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GA-Based Optimal Recloser Placement in DG-Integrated Radial Distribution Systems

by

Raushan Kumar Thakur

A THESIS

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A Thesis submitted in Partial fulfilment of the requirements for the degree of Master of Science in Power System Engineering

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CERTIFICATE OF APPROVAL

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ABSTRACT

Radial Distribution Systems (RDS) are critical for power delivery but often suffer from poor voltage profiles and low reliability due to their extensive length and exposure to faults. The integration of Distributed Generation (DG) units, such as biomass or solar, offers a solution to these issues but introduces new challenges in protection coordination due to bidirectional power flow. This thesis proposes a comprehensive methodology to enhance the reliability and voltage profile of distribution networks by optimally placing DGs and Automatic Circuit Reclosers (ACRs).The study employs a two-stage optimization approach. First, the Improved Harmony Search Algorithm (IHSA) is used to determine the optimal location and size of DG units to minimize power losses and improve voltage stability. Following this, the network is divided into autonomous zones capable of intentional islanding during grid faults. In the second stage, a Genetic Algorithm (GA) is utilized to find the optimal locations for reclosers within these zones to minimize reliability indices such as SAIFI (System Average Interruption Frequency Index) and SAIDI (System Average Interruption Duration Index).The proposed methodology is validated on the standard IEEE 69-bus radial distribution system and a practical 11 kV Hasanpur distribution feeder. The results demonstrate that the optimal integration of DGs and reclosers significantly improves the system's voltage profile (raising minimum voltage from $\approx$0.90 p.u. to $\approx$0.99 p.u.) and drastically reduces customer outage times. Furthermore, the financial analysis confirms the economic feasibility of the proposed upgrades, showing a favorable NPV, IRR and a reasonable payback period. This research provides a practical framework for utility planners to modernize distribution grids for higher reliability and efficiency.

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LIST OF ACRONYMS AND ABBREVIATIONS

Acronym	**Description**
ACR	Automatic Circuit Recloser
AENS	Average Energy Not Supplied
AI	Artificial Intelligence
BFS	Backward/Forward Sweep
CAIDI	Customer Average Interruption Duration Index
CIC	Customer Interruption Cost
DFS	Depth-First Search
DG	Distributed Generation
EENS	Expected Energy Not Supplied
ENS	Energy Not Supplied
GA	Genetic Algorithm
HMCR	Harmonic Memory Consideration Rate
HMS	Harmony Memory Size
IEEE	Institute of Electrical and Electronics Engineers
IHSA	Improved Harmony Search Algorithm
IRR	Internal Rate of Return
KCL	Kirchhoff's Current Law
KVL	Kirchhoff's Voltage Law
kW	Kilowatt
kWh	Kilowatt-hour
MW	Megawatt
NPV	Net Present Value
NR	Newton-Raphson
PSO	Particle Swarm Optimization
PV	Photovoltaic
RBTS	Roy Billinton Test System
RDS	Radial Distribution System
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

1. INTRODUCTION

1.1 Background

In the new age of the fast world of technology and urbanization, the secure and effective provision of electricity energy is key to the socioeconomic growth and industrialization. With the continually rising requirements of the uninterrupted high quality power, utility companies are under increased pressure to make distribution networks more reliable. The distribution system, specifically, the radial distribution system (RDS) is the last part of the electric power delivery, but the most susceptible part since it entails a long length and is subjected to environmental and operation pressure factors. It has been estimated that a large percentage of problems in the power system happens in the distribution system which also causes frequent outages and huge economic losses to the utilities and the consumers.

Protective devices that have traditionally been used to protect the system against faults include fuses, circuit breakers, and switches. Nevertheless, these devices are usually not very helpful in counteracting the effect of faults on system reliability. Reclosers have become some of the most used modern protective equipment because they can automatically identify and isolate temporary faults, resume power following short circuits and minimise the duration of outages. Placement of reclosers in RDS has been found to have a great impact on important key reliability indices like SAIFI (System Average Interruption Frequency Index), SAIDI (System Average Interruption Duration Index), CAIDI (Customer Average Interruption Duration Index), and AENS (Average Energy Not Supplied). The indices are vital indices that utilities need to determine the effectiveness and stability of their networks.

The correct location of reclosers in a radial distribution system is one of the keys of the modern power system design that directly influences the reliability and voltage stability of the power system. Reclosers are automatic protective devices that may be able to sense and de-energize faults (e.g. short circuits or overloads) by cutting off power supply temporarily then restoring power to the line after a delay. This feature greatly minimizes the outage time and minimizes the level of power blackout, which increases the overall stability of the distribution system. Since most distribution networks are radial in nature where the power passes in only one direction between the substation and the consumers, it is important to strategically locate reclosers to allow the selective isolation of faulted areas without involving unaffected areas of the network.

The incorporation of units of Distributed Generation (DG) like solar panels, wind turbines and small scale gas turbines has been increasing in the past few years. DG units are not only used to supply the local loads but also aid in the voltage regulation as well as reduction of power losses because they inject power near the load centers. The DG presence distorts the power flow patterns and fault current values, which impacts the optimal setting of the protective devices such as reclosers. That is why, it is essential to take DG enhancement into consideration, in order to maximize the benefits of DG improvement on system performance within the placement strategy.

This paper utilizes a powerful evolutionary optimization tool, the Genetic Algorithm (GA), which is a nonlinear and complex problem solving method that uses natural selection as a guide to solve the problem of locating the most optimal reclosers to use in a radial distribution network. The GA successfully searches a huge search space of possible configurations to find solutions that maximize the indices of reliability and refines voltage profiles with minimum operational costs and power losses. The proposed solution will be used to build a holistic framework and maximize the protective coordination and voltage stability of the distribution system through integrating GA optimization and DG integration.

It is not only the methodology that facilitates the management of faults and reduces the outage but also makes sure that the voltage measurements do not exceed the acceptable range across the network, which is crucial to the safe and efficient use of delicate electric devices. The results of the study result in helpful insights and practical tools that can be used by the planners and operators of power systems to modernize distribution networks in accordance with the changing grid requirements and integration of renewable energy.

Through case studies in Hasanpur 11 kV feeder in Dhangadhi, the effectiveness of the proposed approach will be demonstrated.

1.2 Problem Statement

In an RDS, a single fault on a feeder can result in outages for a large number of customers unless appropriate protection and isolation mechanisms are in place. The challenge is further complicated by the increasing integration of Distributed Generation (DG) sources into modern distribution networks. DG units, such as solar farms, wind turbines, and small-scale diesel generators, bring several benefits, including improved voltage profiles, reduced losses, and enhanced supply security. However, they also introduce bidirectional power flow, making fault current paths less predictable. This creates a significant protection coordination challenge, particularly in determining optimal recloser placement that accounts for power flows in both directions.

As a result, utilities lack a comprehensive, practical decision-making framework for optimal recloser placement in DG-enhanced RDS. The problem is multi-faceted:

1. Technical Complexity – The placement strategy must consider multiple reliability indices (SAIFI, SAIDI, AENS, etc.) while ensuring coordination between protective devices under varying operating conditions.

2. DG Integration Impact – The solution must handle scenarios where DG units are located at arbitrary nodes, with power potentially flowing in either direction under normal or fault conditions.

3. Optimization Requirements – The problem is inherently combinatorial and nonlinear,

requiring robust optimization techniques capable of finding near-global optimal solutions within reasonable computation time.

Therefore, there is a pressing need for an analytical model that:

- Can evaluate system reliability under bidirectional power flow conditions.
- Accurately reflects the location and capacity of DG units at any node within the network that is capable of supplying the power to its zone in islanded mode with a maintained voltage profile in case of failure of the main grid.
- Identifies the location for the placement of reclosers to achieve a maximum reliability improvement at a minimum cost.

This study proposes addressing these gaps by developing a bi-directional analytical framework combined with a Genetic Algorithm (GA) optimization approach. The model will simulate various recloser placement configurations, evaluate their impact on reliability indices and voltage profile, and select the configuration that yields the best result to the utility.

