concluding that it is economically beneficial to install DG units. Another study that takes economic impact into consideration for its planning is [32]. The authors presented a new methodology to find the maximum energy gained from installing DG units considering the connection cost, energy loss savings and availability of resources. It is important to note that, in both studies, the authors did not take into consideration the protection costs associated with the installation of the DG units.

The study in [33] proposed a distribution planning problem for multiple DG allocation with different technologies to minimize power loss. The study proposed an improved analytical method, which is used to allocate the DG unit's optimal location, size and type. The study demonstrated a higher efficacy in the allocation of the DG units using the improved method. Another planning strategy is presented in [34] to find the near best allocation of DG that provide energy saving, voltage support and increase reliability overall. The study considered a scheduled power generation pattern, also known as load scheduling and day-ahead load dispatch, which is mostly used by utilities for power and economical dispatch. The active and reactive power generation capabilities' limit of dispatchable and non-dispatchable units were taken into consideration to achieve total harmony between the utility generation units and small DG units owners. The authors used probabilistic modelling to address the uncertainty associated with consumer load, wind speed and solar irradiance.

In [35], a planning methodology was proposed with the aim to encourage DG investors to adopt more projects that benefit both investors and the utility network. The proposed algorithm allocates the best sites and sizes of DG units to be installed along with payment incentives for DG installation, which minimize the investment cost and maximize the rate of return of the projects over an extended period of time. The idea is to allocate DG units so that the profit of a distribution company is maximized by obtaining energy from the DG and sharing the profits with the investors, keeping the DG and the market prices at minimum cost while ensuring the investment in the DG units is cost effective.

A usual DG planning problem investigates and studies the optimal allocation, type and size of the DG unit to be installed in the transmission or distribution network throughout one or multiple stages. The main objective function of a DG planning problem can be single or a multi-objective, mainly subjected to operational, network, and economical constraints. As seen from the previous literature reviews, the main objective functions researched in literature are:

- Minimization of the total energy and power loss in the system.
- Increase power system reliability.
- Minimization of cost.
- Maximization of DG capacity in the network.
- Increasing voltage profile and minimizing voltage deviations.
- Maximization of profits through benefits/cost ratio.

The most common constraints subjected to the formulation of DG planning objective functions are:

- Power flow constraints.
- Voltage limits constraints.
- Equipment’s limitation constraints.
- System harmonics constraints.
- Limited buses for DG installation.

There are different methods to solve a DG planning problem. The method used heavily depends on the objective function of the DG problem, along with complicity, constraints and number of variables. The most famous and widely used methods to solve DG planning problems are:

- Analytical methods.
- Numerical methods.
- Heuristic methods.

Each method used in literature has its advantages and disadvantages that depends on the modelling of the system in study and the objective function of the study. Analytical methods make simplified assumptions and usually consider a power system with fixed loads that are easy to implement, have high computational speed and require low computational effort. Numerical methods provide a more accurate solution to the DG planning problem, although the main disadvantage of numerical methods is that they cannot handle large scale systems with a lot of variables. The most numerical methods are nonlinear programming and quadratic programming, which are guaranteed to find the optimum solution to a given problem through an exhaustive search method. The most robust and flexible method is a heuristic method, which provides near-optimal solutions for large scale systems and variables with complex constraints. Heuristic methods include genetic algorithm, particle swarm optimization and practical heuristic algorithms. The main disadvantage of this method is that it requires high computational effort.

2.2. DG Impacts on Protection System

When DG units are added to an already existing network, the DG adds a new layer of complexity to the protection system. Since the integration of DG changes the conventional centralized power system configuration to a distributed and decentralized operation, this causes bi-directional power flow in the system in case of a fault. The current levels during the fault also are affected by the DG units. Fault currents usually increase in the presence of DG in the network in comparison with networks without DG contribution. Therefore, when DG is added to any network, the existing protection scheme prior to the DG installation will fail to operate efficiently and may cause harm to the network and false equipment’s tripping [36]. The required coordination of a protection device is necessary for a safe and reliable distribution network operation. The relay settings and placement must be studied and renewed after every DG installation. The protection coordination problem is discussed in [37], classifying the coordination problem into two categories, either downstream network coordination or downstream-upstream network coordination.

In power system protection, a primary and a secondary/backup relay are usually used. The settings of primary and secondary relays have to be changed accordingly for every additional DG installed in the network. Moreover, if possible, the directional elements should be added to the overcurrent relays to distinguish the upstream or downstream fault currents in the network after the installation of the DG in case power flow becomes bi-directional with the presence of a fault at a certain location. Determination of the new relay setting is a complicated task, especially if the DG planning is multi-stage with different DG types. Therefore, many algorithms are proposed and used in literature to solve the coordination problem through adaptive and non-adaptive algorithms [38, 39].

As mentioned previously, the impact of DG on the protection system is highly dependent on type, location, and size. The characteristics of a DG and the distribution network are also important and must be considered in DG planning and protection. It is important to mention that large fault current is from synchronous generation unit in any type of network, while the inverter-based DG contribution to the fault current is smaller [40].

In the protection system, the most popular devices used for protection in distribution networks are fuses and overcurrent relays. The prime objective in the study of protection coordination in literature are:

- Marinating the standard coordination time interval (CTI).
- Updating the time multiple setting of the relays (TMS).
- Optimizing selectivity, cost, and speed of protection system.
- Increasing the reliability of protection devices.

The contribution of DG units to the fault current in the grid is significant and must be taken into consideration while planning the allocation of DG units. As a result of the contributed current from DG, the fault current detected by the protection devices is greater than the original current from the main generation unit connected to the grid, which can cause serious protection problem if the fault current exceeds the protection device rating [41]. Even if the increase in the current does not harm the protection device, it will certainly disturb the coordination between the primary and secondary relays [42].

The presence of DG in a power system can affect the coordination between protective relays installed in the system. Consider a radial distribution system in Figure 2.1 with no DG installed in the system shown. In case a fault occurred on L-3, the fault current is only fed from the grid generation unit; hence, the fault observed by the relays would be equal. The three relays are designed to coordinate for a fault anywhere in the system. R-3 should operate first, followed by R-2, then R-1 with a delay between each relay operation depending on the CTI and TSM. On the other hand, if a fault occurred on L-1, the only relay that will sense the current coming from the grid generation will operate to clear the fault. It is important to note that, contrary to the case of L-3 fault, R-2 and R-3 do not sense any current when the fault occurs in L-3 since no current flows through them. When DG is added to the system, the new source will contribute to the current depending on the location; hence, the fault current seen by the relays will not be equal. In case of a fault at L-3, with DG units installed, the current observed in R-3 is greater than the current observed in R-2 and R-1. As such, R-3 senses the maximum fault current followed by R-2 and R-1 respectively. If the current exceeds the relay operation margins, then the coordination between them is lost or disturbed. In order to have an acceptable CTI, the protection system settings and coordination should be updated for every DG added to the system [43].

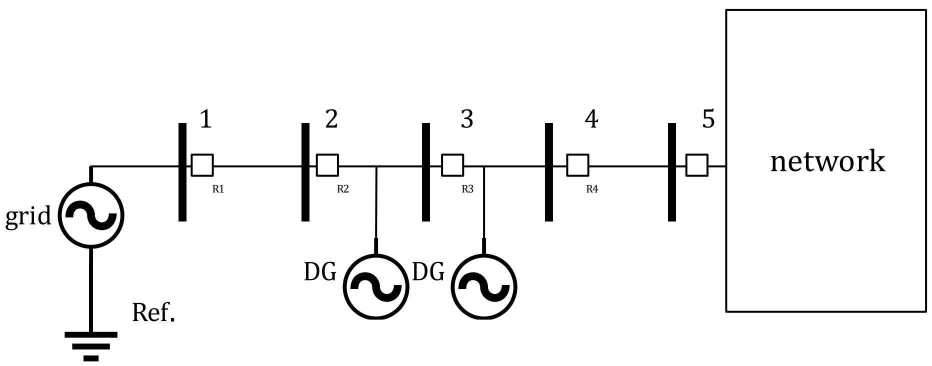

Figure 2.1: Part of the Distribution Network with OCR.

Another problem caused by DG on the protection system is that they may case bi-directional issue in the protection system and, eventually, disturb the system. This issue is more common in the distribution system where several feeders are fed from a common generation source. Consider the system shown in Figure 2.2, where two feeders are connected to the grid without the presence of a DG; if a fault occurred on either of the feeders, the fault current is fed from the grid only. Hence, only the protective device connected to the faulted feeder will operate. On the other hand, for example, when the DG is installed in the system at feeder-2 and a fault occurred on feeder-1, both the grid and the DG will contribute to the fault current. As a result of the DG contribution, relay-2 (R-2) will sense the fault current from the DG unit, causing R-2 to respond to a fault and de-energize the line, thus disconnecting a part of the system that is not affected by the fault. To overcome this unwanted response from the protection system, R-1 response time must be faster than R-2.

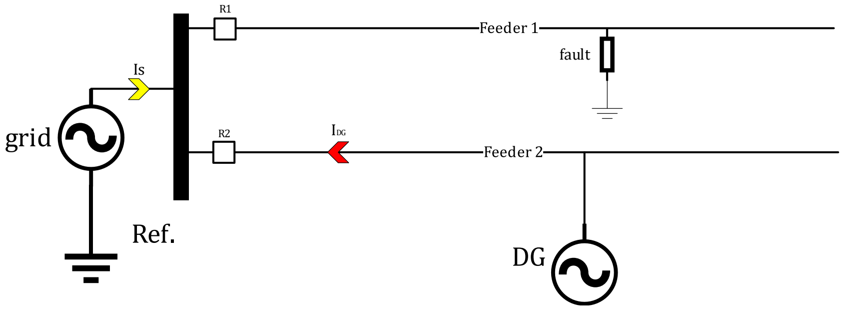

Figure 2.2: Radial Feeders with DG Unit.

Another problem which arises for the protection system when installing DG units is the ability of protective devices to see the fault current, known as the protection devices loss of sensitivity [44], which is illustrated in Figure 2.3. Without the presence of DG units in the system, the substation protective relay senses the minimum fault current coming from the grid generation unit. When DG is integrated into the network, the fault current is now fed from the grid and the DG unit and, as previously mentioned, the fault current from the DG unit depends on its size and type. The existing DG in the network will reduce the fault current contribution from the grid, which affects the minimum fault current that is sensed by the sustained protection relay. Hence, this reduces the possibility that the fault will not be detected by the protection system, causing damages to the network and consumer.

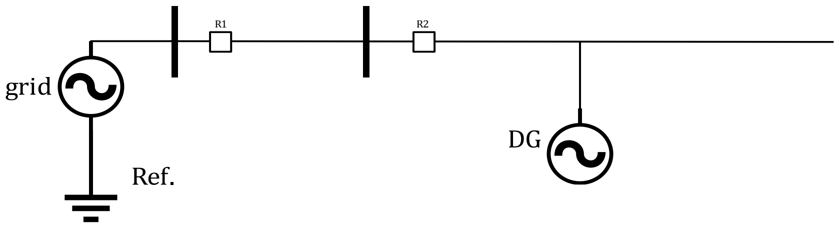

Figure 2.3: Relays in Radial System.

Some authors solve the protection problem in presence of DG units by replacing the protection devices in the system to more adaptable and advanced ones in order to increase the safety of the network operation. The authors of [45] investigated the fuse-recloser coordination problem in presence of DG. In case a fault occurs, the recloser will open when the fault occurs and, after a certain period, will close. In case the fault is still present in the system, the recloser will reopen. Otherwise, if the fault is cleared, it will stay closed. The authors suggest replacing the installed reclosers with microprocessor-based reclosers. This microprocessor based recloser can change the reclosing time of the device, allowing a suitable reclose timing to be chosen for different cases. For the system under study, the author shows that the fault current seen by the fuse is more than the fault current seen by the recloser; hence, a modification shifts the recloser curve to coordinate with the fuse. In [46], a similar idea is proposed but without the adaptive mechanism. The authors suggest choosing the minimum and maximum fault current, giving a wider range in the curve coordination. Minimum fault current is calculated when the DG is disconnected from the network, while maximum current is calculated when the DG is at full generation capacity. The fuse and recloser curves are coordinated in the obtained range.

An adaptive protection is proposed in [47]. The author proposes to modify the pickup current of the relay depending on the DG unit contribution. The main objective of the study is to minimize the effects of DG on the loss of sensitivity (LOS) on the substation overcurrent relay (OCR), which reduce the OCR capability to sense the actual fault current in the network. As a result, the operation time of the relay which is an inverse time OCR increases. In this way, the pickup current of the substation OCR must decrease when the DG is active. It is important to note that when the DG contribution increases, the pickup current of the OCR should decrease. The authors also note that if the DG is disconnected from the system, the proposed scheme can still work but will have a faster response time since the fault current sensed by the substation OCR is higher, indicating a faster response time.

In [48], the author proposed the use of microprocessor-based relays (MPR) to protect low-voltage networks, including islanded microgrids and on grid distribution level networks. The proposed protection system does not need a communication infrastructure, which is a huge economic benefit. The protection scheme relies on MPR capabilities to make decisions and choose the different operation modules. Since it’s not economical to replace all the protection system previously available in the network after adding a DG unit, only necessary OCR and fuses should be replaced. This includes the fuses connected between the DG and the grid. The protection scheme proposed consists of three protection modules: grid-connected mode, islanded mode and high impedance fault mode. The grid-connected mode is similar to the methods proposed in [45, 46].

Communication-based protective relays in the power system have gained more popularity as a solution for power system protection associated with DG with variable power output, despite the high cost of installation for these types of relays. In [49], the author addresses the problem of disconnecting all DG units in the system in case of a minor or temporary fault. The proposed solution is to divide the network into zones, each zone having the load and generation of DG balanced; therefore, in case a fault occurred in any part of the system, only the affected zone is de-energized and the rest of the zones can stay connected to the grid or work in islanded mode. It is important to note that, in each zone, at least one DG must have frequency control capabilities to keep the balance between generation and load.

The authors in [50] proposed a new methodology utilizing a multi objective genetic algorithm to optimize the coordination, allocation, and selectivity of protective devices in a distribution network in the presence of DG. The DG units used in the study are synchronous-based with data for the generation units found in [51]. The author placed three generation units in a 135-bus system, proposing a mathematical model that considers economic issues and network operation to optimize the protection system. From a set of solutions obtained from the multi-objective genetic algorithm, the author concludes that there is always a trade-off between the economic objective and the operation objective, meaning that, for better reliability and equipment safety, more money must be invested on the protection system.

In [52], the authors address the effects caused by DG on non-radial distribution feeders since the OCR on those feeders is only expected to detect unidirectional current coming from the grid. A reliability algorithm is developed for the general cases in non-radial systems to study the impact of DG capacity and constraints on the reliability index. The main contribution of the paper is to optimize the placement of protection devices for a given DG located unit, optimize a DG for a given protection system and optimize the placement of both DG and protection together, usually in the planning phase. The network model used in the study is an asymmetrical three phase non-radial feeder.

In recent years, fault current limiters have been widely studied by researchers as a potential solution to solve the protection problem associated with DG unit installment in the network. In [53] [54], the authors suggest installing fault current limiters (FCL). In series with DG units, the FCL is connected at the output cables, which connects the DG output to the grid, minimizing their contribution to the fault current. FCL is usually used for synchronous generation units, since FCL have the highest fault current contribution with respect to wind and solar. It is shown that the addition of FCL on synchronous based DG units will minimize its fault current contribution, improve the DG unit stability and reduce the effects of DG units on the coordination of the protection system.

FCL is a new concept and needs a lot of development due to its operational time. In [55], transient fault current is used for the coordination of the protection system in a distribution network with DG units. The author considers the transient fault current from synchronous DG showing through simulation that the FCL is very effective at limiting the steady state fault current. Yet, due to high response time and fault detection delay, the transient current is unaffected. Hence, the disturbance between the coordination of the protection devices is still possible due to the transient fault current. As shown in [56], simulation results demonstrate that when a transient current is applied on a protection system that is designed for the steady state fault current condition, the coordination between the relays are lost. However, if the OCR is designed for transient level, the coordination is unaffected. From an economical point of view, if a system was designed for steady state fault currents, it is very costly to change the setting of each relay in the system. This leads back to one of the main objectives of DG installation, which is minimizing investment costs.

In [57], several miscoordination problems caused by DG units are studied. The effectiveness of FCL in restoration the fault current level and the original protection setting in the power system is investigated. Concluding that FCLs are capable of restoring the original protection scheme, if the detection and response to the fault is fast enough. Furthermore, FCL optimization is discussed in [58] and [59] as the way to eliminate the contribution of DG in fault current. The authors of these two studies utilized the genetic algorithm to obtain the near optimal location, size and number of FCLs. The objective of the studies is to minimize the number of protection devices that need replacement or adjustment. The study included the number of FCLs that needs to be added to restore the protection settings, the cost of the FCLs, the number and cost of protection devices that should be replaced in the process. Comparing the results, it is concluded that the location and number of FCL are heavily dependent on the prices of the equipment; it is expected that prices of FCL will decrease with time due to various technologies available.

Chapter 3. Power Flow Analysis

Power flow study is an essential tool for investigating power system behavior. Power flow is a numerical analysis method used for interconnected power system whether it is a radial or meshed system. This type of analysis has to be done for the planning stage, day-to-day operation, control, economic dispatch and unit commitment. Power flow investigates the active and reactive power in the system, voltage profile and phase angles using iterative methods. The most common type of power flow analysis used in the literature are:

- Gauss-Seidel.
- Newton-Raphson.
- Forward-Backward sweep.

The first step begins by identifying the known and the unknown variables in the system. In power system, there are three types of nodes, PV nodes, PQ nodes, and slack node. The node type is important for power flow analysis as it gives us the essential known variable in the system.

1. PQ nodes: for PQ nodes, the active and reactive power are known, while the voltage and phase angle θ of the bus is unknown and should be found through iterations. Usually, substation nodes are considered as PQ nodes; moreover, if a DG is connected to the system with a fixed active and reactive power, the node connecting the DG to the network can be also considered as a PQ node.

2. PV nodes: for PV nodes, active power and voltage magnitude are known variables and specified in the analysis; bus angle θ and the reactive power Q is unknown. Usually, the PV node must have some sort of reactive power control that can maintain the node voltage at a certain value; hence, buses with capacitor banks installed on them are usually PV nodes. Furthermore, power plant or DG buses can be considered as PV nodes if the generation unit is capable of enough reactive power compensation to control the power.

3. Slack node: also known as the slack bus, it is considered the reference node. In power flow analysis, there should be only one slack bus specified in the power

system. The slack bus has a constant voltage and phase, where V=$1_{p.u}$ with zero phase angle. The reactive and active power is the variable to be solved in a slack bus, since the effective generation at this node is responsible for loss compensation in the network. The magnitude of the losses cannot be calculated in the system unless all the currents are calculated; hence, one bus must have zero constraints on the active and reactive power to feed the losses in the system.

As mentioned above, power system load flow analysis can be considered as an analytical problem solving for active power, reactive power, voltage or phase. Complex power is represented by equations of complex voltages. After obtaining the set of equations, iterative or nonlinear methods are utilized to solve the unknown variables. Transmission lines are presented by the admittance between the buses and the system admittance is presented in a matrix called the admittance matrix. If there is no transmission line between the i^{th} and j^{th} bus, the corresponding element Y_{ij} in the admittance matrix is simply set to 0. The relation between the admittance matrix, bus current and voltages are given as:

$$(I_{bus} = Y_{bus} V_{bus}) \tag{3.1}$$

$$Y_{bus} = \begin{bmatrix} Y_{11} & Y_{12} & Y_{13} & \cdots & Y_{1n} \\ Y_{12} & Y_{2} & Y_{23} & \cdots & Y_{2n} \\ \vdots & \vdots & \vdots & \ddots & \vdots \\ Y_{1n} & Y_{2n} & Y_{3n} & \cdots & Y_{nn} \end{bmatrix} \tag{3.2}$$

Where the Y matrix elements are denoted as:

$$Y_{ii} = |Y_{ii}|\angle\theta_{ii} = |Y_{ii}|(\cos\theta_{ii} + j\sin\theta_{ii}) = G_{ii} + jB_{ii} \tag{3.3}$$

$$Y_{ij} = |Y_{ij}|\angle\theta_{ij} = |Y_{ij}|(\cos\theta_{ij} + j\sin\theta_{ij}) = G_{ij} + jB_{ij} \tag{3.4}$$

For the real and reactive power generated or consumed by the bus, which is directly related to the complex voltages on the buses, we can formulate the voltages, current injections, real and reactive power as:

$$V_i = |V_i|\angle\delta_i = |V_i|(\cos\delta_i + j\sin\delta_i) \tag{3.5}$$

$$I_i = Y_{i1}V_1 + Y_{i2}V_2 + \cdots + Y_{in}V_n = \sum_{k=1}^{n} Y_{ik}V_k \tag{3.6}$$

Assuming the current injected in the bus to be positive and current consumed by the bus to be negative, the complex power at bus-i is given by:

$$P_i - jQ_i = V_i^* I_i = V_i^* \sum_{k=1}^{n} Y_{ik} V_k \tag{3.7}$$

$$= \sum_{k=1}^{n} |Y_{ik} V_i V_k| (\cos \delta_i - j \sin \delta_i)(\cos \theta_{ik} + j \sin \theta_{ik})(\cos \delta_k + j \sin \delta_k) \tag{3.8}$$

Therefore, the real and reactive power can be formulated as:

$$P_i = \sum_{k=1}^{n} |Y_{ik} V_i V_k| \cos(\theta_{ik} + \delta_k - \delta_i) \tag{3.9}$$

$$Q_i = -\sum_{k=1}^{n} |Y_{ik} V_i V_k| \sin(\theta_{ik} + \delta_k - \delta_i) \tag{3.10}$$

3.1. Gauss-Seidel Method

The power flow equations (3.9) and (3.10) are nonlinear equations. In an N-bus system, the system has different type of buses, PV-buses, PQ-buses and one slack bus. Each type of bus has its own variables, as mentioned previously. However, it is difficult to obtain a set of closed-form equations from the given power flow formulas; therefore, iterative methods are commonly used to solve the load flow problem. In Gauss-Seidel method, at the beginning of the algorithm, a set of values for the unknown variables is chosen, then the set is updated with each iteration until the errors between the calculated values and actual values are below a pre-set value. The pre-set value depends on how accurate the user wants the obtained solution to be; for higher accuracy, the pre-set value should decrease. The downside for high accuracy is that the number of iterations will increase.

In the Gauss-Seidel method, PV and PQ buses are treated differently. The voltages are updated using the complex power equations. The real and reactive power injection formulas at a certain bus are modified as follows:

$$P_{i,jj} - jQ_{i,jj} = V_i^* \sum_{k=1}^{n} Y_{ik} V_k = V_i^* \left[Y_{il} V_1 + Y_{i2} V_2 + \cdots + Y_{ij} V_i + \cdots + Y_{in} V_n \right] \tag{3.11}$$

$$V_i = \frac{1}{Y_{ii}} \left[\frac{P_{i,inj} - jQ_{i,inj}}{V_i^*} - Y_{i1} V_1 - Y_{i2} V_2 - \cdots - Y_{in} V_n \right] \tag{3.12}$$

In the iterative procedure, the voltages of all the buses are updated as such:

$$V_2{}^{(1)} = \frac{1}{Y_{22}}\left[\frac{P_{2,inj} - jQ_{2,inj}}{V_2^{*(0)}} - Y_{21}V_1 - Y_{23}V_3{}^{(0)} - Y_{24}V_4{}^{(0)} - Y_{25}V_5{}^{(0)}\right] \quad (3.13)$$

For PV buses, the real power is known while the reactive power and phase angel are the unknown. Therefore, to update the voltages of a PV bus, the reactive power must be calculated first as shown:

$$Q_{i,inj} = -Im\left[V_i^*\sum_{k=1}^{n} Y_{ik}V_k\right] = -Im[V_i^*\{Y_{i1}V_1 + Y_{i2}V_2 + \cdots + Y_{ii}V_i + \cdots + Y_{in}V_n\}] \quad (3.14)$$

$$V_i = \frac{1}{Y_{ii}}\left[\frac{P_{i,inj} - jQ_{i,inj}}{V_i^*} - Y_{i1}V_1 - Y_{i2}V_2 - \cdots - Y_{in}V_n\right] \quad (3.15)$$

3.2. Newton-Raphson Method

Newton-Raphson is used to solve a set of nonlinear equations, that have a set of n nonlinear equations with n variables [x_1, x_2, …, x_n]. This is exactly the type of problem presented in power flow analysis. n represents the number of buses in the system, assuming initial values for n variables are [$x_1^{(0)}$, $x_2^{(0)}$, …, $x_n^{(0)}$], and with each iteration, these values are updated with a correction set of variables [$\Delta x_1^{(0)}$, $\Delta x_2^{(0)}$, …, $\Delta i_n^{(0)}$]; hence, the final equation of the set variables can be written as:

$$\begin{gathered} x_1^* = x_1{}^{(0)} + \Delta x_1{}^{(0)} \\ x_2^* = x_2{}^{(0)} + \Delta x_2{}^{(0)} \\ \vdots \\ x_n^* = x_n{}^{(0)} + \Delta x_n{}^{(0)} \end{gathered} \quad (3.16)$$

The set of nonlinear equation (f) is a function of the variables [$x_1^{(0)}$, $x_2^{(0)}$, …, $x_n^{(0)}$] that can be written as:

$$\begin{gathered} f_1(x_1, \cdots, x_n) = \eta_1 \\ f_2(x_1, \cdots, x_n) = \eta_2 \\ \vdots \\ f_n(x_1, \cdots, x_n) = \eta_n \end{gathered} \quad (3.17)$$

Hence, defining another function g as shown below:

$$\begin{gathered} g_1(x_1, \cdots, x_n) = f_1(x_1, \cdots, x_n) - \eta_1 = 0 \\ g_2(x_1, \cdots, x_n) = f_2(x_1, \cdots, x_n) - \eta_2 = 0 \\ \vdots \\ g_n(x_1, \cdots, x_n) = f_n(x_1, \cdots, x_n) - \eta_n = 0 \end{gathered} \quad (3.18)$$

We can g in terms on x as:

$$g_k(x_1^*, \cdots, x_n^*) = g_k\left(x_1{}^{(0)} + \Delta x_1{}^{(0)}, \cdots, x_n{}^{(0)} + \Delta x_n{}^{(0)}\right), \quad k = 1, \dots, n \tag{3.19}$$

Expanding the equation through Taylor series around nominal set values x, giving as an expression of the function (g) as:

$$g_k(x_1^*, \cdots, x_n^*) = g_k\left(x_1{}^{(0)}, \cdots, x_n{}^{(0)}\right) + \Delta x_1{}^{(0)} \left.\frac{\partial g_k}{\partial x_1}\right|^{(0)} + \Delta x_2{}^{(0)} \left.\frac{\partial g_k}{\partial x_2}\right|^{(0)} + \cdots + \Delta x_n{}^{(0)} \left.\frac{\partial g_k}{\partial x_n}\right|^{(0)} \tag{3.20}$$

Or in matrix representation as:

$$\begin{bmatrix} \partial g_1/\partial x_1 & \partial g_1/\partial x_2 & \cdots & \partial g_1/\partial x_n \\ \partial g_2/\partial x_1 & \partial g_2/\partial x_2 & \cdots & \partial g_2/\partial x_n \\ \vdots & \vdots & \ddots & \vdots \\ \partial g_n/\partial x_1 & \partial g_n/\partial x_2 & \cdots & \partial g_n/\partial x_n \end{bmatrix}^{(0)} \begin{bmatrix} \Delta x_1{}^{(0)} \\ \Delta x_2{}^{(0)} \\ \vdots \\ \Delta x_n{}^{(0)} \end{bmatrix} = \begin{bmatrix} 0 - g_1\left(x_1{}^{(0)}, \cdots, x_n{}^{(0)}\right) \\ 0 - g_2\left(x_1{}^{(0)}, \cdots, x_n{}^{(0)}\right) \\ \vdots \\ 0 - g_n\left(x_1{}^{(0)}, \cdots, x_n{}^{(0)}\right) \end{bmatrix} \tag{3.21}$$

The square matrix of partial derivates is known as a Jacobian matrix, *J*; hence, by reformulating the original set of the equation and through the Taylor series, the final matrices can be formulated as:

$$\begin{bmatrix} \Delta x_1{}^{(0)} \\ \Delta x_2{}^{(0)} \\ \vdots \\ \Delta x_n{}^{(0)} \end{bmatrix} = \left[J^{(0)}\right]^{-1} \begin{bmatrix} \Delta g_1{}^{(0)} \\ \Delta g_2{}^{(0)} \\ \vdots \\ \Delta g_n{}^{(0)} \end{bmatrix} \tag{3.22}$$

Since the Taylor series is infinite, any 2nd order values or higher is neglected. Thus, the initial values are just an approximation of the Taylor series, so more iterations are needed to find the accurate solution. It is important to note that if the initial iteration included higher order values of the Taylor series, the number of iterations to reach an accurate solution is decreased.

Applying Newton-Raphson in power systems for power flow analysis, assuming a system with *n*-buses including PV, PQ, and slack bus, as well as using the mismatch equation for the real P and reactive power Q, with each iteration a new Jacobian matrix is formed for the correction values as:

$$J\begin{bmatrix} \Delta\delta_2 \\ \vdots \\ \Delta\delta_n \\ \frac{\Delta|V_2|}{|V_2|} \\ \vdots \\ \frac{\Delta\left|V_{1+n_p}\right|}{\left|V_{1+n_p}\right|} \end{bmatrix} = \begin{bmatrix} \Delta P_2 \\ \vdots \\ \Delta P_n \\ \Delta Q_2 \\ \vdots \\ \Delta Q_{1+n_p} \end{bmatrix} \tag{3.23}$$

The Jacobian matrix is divided into a submatrix as:

$$J = \begin{bmatrix} J_{11} & J_{12} \\ J_{21} & J_{22} \end{bmatrix} \tag{3.24}$$

The size of the Jacobian matrix is $(n + n_p - 1) \times (n + n_p - 1)$, where n is the total number of buses in the system while n_p represents the number of PQ buses. Assuming a 5-bus system shown in Figure 3.1, the total number of buses n=5 and n_p=3; therefore, the dimension of the Jacobian matrix is (7 × 7).

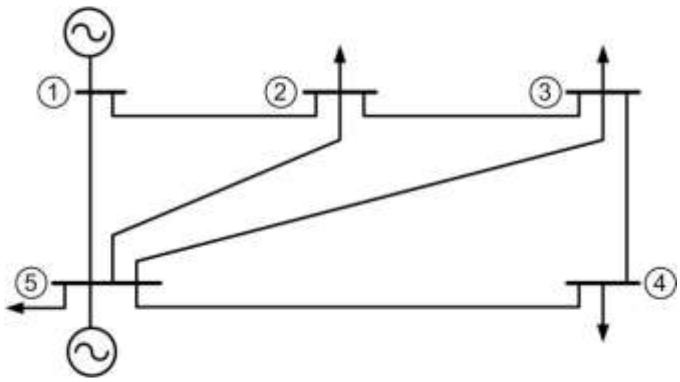

Figure 3.1: A 5 Bus System with Two Generation Units.

The formation of the submatrices in the Jacobian matrix is done using the rewritten real and reactive power equation as shown:

$$P_i = |V_i|^2 G_{ii} + \sum_{\substack{k=1 \\ k\neq i}}^{n} |Y_{ik} V_i V_k| \cos(\theta_{ik} + \delta_k - \delta_i) \tag{3.25}$$

$$Q_i = -|V_i|^2 B_{ii} - \sum_{\substack{k=1 \\ k\neq i}}^{n} |Y_{ik} V_i V_k| \sin(\theta_{ik} + \delta_k - \delta_i) \tag{3.26}$$

Defining J_{11} as a partial derivate of P_i with respect to δ_k; hence, J_{11} can be summarized as:

$$J_{11} = \begin{bmatrix} L_{22} & \cdots & L_{2n} \\ \vdots & \ddots & \vdots \\ L_{n2} & \cdots & L_{nn} \end{bmatrix} \tag{3.27}$$

$$L_{ik} = \frac{\partial P_i}{\partial \delta_k} = -|Y_{ik} V_i V_k| \sin(\theta_{ik} + \delta_k - \delta_i)\,, \quad i \neq k \tag{3.28}$$

$$L_{ii} = \frac{\partial P_i}{\partial \delta_i} = \sum_{\substack{k=1 \\ k\neq i}}^{n} |Y_{ik} V_i V_k| \sin(\theta_{ik} + \delta_k - \delta_i), \quad i = k \tag{3.29}$$

Defining J_{21} as a partial derivate of Q_i with respect to δ_k; hence, J_{21} can be summarized as:

$$J_{21} = \begin{bmatrix} M_{22} & \cdots & M_{2n} \\ \vdots & \ddots & \vdots \\ M_{n_p 2} & \cdots & M_{n_p n} \end{bmatrix} \tag{3.30}$$

$$M_{ik} = \frac{\partial Q_i}{\partial \delta_k} = -|Y_{ik} V_i V_k| \cos(\theta_{ik} + \delta_k - \delta_i)\,, \quad i \neq k \tag{3.31}$$

$$M_{ii} = \frac{\partial Q_i}{\partial \delta_i} = \sum_{\substack{k=1 \\ k\neq i}}^{n} |Y_{ik} V_i V_k| \cos(\theta_{ik} + \delta_k - \delta_i) = P_i - |V_i|^2 G_{ii}, \quad i = k \tag{3.32}$$

Defining J_{12} as a partial derivate of P_i with respect to $|V_i|$; hence, J_{12} can be summarized as:

$$J_{12} = \begin{bmatrix} N_{22} & \cdots & N_{2n_p} \\ \vdots & \ddots & \vdots \\ N_{n2} & \cdots & N_{nn_p} \end{bmatrix} \tag{3.33}$$

$$N_{ik} = |V_k| \frac{\partial P_i}{\partial |V_k|} = |Y_{ik} V_i V_k| \cos(\theta_{ik} + \delta_k - \delta_i) = -M_{ik} \quad i \neq k \tag{3.34}$$

$$N_{ii} = |V_i| \frac{\partial P_i}{\partial |V_i|} = |V_i| \left[2|V_i| G_{ii} + \sum_{\substack{k=1 \\ k\neq i}}^{n} |Y_{ik} V_k| \cos(\theta_{ik} + \delta_k - \delta_i) \right], \quad i = k \tag{3.35}$$

Following the same methodology, we can formulate J_{22} since it is a partial derivate of Q_i with respect to $|V_i|$ as:

$$J_{22} = \begin{bmatrix} O_{22} & \cdots & O_{2n_p} \\ \vdots & \ddots & \vdots \\ O_{n_p2} & \cdots & O_{n_pn_p} \end{bmatrix} \tag{3.36}$$

$$O_{ik} = |V_i|\frac{\partial Q_i}{\partial |V_k|} = -|V_i||Y_{ik}V_iV_k|\,sin(\theta_{ik} + \delta_k - \delta_i) = L_{ik}, \quad i \neq k \tag{3.37}$$

$$O_{ii} = |V_i|\frac{\partial Q_i}{\partial |V_k|} = |V_i|\left[-2|V_i|B_{ii} - \sum_{\substack{k=1 \\ k\neq i}}^{n}|Y_{ik}V_k|\,sin(\theta_{ik} + \delta_k - \delta_i)\right], \quad i = k \tag{3.38}$$

The steps for solving power system using Newton-Raphson is simplified in the flow chart in Figure 3.2.

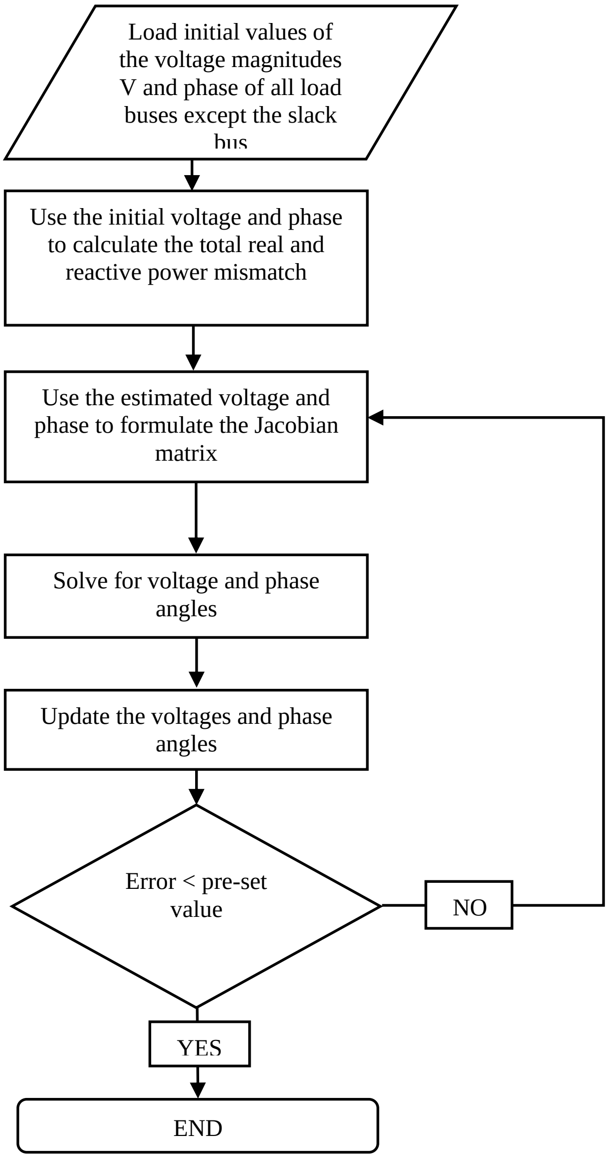

Figure 3.2: Flow Chart for Newton-Raphson Method.

3.3. Forward-Backward Sweep

Due to some ill-conditioned features in distribution systems, the traditional use of Gauss-Seidel, Newton-Raphson and other power flow solving techniques fail to successfully solve the power flow problem. Some of the special features that may cause the system to be ill-conditioned are:

- High R/X ratios.
- Weak meshed or radial networks.
- Unbalanced operation.
- Unbalanced distribution loads.
- Installation of DG units.

Thus, the backward-forward sweeping process is proposed to solve these types of up-normal distribution networks, without need for the calculation of a Jacobian matrix used in Newton Raphson method [60]. However backward forward sweep (BFS) is not efficient in solving active distribution networks. BFS numbers the nodes in ascending order then adds layers to the network, in the theory similar to building a Z matrix. The layer added in the path from the root node to the terminal node encounters other nodes, which are also numbered in ascending order.

The load flow can be then solved iteratively from two separate sets of equations; one for the forward sweep and the other for the backward sweep. The first set of equations calculates the power flow through the nodes starting from the highest branch numbered, which is the last branch in the system, then proceeds the backward sweep until it reaches the first node. the forward sweep uses the other set of equations to calculate the voltages and phases of each node starting from the root node and proceeding in a forward direction towards the last node.

The formulation of the BFS is given as:

$$P_{k+1} = P_k - P_{Loss,k} - P_{Lk+1} \tag{3.39}$$

$$Q_{k+1} = Q_k - Q_{Loss,k} - Q_{Lk+1} \tag{3.40}$$

Where P_k represents the real power flowing out, Q_k represents the reactive power flowing out, P_{Lk+1} and Q_{Lk+1} is the load on the bus. The voltage and phase can be calculated from the following equation:

$$I_k = \frac{V_k \angle \delta_k - V_{k+1} \angle \delta_{k+1}}{r_k + jx_k} \tag{3.41}$$

Chapter 4. Fault Analysis

This chapter discusses the modeling of the system under fault conditions. Under normal conditions, the power flow equations and methods are capable of solving the power system variables, but in case of fault, the system becomes ill-conditioned and considered an abnormal system. Normal power flow analysis of an ill-conditioned system will not converge. Hence, fault analysis, also known as short circuit analysis, is required to study the system in case of fault occurrence. A short circuit fault occurs when the isolation system failure results in a short circuit with low impedance in the system. There are two types of short circuit faults:

- Symmetrical faults.
- Unsymmetrical faults.

Symmetrical includes the three transmission lines. The most occurring symmetrical fault are LLL fault or LLLG faults. Hence, all lines are affected by the fault current and the system remains balanced respectively. This type of fault has the most severe effects on the network since it causes the highest fault current in the system. Fault current analysis is usually carried on for the installment and design of the protection system while taking the worst-case scenario into consideration, which is a symmetrical three-phase fault.