1.3 Objectives of the Project

The main objectives of this research are:

1. To determine the optimal location and capacity of DGs and their islanded zones using Improved Harmony Search Algorithm (IHSA).
2. To develop a Bi-Directional analytical model to evaluate reliability indices and handle DG located at any node within the network.
3. To optimize recloser placement using a Genetic Algorithm (GA) for best reliability values.

1.4 Scope and Limitations

The primary scope of this research is to enhance the reliability of a radial distribution network by optimizing the placement of automatic reclosers and Distributed Generation (DG) units. The specific areas covered in this study include:

Reliability Improvement: The study focuses on minimizing customer interruptions by calculating reliability indices such as SAIFI (System Average Interruption Frequency Index), SAIDI (System Average Interruption Duration Index), and ENS (Energy Not Supplied).

Algorithm Implementation: Improved Harmony Search Algorithm (IHSA) and Genetic Algorithm (GA) is implemented in MATLAB to determine the optimal size and location of DG units and reclosers.

DG Integration: The impact of integrating renewable energy sources (modeled as biomass DGs) on system reliability and voltage profiles is analyzed.

Case Study Application: The proposed method is tested on standard IEEE 69-bus radial distribution test systems and a real distribution feeder (Dhangadhi Feeder) to validate its practical applicability.

Financial Feasibility: A cost-benefit analysis is performed to justify the investment in reclosers and DGs, considering the reduction in outage costs and power losses.

While this research provides a comprehensive analysis of reliability improvement, it is subject to the following limitations:

Simplified Load Models: The study assumes constant load demand for the reliability analysis. Dynamic load variations and seasonal load growth patterns have not been modeled in real-time.

DG Modeling Assumptions: The Distributed Generation units are modeled as constant power sources (PQ models). The intermittent nature of renewable sources like solar or wind (variable generation) and complex inverter dynamics are not considered.

Protection Coordination: The study focuses on the placement of reclosers but does not perform a detailed protection coordination study (e.g., time-current characteristic curves) to ensure selectivity between the reclosers and fuses.

Economic Data: The financial analysis relies on estimated unit costs for equipment and fuel, which may vary based on market conditions and location-specific tariffs.

2. REVIEW OF LITERATURE

2.1 Challenges in Radial Distribution System

Radial Distribution Systems (RDS) are the most common configuration for serving electrical loads due to their simplicity and cost-effectiveness. However, they inherently suffer from two major drawbacks: low reliability and poor voltage profile towards the feeder ends. The majority of customer interruptions (up to 80%) occur at the distribution level, often due to transient faults (e.g., lightning strikes, momentary contact with tree branches).

Early research established the critical need for advanced protection and automation to mitigate these issues. Automatic Circuit Reclosers (ACRs) emerged as the primary solution for reliability improvement, as they automatically clear transient faults and isolate permanent faults, thereby reducing the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI)[1].

2.2 DG technologies and its importance

Distributed power is electric generating or storage that is modular and positioned close to the users [2]. These units include PV solar panels, wind turbines, biomass power plants, various combustion engine-based turbines, battery storage systems, micro turbines, synchronous generators, generator sets, and other control technologies [3]. Grid-tied or isolated distributed resources are available in the power system operation. The typical overviews transmission and distribution system with different DG technologies installed in the consumer side is shown in the Figure 2.1 below.

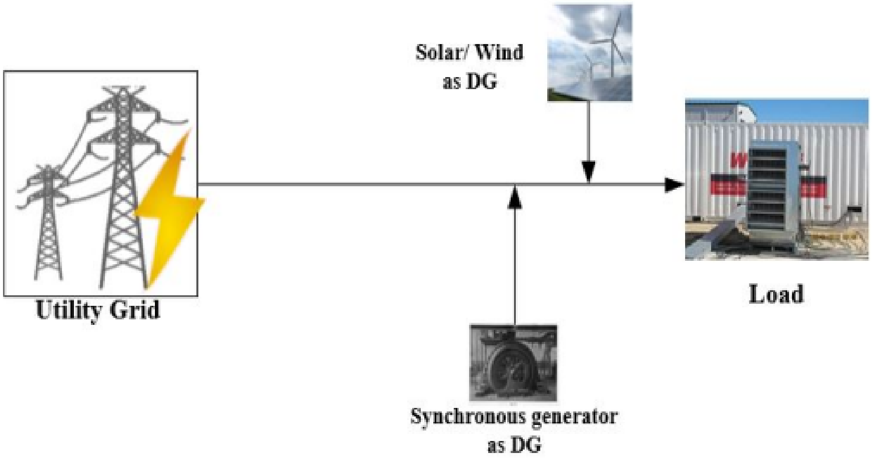


Figure 2.1: Distribution Generation Technology in grid connected mode

One of the crucial aspects of the contemporary electric power system is distributed generating technology. In addition, three key developments now dominate the recent energy market: deregulation, rising environmental concerns, and a shift toward the power generation technologies with various DG units. “Generation of electricity by facilities that are sufficiently smaller than central generating plants to allow interconnection at practically any point in a power system,” according to the IEEE. International Council on Large Electric Systems (CIGRE) and Center for International Research Education and Development (CIRED) help to define DG more precisely depending on its allocation and the size [4]. It defines DG as ”all generating units with a maximum capacity of 50-100MW that are generally linked to the distribution network but are not planned or dispatched centrally ”. “All generating units that are typically linked to the distribution network and have a maximum capacity of 50-100 MW,” according to CIRED. Also, DG technology is referred as ”an electric power generation source connected directly to the distribution network or on the customer side of the meter”. The DG technology is critical for power system reliability, availability, and stability, among other things.

2.3 Distributed Generation Resources

In the electric power system, there are often many different types of DG technologies. These technologies are divided into two sorts based on the distributed generation technologies utilized in distribution systems: dispatchable and non-dispatchable.

2.3.1 Dispatchable Resources

In general, dispatchable renewables are always available for energy production at high-capacity factors but not in the case of maintenance time. There are so many types of the dispatchable energy resources.

1.Micro - turbines: It consists of a turbine run with gas, a fixed compressor, and an alternating current (AC) generator that can create green energy with the help of a variety of fuels with little emission. Micro-turbines range in size from a few KW to MW [5]. Micro-turbines have a number of advantages, including their tiny size, maximum productivity, low noise, minimal emissions, and least capital and running costs.

2.Internal Combustion Engines: Internal Burning Engine runs with the help of combustion of the fuel and it is also called as a reciprocating engine [6]-[7]. These types of engines run with internal combustion are widely employed in transportation and generators. Internal combustion engines with synchronous generators or induction generators seem to be the most popular DG technology today, and they may be connected to the grid without the interconnection of the power electronic devices [8].

3.Combustion Engines: For the most part, gas turbines are utilized as combustion engines in DG applications. Natural gas is burned externally in combustion engines, which drive the turbine depending on pressure differences [7].

4.Fuel Cell: Chemical energy is converted into electrical or thermal energy using an electromechanical device. It differs from a battery in that the electrical and chemical components required for the operation are continuously given to the cell, eliminating the need to charge it. When utilized to generate energy, the productivity of the cells is quite ambitious, ranging between forty and sixty percent.

2.3.2 Non-dispatchable Resources

Variable Renewable Energy (VRE), often known as non-dispatchable energy resources, is dependent on weather scenario. Such resources are unpredictable in terms of availability, have location-specific characteristics as a result of their territorial accessibility, and have relatively low costs since they are available for free.