In fault current analysis, the first step is to obtain the admittance matrix *Y*. The *Y* matrix is already created from the Newton-Raphson method since it is used in power flow analysis. Moreover, the pre-fault voltages calculated in the power flow will be used to find the new bus voltages post-fault. After obtaining the *Y* matrix, the *Y* matrix is converted to an impedance matrix called the *Z* bus matrix. The relation between the *Y* bus and the *Z* bus matrix is:

$$\boldsymbol{Z}_{bus} = \boldsymbol{Y}_{bus}^{-1} \tag{4.1}$$

Since the system is under fault, the faulted bus *K* is assumed to be the only bus with current injection. This assumption is viable since the fault current is much higher than the load currents in other buses; therefore, to calculate the fault current injected at the fault, using the pre-fault voltage at bus-*k* as:

$$I_f = \frac{V_k^{(1)}}{Z_{kk}} \tag{4.2}$$

Where Z_{kk} represents the impedance seen by bus k, $V_k^{(1)}$ represents the pre-fault voltage on bus k and I_f is the fault current. This equation will represent the worst case for three-phase fault, where the fault impedance is equal to zero, hence maximizing the fault current. After calculating the fault current, the Z bus matrix and the injected fault current is used to see the effects the current has on the pre-fault voltages through equation (4.3) and (4.4) as:

$$[\boldsymbol{Z}][\boldsymbol{I}] = \boldsymbol{V} \tag{4.3}$$

$$\begin{bmatrix} Z_{11} & \cdots & Z_{1n} \\ \vdots & \ddots & \vdots \\ Z_{n1} & \cdots & Z_{nn} \end{bmatrix} \begin{bmatrix} \vdots \\ 0 \\ -I_f \\ 0 \\ \vdots \end{bmatrix} = \begin{bmatrix} V_1^{(2)} \\ V_2^{(2)} \\ \vdots \\ V_{n-1}^{(2)} \\ V_n^{(2)} \end{bmatrix} \tag{4.4}$$

Where I_f is the calculated fault current, Z is the impedance matrix and $V_i^{(2)}$ is the change in voltage on the buses due to the fault current. The bus voltages V_f during the fault is calculated as:

$$V_f = V_i^{(1)} + V_i^{(2)} \tag{4.5}$$

4.1. Fault Analysis in Presence SDG

Synchronous generators are used to generate electrical energy from high power mechanical rotational machines called turbines [61]. The most popular types of turbines are gas, steam and hydro turbines. These types of generators are usually modelled as a voltage source followed by a series impedance [62]. In the case of fault, a synchronous generator is modeled as a decaying voltage source with a constant impedance to represent the characteristics of the machine or, in some cases, the generator is modeled as a constant voltage and an increasing impedance for simplicity [63]. For the first few cycles in fault conditions, the fault current produced by the generators consists of both AC and DC components, reaching the maximum fault current then decaying rapidly due to the resistance and inductance of the circuit.

The effects of DG have been analysed in depth in [64]. Consider the system shown in Figure 4.1. For a fault R_f, if no DG unit is connected to the system, the fault current following through the lines and the two relays are equal to the current fed by the grid since it is the only source for the fault current in the system.

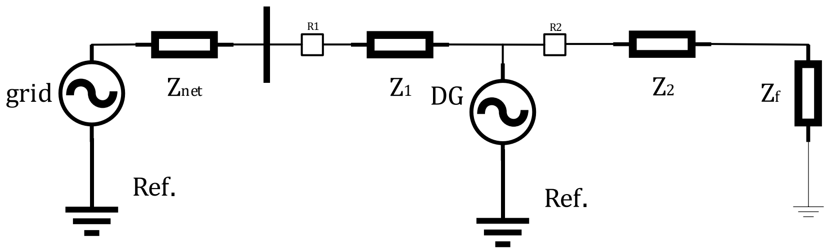

Figure 4.1: Radial System with Synchronous DG.

$$I_s = \frac{E}{Z_{net} + Z_1 + Z_2 + R_f} = I_{R_1} = I_{R_2} \tag{4.6}$$

The fault impedance is represented as R_f, Z_1 and Z_2 represent the line impedance, Z_{net} represents the network impedance upstream of the substation and E is the grid voltage source.

When a synchronous DG is installed as shown in Figure 4.1, for the same fault location and same impedance R_f, the fault current contribution of the grid and synchronous DG is calculated as:

$$\left(\mathrm{I}_{\mathrm{s_{DG}}} = \frac{\mathrm{E}}{\mathrm{Z}'}\right) \tag{4.7}$$

$$I_{Synch} = \frac{E_{Synch}}{Z''} \tag{4.8}$$

Where

$$Z' = \frac{X' \times \left(Z_2 + R_f\right)}{X' + Z_2 + R_f} + Z_1 + Z_{Net} \tag{4.9}$$

$$Z'' = \frac{(Z_1 + Z_{Net}) \times \left(Z_2 + R_f\right)}{Z_1 + Z_{Net} + Z_2 + R_f} + X' \tag{4.10}$$

The current contribution from the synchronous generator during fault flows in all parts of the system. The current flowing is calculated as:

$$I_{Synch_1} = I_{Synch} \cdot \frac{Z_2 + Z_{flt}}{Z_{net} + Z_1 + Z_2 + R_f} \tag{4.11}$$

$$I_{Synch_2} = I_{Synch} \cdot \frac{Z_1 + Z_{net}}{Z_{net} + Z_1 + Z_2 + R_f} \tag{4.12}$$

Hence, the fault current seen by the relays is calculated as:

$$I_{R_1} = I_{s_{DG}} - I_{Synch_1} \tag{4.13}$$

$$I_{R_2} = I_{s_{DG}} + I_{Synch_2} \tag{4.14}$$

Comparing the two cases with and without the installation of the DG, it is clear that the fault current seen in the second relay increases in presence of the DG, while the current seen by the first relay will be less respectively. It is important to note that currents sensed by the relays are highly dependent on the impendence of the line, DG reactance and fault impedance.

4.2. Fault Analysis in Presence IBDG

Inverter-based generation units such as wind turbines and photovoltaic panels require a power electronic block/interface to be effectively connected to the power system. Depending on the type of power produced by the generators, the power electronic used consists of a combination of DAC inverters, DAC inverters and rectifiers. In order to simplify the analysis, IBDG is modeled as a constant DC source at the input of the grid [65].

Advanced studies and solutions have been proposed in the literature to keep the DG active in the system in case of fault and minimize the DG contribution to the fault current. The need to model such IBDG units is extremely crucial for a complete and accurate fault current analysis of the power system that contains such units. Unlike the behavior of synchronous generation units, which is well known, the behavior of IBDG during fault conditions is highly dependent on the type, technology, and control unit of the IBDG. In case of a fault, the control unit disconnects the IBDG when its current exceeds a certain threshold which is usually 100%-400% of the rated current in order to protect the DG and reduce its contribution to the fault current [9]. Many other studies propose the modeling of IBDG as a constant current source under fault conditions such as [66] for both grid connected IBDG and islanded conditions.

Similar to the synchronous DG, IBDG has effects on the network under fault. For a fault at R_f, when no IBDG is connected in the network Figure 4.2, the current flowing through both relays is equal since the current is only fed from the grid:

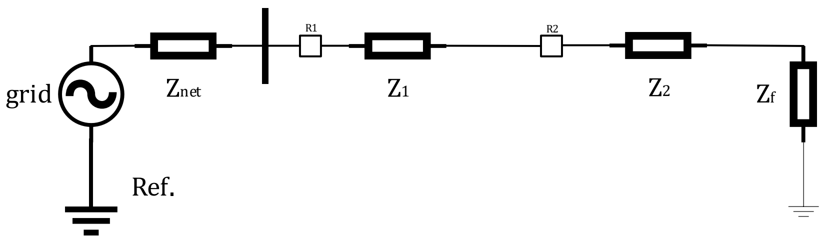

Figure 4.2: Conventional System with no DG Units.

$$I_s = \frac{E}{Z_{net} + Z_1 + Z_2 + R_f} = I_{R_1} = I_{R_2} \tag{4.15}$$

When IBDG is connected to the power system, it is modeled as a current source for simplicity as mentioned in previous sections. Figure 4.2 shows an equivalent model of a distribution network with IBDG connected in the same location as the synchronous DG was previously connected. This is done for comparison between the effects of synchronous based DG and IBDG on the fault current and how the differences between them should be accounted for . Z_1 and Z_2 represent the line impedance, Z_{net} represents the network impedance upstream of the substation, E is that grid voltage source which had minimal effects on the fault current since IBDG is modelled as a current source and the fault impedance is represented as R_f. I_{IBDG} is the total current fault contribution by the IBDG unit which then branches to two current I_{IBDG_1} and I_{IBDG_2}. One current goes to the grid side while the other current goes to the fault location depending on the system impedance seen by the current source and the fault location and fault impedance. I_{IBDG_1} and I_{IBDG_2} are the fault currents that branch in the system are calculated using current division rule as shown in equations (4.16) and (4.17).

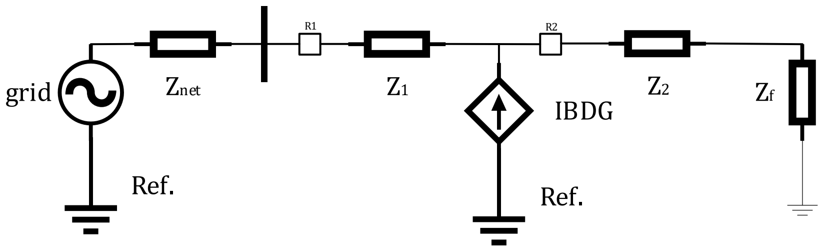

Figure 4.3: Radial System with IBDG at bus 2.

$$I_{IBDG_1} = I_{IBDG} \cdot \frac{Z_2 + Z_{flt}}{Z_{net} + Z_1 + Z_2 + R_f} \tag{4.16}$$

$$I_{IBDG_2} = I_{IBDG} \cdot \frac{\mathrm{Z}_1 + \mathrm{Z}_{net}}{Z_{net} + \mathrm{Z}_1 + \mathrm{Z}_2 + R_f} \tag{4.17}$$

From the previous equation, the fault current seen by the relays can also be calculated as:

$$I_{R_1} = I_s - I_{IBDG_1} = \frac{E}{Z_{net} + Z_1 + Z_2 + R_f} - I_{IBDG} \cdot \frac{Z_2 + R_f}{Z_{net} + Z_1 + Z_2 + R_f} \tag{4.18}$$

$$I_{R_2} = I_s + I_{IBDG_2} = \frac{E}{Z_{net} + Z_1 + Z_2 + R_f} + I_{IBDG} \cdot \frac{Z_1 + Z_{net}}{Z_{net} + Z_1 + Z_2 + R_f} \tag{4.19}$$

As shown in the current equations, the difference in currents seen by the relays R_1 and R_2 depends on Z_1, Z_1, Z_{net}, and R_f. Some extreme cases may occur depending on the location of the DG unit whether the DG is synchronous, or inverter based. For a fault occurring near the location of the DG unit, Z_{eq1} will be small; hence, I_{IBDG} can be neglected and the current passing through R_1 and R_2 can be calculated as:

$$I_{R_1} \approx I_s = \frac{E}{Z_{net} + Z_1 + Z_2 + R_f} \tag{4.20}$$

$$I_{R_2} \approx I_s + I_{IBDG} = \frac{E}{Z_{net} + Z_1 + Z_2 + R_f} + I_{IBDG} \tag{4.21}$$

On the other hand, if the DG is located far away from the location of the fault, the lime impedance must be considered; hence, the current that passes through the relays is calculated as:

$$I_{R_1} \approx I_s - I_{IBDG} = \frac{E}{Z_{net} + Z_1 + Z_2 + R_f} - I_{IBDG} \tag{4.22}$$

$$I_{R_2} \approx I_s = \frac{E}{Z_{net} + Z_1 + Z_2 + R_f} \tag{4.23}$$

IBDG units are modeled in power systems as a current source which injects current to the system. Under fault conditions, the IBDG control scheme will disconnect the IBDG unit if the current output exceeds a certain current. According to IEEE standards, if a DG exceeds 120%-150% of its rated output current, the DG is disconnected from the network. Hence, it is appropriate to assume that the IBDG contribution to the fault current is limited to 1.2 to 1.5 its rated value. To model the IBDG in the proposed study, superposition is used. After calculating the fault currents from the grid and synchronous DG units, we kill all power sources connected to the system and consider the IBDG alone. To model the IBDG under fault condition the IBDG is set to inject 120% of its rated current value to the network; then, the effects of the current injected on the system are calculated. The effect of the injection current on the voltages is calculated as:

$$\begin{bmatrix} V_1 \\ V_2 \\ V_3 \\ V_4 \\ V_n \end{bmatrix} = \begin{bmatrix} Z_{11} & Z_{12} & Z_{13} & Z_{1n} \\ Z_{21} & Z_{22} & Z_{23} & Z_{2n} \\ Z_{31} & Z_{32} & Z_{33} & Z_{3n} \\ Z_{41} & Z_{42} & Z_{43} & Z_{4n} \\ Z_{n1} & Z_{n2} & Z_{n3} & Z_{nn} \end{bmatrix} \begin{bmatrix} 0 \\ I_{inj} \\ 0 \\ I_{Kf} \\ 0 \end{bmatrix} \tag{4.24}$$

Where I_{inj} the current injected at the K^{th}, therefore, is positive with a magnitude of 120% of the IBDG rated current, and I_{Kf} is the current contribution to the fault at bus K^{th} subjected to current division.

4.3. System Impedance Matrix with DG Units

This section discusses the impedance matrix building algorithm and the reason for building the Z matrix. The system impedance matrix is usually easy to obtain from the *Y* matrix, since it is just the inverse of the *Y* matrix, but in some cases, such as the system in the study, it is not possible to inverse the *Y* matrix, since it contains a lot of zero elements due to the radial system structure. As seen from the fault analysis section, the impedance matrix is essential for the calculation of fault currents. Another problem is that during the addition DG units with different capacities and types to the distribution network throughout the planning period, the system may become ill conditions system after adding a certain DG The solution to this problem is to build the *Z* matrix from scratch each time a DG unit is added to the distribution system.

The whole system is built element by element starting from a single element connected to a reference bus. The reference bus in the study is assumed to be the grid bus which is the substation feeding the distribution network; one element is added at a time and the matrix is modified depending on the added element type. The three types of branches needed to build the system under study due to its radial structure are:

- Adding a new branch to the reference bus.
- Adding a branch from new bus to old bus.
- Adding an old branch to the reference bus.

With each element added, the *Z* matrix is updated with the required modification type for the first case, Case 1, when adding a new bus to the reference bus, as shown in Figure 4.4. The *Z* matrix size increases by one, becoming $(n+1)(n+1)$ matrix, where n is the old matrix size before the addition of the branch, I represent the old buses, k is the new bus. Using the following equations:

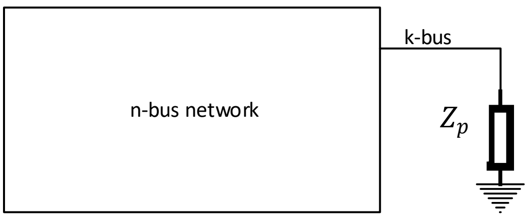

Figure 4.4: Adding a New Bus to the Reference Bus.

$$Z_{ki} = Z_{it} = 0\,;\; i = 1,2,\;\dots,\; n \tag{4.25}$$

$$Z_{kk} = Z_p \tag{4.26}$$

Hence, the updated Z bus matrix will look like:

$$Z_{new} = \begin{bmatrix} Z_{11} & Z_{12} & Z_{1n} & 0 \\ Z_{21} & Z_{22} & Z_{2n} & 0 \\ Z_{31} & Z_{32} & Z_{3n} & 0 \\ Z_{n1} & Z_{n2} & Z_{nn} & 0 \\ 0 & 0 & 0 & Z_p \end{bmatrix} \tag{4.27}$$

Case 2 represents the case of adding a new bus to an existing bus, as shown in Figure 4.5, the *Z* matrix size increase by one, becoming (*n*+1)(*n*+1) matrix, where *n* is the old matrix size before the addition of the branch, *I* represents the old buses, *k* is the new bus.

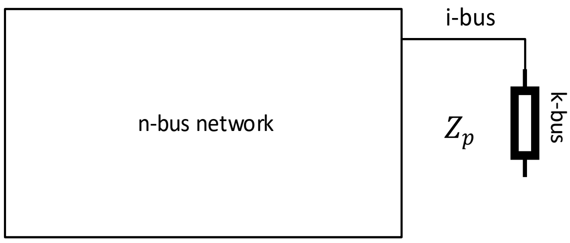

Figure 4.5: Adding a New Bus to the Reference Bus.

Hence, the updated *Z* bus matrix will look like:

$$Z_{new} = \begin{bmatrix} Z_{11} & Z_{12} & Z_{1n} & Z_{1i} \\ Z_{21} & Z_{22} & Z_{2n} & Z_{2i} \\ Z_{31} & Z_{32} & Z_{3n} & Z_{3i} \\ Z_{n1} & Z_{n2} & Z_{nn} & Z_{ni} \\ Z_{i1} & Z_{i2} & Z_{in} & (Z_p + Z_{ii}) \end{bmatrix} \tag{4.28}$$

Case 3 is the case of adding an existing bus to the reference bus in Figure 4.6, the matrix size does not increase since a reference is just being added to an existing bus. The Z matrix stays (*n*)(*n*) matrix, where *n* is the old matrix size before the addition of the branch, *I* represent the old buses, *k* is the new bus. There are other types of modification done for building a *Z* bus matrix, but due to the structure of a radial system, the three cases presented above are the only modification needed.

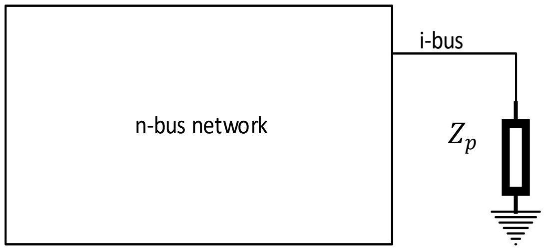

Figure 4.6: Adding an Old Bus-I to Reference Bus.

Where the Z matrix is calculated as:

$$Z_{\text{new}} = [\, Z_{\text{old}}\,] - \frac{X\mathrm{X}^{\mathrm{t}}}{Z_{\mathrm{p}}} \tag{4.29}$$

$$X = [Z_{1i}\; Z_{2i}\; Z_{3i} \,..\, Z_{ni}] \tag{4.30}$$

In fault analysis, synchronous DG units are represented as a voltage source in series with an inductor connected to the ground. Where the current contribution of the DG unit is calculated as:

$$I_{Synch} = \frac{E_{Synch}}{Z''} \tag{4.31}$$

$$Z'' = \frac{Z''_{base}}{SDG_{MW}} \tag{4.32}$$

where Z'' represents the synchronous machine inductance. Z'' is calculated depending on the synchronous generation unit maximum capacity when installed. E represents the terminal voltage of the machine; hence, E signifies the bus voltage the DG is connected to. Following this observation, the synchronous DG inductive characteristic can be integrated into to the formation of the Z bus matrix. Recalling case three from the Z bus matrix building technique, the DG unit is a typical case three modification to the Z bus matrix, adding an inductance Z'' between an existing bus to the ground. Knowing the synchronous generator internal inductance, the fault contribution of the synchronous generator can be studied by modifying the Z bus matrix with a type three modification technique. After the Z bus matrix is updated with the synchronous DG modification, fault analysis is carried out to study the effects of the installed DG on the system.

The direction of the fault current is an essential piece of information considered in the study. Since it is used to determine if the line needs an upgrade from fuse-based protection typology to a relay-based typology. The voltage and current phase of the bus during fault conditions is used to determine the direction of the fault current.

Chapter 5. Proposed Methodology

In this chapter, the proposed algorithm for multi-stage planning of DG is discussed. Additionally, the economic aspect of the planning algorithm is explained, along with other models used in the proposal. The models are combined to form a multi-stage planning algorithm, including the protection perspective that is proposed to minimize investment costs and investigate the effects of DG units on protective devices.

Genetic algorithm (GA) is a general-purpose search technique inspired from the evolution mechanism of nature and living organisms. GA starts by creating an initial population, then evaluates the fitness function and produces new populations derived from previous results as shown in Figure 5.1. There are usually operators in GA that lead off high preforming generations. The first is the elitism operator which is responsible for producing copies of any chromosome having a high fitness value. The second operator is the crossover operator which selects two individual chromosomes carrying out a swapping operation of the string bits for both individuals, thus increasing the probability of producing a better offspring. The third operation is called the mutation operator which is used to explore random chromosomes by randomly flipping a bit in a population of chromosomes. The mutation operators are completely random; hence, a very low probability is usually assigned to its activation.