Also, the exchange of power (“both active and reactive”) in the system Distribution generation resources can be categorized as

a)Those DG, which supplies the active power to the system called PV solar

b)Those DG, which provide the only the reactive power to the system called synchronous compensator

c)Those DG, which absorbs the reactive power and on the base of that supplies active power to the system and called induction generator

Those DG, which helps to provide the both reactive as well as active power to the system and called as synchronous generator

2.4 Distribution System Classification

According to the shape of the system, the distribution network is classified into three types.

a)Radial Distribution System (RDS) In this type of system, there is the substation at one end and the single lateral line that will supplies the load to the consumer side as shown in the Figure 2.2. As depicted in the figure, between the source and the load, there will be the single path that will feed them with required amount of power. Since there is only one path between the source and load, the reliability of the system is too low. If any fault occurs in between the system, whole system will go under successive collapse. However, the initial cost of the RDS system is minimal with compared to other systems and also it is very simple to design, plan and operate.

b)Loop Distribution System: The load is managed to supply with two parallel paths from the substation as shown in the Figure 2.3. The size of the bus bar is taken to carry the more than the full load as if any one-line outage occurs, it has to carry double of its initial power demand. It has higher system reliability and availability. Also, it causes the lower voltage fluctuations and so have better regulation. As contrast to the design of a RDS system, it is more complicated and also it is more expensive as compared to the RDS system.

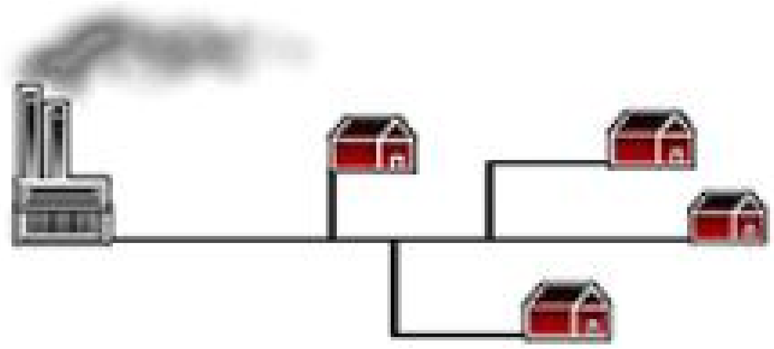


Figure 2.2: Overview of RDS System

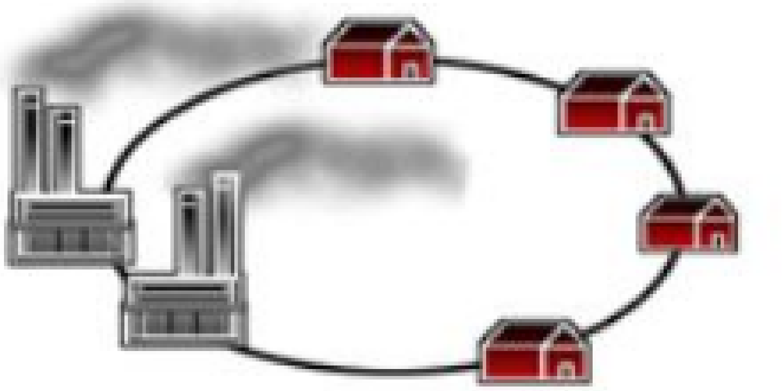


Figure 2.3: Overview of a Loop Distribution System

c)Network Distribution System The consumer is supplied with more than two path from the substation. There will be more than single substation in the system and so that the supply reliability of the network is so high. As it forms the interconnected system, the fault impedance becomes too low as it will increase the inertia so the stability of the system. The network configuration is so large and it cost more than that of the radial and loop system. Designing and operating it is more complicated than radial or loop systems. Also, it is more efficient and losses are too low for these cases. The network configuration is as shown in the Figure 2.4 below.

2.5 DG integration and its effect in distribution system

To balance the voltage control limit of the network, transformers with the tap changing facility and/or capacitor banks are used at the substation, assuming that power flows from the S/S to the loads. The power and voltage condition of the consumer side strongly depends on the allocation of the DG units in the distribution network. The positive and negative effects of DG sets are determined by distribution system operation and DG unit features. The incorrect placement of the DG unit may result in increased system power loss,

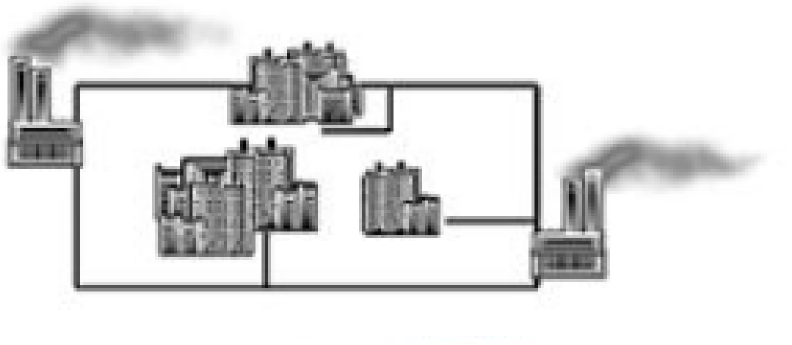


Figure 2.4: Overview of a Network (Mesh) Distribution System

voltage mismatch, less reliability and stability at the consumer end. The flow of power from the customer to the substation end isn't required for normal distribution system operation. This is due to the DG unit being installed incorrectly.so the allocation of them must be in an optimal manner. A DG unit, as opposed to a capacitor bank, may provide both power ("active and reactive power"), resulting in considerable loss reduction.

2.6 Power Flow computation in Distribution System

Power flow calculation is an essential numerical (often nonlinear) analysis needed when making power systems studies. The practical application of proposed methods for reliability and power quality improvement of the power distribution network typically requires many power flow analysis algorithms runs. The power flow methodologies applied to distribution systems will have to adapt to the nature of the distribution network, in strict terms, they will be demanded to include single phase and three phase unbalanced system analysis, as well as the influence of distributed generation interconnection. In Distribution system, the objectives are to improve reliability and enhance voltage profile, consequently, power flow analysis becomes an essential procedure to be performed in order to obtain steady state electrical characteristics of the distribution system as consequence of isolation of faulty part from the network. Often, power flow analysis methodology applied to transmission systems is mainly comprised by the Gauss-Seidel, Newton-Raphson (NR) and its decoupled version. These power flow methods are typically used assuming a balanced system, consequently using a single-phase representation of a three-phase system. Due to the particular characteristics of distribution systems (i.e. unbalanced loads, radial topology, often un-transposed lines, distributed generation, etc.) the assumptions made in the analysis of transmission systems fail to be extrapolated to the distribution system.

The R/X Ratio Issue: Distribution networks are characterized by high Resistance-to-Reactance (R/X) ratios compared to transmission lines. Researchers have consistently demonstrated that the Jacobian matrix in the NR method becomes ill-conditioned under high R/X ratios, leading to divergence or extremely slow convergence.

Radial Topology: Unlike the meshed structure of transmission grids, distribution systems are typically radial. Conventional methods do not exploit this radial feature, resulting in computational inefficiency.

The Backward/Forward Sweep (BFS) Method: To overcome these limitations, the Backward/Forward Sweep (BFS) algorithm has emerged as the preferred technique for RDS.Methodology: The literature describes BFS as an iterative two-step process. The ”Backward Sweep” calculates branch currents or power flows from the receiving end (loads) back to the source node using Kirchhoff’s Current Law (KCL). The ”Forward Sweep” then calculates the nodal voltages from the source to the receiving ends using the updated currents and Kirchhoff’s Voltage Law (KVL).

Studies verify that BFS is computationally robust, does not require matrix inversion (unlike NR), and converges rapidly even for ill-conditioned networks. It is particularly suitable for MATLAB implementation in optimization loops (like GA) where thousands of load flow calculations are required quickly.

2.7 Reliability Indices

Optimization must quantify ”reliability.” In distribution system analysis, this is done using indices defined by the IEEE 1366 standard. The placement of reclosers directly affects these values:

1. SAIFI (System Average Interruption Frequency Index):Measures the average number of sustained interruptions per customer.

$$SAIFI = \frac{\sum \lambda_i \cdot N_i}{\sum N_T}$$

λ_i: Failure rate of section i (faults/year).N_i: Number of customers interrupted by a fault in section i.N_T: Total number of customers in the system.Role of Recloser: A recloser reduces N_i by isolating the fault so that upstream customers are not interrupted.

2. SAIDI (System Average Interruption Duration Index):Measures the average duration of interruptions per customer (hours/year).

$$SAIDI = \frac{\sum U_i \cdot N_i}{\sum N_T}$$

U_i: Annual unavailability or outage duration (hours/year) for section i.Role of Recloser: Reclosers effectively reduce U_i for temporary faults (by clearing them in seconds) and limit the number of customers (N_i) subjected to long repair times for permanent faults.

3. EENS (Expected Energy Not Supplied):This is often the most critical metric for the

cost function because it translates reliability into energy (kWh) and money.

$$EENS = \sum L_{avg,i} \cdot U_i$$

$L_{avg,i}$: Average load connected to load point i.

2.8 Optimal Placement and Sizing of Distributed Generators (DGs)

In a traditional radial system, current only flows one way (Source → Load). With Distributed Generation (DG), the problem becomes harder:

1. Blinding of Protection: DG can contribute fault current that ”blinds” upstream reclosers, causing them not to trip when they should.

2. Sympathetic Tripping: A recloser on a healthy feeder might trip incorrectly due to fault current contributions from a DG on that feeder feeding a fault elsewhere.

Islanding: If a recloser opens, the downstream DG form an ”island.”

Impact of DGs on System Performance: The integration of DGs such as solar PV, wind turbines, and biomass units can significantly reduce real power losses (I^2R) and improve voltage profiles. However, improper placement can have detrimental effects.

The ”Bathtub Curve” of Losses: Analytical studies have shown that as DG penetration increases at a specific node, losses initially decrease to a minimum but eventually rise again if the DG size exceeds the local load demand, causing reverse power flow.

Voltage Rise Effect: Literature highlights that excessive active power injection at the end of weak feeders can cause voltage magnitudes to violate the upper statutory limits (typically 1.05 p.u.).

Optimization Techniques: Finding the ”optimal” location and size is a non-linear, non-convex optimization problem.

Analytical Methods: Early research utilized ”exact loss formulas” and sensitivity factors (e.g., Voltage Sensitivity Index or Loss Sensitivity Factors) to rank candidate buses. While fast, these methods often get trapped in local optima and struggle with multi-objective constraints.

2.9 Improved Harmony Search Algorithm for DG Optimization

The Harmony Search Algorithm (HSA) was originally developed by Geem et al.[9] as a meta-heuristic optimization method inspired by the musical process of improvisation. Just as jazz musicians seek a ”perfect state of harmony” by adjusting the pitches of their instruments, the algorithm seeks a global optimal solution by adjusting decision variables within a search space. The core analogy is that a musical harmony corresponds to a solution vector, and the listener’s aesthetic estimation corresponds to the objective function evaluation.

HSA has several advantages over traditional optimization techniques:

It does not require initial values for decision variables.

It does not require complex derivative information (gradient-free).

It uses a stochastic random search which helps in escaping local optima.

The Need for Improvement: Limitations of Traditional HSA While the traditional HSA is effective, it has limitations that can affect its performance in complex engineering problems like power system optimization. The standard algorithm uses fixed values for its key control parameters: the Pitch Adjusting Rate (PAR) and the Bandwidth (bw).

Fixed Parameters: Using constant values for PAR and bw can lead to slow convergence or getting trapped in local optima because the algorithm cannot adapt to the changing search landscape as iterations progress.

Search Efficiency: A small fixed PAR may result in poor exploration (finding new areas), while a large bw might prevent the algorithm from fine-tuning the solution in the final stages.

Development of Improved Harmony Search Algorithm (IHSA) To overcome these drawbacks, in [10] the Improved Harmony Search Algorithm (IHSA) was proposed. The key innovation in IHSA is the dynamic adjustment of the control parameters (PAR and bw) during the optimization process, rather than keeping them fixed.

Dynamic Pitch Adjusting Rate (PAR): In IHSA, the PAR value increases linearly as the generations (iterations) proceed. This allows for higher exploration in the early stages and more frequent adjustment of solutions in later stages to refine the result.

Dynamic Bandwidth (bw): The bandwidth decreases exponentially over time. A large bandwidth at the beginning allows the algorithm to search the entire solution space (exploration), while a small bandwidth towards the end allows for precise fine-tuning of the best solution found (exploitation).

Application of IHSA to Distributed Generation (DG) Optimization The placement and sizing of Distributed Generators (DG) in power systems is a complex, non-linear optimization problem involving multiple constraints such as voltage limits and power balance. Inappropriate selection of DG location and size can lead to increased system losses rather than reducing them.

Researchers have successfully applied IHSA to this specific problem to minimize power losses and improve voltage profiles. For example:

Performance: Studies have demonstrated that IHSA often outperforms other well-known algorithms like the Genetic Algorithm (GA), Particle Swarm Optimization (PSO), and the original HSA in terms of convergence speed and solution quality.

Robustness: IHSA has been proven effective for radial distribution systems (like the 33-bus, 69-bus, or 102-bus systems), efficiently handling the non-linear constraints of power flow equations.

Specific Implementations: In the context of DG optimization, IHSA is typically used to determine the optimal bus number (location) and the capacity (size in MW/MVar) of the units. The objective function usually combines active power loss reduction and voltage deviation minimization.

2.10 Zone Formation and Intentional Islanding

Concept of Zones in Active Distribution Networks: Traditionally, a fault in a distribution feeder would result in the disconnection of the entire downstream network. With the advent of DGs, the concept of ”zoning” has been introduced. A zone is defined as a section of the network that can be isolated by protection devices (reclosers, sectionalizers, fuses). Research distinguishes between ”unintentional islanding” (dangerous, must be detected and stopped) and ”intentional islanding” (beneficial). Intentional islanding allows a zone with sufficient local DG generation to disconnect from the main grid during a fault and continue supplying local loads. This transforms a passive outage into a functioning ”island” or microgrid.

2.10.1 Algorithms for Zone Formation

Defining the boundaries of these zones is a complex graph-theoretic problem.

Graph Traversal Algorithms: Literature suggests using Depth-First Search (DFS) or Breadth-First Search (BFS) to identify connected components.

Power Balance Constraints: For a zone to be successfully islanded, the aggregate DG capacity within the zone must meet or exceed the critical load demand ($P_{DG} \geq P_{load}$).

Reliability Impact: Studies show that dynamic zone formation significantly improves reliability indices. By converting a permanent outage into a momentary one (or no outage at all) for customers within the island, the System Average Interruption Duration Index (SAIDI) is drastically reduced.

2.11 Genetic Algorithm

The Genetic Algorithm (GA) is a meta-heuristic search heuristic inspired by Charles Darwin’s theory of natural evolution. It is widely recognized in the literature as one of the most robust methods for solving non-linear, non-convex, and combinatorial optimization problems where the search space is vast and traditional calculus-based methods fail.

2.11.1 Origins and Fundamental Theory

The concept was first introduced by John Holland [11] in his seminal work, Adaptation in Natural and Artificial Systems. Holland proposed that biological evolution processes—specifically selection, crossover, and mutation—could be simulated mathematically to evolve a population of candidate solutions toward an optimal solution. David Goldberg

[12] further popularized the technique, demonstrating its practical application in engineering and complex systems. In the context of optimization, a potential solution is represented as a ”chromosome” (often a binary string), and its quality is evaluated using a ”fitness function.” Mechanism of Operation Literature describes the operation of GA as an iterative process involving three primary operators:

Selection: Similar to ”survival of the fittest,” individual solutions with higher fitness scores (e.g., those resulting in lower SAIFI/SAIDI) are selected to pass their genes to the next generation.

Crossover: Selected pairs of parents exchange segments of their genetic code to create offspring. This allows the algorithm to combine the best features of different solutions.