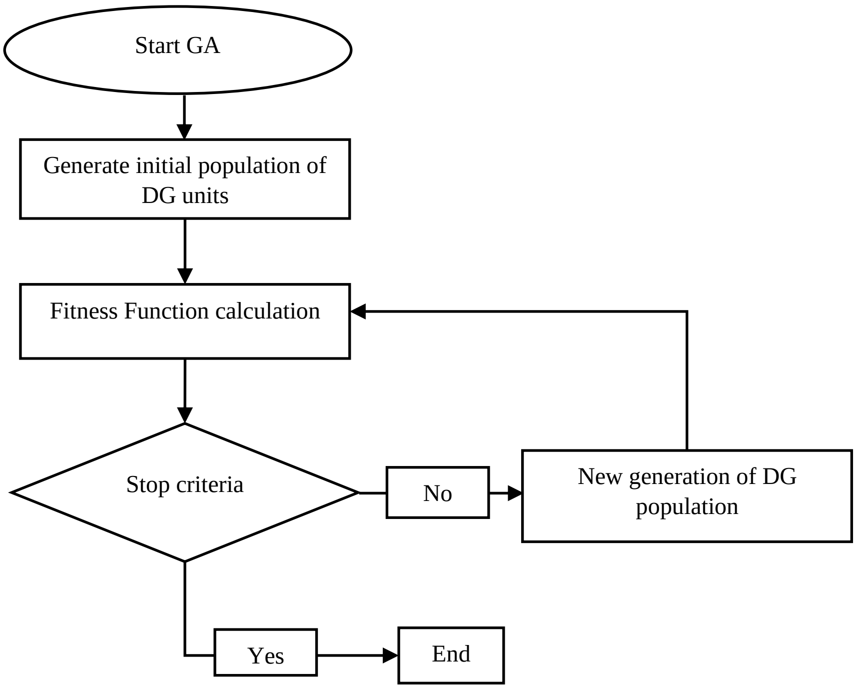

Figure 5.1: GA Flow-Chart.

The proposed planning algorithm will utilize genetic algorithms to find the near optimal location, type, size and location of DG unit installment. Moreover, the type, location, and costs of the protection devices that needs to be installed or upgraded in the presence of the DG units through an objective function shown in Figure 5.2.

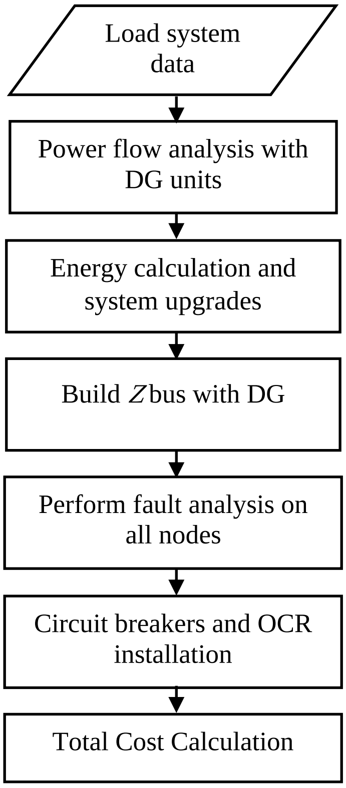

Figure 5.2: Objective Function Calculation.

This work adopts GA for the optimization process, which is one of the widely used algorithms in DG planning. GA has been proven to be a powerful technique that is used to solve complicated optimization problem such as DG planning problems. Compared to other heuristic methods, GA offers faster convergence time and reduced computational efforts [67] .

A gene is the smallest part in GA which represents a part of a possible solution to an optimization problem. A chromosome, which is a series of genes, represents a possible solution to a problem. A population is a series of chromosomes which is created with a group of chromosomes representing a set possible solution. The selection criteria adopted in the study is stochastic uniform. After the selection criteria is chosen, crossover mutation mechanism takes place between chromosomes to create a new offspring. It can be considered as a combination of two chromosomes to form a chromosome for the next generation, thus improving further chromosomes with better characteristics, resulting in a better solution.

For the proposed planning problem, each chromosome in a population consists of a vector of four times the number of candidate bus in the distribution system, so that each four genes in a chromosome represent the year of installation and the generation capacity for both synchronous DG and photovoltaic DG. The genes carry integer values denoting the capacity and year of installation of each DG unit in relation to a defined step.

The methodology adopted in this study is outlined in the following steps:

1. For each candidate solution of DG size, year and placement, execute steps 2 to 8.
2. Identify the output power of each DG state and identify load state.
3. Use the values from step 2 to solve the power flow analysis using Newton-Raphson power flow analysis.
4. For all system states and price states, record energy purchased from the grid and energy sold to the grid throughout the planning period.
5. Calculate initial and operational costs of DG units throughout the planning period.
6. Calculate system upgrades, including the protection system upgrades throughout the planning period.
7. Check system for violations and if any violations exist, set a high cost penalty on the objective function.
8. Perform economic analysis on steps 4 to 7 to form the fitness of the individual, which is the net present value of the investment.
9. GA will repeat this process until the solutions satisfies the stopping criteria.

5.1. Cost Modeling

In this section, the economic variables are discussed for the proposed planning algorithm, including the financial investment associated with DG installation; therefore, the following costs are considered:

- Capital costs for DG installation.
- Maintenance and operation costs of the DG unit.
- Cost of protection system upgrades.
- Revenue from DG units selling energy.
- Line upgrade avoided or delayed.
- Grid costs.

Economic analysis is carried to find the net present worth of the investment through compound amounts. Depending on inflation, the equations used for the economic analysis is given as:

$$P = F(1+i)^{-n} \tag{5.11}$$

$$F = P(1+i)^{n} \tag{5.12}$$

$$A = F\frac{(1+i)^{n}-1}{i(1+i)^{n}} \tag{5.13}$$

where P represents the present worth of money, F represents the future worth of money, A represents the annual net worth of the project, which is the capital recovery of the project, and i represents the increase rate. In economic analysis, i represents the inflation.

5.2. DG Installation and Operational Costs

When evaluating a DG project, the specific investment costs of either synchronous DG or photovoltaic based DG are estimated in $/kw. The cost of DG units is usually estimated from actual DG projects done previously or from fuzzy interface systems. In this study, the factors that determine the price of DG units are the capital costs of installing the DG units and operational costs.

5.2.1. SDG installation and operational costs. In this study, the main input that determines the synchronous DG capital and operational costs are the generation unit capacity and the fuel price. Fuel price changes throughout the year depending on the fuel stock market, yet, generally, it is assumed to increase on annual basis. To simplify the mathematical operational cost modeling of synchronous generation, fuel price is modeled as a geometric growth. Synchronous DG capital, operation and maintenance cost is shown in Table 5.1 [68]. Synchronous DG Capacity

Table 5.1: SDG Capital and Continuous Costs [68].

Synchronous DG Capacity	**capital costs $/kW**	**Operation and Maintenance costs $/MWh**
0 - 1 MW	575	120.7
1 - 2 MW	500	114.3
2 - 3 MW	364	108.4
Fuel Prices Annual Growth		**2%**

As seen from Table 5.1, as the capacity of the generation unit increases, the capital $/kW and the operational costs $/MWh decrease. For example, if a 500-kW generation unit is installed, the capital costs is $287,500 and the operational costs for that year is $528,666. For the same unit, the next years operational costs after adjusting to the fuel price growth results in an operational cost of $539,239.2.

5.2.2. PVDG installation and operational costs. Similar to synchronous DG units, a large-scale photovoltaic DG project is evaluated economically to determine the equivalent cost of the project in $/kW which represents the capital investment costs and operational costs of the project. Photovoltaic generation differs from synchronous generation in that its capital installation cost ($/kW) is much higher, but the operational and maintenance cost ($/MWh) is lower.

A thorough study is done on big scale photovoltaic projects in [69]; all economical aspects of photovoltaic DG projects are detailed and discussed. The study includes the civil, mechanical, electrical and other indirect costs associated with PV projects to calculate its capital and operational costs as shown in Table 5.2.

Table 5.2: SDG Capital and Continuous Costs [69].

Investment type	**Cost $/kW**
Civil Structural Material and Installation	317.60
Mechanical Equipment Supply and Installation	973.27
Electrical / I and C Supply and Installation	464.58
Indirect Costs, Fee and Contingency	515.87
Owner Costs	368.68
Total Capital Cost	2640.00
Annual Operation and Maintenance Costs	60.83 $/kW-year

As seen from Table 5.2, the capital costs for installing photovoltaic DG unit is much higher than synchronous DG. For example, the capital cost for installing a 500-kW generation unit will cost $1,320,000, which is nearly 5.5 times the cost of installing the same unit if it was a synchronous DG. On the other hand, the operation cost per year of a 500-kW unit is $30,415 while the synchronous DG costs $528,666.

5.3. Energy Price Modeling

A multi-state probabilistic price model is constructed for the buying and selling price of energy from and to the electrical grid. The probabilistic price multi-state model is built from a 8,740 hourly price data taken from Ontario hourly energy price for the year 2018 [70]. Then K-means clustering is used, which is a type of unsupervised learning used when a set of data is without a defined category or group. The goal of a K-means algorithm is to cluster a set of data into different groups based off features provided to the algorithm. Data points are usually clustered into individual groups based on similarities. Each group of clusters has a centroid which can be considered the center of a given cluster. After the set of clusters is defined, the K-means algorithm returns the clustered groups with a centroid for each group. Each centroid is treated as a state in the energy price multi-state model, then the probability of each state is calculated, resulting in a multi-state probabilistic model used to calculate the energy selling price to the electrical grid and energy purchasing price from the grid. As shown in Table 5.3.

Table 5.3: Energy Price Multi-State Model.

State number	Price $/MWH	Probability
1	71.13519531	0.0584475
2	34.68871221	0.3926941
3	7.741518303	0.5488584

The energy price calculated from the K-means algorithm shown in Table 5.3 is only one part of the total energy cost paid by the DISCO. The total commodity cost for electrical energy price also depends on the global adjustment. The global adjustment cost is usually added on top of the energy price. When buying energy from the grid, the additional global adjustment cost is used to cover the cost of upgrading the infrastructure of the power grid, maintaining the existing power grid equipment and demand management programs. The global adjustment is only applied when buying energy from the grid; however, when selling energy to the power grid, the price of energy is calculated without the global adjustment. The value of the global adjustment varies depending on the hourly price; when the hourly price is low, the global adjustment is higher to cover the regulated generation costs, costs of energy contracts and system conditions changes. The average global adjustment price for the year 2018 was 91.825$/MWh [71] .

A monthly transmission charge is also added on top of the total cost of purchased energy. Transmission charges cover the cost of transmitting energy from the generation units through high voltage transmission lines to finally reach the distribution network. The transmission charges are calculated per month as 510$/MW, which depend on the peak power the DISCO consumes from the grid.

5.4. Protective Fuses Upgrades

Fuses are considered the main protection devices in traditional radial distribution systems due to their simplicity and inexpensive capital, operation and maintenance costs. Moreover, fuses do not need any relay or current transformers to operate. When the current in the fuse increases beyond a certain threshold, the fuse melts, forming a gap between the feeder and the load, creating an open circuit between the feeder and the load. Fuses are characterized by their time-current and maximum current rating as shown in Figure 5.3. Fuses are used on all distribution level voltages ranging from 5.5KV to 38KV [72].

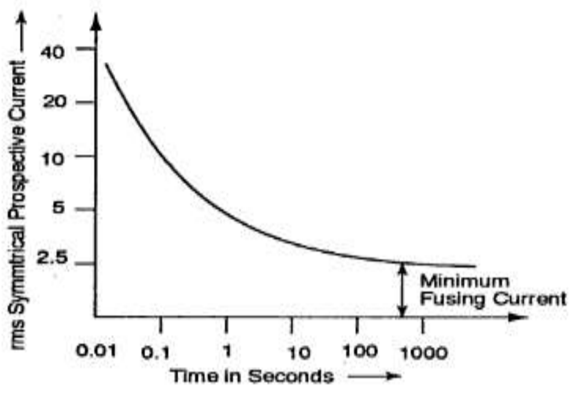

Figure 5.3: Relay Inverse Characteristics [72].

The disadvantages of fuses are their fixed characteristics; once a certain fuse is placed on a distribution feeder, the setting of the fuse cannot be changed, meaning that every time the load level increases beyond a certain level, fuses must be interchanged with other higher rated fuses to keep the system reliable and prevent false tripping. Another disadvantage to fuses is that they need to be replaced after every fault clearance. However, the main disadvantage of using fuses is their unidirectional current characteristics, which may cause a system failure in case a fault occurred in presence of DG units in the radial system.

This work considers the costs of installation and upgrades of fuses in the distribution power systems which is directly related to the continuous current levels. In order to reduce the mathematical model for fuses upgrades, fuses installation and uninstallation costs are fixed to $2000, while the price of fuses depends on their current ratings as shown in Table 5.4. At the beginning of the study all the system protection devices are assumed to be fuses since there is no DG units present in the system. only the cost of fuses upgrades throughout the planning period is considered.

5.5. Protective OCR Upgrades

Protective relays are another way to protect power systems. A protective relay is a device which is triggered by current or voltage to detect abnormal behaviors in the system and isolate it. Unlike fuses, relays have adjustable settings where some type of relays can be controlled remotely through a relay communication network and are usually paired with circuit breaker for systems above 600V. Protection relays trigger the circuit breaker in case a fault is detected, hence, isolating the faulted section of the power system.

Table 5.4: Fuses Operation Range and Cost.

Fuses Range (A)	**Cost ($)**
0-20	400
20-50	700
50-80	850
80-100	1000
100-200	1100
200-300	1500
300-400	1800

The most commonly used type of protective relays is the overcurrent protective relays, which one of the first developed and widely used in the protection system [73]. Overcurrent relays are characterized by their lower cost with respect to other types of protection systems. They also provide a vast range of flexibility due to its settings characteristics [74]. An over current relay has several taps; each tap determines a certain threshold level for the relay operation. The tap levels can be controlled remotely if a communication platform is available. Another controlled aspect of overcurrent relay is that the time dial setting of over current relays can be controlled in a similar fashion to the current tap control; the time dial setting determines the operation time of a relay with respect to a certain current value. The higher the time dial setting of a relay, the longer it takes the relay to trigger the circuit breakers for a certain fault level. Overcurrent relays have four different curves that characterizes the time dial setting, long inverse, normal inverse, very inverse and extremely inverse time [73].

Directional over current relays are a type of over current relays, which are mainly used to protect non-radial power distribution systems. A directional over current relay combines an over current relay with a directional device that detects the current direction using the current magnitude and phase angle. The relay sends a trip signal to the circuit breaker only if the current flow in one direction, the relay is insensitive to current flowing in opposite direction unlike fuses.

In non-radial and distribution systems, where DG units are present, directional relays are necessary for the protection system due to their bi-directional current capability. Relays connected for the same fault current direction must be coordinated as shown in Figure 5.4.

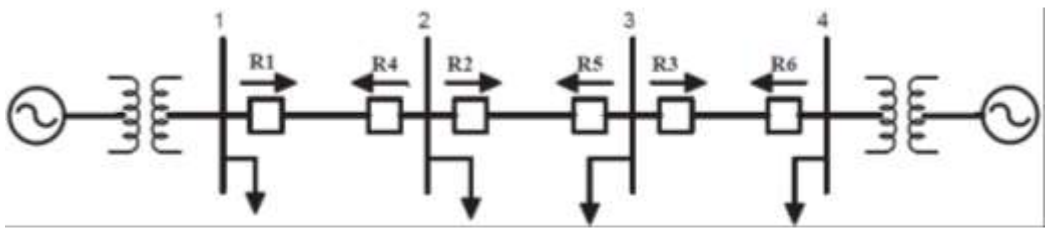

Figure 5.4: Relay Coordination and Placement.

This work considers the costs of installation and upgrades of relays and circuit breakers in the distribution power systems, which is directly related to the continuous current levels. While the price of relays depends on their current ratings as shown in Table 5.5, the cost for circuit breaker is fixed at $40,000. At the beginning of the planning study, all the system protection devices are assumed to be fuses since there is no DG units present in the system. Only the cost of relay protection upgrades throughout the planning period is considered.

Table 5.5: Relay Operational Range and Cost.

Relay Range (A)	Cost ($)
0-50	4000
50-100	4500
100-200	5000
200-500	5500
500-1000	6000

5.6. Power Lines Upgrade

The most omnipresent part of the distribution system is moving power from one point to another. Distribution lines is the final stage of delivering power to the consumer; when the line voltage is between 1-kilovolt and 40-kilovolt, the power line is typically considered a distribution line. Power line conductors are available in various power capacity ranges. Regardless of the power line capacity, every line has a resistance and impedance that causes voltage drop across it, as well as electrical power losses through it proportional to the current. If the load on the line doubles, the power loss across increase by four.

One of the factors affecting the distribution system design is that it costs more to upgrade the power line that suits a higher capacity than building to that capacity in original construction phase. A 9-MW distribution power line might cost 150,000 $/mile to build; however, updating a 4-MW distribution power line to 9-MW line around costs 200,000 $/mile. Upgrading the power lines costs more because it includes removing old conductors and replacing them along with breakers and other hardware requirements to support higher capacity lines. In this study, line upgrades cost $200,000.

For the line upgrade criteria, power flow analysis is utilized to calculate the power passing through each line in the distribution system. When the power passing through a line is greater than the line power capacity, a parallel line is installed. After upgrading the power line, its capacity is doubled, and its resistance and impedances are halved.

5.7. Load Model

In this section, the load growth is discussed, combined into a multi-level load price model, which represents the most operational states of the system's loads, based on the following:

- An n-year planning period.
- Load increase by K% annual.
- Multi-state propaslitic load model.

This model allows for an accurate representation of the load for any number of years with an annual increase in the load demand. Therefore, enabling the estimation of when a line upgrade is necessary for the system. Moreover, it is important for estimating the increase in the price of energy as the load increases. It is vital to note that the price of energy increase has an exponential relation time. A multi-level load is used to study the extreme cases presented in the distribution system, choosing 6 states for load modeling. It is efficient to study the system under all possible loading conditions, assuming a 5% increase in load with a planning study for 20 years. Figure 5.5 shows the annual increase in load for 20 years. The same equation (5.12) , can be used to calculate the annual load increase.

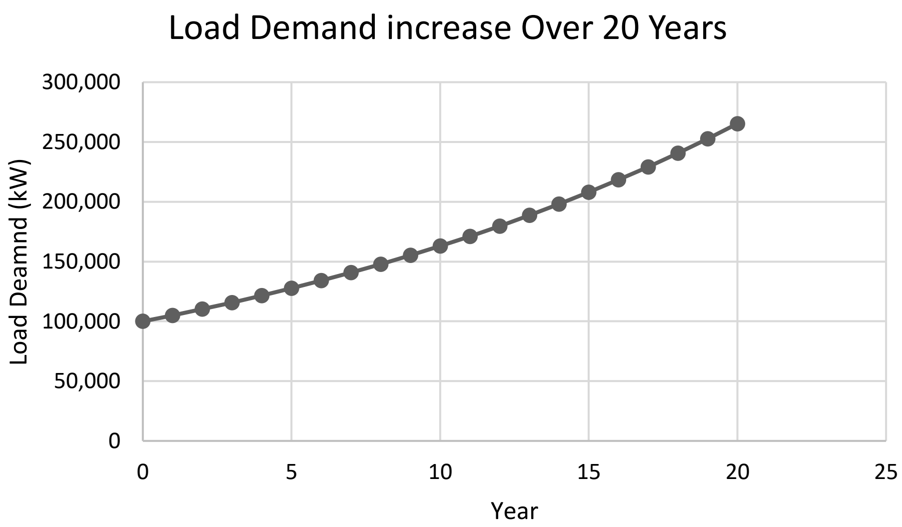

Figure 5.5: A 5% Load Increase Over 20-Years.

A multi-state probabilistic load model is constructed to represent the distribution system load model accurately. The multi-state probabilistic load model is built from a 8,740 hourly demand load data from Ontario hourly demand load for the year 2018 [75]. K-means clustering is used to create states from load demand data; then, the associated probability with each state is calculated resulting in a multi-state probabilistic model representing the load demand. As shown in Table 5.6.

Table 5.6: Load State Probabilistic Multi-State Model.

State number	Load State	Probability
1	0.474505	0.011758
2	0.559356	0.255822
3	0.650166	0.319521
4	0.735587	0.276484
5	0.842796	0.13379
6	0.966897	0.002626

It is important to note that K-means clustering is a stochastic method used in machine learning; hence, the clusters and sates obtained from K-means is random in nature. For the purpose of power flow calculation and the system equipment upgrades, worst case scenarios must be considered to study extreme conditions that may occur on the power distribution system equipment and, due to the nature of K-means, it is sometimes not feasible to get extreme cases as states. To overcome this problem, a large number of states is constructed through K-means. Then, the maximum and minimum state values are kept while the states between the extreme cases are reduced respectively.

5.8. PVDG Generation Model

In the past decade, photovoltaic generation has become increasingly integrated into power systems, especially in distribution networks due to the price drop of photovoltaic technologies, the rapid increase of prices of conventional energy sources and the global concern on environmental impacts from such conventional energy sources. Photovoltaic generation is considered to be a clean cost-effective substitute. The main concern regarding photovoltaic generation units is the that their power output depends on external natural resources such as solar irradiance. Due to the random nature of these resources, photovoltaic generation behaves differently from conventional synchronous generators. These external random factors place additional pressure on the planning process and distribution system reliability with any type of renewable energy sources [76].