Mutation: Random changes are introduced to a chromosome (e.g., flipping a bit from 0 to 1). As noted by Haupt and Haupt [13], mutation is critical for maintaining genetic diversity and preventing the algorithm from getting stuck in ”local optima.”

2.11.2 Relevance to Power System Optimization

In the specific domain of power distribution, Miranda et al. [14] were among the first to demonstrate GA’s superiority in network planning. Unlike derivative-based methods, GA does not require the objective function to be continuous or differentiable. This is particularly relevant for the Recloser Placement Problem, which is inherently discrete (a recloser is either placed on a pole or it is not).

More recently, Gomez-Gonzalez et al. [15] highlighted that GA is exceptionally well-suited for DG-enhanced networks because it can easily handle the complex, non-linear constraints introduced by bidirectional power flow and voltage limits. While newer algorithms like Particle Swarm Optimization (PSO) offer faster convergence speeds in some contexts, GA remains the preferred choice in reliability studies due to its stability and ability to handle binary decision variables (0 or 1) naturally.

2.11.3 Techniques for DG Optimization

When optimizing Distributed Generation (DG), the primary goal in the literature is usually Power Loss Reduction and Voltage Profile Improvement.

Analytical Methods: Acharya et al. [16] used ”exact loss formula” methods. These calculate the sensitivity of power loss with respect to current injection at every node.

Technique: Calculate a ”Sensitivity Factor.” The node with the highest factor is the best place for DG.

Limitation: These methods often get stuck if the system is complex or has multiple DGs.

Meta-Heuristic Methods (GA, PSO): Modern literature prefers Genetic Algorithms (GA) or Particle Swarm Optimization (PSO).

Technique: The algorithm randomly places a DG of size P_{dg} at location L. It then runs a

Load Flow Analysis (typically Backward-Forward Sweep) to check if the voltage constraints ($0.95 < V < 1.05$ p.u.) are met.

Constraint Handling: If a solution violates voltage limits, it is assigned a heavy ”penalty” score, ensuring it ”dies out” in the next generation.

2.11.4 Techniques for Recloser Optimization

For reclosers, the optimization focus shifts from physics (voltage/loss) to Reliability Economics.

Reliability Indices Calculation: The standard technique involves simulating faults on every line section.

If a fault occurs at Section i, the algorithm checks: ”Is there a recloser upstream?”

Yes: Only the section downstream of the recloser is cut off.

No: The entire feeder back to the substation is cut off.

Cost-Benefit Analysis: The fitness function is almost always a summation of costs:

$$\text{Minimize } F = \sum(\text{Cost of Installation}) + \sum(\text{Cost of Unserved Energy})$$

Technique: The ”Cost of Unserved Energy” is calculated using the Customer Interruption Cost (CIC) multiplied by the Expected Energy Not Supplied (EENS).

Fig. 2.5 depicts the steps followed in Genetic Algorithm.

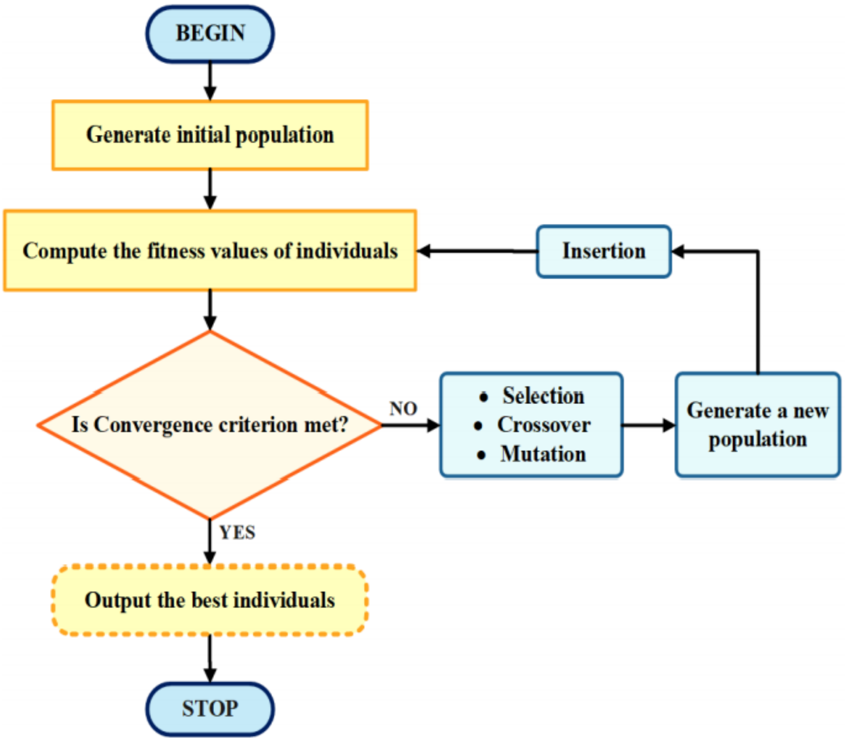


Figure 2.5: Flowchart depicting the GA algorithm strategy

2.12 Financial Analysis and investment decision making criteria

There are so many mechanisms for economic analysis. Net present value (NPV) technique, payback period method, internal rate of return method, and so on are some of them[18].

a) **NPV method**

There is always the inflow and outflow of cash in the financial process. This method is performed to evaluate whether the investment in a certain project is eligible or not. Also, the final present value is the current worth of the whole future cash flow that we can achieve from the analysis. The equation 2.1 calculates the present worth of the cash flow, equation 2.2 gives the present worth of the cash flow from the future, and equation 2.3 provides the annual cash flow data with the present value.

$$NPV = \sum_{t=0}^{n} \frac{R_t}{(1+r)^t} \tag{2.1}$$

$$P = \frac{F}{(1+r)^n} \tag{2.2}$$

$$P = A\left[\frac{(1+r)^n - 1}{r(1+r)^n}\right] \tag{2.3}$$

In equation 2.1, R_t refers to the net cash flow during a time period t. r is the discount rate or the return that could be earned from the investment, n is the time period considered, P is the present value, and A is the annual value of the return.

If $NPV \geq 0$, then the investment is safe.

b) **Payback period method**

When there is some investment in projects, it will take some duration to return the investment. The time that it takes to return the initial cost of investment is known as the payback period. Simply expressed, the payback period is the duration of time it requires for an investment to pay for itself. The higher the payback period, the lower the attractiveness of that project. And so, it is always desirable to have a lower payback period for the investment. The payback period should be as low as possible.

c) **Benefit to cost ratio method**

It is the ratio of benefits assured from the project to the total cost of the projects. BCR may be quantified in both monetary and qualitative measures. A project with a BCR of more than 1.0 is expected to produce a positive net present value for the company and its investors.

$$BCR = \frac{\text{Total Benefits}}{\text{Total Costs}} \tag{2.4}$$

It is always desirable to have a BC ratio greater than one.

The financial analysis of the proposed algorithm in the distribution feeder shall be performed taking the cost of DG installation, cost of Operation and maintenance, cost of outage, income with energy sale from the installed DG unit, income from loss reduction, and income from the reliability improvement. The detail is explained in Chapter 3 later.

3. METHODOLOGY

In this chapter, the overall procedure for performing the improvement of the reliability and voltage profile by optimal placement of the Recloser and DGs is explained.

3.1 Radial Distribution System Modeling

In this work, MATLAB was utilized to carry out power flow simulations of the case under study. The system topology and loads taken from real field data was modelled in MATLAB. Initially, n number of branch data was supplied in n number of rows. Branch data included branch resistance and branch reactance. Bus data for b number of buses was also fed to the computer program. Bus data included bus number, active power load and reactive power load at the bus. It is to be noted that b = (n + 1) in a radial network. For optimization, MATLAB software was used in which the program for optimal sizing and location of DGs, zone formation and islanding and optimal location of recloser was designed seperately.

3.2 Optimization Problem Formulation for DGs

This study employs an Improved Harmony Search Algorithm (IHSA) to determine the optimal location and sizing of Distributed Generators (DGs) in the IEEE 69 bus test system and 102-bus radial distribution system. The primary goal is to minimize active power losses while improving the voltage profile, subject to technical and operational constraints.

1. Optimization Technique: Improved Harmony Search Algorithm (IHSA)The core optimization engine is based on the Harmony Search (HS) meta-heuristic algorithm, which mimics the improvisation process of musicians. The ”Improved” variant (IHSA) is utilized to enhance convergence speed and avoid local optima by dynamically adjusting the pitch adjustment rate (PAR) and bandwidth (bw) during iterations.

2. Algorithm Parameters:

Harmony Memory Size (HMS): 30 (Number of solution vectors stored)

Harmony Memory Consideration Rate (HMCR): 0.9 (Probability of selecting a value from memory)

Pitch Adjustment Rate (PAR): Dynamically varies from $PAR_{min} = 0.3$ to $PAR_{max} = 0.9$

Bandwidth (bw): 0.01 (Step size for pitch adjustment)

Maximum Iterations: 500 per run

Number of Independent Runs: 5 (To ensure statistical robustness)

Objective Function: The problem is formulated as a minimization problem with a weighted multi-objective function. The fitness function F evaluates the quality of each solution vector (a specific set of DG locations and sizes):

$$\text{Minimize } F = w_1 \cdot P_{loss} + w_2 \cdot V_{penalty} + w_3 \cdot P_{DG,total}$$

Where:P_{loss} is the total active power loss of the system in kW, calculated via the Backward-Forward Sweep load flow method.$V_{penalty}$ is a penalty term applied when bus voltages violate the lower limit (0.95 p.u.). It is calculated as:

$$V_{penalty} = \sum_{i=1}^{N_{bus}} (0.95 - |V_i|)^2 \quad \text{if } |V_i| < 0.95$$

$P_{DG,total}$ is the sum of the capacities of all installed DGs (in MW). This term acts as a cost proxy to prevent oversizing.

w_1, w_2, w_3 are weighting factors set to 1.0, 1000, and 1.0, respectively. The high value for w_2 ensures that voltage constraints are strictly prioritized.

Decision Variables: The optimization algorithm searches for two types of variables for each of the 3 DGs + 3 Location (Loc_{DG}): Integer value representing the bus number where the DG is installed.

Size (P_{DG}): Continuous value representing the active power capacity of the DG in MW.

Constraints: The optimization is subject to the following inequality constraints:

A. DG Location Constraint: DGs can be placed at any bus except the slack bus (Bus 1).

$$2 \leq Loc_{DG} \leq 102$$

B. DG Sizing Constraint: The capacity of each DG is bounded to ensure realistic sizing relative to the system load.

$$0 \text{ MW} \leq P_{DG} \leq 3.0 \text{ MW}$$

C. Voltage Constraint: The voltage magnitude at every bus i must be maintained within acceptable limits, ideally above 0.95 p.u.

$$|V_i| \geq 0.95 \text{ p.u.}$$

D. Constraint of power factors: All DGs are assumed to operate at a lagging power factor of 0.90, meaning that they inject active (P) and reactive (Q) power into the grid.

3. Load Flow Analysis: To evaluate the fitness of each candidate solution, a Backward-Forward Sweep (BFS) load flow algorithm is implemented. This iterative method is specifically chosen for its efficiency and stability in solving radial distribution networks.

Backward Sweep: Calculates branch currents by summing nodal currents from the last node back to the source.

Forward Sweep: Updates nodal voltages based on the voltage drop across branches from the source to the end nodes.

Convergence: The process repeats until the maximum voltage mismatch between iterations is less than 10^{-5}.

The flow chart is depicted in the figure below.

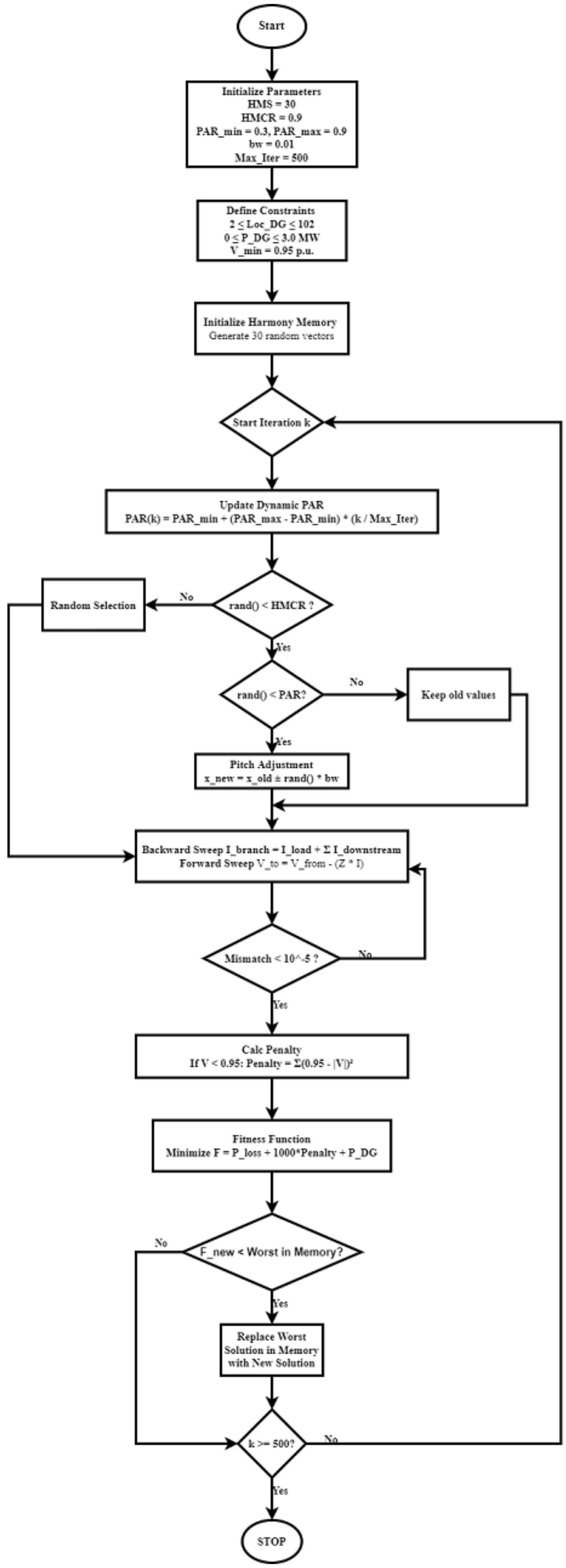


Figure 3.1: DG Optimization Flowchart

3.3 Zone formation for islanding

To enhance the resilience, the network is partitioned into distinct, self-adequate protection zones (microgrids). Each zone is designed to operate autonomously using its local Distributed Generation (DG) resources in the event of upstream faults. The partitioning process is implemented using a graph-theoretic approach combined with a stability enforcement algorithm to ensuring power balance.

1. Graph Theoretic Formulation: The distribution network is modeled as a graph $G = (V, E)$, where V represents the set of buses (nodes) and E represents the distribution lines (edges). The weight of each edge corresponds to the physical length of the line, ensuring that the resulting zones are geographically compact.The system is initialized with specific ”Source Nodes” that define the centers of the zones:

Zone 1 (Main Grid): Powered by the Substation (Bus 1) and the largest DG. This zone represents the main connected grid and is assumed to have infinite capacity for the purpose of partitioning.

Zone 2 (Island 1): Centered around the second DG which forms the first island.

Zone 3 (Island 2): Centered around the third DG which forms the second island.

2. Initial Voronoi Partitioning: The initial formation of zones is performed using a Voronoi partition method based on the shortest electrical distance. For every bus i in the system, the algorithm calculates the graph distance to all defined source nodes using Dijkstra’s algorithm:

$$D_{i,k} = \min(\text{dist}(i, S_k))$$

Where S_k is the set of source nodes for Zone k. Each bus is assigned to the zone Z_k corresponding to the minimum distance:

$$\text{Zone}(i) = \arg\min_k(D_{i,k})$$

Priority is given to the Main Grid (Zone 1) in cases where distances are equal, ensuring that buses are only islanded if they are significantly closer to a DG.3.