The mainstream method for computing power system reliability indices for various areas in power systems, including photovoltaic generation systems, in distribution networks is the Monte Carlo simulation. Generally, a Monte Carlo simulation is effective in approximating the power system behavior, but it can suffer from lengthy computation time and accuracy problems, especially in binary state representation and analytical models. For a realistic reliability assessment of distribution power systems, a multi-state model is preferred, which is widely used to study the random behavior of photovoltaic generation in distribution level networks [77, 78]. A multi-state model offers an accurate approximation of the power system states' representation and offer greater flexibility to the power system [79].

In this thesis, due to the nature of photovoltaic generation, the photovoltaic DG is modeled as a multi-state probabilistic model with five states. Each state represents the power generation output with its probability as given in [80]. The same multi-state probabilistic model will be used to study the photovoltaic DG in the Newton-Raphson power flow analysis. Each state represents a photovoltaic power generation state associated with its probability; hence, power flow analysis will be done on each state of the photovoltaic DG states to achieve accurate results for the power flow analysis. The five-state represented is a result of Mohamed and Koivo [81] beta distribution of solar irradiation divided into five equal sized states with different intervals and probabilities as shown in Table 5.7.

Table 5.7: PVDG Probabilistic Multi-State Model [81].

State Number	PVDG Power Output State	Probability
1	0.114583333	0.59
2	0.333333333	0.13
3	0.562500000	0.1
4	0.781250000	0.08
5	1	0.1

5.9. System Model

The system under study is IEEE-38 bus radial distribution system shown in Figure 5.6. The system has a peak demand load of 4.6MVA. The distribution system data, including bus loads, line impedances and line capacities, are given in [82]. The voltage variation limits are assumed at 6%, which is used for voltage constraints. any number of buses can be selected as a possible candidate for DG placement as the study aims to find the most economically beneficial placement of the DG unit. The protection and fault analysis study will be discussed in the following section.

Power flow analysis is performed in the 38-bus system utilizing the Newton-Raphson method, since the method is well defined in the literature, easy to implement on a large-scale system and the number of iterations needed to reach a solution does not depend on the number of buses, unlike the Gauss-Seidel method. Moreover, it is easier to add DG unit to the network and study its effects using the Newton-Raphson method as mentioned in the Sec.3.3. The bus with DG installed on it is just represented as PQ bus throughout the analysis.

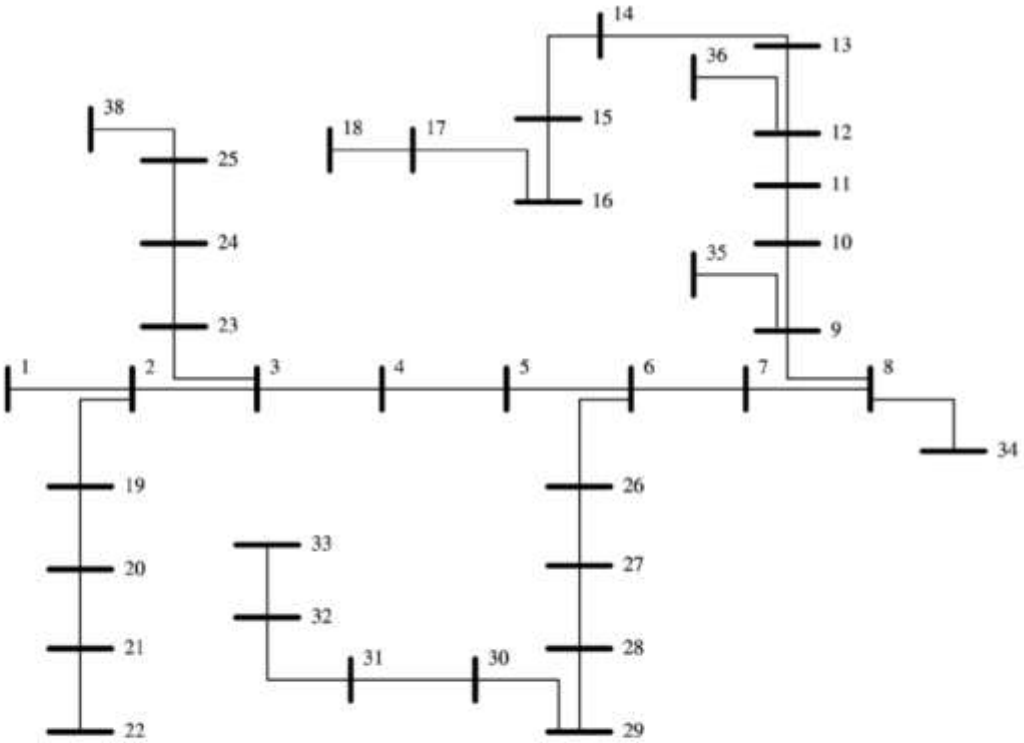

Figure 5.6: Represents the 38-bus System Under Study.

For an accurate representation of the distribution power system and the system power flow analysis, all possible states must be considered and analyzed. Therefore, a multistate model is constructed by joining the photovoltaic probabilistic state model and the load probabilistic state model through a joint discrete probability distribution functions of both models. In contrary to PV generation units, a synchronous DG unit, which is considered a dispatchable generation unit, is assumed to be continuously generating a fixed amount of power. Consequently, a multi-state model is not needed to represent any synchronous DG. Instead, it is represented as a PQ generation bus in power flow analysis. Thus, the total probabilistic state model for power flow analysis and system upgrade requirements consists of 30 states containing all possible combinations of load states and photovoltaic generation states as shown in Table 5.8.

Table 5.8: System States for Power Flow Analysis.

State Number	PV States	Load States	Probability
1	0.114583	0.47450454	0.0069372
2	0.114583	0.55935588	0.1509349
3	0.114583	0.6501662	0.1885171
4	0.114583	0.7355871	0.1631256
5	0.114583	0.84279572	0.0789361
6	0.114583	0.9668974	0.0015491
7	0.333333	0.47450454	0.0015285
8	0.333333	0.55935588	0.0332568
9	0.333333	0.6501662	0.0415377
10	0.333333	0.7355871	0.0359429
11	0.333333	0.84279572	0.0173927
12	0.333333	0.9668974	0.0003413
13	0.5625	0.47450454	0.0011758
14	0.5625	0.55935588	0.0255822
15	0.5625	0.6501662	0.0319521
16	0.5625	0.7355871	0.0276484
17	0.5625	0.84279572	0.013379
18	0.5625	0.9668974	0.0002626
19	0.78125	0.47450454	0.0009406
20	0.78125	0.55935588	0.0204658
21	0.78125	0.6501662	0.0255616
22	0.78125	0.7355871	0.0221187
23	0.78125	0.84279572	0.0107032
24	0.78125	0.9668974	0.0002100
25	1	0.47450454	0.0011758
26	1	0.55935588	0.0255822
27	1	0.6501662	0.0319521
28	1	0.7355871	0.0276484
29	1	0.84279572	0.0133790
30	1	0.9668974	0.0002626

5.10. Planning Problem Formulation

In this section, the formation of the proposed multi-year planning problem is presented, including a representation of the GA method adopted in the study. The problem is classified as a mixed integer nonlinear programming solved using an integer constrained GA. The main objective of the proposed is to determine the optimal type, size and location of DG units taking into consideration the protection system upgrades associated with DG installation in order to reduce the overall investment costs for the power distribution company (DISCO).

5.10.1. Objective function. The objective function to be minimized which represents the DISCO expenses. The overall total cost is composed of capital and continuous costs described in (5.18).

$$\min_{\Omega}\left(\sum_{i\in J_{DG}^{S}} PW_{SDG(i)}^{O\&M} + \sum_{i\in J_{DG}^{PV}} PW_{PV(i)}^{O\&M} + \left(\sum_{z\in S_{sys}} \mathrm{p}(z) PW_{(z)}^{buy} - PW_{(z)}^{sell}\right) + C_{SDG} + C_{PV} + C_{L} + C_{P}\right) \tag{5.18}$$

$$C_p = C_F + C_R + C_{CB} \tag{5.19}$$

$$PW_{(z)}^{buy} = \begin{cases} C_{E(z)}^{buy} \times \left(P_{grid(i,z)} - P_{loss}(z)\right) & \forall P_{grid(i,z)} - P_{loss(z)} > 0 \\ 0 & \forall P_{grid(i,z)} - P_{loss}(z) \le 0 \end{cases} \tag{5.20}$$

$$PW_{(z)}^{sell} = \begin{cases} -C_{E(z)}^{sell} \times \left(P_{grid(i,z)} - P_{loss(z)}\right) & \forall P_{grid(i,z)} - P_{loss(z)} < 0 \\ 0 & \forall P_{\mathrm{grid}(i,z)} - P_{loss(z)} \ge 0 \end{cases} \tag{5.21}$$

where Ω is the vector of decision variables obtained from GA, i and j are the index of buses and system buses, J_{DG}^{S} and J_{DG}^{PV} are the subsets of candidate busses for synchronous and photovoltaic DG installation. C_{PV} is the capital cost for photovoltaic installation on bus i, C_{SDG} is the capital cost for synchronous DG installation on bus i , $PW_{(z)}^{buy}$ and $PW_{(z)}^{sell}$ is the net present worth of the energy bought from the grid and energy sold to the grid corresponding to system state (z), $PW_{SDG(i)}^{O\&M}$ and $PW_{PV(i)}^{O\&M}$ is the net present value of the operational and maintenance cost for synchronous and photovoltaic DG, respectively. $C_{E(z)}^{buy}$ and $C_{E(z)}^{sell}$ are the price of energy for every state (z) after adjusting the buying price with the global adjustment price. $P_{grid(i,z)}$ is the delivered energy from the grid to the system at any state (z), $P_{loss(z)}$ is the losses in the distribution system at state (z), C_L represents the line update costs in the distribution system, C_p represents the distribution system protection costs, C_F is the cost of fuses installation and upgrades, C_R is the cost of directional relay upgrades and installation, C_{CB} is the cost of circuit breakers installation.

5.10.2. System constraints. The following are the relevant constraints subjected on the system in the proposed problem formulation.

1) Power flow constraints: the optimization problem must satisfy the active and reactive power balance constraints on all system states (z) described in (5.22) and (5.23).

$$P_{grid(i,z)} + P_{DG(i,z)}^{synch} + P_{DG(i,z)}^{PV} - P_{L(z)} = \sum_{j\in\mathcal{J}} V_{(i,z)}V_{(j,z)}Y_{(i,j)}\cos\big(\theta_{(i,j)} + \delta_{(j,z)} - \delta_{(i,z)}\big) \quad \forall i \in \mathcal{J}, z \in \mathcal{S}_{sys} \tag{5.22}$$

$$Q_{grid(i,z)} - Q_{L(z)} = -\sum_{j\in J} V_{(i,z)}V_{(j,z)}Y_{(i,j)}\ \sin\big(\theta_{(i,j)} + \delta_{(j,z)} - \delta_{(i,z)}\big)\ \forall i \in \mathcal{J}, z \in \mathcal{S}_{sys} \tag{5.23}$$

$$P_{DG(i,z)}^{synch} = P_{F(z)}^{synch} \times P_{DG-MAX(i)}^{synch} \tag{5.24}$$

$$P_{DG(i,z)}^{PV} = P_{F(z)}^{PV} \times P_{DG-MAX(i)}^{PV} \tag{5.25}$$

where $P_{DG(i,z)}^{synch}$ and $P_{DG(i,z)}^{PV}$ are the per unit active power of SDG and PVDG on bus i for state (z) , $P_{L(z)}$ is the per unit active load consumption at bus i corresponding to system state z for all load levels, $Q_{L(z)}$ is the per unit reactive load consumption at bus i corresponding to system state z for all load levels, $V_{(i,z)}$ and $\delta_{(i,z)}$ are the per unit magnitude and angle of the (i,j) elements in the admittance matrix $Y_{(i,j)}$. $P_{F(z)}^{synch}$ and $P_{F(z)}^{PV}$ are the generation state of the DG units associated with system state (z).

2) Voltage limits constraints on buses: the voltage magnitude of the buses must be within acceptable limits for all system states z, as in (5.26).

$$V_{min} \leq V_{(i,z)} \leq V_{max} \quad \forall\, i, z \tag{5.26}$$

3) Distributions lines capacity constraints: the power flowing through any distribution line must be within the line power capacity. If the power flowing through the line is greater than the line capacity, a line upgrade is required as in (5.27).

$$S_{(i,j,z)} \leq S_{MAX(i,j)} \; \forall\, i, z \tag{5.27}$$

4) Protection equipment operation range: current passing through relays and fuses must be within operation limits. If the load current exceeds the operation range of a fuse or a relay, an upgrade to the protection system is required.

$$IF_{MIN} \leq I_{(i,j,z)} \leq IF_{MAX} \quad \forall\, i, z \tag{5.28}$$

$$IR_{MIN} \leq I_{(i,j,z)} \leq IR_{MAX} \quad \forall\, i, z \tag{5.29}$$

5) Discrete size of DG capacity: the connected DG capacities at each bus are assumed to be discretized at a fixed step that is dependent on the type of DG.

$$P_{DG-MAX(i)}^{synch} = wx_{(i)} \times P_{step}^{synch} \tag{5.30}$$

$$P_{DG-MAX(i)}^{PV} = Sx_{(i)} \times P_{step}^{PV} \tag{5.31}$$

where $wx_{(i)}$ and $Sx_{(i)}$ are the integer variables indicating the capacity of the installed SDG and PVDG as multiples of a fixed discrete step sizes P_{step}^{synch} and P_{step}^{PV}, it is important to note that $wx_{(i)}$ and $Sx_{(i)}$ can be equal to zero, denoting that no DG units is installed on bus i.

6) Candidate bus constraints: DG units are not permitted to be connected to any bus in the distribution system. DG units are only allowed to be installed on a predefined set of buses called candidate buses as in (5.32) and (5.33).

$$wx_{(i)} = 0 \; \forall i \notin J_{DG}^{synch} \tag{5.32}$$

$$sx_{(i)} = 0 \; \forall i \notin J_{DG}^{PV} \tag{5.33}$$

7) Maximum DG installation: the maximum capacity of DG generation at any individual bus i is limited based on the system voltage profile and technical constraints chosen by the local distribution company denoted by $P_{MAX(i)}$ as in (5.34).

$$P_{DG-MAX(i)}^{synch} + P_{DG-MAX(i)}^{PV} \leq P_{MAX(i)} \tag{5.34}$$

8) Installation year constraints: DG installation is permitted on specific years throughout the planning period as in (5.45) and (5.46).

$$P_{DG-inst(i)}^{synch} = 0 \;\; \forall i \notin \; Y_{DG}^{synch} \tag{5.45}$$

$$P_{DG-inst(i)}^{PV} = 0 \;\; \forall i \notin \; Y_{DG}^{PV} \tag{5.46}$$

5.11. GA Implementation

One of the most important decisions to make while implementing a genetic algorithm to solve an optimization problem is deciding the representation of the solution. It has been observed that improper representation of a GA solution vector can lead to poor performance of the GA. Therefore, choosing a proper representation for chromosomes and having a proper representation of the planning problem is essential for the success of GA.

In this section, we present some of the most commonly used representations for genetic algorithms. However, chromosome representation is exceedingly problem specific depending on many factors; for different problems, the representation might use one or a mix of representations mentioned below.

5.11.1. Binary representation. This is one of the simplest and most used representation in GA. The chromosomes in this type of representation consist of binary vectors as shown in Figure 5.7. Binary representation is used in problems where the solution consists of Boolean decision variables; if there is a ‘n’ numbers of decision variables, then the binary chromosome has a length equivalent to ‘n’ similar to the 0/1 knapsack problem.

0	0	1	0	1	1	1	0	1	0

Figure 5.7: Represents a Binary chromosome.

Binary representation can be used for other problems dealing with integers, as well. This is done by grouping a set of bits in the binary chromosome, where each set represents an integer in binary representation. The problem with this kind of encoding is that different bits have different significance and different effects on the fitness function. Moreover, this causes the mutation and crossover operators to have undesired consequences.

5.11.2. Integer representation. For discrete valued solution, it is not always feasible nor accurate to limit the solution to be Boolean due to difficulties and problems in binary representation of integers. In such cases, integer chromosome representation is desirable as shown in Figure 5.8.

12	5	8	3	1	0	21	6	0	7

Figure 5.8: Represents an Integer Chromosome.

The integer limits can be bound to minimum and maximum value. It is important to note that, for a binary representation of the chromosome in Figure 5.13, a binary chromosome of length 50 is needed where each five genes represent one integer.

5.12. Optimization Planning Problem Implementation in GA

For the proposed multi-stage optimization problem, the size, location and type are to be optimized using GA. A total of five buses are chosen to be optimized: buses 34, 35, 36, 37 and 38 with two types of DG technologies, PVDG and SDG. The maximum generation allowed on each bus is 2MW; the study planning period is 20-years, where DG units can be installed on year 1, 5, 10, 15 and 20. The step size of DG capacity installation is 50-KW. The chromosome representing the solution is a vector of length 20. As shown in Figure 5.9.

5.12.1. GA representation in power flow. For the purpose of power flow, GA chromosomes must be expressed as power generation units on candidate buses and the installation year of those generation units must be expresses in years. However, due to the nature of GA integer representation, as seen from Figure 5.14, the chromosome must be represented as generation capacity and years within the optimization problem. Therefore, the chromosome is divided into four sections, with each section containing 5 genes. Genes 1 to 5 represent the SDG generation and genes 6 to 10 represent the PVDG on buses 34 to 38. Each gene takes an integer value from 0 to 20, where the integer is multiped by 50-KW, representing the power generation capacity. Genes 11 to 15 represent the installation year of SDG and genes 16 to 20 represent the installation year of PVDG. Each gene takes an integer value from 1 to 5, where the integers represents values in a vector containing the allowable installation years as shown in Table 5.9. For example, if wx_{34} is equal to 10 and $P_{DG-inst}^{syn-34}$ is equal to 3 means there is a 500KW synchronous generation unit placed on bus 34 on year 10.

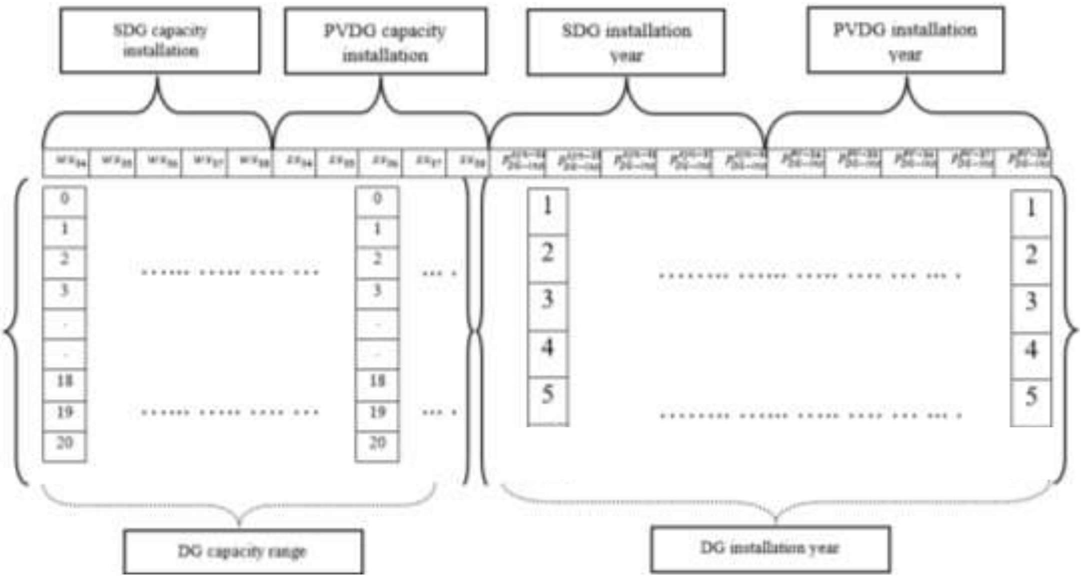

Figure 5.9: Represents the Solution Chromosome and Each Gene Range Vector.

Table 5.9: Installation Year Vector.

Installation Year Vector	Year Representation
1	1
2	5
3	10
4	15
5	20

Chapter 6. Simulation Results and Discussion

6.1. Sample Case Study

The distribution system considered for this study consists of a multi-probabilistic load model. The 38-bus 12.66KV is illustrated in Figure 5.12. The peak load of the entire system is 4.37MVA initially. The distribution system and load data are given in [82]. The voltage limit is assumed to be ±6% of the nominal per unit value. Five buses are chosen as candidate buses, which are 34, 35, 36, 37 and 38. The power flow analysis is carried out using Newton-Raphson method. Actual recent price and load data were taken, modeled probabilistically as presented in Tables 5.3, 5.6 and 5.7. The capital, operational and maintenance cost of SDG and PVDG are presented in Tables 5.1 and 5.2.

6.2. Results and Discussion

This section includes the optimal results of the planning problem, along with a comparison between the optimized system and a non-optimized system with identical initial values. The values presented in this section are highly system dependent and are subjected to a lot of factors and constraints, such as candidate buses, allowable DG installation capacity, demand load data, system states and the distribution system typology. The results of each case are described in section (6.2.1 - 6.2.2).

6.2.1. CASE A. For the base case defined by Case-A, which does not include any DG in the system, the total energy supplied by the grid meets the demand load for all load states for the entire period of the study, including the system losses.

The results show that the total cost of the DISCO operation and cost of energy supply requirements over the total period of the study is approximately $98.3M as shown in Tables 6.1 - 6.4. This cost includes energy purchasing price from the grid and the power loss associated with power delivery, the protection upgrades cost and system upgrades throughout the planning. A detailed explanation for factors affecting the total cost is shown in section 6.2.1.

6.2.1.1 ***Case-A fuses upgrades****:* as shown from Table 6.1 fuses are upgrades regularly throughout the planning period. Table 6.1 represents all the protection system fuses upgrades throughout the planning period and the annual cost upgrades of fuses, which includes the capital cost and the installation cost of the fuse. The total NPV of fuses upgrades is $530,000.

Table 6.1: Fuses Upgrades Throughout the Planning Period Case-A.

From Bus	To Bus	Fuse Rating (A)	Year	Cost $	Total Annual Cost ($)
29	**30**	50.74816	2	17100	17,100
7	**8**	50.00142	3	17100	34,200
3	**23**	51.39022	3	17100	
2	**3**	205.6931	4	21000	37,200
2	**19**	20.31280	4	16200	
23	**24**	50.92111	5	17100	17,100
6	**26**	82.51072	7	18000	18,000
26	**27**	83.03097	8	18000	34,200
31	**32**	20.07757	8	16200	
6	**7**	82.02056	9	18000	53,100
8	**9**	51.60755	9	17100	
27	**28**	83.42378	9	18000	
1	**2**	312.2297	10	22800	73,200
14	**15**	20.95225	10	16200	
19	**20**	20.47436	10	16200	
28	**29**	83.73075	10	18000	
3	**4**	208.9779	11	21000	56,700
9	**10**	52.24754	11	17100	
6	**26**	101.2238	11	18600	
2	**3**	306.7820	12	22800	136,500
4	**5**	208.9217	12	21000	
5	**6**	203.7748	12	21000	
10	**11**	50.01796	12	17100	
3	**23**	80.06025	12	18000	
26	**27**	101.9063	12	18600	
29	**30**	82.44914	12	18000	
6	**7**	100.5511	13	18600	55,200
7	**8**	81.93965	13	18000	
27	**28**	102.4611	13	18600	
11	**12**	50.75501	14	17100	51,900
15	**16**	20.30535	14	16200	
28	**29**	103.1606	14	18600	
23	**24**	83.83647	15	18000	18,000
29	**30**	101.1893	16	18600	18,600
12	**13**	51.20835	17	17100	35,700
3	**23**	101.7326	17	18600	
7	**8**	102.8360	18	18600	
20	**21**	20.13580	18	16200	

30	**31**	50.53017	18	17100	51,900
3	**4**	306.8662	19	22800	76,500
8	**9**	83.55962	19	18000	
23	**24**	100.8033	19	18600	
24	**25**	50.44829	19	17100	
4	**5**	305.6500	20	22800	57,900
9	**10**	80.63958	20	18000	
13	**14**	50.58838	20	17100	
Total NPV					**$529,312**

6.2.1.2 ***Case-A line upgrades****:* line capacity data are given in [82]. Distribution line is upgraded whenever the power flowing through them exceeds the capacity of the line. When a line is upgraded, its power capacity is doubled. Table 6.2 represents all the distribution line upgrades in the distribution system throughout the planning period and the total annual upgrade costs. The total NPV for line upgrades is approximately $7.589M**.**

Table 6.2: Line Upgrades Throughout the Planning Period Case-A.

From Bus	To Bus	Line Capacity (MVA)	Line Power Flow (MVA)	Year	Total Annual Cost ($)
1	**2**	4.6	4.662273293	1	1,200,000
2	**3**	4.1	4.133521229	1	
3	**4**	2.9	2.931514118	1	
3	**23**	1.05	1.059857870	1	
12	**13**	0.5	0.507163658	1	
17	**18**	0.1	0.100049463	1	
4	**5**	2.9	2.904748395	2	1,000,000
13	**14**	0.45	0.455740314	2	
14	**15**	0.3	0.304522939	2	
20	**21**	0.21	0.210188762	2	
30	**31**	0.5	0.503015208	2	
5	**6**	2.9	2.957520391	3	1,400,000
6	**26**	1.5	1.521093565	3	
7	**8**	1.05	1.102279366	3	
15	**16**	0.25	0.252311997	3	
21	**22**	0.11	0.110309962	3	
23	**24**	1.05	1.050255772	3	
24	**25**	0.5	0.522468112	3	
26	**27**	1.5	1.525302569	4	200,000
27	**28**	1.5	1.526431156	5	200,000
2	**19**	0.5	0.512550123	6	

6	**7**	1.5	1.571902635	6	600,000
28	**29**	1.5	1.512501684	6	
8	**9**	1.05	1.085498136	8	400,000
32	**33**	0.1	0.103052689	8	
29	**30**	1.5	1.540525912	9	200,000
9	**10**	1.05	1.089819304	10	400,000
16	**17**	0.25	0.25528541	10	
31	**32**	0.5	0.503701163	11	200,000
10	**11**	1.05	1.082997815	12	
19	**20**	0.5	0.516248443	12	400,000
11	**12**	1.05	1.091105198	14	200,000
1	**2**	9.2	9.225849885	15	
3	**4**	5.8	5.800815991	15	600,000
12	**13**	1	1.004029161	15	
2	**3**	8.2	8.582228361	16	
3	**23**	2.1	2.204245544	16	
13	**14**	0.9	0.902417107	16	1,000,000
14	**15**	0.6	0.60300625	16	
17	**18**	0.2	0.207999125	16	
4	**5**	5.8	6.049418644	17	
5	**6**	5.8	5.857607534	17	
6	**26**	3	3.014004551	17	
7	**8**	2.1	2.182312047	17	1,400,000
20	**21**	0.42	0.436984832	17	
24	**25**	1	1.034414422	17	
30	**31**	1	1.045965586	17	
15	**16**	0.5	0.524567151	18	
21	**22**	0.22	0.229332415	18	
23	**24**	2.1	2.18220047	18	800,000
26	**27**	3	3.019085102	18	
27	**28**	3	3.021324974	19	200,000
2	**19**	1	1.014772084	20	
6	**7**	3	3.111587588	20	400,000
Total NPV				**$7.589M**	

6.2.1.3 ***Case-A energy costs:*** The grid costs depend on the probabilistic combination of the load state and the price state. Since no DG units are present in CASE-A, the total number of states for each year throughout the planning period used to calculate the grid costs is 18-states, as shown in Table 6.3, represents the grid cost for year-20. The annual price grid costs, which include energy price increment and transmission costs, are shown in table 6.4. The total NPV of grid cost is approximately $90.176M.

Table 6.3: Load and Price States for year-20.

State Number	Load-State	Price-State	Combined Probability	Load (MVA)	Cost ($)
1	0.474505	99.56651	0.006453	4.750795	3.05262
2	0.559356	99.56651	0.140410	5.616661	78.5216
3	0.650166	99.56651	0.175372	6.549164	114.355
4	0.735587	99.56651	0.151751	7.431968	112.291
5	0.842796	99.56651	0.073432	8.547907	62.4966
6	0.966897	99.56651	0.001441	9.851123	1.41345
7	0.474505	126.5137	0.004617	4.750795	2.77518
8	0.559356	126.5137	0.100460	5.616661	71.3851
9	0.650166	126.5137	0.125474	6.549164	103.962
10	0.735587	126.5137	0.108574	7.431968	102.085
11	0.842796	126.5137	0.052539	8.547907	56.8165
12	0.966897	126.5137	0.001031	9.851123	1.28499
13	0.474505	162.96019	0.000687	4.750795	0.53204
14	0.559356	162.96019	0.014952	5.616661	13.6855
15	0.650166	162.96019	0.018675	6.549164	19.9311
16	0.735587	162.96019	0.016160	7.431968	19.5713
17	0.842796	162.96019	0.007820	8.547907	10.8925
18	0.966897	162.96019	0.000153	9.851123	0.24635
Total State Cost					**$775.3**
Total Cost Year-20					**$6.791 M**

Table 6.4: Total Annual Grid Costs Case-A.

Year	Transmission cost ($)	Annual Grid Cost Before Escalation ($)	Annual COST ($)
1	242355	2707625	3,047,455
2	252042	2831356	3,290,925
3	264397	2967424	3,563,978
4	276053	3109784	3,858,414
5	290218	3266921	4,189,076
6	304723	3430392	4,546,056
7	319993	3603849	4,936,196
8	336611	3787991	5,363,357
9	353845	3980533	5,826,260
10	371997	4183050	6,329,860
11	391092	4396890	6,878,973
12	411514	4623006	7,478,619
13	432944	4861013	8,131,399
14	455687	5112034	8,843,145
15	479586	5369550	9,606,715
16	502481	5625158	10,408,310
17	524788	5881770	11,255,384
18	546790	6157635	12,185,089
19	574401	6466699	13,236,858
20	603110	6792620	14,382,576
Total NPV			**$90.176M**

The total state cost represents the hourly expected grid costs, taking into consideration all system states. The total annual cost for year '*n*' is the multiplication of the total state cost of year '*n*' with the number of hours in a year. For the 20-year planning period, the energy escalation factor es = 3.6%. It is important to note that the transmission cost is not affected by the escalation factor.

6.2.2. CASE B. This case represents the case with DG optimization results. The energy supplied is from the grid and DG units to meet the demand load for all the load states subjected to system constraints. The optimization objective is to minimize the DISCO NPV costs.

The results in Table 6.5 is the optimal allocation of DG units achieved by the GA, consisting of a population size of 100 chromosomes, StallGen function set to 50 and max generation of 1500 populations with a crossover set to 0.85. The best fit chromosome is shown in Figure 6.1.

Table 6.5: Optimal Capacity, Size and Location of DG Units.

	PVDG		**SDG**	
Candidate buses	Capacity (MW)	Year	Capacity (MW)	Year
Bus 34	0.55	1	0.65	10
Bus 35	0.60	1	0.10	20
Bus 36	-	-	0.55	15
Bus 37	-	-	0.30	5
Bus 38	1.0	1	0.90	10

13	2	11	6	18	11	12	0	0	20	3	5	4	2	3	1	1	4	3	1

Figure 6.1: The Chromosome with Lowest Cost Evaluation.

The results show that the total DISCO operation cost of energy supply requirements over the total period of the study is approximately $88.537M**,** as shown in Tables (6.6 - 6.14), which include energy purchased from the grid, energy sold to the grid, power loss associated with power delivery, the protection cost and system upgrades throughout the planning period. A detailed explanation is shown in section 6.2.2.

6.2.2.1 ***Case-B fuses upgrades****:* as shown from Table 6.6 fuses are upgrades regularly throughout the planning period. All the protection system fuses upgrades throughout the planning period and the annual cost upgrades of fuses, which includes the capital cost and the installation cost of the fuse. The total NPV of fuses upgrades is $187,909.

Table 6.6: Fuses Upgrades Throughout the Planning Period.

From Bus	To Bus	Fuse Rating (A)	Year	Cost ($)	Total Annual Cost ($)
29	**30**	51.32973	2	17100	17,100
2	**19**	20.31159	4	16200	16,200
6	**26**	82.23911	7	18000	18,000
26	**27**	82.75491	8	18000	34,200
31	**32**	20.01026	8	16200	
27	**28**	83.14721	9	18000	18,000
19	**20**	20.46195	10	16200	34,200
28	**29**	82.93329	10	18000	
6	**26**	100.2565	11	18600	18,600
26	**27**	100.9227	12	18600	36,600
29	**30**	81.65053	12	18000	
27	**28**	101.462	13	18600	18,600
28	**29**	102.1394	14	18600	18,600
29	**30**	100.3487	16	18600	18,600
20	**21**	20.15378	18	16200	33,300
30	**31**	51.34942	18	17100	
Total NPV					**$187,909**

6.2.2.2 ***Case-B relays and circuit breaker upgrades***: when DG units are installed, all lines with bi-directional fault current will have their protection system updated with a combination of relays and circuit breakers. Similar to fuses, relays are upgraded regularly depending on their current rating shown in Table 6.7. The annual cost of relays and circuit breakers are shown in Table 6.8. The total NPV for relays and circuit breakers updates is $3.05M**.** the installation cost of the circuit breaker and relays are taken into consideration for all three-phase system. one breaker is installed on the bus with three relays for each phase this is done for each bus with a possibility of having an upstream fault current. Relays and CB are also installed on the busses connecting the DG to the distribution system. as shown in Table 6.7 in year 1, 5 and 15.

Table 6.7: Relay Upgrades Throughout the Planning Period Case-B.

From Bus	To Bus	Relay-Rating (A)	Year	Cost ($)	Annual Cost ($)
1	**2**	193.56441	1	42000	537,000
2	**3**	171.09814	1	42000	
3	**4**	124.72426	1	42000	
4	**5**	118.20551	1	42000	
5	**6**	115.203	1	42000	
6	**7**	50.775618	1	39000	
7	**8**	40.384134	1	36000	
8	**9**	32.500231	1	36000	
3	**23**	42.339934	1	36000	
23	**24**	37.695144	1	36000	
24	**25**	16.672511	1	36000	
Relay installation at DG line buses (34,35,38)			1	108000	
1	**2**	204.18667	2	45000	45,000
9	**10**	26.576376	5	36000	399,000
10	**11**	23.261397	5	36000	
11	**12**	20.252303	5	36000	
12	**13**	16.448933	5	36000	
13	**14**	12.699278	5	36000	
14	**15**	5.3268763	5	36000	
16	**15**	4.8951766	5	36000	
17	**16**	6.2384558	5	36000	
18	**17**	8.9082802	5	36000	
3	**23**	52.103198	5	39000	
Relay installation at DG line bus (37)			5	36000	
2	**3**	205.72968	6	45000	45,000
23	**24**	51.598612	7	39000	39,000
3	**4**	203.55687	14	45000	84,000
8	**9**	50.916674	14	39000	
Relay installation at DG line bus (36)			15	36000	36,000
4	**5**	210.59464	17	45000	90,000
5	**6**	204.39325	17	45000	
7	**8**	52.556058	19	39000	39,000
Total NPV					**$1.193M**

Table 6.8: Number of Circuit Breaker Installation Case-B.

Year	Number of CB Installed	Cost ($)
1	15	1,200,000
5	10	800,000
15	1	80,000
Total NPV		**$1.8558M**

6.2.2.3 ***Case-B line upgrades****:* distribution line is upgraded whenever the power flowing through them excides the capacity of the line. DG installation effects the power flowing in all line in the distribution system. When a line is upgraded, its power capacity is doubled. Table 6.9 represents the all the distribution line upgrades in the distribution system throughout the planning period and the total annual upgrade costs. The total NPV for line upgrades is approximately $5.763M**.**

6.2.2.4 ***Case-B SDG capital and operational costs****:* the capital cost per MW ($/MW), operational and maintenance cost ($/MWh) is presented in Table 4.1. Throughout the planning period, a fuel escalation factor *fes*= 2%. Fuel escalation is similar to electricity price escalation but affects the operational cost of the SDG units. Table 6.10 presents the SDG installation and Table 6.11 is the operational costs throughout the planning period of the optimized DG. The total NPV of SDG capital and operational cost is approximately $20.880M**.**

6.2.2.5 ***Case-B PVDG capital and operational costs***: the capital cost per MW ($/KW), operational and maintenance cost ($/KW) for PVDG is presented in Table 4.2. Unlike SDG unit's PVDG, operational cost is not affected by any escalation factors and is calculated depending on the generation unit maximum capacity. Table 6.12 presents the PVDG installation and Table 6.13 represents the operational costs throughout the planning period. The NPV of installation and operational cost of PVDG is approximately $7.235M**.**

6.2.2.6 ***Case-B energy costs****:* energy prices are calculated using the price multi-state probabilistic model shown in Table 4.3. The grid costs depend on the probabilistic combination of the load state and the price state since DG are present in CASE-B. The total number of states for each year throughout the planning period used to calculate the grid costs is 90-states as shown in Table 6.14-6.16 represents the grid cost for year-1. The annual price grid costs, which include energy price increment and transmission costs, are shown in Table 6.15. The total NPV of grid cost is approximately $51.608M**.**

Table 6.9: Distribution Lines Upgrades Throughout the Planning Period.

From Bus	To Bus	Line Capacity (MVA)	Line Power Flow	Year	Total Annual Cost ($)
8	**34**	0.5	0.54642	1	1,200,000
9	**35**	0.5	0.595728	1	
12	**13**	0.5	0.506855	1	
17	**18**	0.1	0.100046	1	
24	**25**	0.5	0.605294	1	
25	**38**	0.1	0.997163	1	
13	**14**	0.45	0.455665	2	800,000
14	**15**	0.3	0.304484	2	
20	**21**	0.21	0.210189	2	
30	**31**	0.5	0.502982	2	
6	**26**	1.5	1.520928	3	600,000
15	**16**	0.25	0.252293	3	
21	**22**	0.11	0.11031	3	
26	**27**	1.5	1.526107	4	200,000
27	**28**	1.5	1.52699	5	200,000
2	**19**	0.5	0.512552	6	400,000
28	**29**	1.5	1.512882	6	
3	**4**	2.9	3.007955	8	400,000
32	**33**	0.1	0.103054	8	
1	**2**	4.6	4.883959	9	800,000
2	**3**	4.1	4.166543	9	
4	**5**	2.9	2.984631	9	
29	**30**	1.5	1.540731	9	
24	**25**	1	1.267049	10	200000
5	**6**	2.9	2.908647	11	400,000
31	**32**	0.5	0.503688	11	
19	**20**	0.5	0.516241	12	200,000
9	**10**	1.05	1.053945	14	200,000
7	**8**	1.05	1.208472	15	400,000
12	**36**	0.5	0.546397	15	
6	**26**	3	3.012583	17	600,000
20	**21**	0.42	0.436985	17	
30	**31**	1	1.045874	17	
3	**23**	1.05	1.099593	18	600,000
21	**22**	0.22	0.229333	18	
26	**27**	3	3.020245	18	
27	**28**	3	3.02272	19	200,000
2	**19**	1	1.014776	20	600,000
12	**13**	1	1.012821	20	
23	**24**	1.05	1.075448	20	
Total NPV					**$5.763M**

Table 6.10: SDG Installation Costs CASE-B.

Bus	SDG Capacity (MW)	Installation year	Cost ($)
37	0.30	5	172,500
34	0.65	10	891,250
38	0.90	10	
36	0.55	15	316,250
35	0.10	20	57,500
Total NPV			**$945,723**

Table 6.11: SDG Operational and Maintenance Cost CASE-B.

Year	Bus-37	Bus-34	Bus-38	Bus-36	Bus-35	Total Annual Cost ($)
1	-	-	-	-	-	-
2	-	-	-	-	-	-
3	-	-	-	-	-	-
4	-	-	-	-	-	-
5	348183	-	-	-	-	348,183
6	355147	-	-	-	-	355,147
7	362250	-	-	-	-	362,250
8	369495	-	-	-	-	369,495
9	376884	-	-	-	-	376,884
10	384422	832915	1153266	-	-	2,370,603
11	392111	849573	1176332	-	-	2,418,015
12	399953	866564	1199858	-	-	2,466,375
13	407952	883896	1223855	-	-	2,515,703
14	416111	901573	1248332	-	-	2,566,017
15	424433	919605	1273299	778127	-	3,395,464
16	432922	937997	1298765	793690	-	3,463,374
17	441580	956757	1324740	809564	-	3,532,641
18	450412	975892	1351235	825755	-	3,603,294
19	459420	995410	1378260	842270	-	3,675,360
20	468608	1015318	1405825	859115	156203	3,905,070
Total NPV						**$19.935M**

Table 6.12: PVDG Capital Costs CASE-B.

Bus	PVDG Capacity (MW)	Installation year	Cost ($)
34	0.55	1	5,676,000
35	0.60	1	
38	1	1	
36	-	-	-
35	-	-	-
Total NPV			**$5.458M**

Table 6.13: PVDG Operational and Maintenance Cost CASE-B.