3. Stability Enforcement and Load Balancing: A critical constraint for islanded operation is that the local generation capacity must meet the local demand. The algorithm employs an iterative ”Stability Enforcement Loop” to ensure this condition is met for every island.

Constraint Checking: For each island zone z (Zone 2 and Zone 3), the total active power load ($P_{load,z}$) is calculated and compared against the maximum capacity of the DG ($P_{cap,z}$) assigned to that zone:

$$\sum_{i \in Z_z} P_{load,i} \leq P_{cap,z}$$

Iterative

Zone Correction: If a zone is found to be unstable (i.e., Load ¿ Capacity), the algorithm applies a heuristic shrinking process:

Identify Boundary Nodes: The algorithm identifies the set of buses in the unstable zone that are directly connected to the Main Grid (Zone 1).

Select Candidate for Removal: From these boundary buses, the algorithm selects the node that is electrically farthest from the zone's DG source.

Reassignment: The selected node is reassigned (flipped) back to Zone 1.

Convergence: This process repeats iteratively until the load within the island decreases sufficiently to satisfy the capacity constraint ($P_{load,z} \leq P_{cap,z}$).This ensures that the formed islands are not only topologically compact but also energetically self-sufficient.

4. Boundary Definition and Switching Configuration: Once the stable configuration is achieved, the algorithm identifies the boundary lines that connect buses belonging to different zones. These lines are designated as Tie-Lines (Open Switches). In normal operation, these switches may remain closed or open depending on the control strategy, but for the purpose of reliability and protection coordination, they define the boundaries where fault isolation devices (reclosers) are strategically placed.

3.4 Optimal Placement of additional reclosers

To enhance the reliability of the distribution system, an optimization framework is proposed to determine the optimal number and location of automatic reclosers. The problem is formulated as a non-linear integer programming problem aimed at maximizing the Net Present Value (NPV) of the reliability investment. The solution utilizes a Genetic Algorithm (GA) combined with a graph-theoretic reliability assessment module that accounts for zonal operation and distributed generation (DG) islanding.

1. Objective Function: The primary objective is to maximize the Net Profit, defined as the difference between the economic benefits derived from improved reliability and the total cost of the recloser deployment over the project's lifespan.

The objective function F is maximized as follows:

$$\text{Maximize } F = \text{Benefit}_{Reliability} - \text{Cost}_{Total}$$

Where:Benefit$_{Reliability}$: The monetary value of the reduction in outage costs compared to the base case (no reclosers).

$$\text{Benefit}_{Reliability} = (TIC_{base} - TIC_{new}) \times FAC_1 + (ENS_{base} - ENS_{new}) \times C_E \times FAC_2$$

TIC: Total Interruption Cost (Customer outage penalties).ENS: Energy Not Supplied (kWh lost).C_E: Cost of energy ($\$/kWh$).$FAC_1, FAC_2$: Present value factors converting annual savings to NPV.

Cost_{Total}: The sum of capital investment and operational maintenance costs.

$$\text{Cost}_{Total} = \sum_{i=1}^{N_{lines}} x_i \times C_{unit} \times (1 + R_{maint} \times FAC_3)$$

x_i: Binary decision variable (1 if recloser is placed on line i, 0 otherwise).

C_{unit}: Unit cost of a single recloser hardware and installation.

R_{maint}: Annual maintenance rate (expressed as a percentage of investment).

FAC_3: Present value factor for maintenance costs.

2. Decision Variables and Constraints: The optimization searches for a binary vector $X = [x_1, x_2, ..., x_N]$, where N is the total number of distribution lines.

The problem is subject to the following constraints:

A. Nodal Connectivity Constraint: Reclosers cannot be placed on lines designated as ”Tie-Lines” or ”Zonal Boundaries” (Open Switches), as these lines are physically disconnected during normal operation to maintain the radial structure of the network.

$$x_i = 0, \quad \forall i \in \text{Set of Cut Lines}$$

B. Radiality Constraint: The placement of reclosers must not alter the radial topology of the network. The system must remain a set of connected trees rooted at the respective substation or DG sources2.

3. Reliability Evaluation Algorithm: To evaluate the fitness of each candidate solution, a graph-theoretic reliability assessment is performed. The distribution network is modeled as a graph $G(V, E)$, and the impact of a fault on any line f is evaluated as follows:

1.Fault Location: A fault is simulated on line f with failure rate λ_f and repair time r_f.

2.Upstream Path Search: The algorithm traces the shortest electrical path from the fault location back to the supplying source (Main Grid or DG)

3.Isolation Logic: The path is scanned for the nearest upstream protection device (recloser).If a recloser is found, it trips, isolating the downstream section.If no recloser is found, the main substation breaker trips, causing a momentary or sustained interruption for the entire zone.

4.Island Formation: Using the conncomp (Connected Components) graph algorithm, the network is analyzed to determine which buses remain energized by local DGs and which are de-energized

5.Cost Calculation: The outage cost is aggregated for all de-energized buses based on their load type (Residential/Commercial) and specific Customer Interruption Cost (CIC) rates.

4. Optimization Technique: Genetic Algorithm (GA)The binary optimization problem is solved using a Genetic Algorithm, a meta-heuristic inspired by natural selection.

Encoding: Each chromosome is a binary string of length N (number of branches), representing the presence or absence of a recloser on each line.

Initialization: A sparse initialization strategy is employed to favor solutions with fewer reclosers, reducing early-stage computational overhead.

Aggressive Mutation: To prevent premature convergence to local optima, a modified ”Aggressive Mutation” operator is implemented. Instead of single-bit flips, the operator evaluates a mutation mask across the entire chromosome, allowing multiple reclosers to be added or removed simultaneously with a probability of 4-5

Selection Crossover: Tournament selection is used to choose parents for reproduction, followed by uniform crossover to generate offspring solutions.

The algorithm terminates when the maximum number of generations is reached or when the fitness value stabilizes, indicating an optimal trade-off between investment cost and reliability reliability improvement.

The flow chart is depicted in the figure below.