Year	Bus-34	Bus-35	Bus-38	Bus-36	Bus-37	Total Annual Cost ($)
1	33456.5	36498	60830	-	-	130,784.5
2	33456.5	36498	60830	-	-	130,784.5
3	33456.5	36498	60830	-	-	130,784.5
4	33456.5	36498	60830	-	-	130,784.5
5	33456.5	36498	60830	-	-	130,784.5
6	33456.5	36498	60830	-	-	130,784.5
7	33456.5	36498	60830	-	-	130,784.5
8	33456.5	36498	60830	-	-	130,784.5
9	33456.5	36498	60830	-	-	130,784.5
10	33456.5	36498	60830	-	-	130,784.5
11	33456.5	36498	60830	-	-	130,784.5
12	33456.5	36498	60830	-	-	130,784.5
13	33456.5	36498	60830	-	-	130,784.5
14	33456.5	36498	60830	-	-	130,784.5
15	33456.5	36498	60830	-	-	130,784.5
16	33456.5	36498	60830	-	-	130,784.5
17	33456.5	36498	60830	-	-	130,784.5
18	33456.5	36498	60830	-	-	130,784.5
19	33456.5	36498	60830	-	-	130,784.5
20	33456.5	36498	60830	-	-	130,784.5
Total NPV						**$1.777M**

Table 6.14: State 1 to 37 of the Final State Model for CASE-B.

State Number	PVDG State	Load State	Price State	Probab -ility	State Cost ($)	Net power From Grid (MW)	Cost ($)
1	0.1146	0.4745	162.96	0.00041	0.0661	1.6401	0.108
2	0.1146	0.4745	126.51	0.00272	0.3446	1.6401	0.565
3	0.1146	0.4745	99.57	0.00381	0.3791	1.6401	0.622
4	0.1146	0.5594	162.96	0.00882	1.4376	1.9868	2.856
5	0.1146	0.5594	126.51	0.05927	7.4986	1.9868	14.898
6	0.1146	0.5594	99.57	0.08284	8.2483	1.9868	16.388
7	0.1146	0.6502	162.96	0.01102	1.7956	2.3613	4.24
8	0.1146	0.6502	126.51	0.07403	9.3658	2.3613	22.115
9	0.1146	0.6502	99.57	0.10347	10.3021	2.3613	24.326
10	0.1146	0.7356	162.96	0.00953	1.5537	2.7169	4.221
11	0.1146	0.7356	126.51	0.06406	8.1043	2.7169	22.019
12	0.1146	0.7356	99.57	0.08953	8.9145	2.7169	24.22
13	0.1146	0.8428	162.96	0.00461	0.7518	3.1682	2.382
14	0.1146	0.8428	126.51	0.031	3.9216	3.1682	12.424
15	0.1146	0.8428	99.57	0.04332	4.3137	3.1682	13.666
16	0.1146	0.9669	162.96	0.00009	0.0148	3.6975	0.055
17	0.1146	0.9669	126.51	0.00061	0.077	3.6975	0.285
18	0.1146	0.9669	99.57	0.00085	0.0847	3.6975	0.313
19	0.3333	0.4745	162.96	0.00009	0.0146	1.1615	0.017
20	0.3333	0.4745	126.51	0.0006	0.0759	1.1615	0.088
21	0.3333	0.4745	99.57	0.00084	0.0835	1.1615	0.097
22	0.3333	0.5594	162.96	0.00194	0.3168	1.5054	0.477
23	0.3333	0.5594	126.51	0.01306	1.6522	1.5054	2.487
24	0.3333	0.5594	99.57	0.01825	1.8174	1.5054	2.736
25	0.3333	0.6502	162.96	0.00243	0.3956	1.8769	0.743
26	0.3333	0.6502	126.51	0.01631	2.0636	1.8769	3.873
27	0.3333	0.6502	99.57	0.0228	2.2699	1.8769	4.26
28	0.3333	0.7356	162.96	0.0021	0.3423	2.2296	0.763
29	0.3333	0.7356	126.51	0.01411	1.7857	2.2296	3.981
30	0.3333	0.7356	99.57	0.01973	1.9642	2.2296	4.379
31	0.3333	0.8428	162.96	0.00102	0.1657	2.6769	0.443
32	0.3333	0.8428	126.51	0.00683	0.8641	2.6769	2.313
33	0.3333	0.8428	99.57	0.00955	0.9505	2.6769	2.544
34	0.3333	0.9669	162.96	0.00002	0.0033	3.2016	0.01
35	0.3333	0.9669	126.51	0.00013	0.017	3.2016	0.054
36	0.3333	0.9669	99.57	0.00019	0.0187	3.2016	0.06
37	0.5625	0.4745	162.96	0.00007	0.0112	0.6664	0.007

Table 6.15: State 38 to 77 of the Final State Model for CASE-B.

State Number	PVDG State	Load State	Price State	Probabi -lity	State Cost ($)	Net power From Grid (MW)	Cost ($)
38	0.5625	0.4745	126.51	0.00046	0.0584	0.6664	0.039
39	0.5625	0.4745	99.57	0.00065	0.0643	0.6664	0.043
40	0.5625	0.5594	162.96	0.0015	0.2437	1.0076	0.246
41	0.5625	0.5594	126.51	0.01005	1.271	1.0076	1.281
42	0.5625	0.5594	99.57	0.01404	1.398	1.0076	1.409
43	0.5625	0.6502	162.96	0.00187	0.3043	1.376	0.419
44	0.5625	0.6502	126.51	0.01255	1.5874	1.376	2.184
45	0.5625	0.6502	99.57	0.01754	1.7461	1.376	2.403
46	0.5625	0.7356	162.96	0.00162	0.2633	1.7257	0.454
47	0.5625	0.7356	126.51	0.01086	1.3736	1.7257	2.37
48	0.5625	0.7356	99.57	0.01518	1.5109	1.7257	2.607
49	0.5625	0.8428	162.96	0.00078	0.1274	2.1692	0.276
50	0.5625	0.8428	126.51	0.00525	0.6647	2.1692	1.442
51	0.5625	0.8428	99.57	0.00734	0.7311	2.1692	1.586
52	0.5625	0.9669	162.96	0.00002	0.0025	2.6893	0.007
53	0.5625	0.9669	126.51	0.0001	0.013	2.6893	0.035
54	0.5625	0.9669	99.57	0.00014	0.0143	2.6893	0.039
55	0.7813	0.4745	162.96	0.00005	0.009	0.1997	0.002
56	0.7813	0.4745	126.51	0.00037	0.0467	0.1997	0.009
57	0.7813	0.4745	99.57	0.00052	0.0514	0.1997	0.01
58	0.7813	0.5594	162.96	0.0012	0.1949	0.5383	0.105
59	0.7813	0.5594	126.51	0.00804	1.0168	0.5383	0.547
60	0.7813	0.5594	99.57	0.01123	1.1184	0.5383	0.602
61	0.7813	0.6502	162.96	0.00149	0.2435	0.9039	0.22
62	0.7813	0.6502	126.51	0.01004	1.2699	0.9039	1.148
63	0.7813	0.6502	99.57	0.01403	1.3969	0.9039	1.263
64	0.7813	0.7356	162.96	0.00129	0.2107	1.251	0.264
65	0.7813	0.7356	126.51	0.00869	1.0989	1.251	1.375
66	0.7813	0.7356	99.57	0.01214	1.2087	1.251	1.512
67	0.7813	0.8428	162.96	0.00063	0.1019	1.691	0.172
68	0.7813	0.8428	126.51	0.0042	0.5317	1.691	0.899
69	0.7813	0.8428	99.57	0.00587	0.5849	1.691	0.989
70	0.7813	0.9669	162.96	0.00001	0.002	2.2068	0.004
71	0.7813	0.9669	126.51	0.00008	0.0104	2.2068	0.023
72	0.7813	0.9669	99.57	0.00012	0.0115	2.2068	0.025
73	1	0.4745	71.14	0.00007	0.0049	-0.2616	-0.001
74	1	0.4745	34.69	0.00046	0.016	-0.2616	-0.004
75	1	0.4745	7.74	0.00065	0.005	-0.2616	-0.001
76	1	0.5594	162.96	0.0015	0.2437	0.0746	0.018
77	1	0.5594	126.51	0.01005	1.271	0.0746	0.095

Table 6.16: State 78 to 90 of the Final State Model for CASE-B.

State Number	PVDG State	Load State	Price State	Probabi -lity	State Cost ($)	Net power From Grid (MW)	Cost ($)
78	1	0.5594	99.57	0.01404	1.398	0.0746	0.104
79	1	0.6502	162.96	0.00187	0.3043	0.4376	0.133
80	1	0.6502	126.51	0.01255	1.5874	0.4376	0.695
81	1	0.6502	99.57	0.01754	1.7461	0.4376	0.764
82	1	0.7356	162.96	0.00162	0.2633	0.7821	0.206
83	1	0.7356	126.51	0.01086	1.3736	0.7821	1.074
84	1	0.7356	99.57	0.01518	1.5109	0.7821	1.182
85	1	0.8428	162.96	0.00078	0.1274	1.2187	0.155
86	1	0.8428	126.51	0.00525	0.6647	1.2187	0.81
87	1	0.8428	99.57	0.00734	0.7311	1.2187	0.891
88	1	0.9669	162.96	0.00002	0.0025	1.7305	0.004
89	1	0.9669	126.51	0.0001	0.013	1.7305	0.023
90	1	0.9669	99.57	0.00014	0.0143	1.7305	0.025

Table 6.17: Total Annual Grid Costs CASE-B.

Year	Transmission cost ($)	Annual Grid Cost Before Escalation ($)	Annual COST ($)
1	226289	1990456	2,288,402
2	238915	2128645	2,523,581
3	252253	2274456	2,781,299
4	266324	2428026	3,063,324
5	260527	2273223	2,973,471
6	275555	2438655	3,290,705
7	291554	2613966	3,639,806
8	308937	2802244	4,027,576
9	326090	2993476	4,441,504
10	241118	1620893	2,549,736
11	260450	1827179	2,956,566
12	278523	2033360	3,386,884
13	299702	2262506	3,882,865
14	322136	2508524	4,437,942
15	309674	2211753	4,069,199
16	334288	2478059	4,698,118
17	360402	2763451	5,401,993
18	387629	3061775	6,174,567
19	416199	3375423	7,025,623
20	439123	3598899	7,739,828
Total NPV			**$51.608M**

The total state cost represents the hourly expected grid costs, taking into consideration all system states. The total annual cost for year ‘*n*’ is the multiplication of the total state cost of year ‘*n*’ with the number of hours in a year. For the 20-year planning period, the energy escalation factor *es* = 3.6%. It is important to note that the transmission cost is not affected by the escalation factor. As seen from Table 6.15, state 73, 74 and 75 are the only states in year-1, where energy is sold to the grid. The sell price is equal to the buy price but without the global adjustment cost.

6.3. Case Comparison

Different comparisons between CASE-*A* and CASE-*B* are provided in this section. The comparisons are based on the grid purchased energy, line upgrades, protection upgrades, and DG costs.

6.3.1. Purchased energy from the grid. For the base case defined by CASE-*A*, which does not include any DG in the system, as shown in Figure 6.2 the total cost to meet demand load over the study period including system losses is \$90.176M, which included the power losses in the distribution system. For the DG optimized case, *CASE-B*, the grid cost to meet the demand load over the study period is \$51.608M. The grid cost decreased by 42.77%; the reduction is due to the DG unit supplying power to loads instead of the grid.

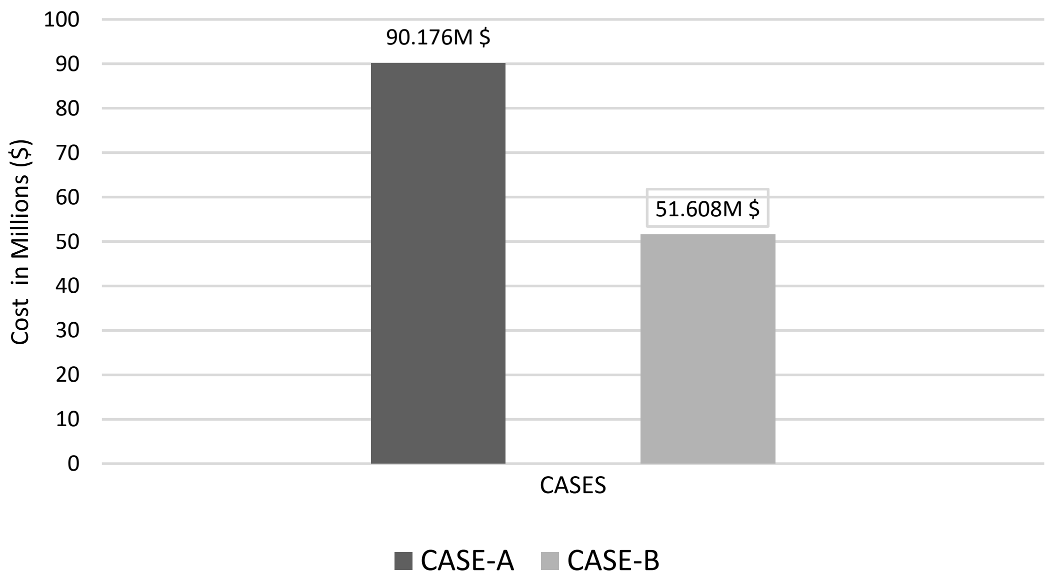

Figure 6.2: NPV Energy Cost Comparison.

As seen in Figure 6.3, the decrease in the initial grid costs from CASE-A and CASE-B is due to the PVDG installed in the first year. A small decrease is noticed in year 5 and 15 is due to the 0.3MW and 0.55MW SDG installed. The largest decrease in grid cost in year 10 where the largest SDG capacity is installed on bus 34 and 38 totaling 1.55MW.

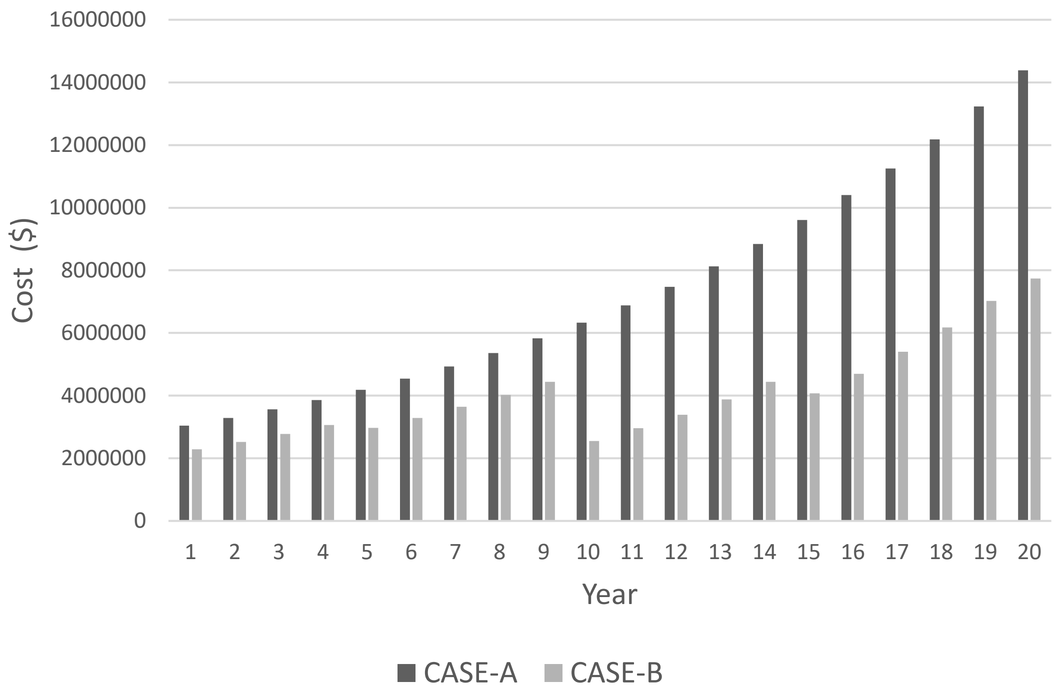

Figure 6.3: Annual Energy Cost Comparison.

6.3.2. Line upgrades. The NPV of line upgrades for the base CASE-*A* is \$7.589M while for CASE-*B* the NPV of line upgrades is \$5.763M as shown in Figure 6.4. A 24.06% decrease in the NPV cost of line upgrades between CASE-*A* and CASE-*B* is observed. It is important to note that the study considers the lines connecting the DG to the grid when installed. The decrease in line update cost is due to the fact that DG units reduce the power flowing throw most lines in the system, especially lines placed near the grid connected bus. The annual cost of line upgrades is presented in Figure 6.5.

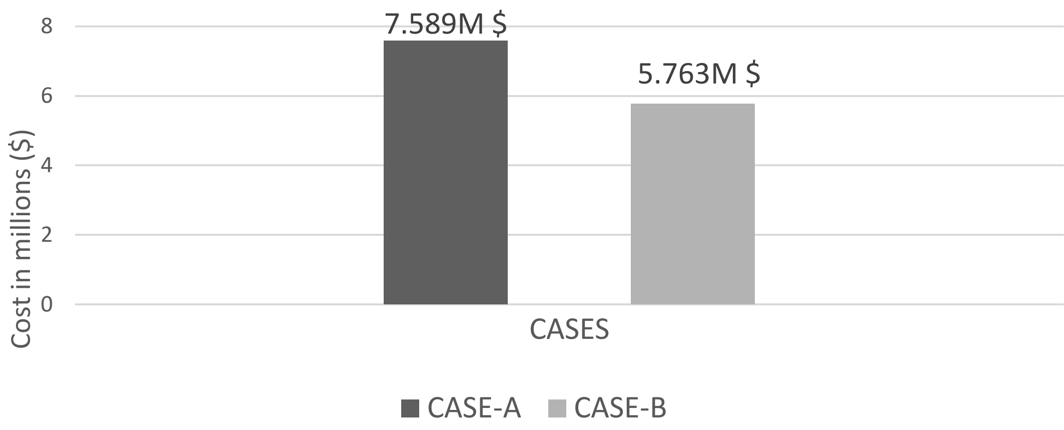

Figure 6.4: NPV Lines Upgrade Cost Comparison.

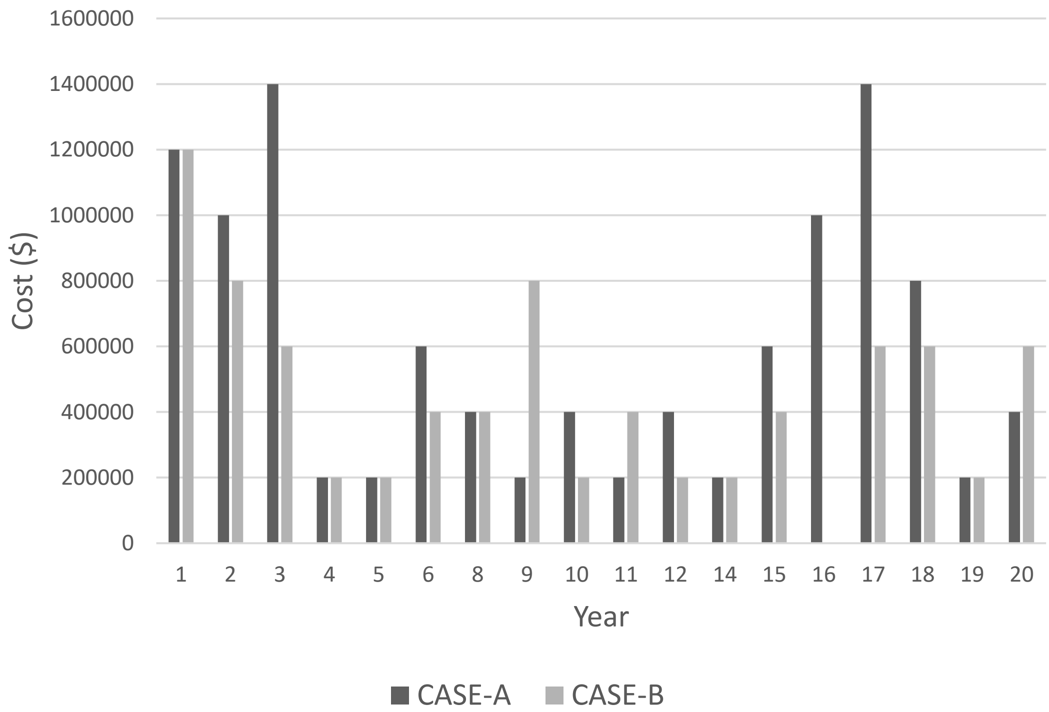

Figure 6.5: Annual Lines Upgrade Cost Comparison.

6.3.3. Protection upgrades. In CASE-*A*, protection costs consist of fuses upgrades only. Since there are no DG units, there is no upstream fault currents in the distribution system. The NPV for protection upgrades for CASE-*A* is approximately \$529,312. For CASE-*B*, where faults may cause upstream currents in distribution lines, relays and CB are installed on all lines that may experience upstream current. The NPV of fuses upgrades in CASE-*B* is approximately \$187,909, a decrease of 64.49% from

CASE-*A*. On the other hand, the NPV cost of relays and CB upgrades is approximately \$3.081M. The total protection cost for CASE-*B* is approximately \$3.269M, resulting in an overall increase in protection cost of \$2.739M, nearly a 517% increase in the NPV of protection cost from CASE-*A* to CASE-*B*.

The initial high cost of protection upgrades shown in Figure 6.6 is due to the installation of PVDG on buses 34, 35 and 38. In year 5 the peak in protection cost is due to the SDG installed on bus 37. The circuit breaker costs is considered as a fixed cost with no running of upgrade costs, unlike fuses and relays. the protection upgrades cost in CASE-A is made up of fuses upgrades only , while as shown in Figure 6.7 CASE-B the protection upgrades cost is made up of fuses , circuit breakers and over current relays.

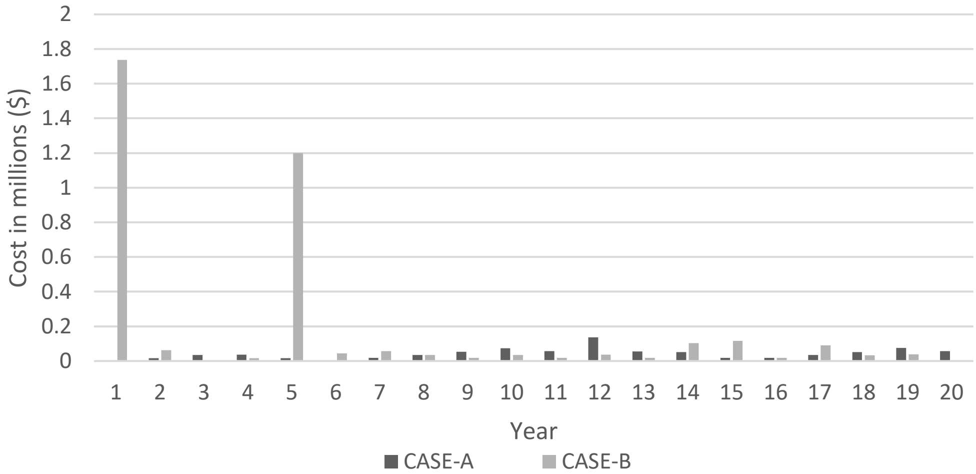

Figure 6.6: Annual Protection Costs Comparison.

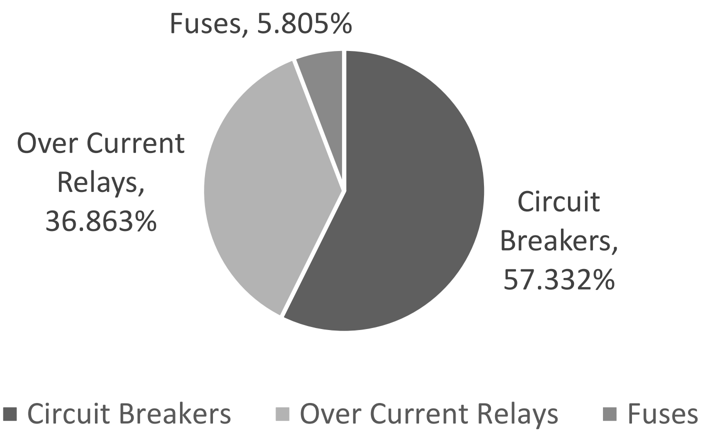

Figure 6.7: CASE-B NPV Protection Costs Breakdown.

6.3.4. NPV of the DISCO expenses. In CASE-*A*, the NPV is $98.3M, Figure 6.8 represents both cases cost breakdown and the its contribution to the total cost. where, 0.539% of the total cost is associated with protection upgrades, 7.720% is associated with line upgrades and 91.692% of the total cost is associated with grid cost. The total NPV of the DISCO expenses in case CASE-*B* is $88.537M. where 3.446% of the total cost is associated with protection upgrades, 6.509% is associated with line upgrades, 58.290% of the total cost is associated with grid cost. The total NPV of capital and operational cost of DG units is $28.115M equivalent to 31.757% of the total cost.

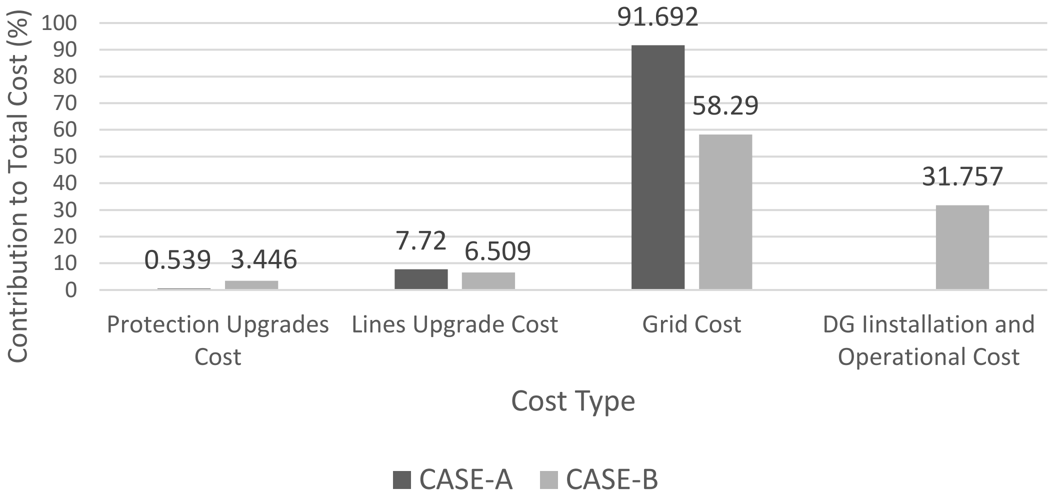

Figure 6.8: Contribution to Total Expenses.

The total decrease in DISCO expenses after installing DG units is $9.763M. The 9.93% decrease is mainly a result of reducing the energy bought from the grid and replacing it by DG units' generation, which is very effective, considering states with high energy prices. The profits of energy sold to the grid is only present in 14 years with a total of 78 low probability states of the study's 1800 states. The low profits are expected since the selling price is low, and the GA main objective is to reduce DISCO cost rather than maximizing DG profits. The total profit from selling energy to the grid is $7641, which is approximately 0.0148% of the grid total cost. The states where energy is sold to the grid mainly occurs when the PVDG state is high and the load state is low. Figure 6.9 represents the NPV of the total cost for CASE-A and CASE-B.

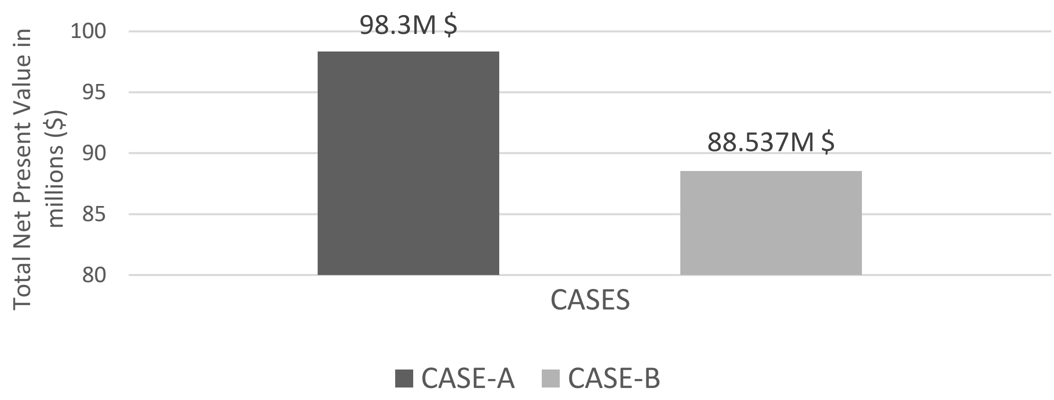

Figure 6.9: CASE-A and CASE-B Total Expenses NPV.

A side by side comparison is shown in Figure 6.10 , with a total investment in DG units is $28.11M in CASE-B ; the 9.93% decrease in price is only a part of the profits as the DISCO is expected to sell energy to consumers at a rate competitive with other companies. In other words, the decrease in price is also considered an additional profit added to the profit from selling energy to consumers. The rate of return of the DG investment is calculated as the total expenses saved in NPV $38.115M with respect to the cost in NPV of DG investment $28.11M and NPV for protection upgrades $3.269 M, yielding a rate of return of 21.466%.

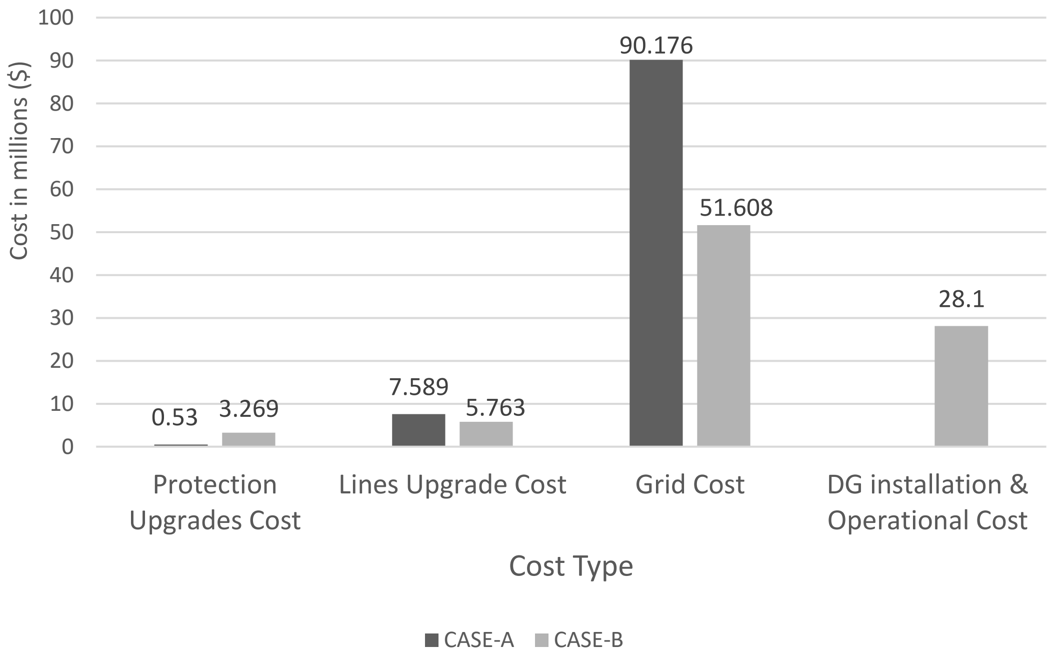

Figure 6.10: CASE-A and CASE-B Costs Comparison.

The total allocated DG capacity installed at the end of the planning period is 4.65 MW, composed of 2.15MW in PVDG and 2.5MW SDG as shown in Figure 6.11. The total DG penetration at the end of the planning period is 40.7%. The real power supplied from the DG units with respect to grid varies between 27.86% and 47.18%. The varying real power generation is due to the PVDG units power output depending on states.

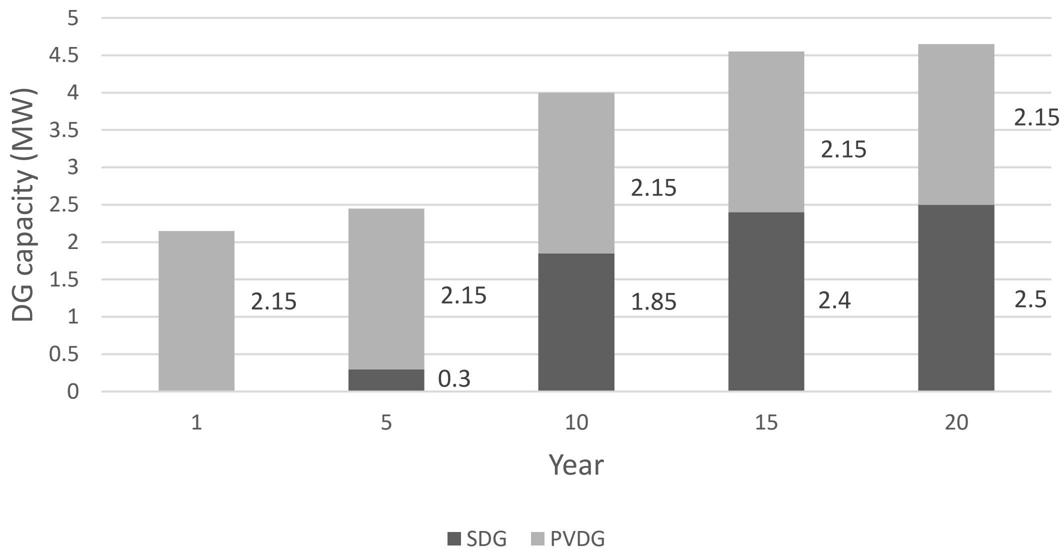

Figure 6.11: Total Annual DG Installed Capacity.

6.4. Fault Analysis Results Sample

This section includes a sample of fault analysis results. The values presented are for IEEE 38 bus system. the results presented are for a fixed load, with multiple of DG connected to the system. It’s important to note that due to the high number of possible DG allocation possibilities its tedious to represent each case serpreatly.

A symmetrical three phase fault analysis was carried on bus-4 in all cases. It’s important to note that fault analysis must be implemented on all buses in the system to upgrade the protection system since a fault can occur on any bus in the system. It’s important to note that since the proposed planning algorithm is dynamic and DG units can be installed at any year with respect to installation year constraints. Therefore, fault analysis is carried out at the beginning of every year on maximum DG output capacity and the fault location is applied on each bus for an accurate representation of the system under all fault locations. At the end of the fault analysis the worst case conditions and the system is upgraded accordingly. Once an upgrade is made to the protection system , the upgrade is carried on throughout the remaining planning period. For example: if at year 10 a bus fuse is upgraded to an OCR , in year 11 the protection system on the bus is treated as an OCR and its rating is upgraded accordingly throughout the planning period.

6.4.1. Case-A fault analysis. Case-A does not include any DG units in the system with a fault Implemented on bus 4 in the distribution system. as seen from the fault analysis results in Table 6.18, the fault current is going downward stream with a magnitude of 22.9802 *p.u* with respect to the systems *p.u* data. Since the fault occurred on bus-4 and the system power injection is from the grid, no fault current passes through the rest of the system. Moreover , since the fault current in going down stream a fuse based protection system can be used to protect the system and clear the fault.

Table 6.18: Case-A Fault Current Analysis with no DG units.

From Bus	To Bus	Fault Current Magnitude ($I_{p.u}$)
1	2	22.9802
2	3	22.9802
3	4	22.9802
4	4	22.9802

6.4.2. Case-B fault analysis. Case-B Includes a synchronous DG installed at bus-38 as shown in Figure 6.12, the synchronous DG has a generation of 1MW injected at bus-38. As shown in Table 6.19 the fault current is going in a bidirectional manner , upstream and downward stream with a maximum magnitude of 38.73056*p.u* with respect to the systems *p.u* data. The current contribution from the grid to the fault current is 22.226*p.u* while the DG contribution to the fault is 16.730*p.u* , the two currents add up to 38.72017*p.u* injected at bus 3 as seen in Figure 6.12. Since the fault occurred on bus-4 anything downstream the faulted bus doesn’t sense any fault current. Hence, the current passing through them is zero. Note that the fault current from bus 38 to bus 3 is opposite in direction to the load current without the presence of a DG unit. due to that nature, bidirectional relays should be installed on those buses to protect the system. Moreover, the fault current seen by the relays on bus 2 is different from the current seen by the relays on bus 3. meaning that the coordination between the relays needs to be reconfigured.

The negative fault current values in Table 6.19 represents the upstream current where the protection system should be upgraded to relays paired with circuit breakers, a total of four protection systems is required to be upgraded in this case . It's important to note that when the fault bus changes new upgrade requirement should be taken into consideration. For example, in Case-B if we add another DG unit on bus 37. And applied a fault on bus-4 the total number of buses protection system that needs to be updated is 19. Moreover, if the fault location changes the number of upgrades changes.

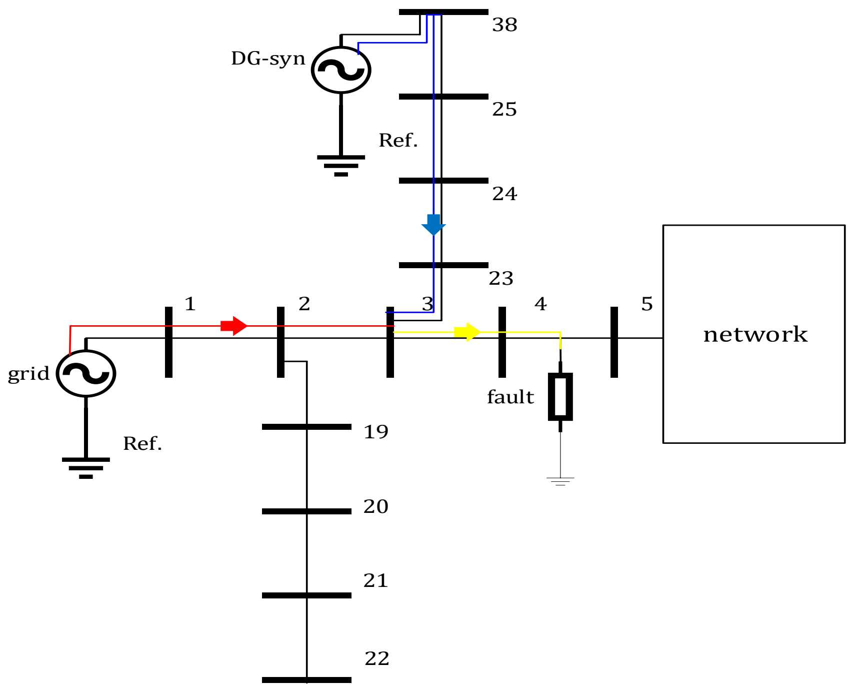

Figure 6.12: Case-B Fault Analysis Representation.

Table 6.19: Case-B Fault Analysis.

From bus	To bus	Fault current magnitude ($I_{p.u}$)
1	2	22.22652
2	3	22.22652
23	3	-16.73056
24	23	-16.73056
25	24	-16.73056
38	25	-16.73056
3	4	38.72017

Chapter 7. Conclusion and Future Work

This thesis proposed a new planning scheme of distributed generation units penetration within the distribution network. The proposed scheme can help investors and distribution companies in optimization of the placement, sizing and type of distributed generation units within the distribution networks in order to minimize the overall investment costs and expenses.

This study takes into consideration the intermittent and random nature of renewable generation units, load variability and energy pricing. The proposed methodology relies on developing a probabilistic multi-states model of the system and combines them into one load-generation-price model. The multi-state model allows for an accurate representation of the distribution system normal operation states and extreme states cases.

The difference between the proposed planning scheme and other studies related to this area of study is the consideration of the cost associated with the protection system throughout the planning period, as the installation of DG units have high impacts on the protection system operational scheme. After the installation of any DG unit, the algorithm performs fault analysis on each bus in the distribution system and upgrades the protection system to accommodate the DG units' effects. Moreover, the study takes into consideration the relays and fuses upgrades throughout the planning period. In the base CASE-A with no DG units, the highest NPV is observed at $98.3M, while the optimized CASE-B shows the optimized DG allocation resulting in a NPV of $88.537M. Genetic algorithm is utilized to optimize the DG planning problem. The total decrease in DISCO expenses after installing DG units is $9.763M a 9.93% decrease, mainly a result of reducing grid costs.

All previous work done in this area of study did not include the protection aspect of the DG planning problem. The study focuses on the DG planning problem while taking into consideration its effects on the protection system cost upgrades. For example, for the achieved near optimal DG allocation problem, if the protection cost upgrades were not taken into consideration, the NPV of the DISCO expenses would be $85.4 M, resulting in a higher rate of return for the project at 35.59%. A 14.124% difference in the expected rate of return of the DG projects calculated at 21.466%, as a result of the protection system cost, which is misleading to the investors and the DISCO if not considered.

The reduction in total cost results obtained from the GA in this study is very close to values obtained by other literatures using different heuristic methods , the reduction in total DISCO cost in previous literature ranges from 8% to 14% for long planning periods. The variables are highly system dependent and changing any value may dramatically alter the results.

Future work is needed as this study combines two vast areas of research, which are DG planning and power system protection. Future work includes adding wind-based DG units to the optimization problem, adding transformers cost upgrades, the decrease of PVDG units price, the addition of interruptions cost, allowing DG units to increase their capacity throughout the planning period, adding dispatchable units, finding the optimal protection system operational time and adding equipment lifetime expectancy and salvage values.

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