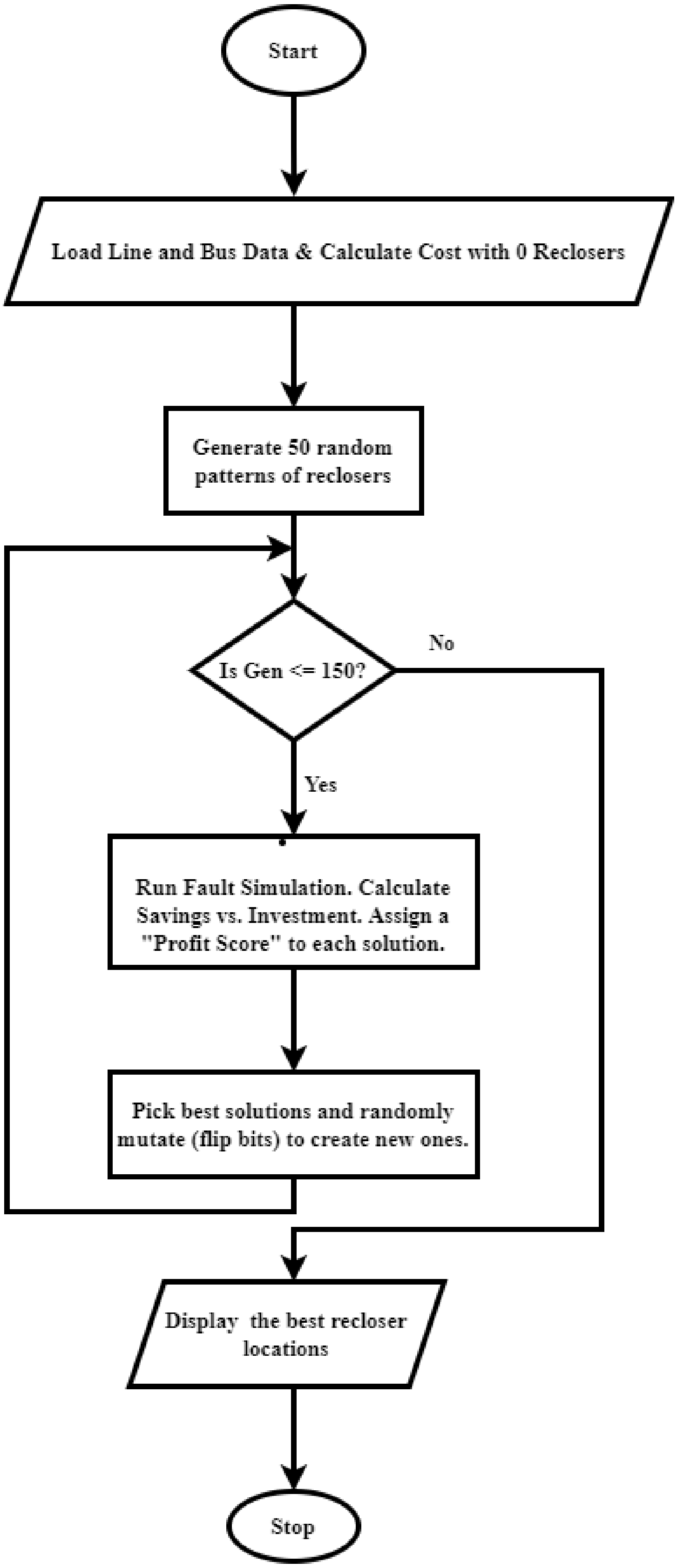


Figure 3.2: Genetic Algorithm Flowchart

3.5 Assumptions

The maximum number of DG for the system is allowed upto 3.
The voltage deviation allowed is +/-5%.
The failure rate of lines is considered as 0.065 f/km./yr. as according to RBTS Bus-2.
The repair time is considered 240 minutes.
Total number of consumers at any bus is considered equal to the total load at that bus in kW.

3.6 Method of Implementation of GA for Reliability and Voltage Profile Improvement

The procedure for optimization of DG and recloser placement using Improved Harmony Search Algorithm is summarized as follows:

3.6.1 Implementation steps for DG placement and sizing

The optimization process is carried out in the following six steps using the Improved Harmony Search Algorithm (IHSA):
Step 1: System Data Preparation
The system data (line impedances and bus loads) is loaded into the program.
All electrical values are converted into per-unit (p.u.) values to simplify calculations.
A base case load flow simulation is run to record the initial power losses and voltage levels before adding any DGs.
Step 2: Setting Optimization Constraints
Location Limits: DGs are allowed to be placed on any bus from 2 to 102.
Size Limits: The capacity of each DG is restricted to be between 0 MW and 3.0 MW.
Quantity: The algorithm is set to find the optimal configuration for exactly 3 DGs.
Step 3: Initialization
The algorithm parameters are defined: a Harmony Memory Size (HMS) of 30 and a maximum of 500 iterations.
An initial population of 30 random solutions (random locations and sizes) is generated to start the search process.
Step 4: Fitness Evaluation
Each solution is tested using a Backward-Forward Sweep (BFS) Load Flow.
The ”fitness” (quality) of a solution is calculated using a formula that minimizes active power loss while penalizing any solution that causes undervoltage (below 0.95 p.u.).

Step 5: The Optimization Loop (IHSA)

The algorithm enters a loop that repeats 500 times.

In each iteration, a New Harmony (new solution) is created using three methods:

Memory Consideration: reusing good parts of existing solutions.

Pitch Adjustment: slightly tweaking the location or size of a DG.

Random Selection: picking a completely new random value to explore the search space.

If the new solution is better (lower cost) than the worst solution currently in memory, it replaces the worst one.

Step 6: Final Selection

After the loop finishes, the best solution remaining in the memory is selected as the final result.

The program outputs the optimal bus locations and sizes for the DGs and prints the final power loss reduction achieved.

3.6.2 Implementation steps for recloser placement

The optimization process is carried out in the following six steps using a Genetic Algorithm (GA):

Step 1: System Graph Setup

The system data is loaded, and a mathematical Graph is created to represent the network connections.

The system is divided into ”Zones.” The program identifies which buses are powered by the Main Grid and which can be powered by DGs during a fault.

Step 2: Setting Costs and Constraints

Costs: The price of a single recloser and the cost of customer outages (Energy Not Supplied) are defined.

Constraint: The algorithm is forbidden from placing reclosers on ”Tie-Lines” (lines that are already open switches).

Step 3: Initialization

The Genetic Algorithm settings are established: a Population Size of 50 and a maximum of 120 Generations.

A starting population of 50 random solutions (random recloser locations) is gener ated.

Step 4: Reliability Fitness Check

For every proposed solution, the program runs a Reliability Simulation:

It simulates a fault on every single line.

It checks if a recloser exists to isolate the fault.

Smart Islanding: It checks if the isolated healthy section contains a DG. If yes, those

customers remain online; if no, they lose power.
The ”Fitness” is calculated as the Net Profit (Money saved from avoided outages minus the cost of the reclosers).
Step 5: The Optimization Loop (GA)
The algorithm repeats the process for 120 generations.
Selection: The solutions with the highest profit are chosen to be ”parents.”
Crossover Mutation: Good patterns are combined, and random changes (”Aggres sive Mutation”) are applied to try and find better locations or remove unnecessary switches.
Step 6: Final Result
The algorithm stops and results the output.

3.7 Financial Analysis

The economic feasibility of the proposed system is evaluated by performing a Cost-Benefit Analysis. This analysis compares the total investment required for the system upgrades against the monetary benefits gained from improved reliability and power generation. The financial model considers both the initial installation costs and the ongoing operational expenses.

1. Estimation of Costs (Cash Outflow)The total cost is categorized into Capital Expenditure (CAPEX) and Operational Expenditure (OPEX).Initial Capital Expenditure (CAPEX): This represents the one-time investment required to implement the proposed solution. It includes the purchasing and installation costs of the Biomass Distributed Generator (DG) units, the new Automatic Circuit Reclosers (ACRs), and the Zone Boundary Switches (tie-switches)1.Annual Operating Expenditure (OPEX): This includes the recurring costs to keep the system running. It consists of the fuel cost for the biomass DGs (calculated based on the price of rice husk) and the annual Operation and Maintenance (OM) costs for both the DG units and the protection system (reclosers and switches).

2. Estimation of Benefits (Cash Inflow)The annual financial benefits are derived from three main sources:Revenue from Energy Generation: This is the income generated by the DG units. It is calculated by multiplying the total energy units (kWh) produced annually by the grid feed-in tariff rate.

3. Savings from Loss Reduction: The installation of DGs reduces the active power losses (I^2R) in the distribution lines. These energy savings are quantified monetarily using the cost of energy.

4. Reliability Improvement Savings: The improvement in system reliability reduces the Energy Not Supplied (ENS) to customers during faults. This reduction in lost energy is monetized using the Value of Lost Load (VoLL) or Customer Interruption Cost, representing the avoided economic loss from outages. 5. Financial Evaluation IndicatorsTo determine

the viability of the project, the following indicators are calculated:Net Annual Cash Flow: This is the net profit generated per year, calculated by subtracting the Total Annual OPEX from the Total Annual Benefits.

$$\text{Net Cash Flow} = \text{Total Benefits} - \text{Total OPEX}$$

Payback Period: This indicates the time required to recover the initial investment. It is calculated by dividing the Total CAPEX by the Net Annual Cash Flow.

$$\text{Payback Period (Years)} = \frac{\text{Total CAPEX}}{\text{Net Annual Cash Flow}}$$

The overall step by step process is described in the block diagram below.

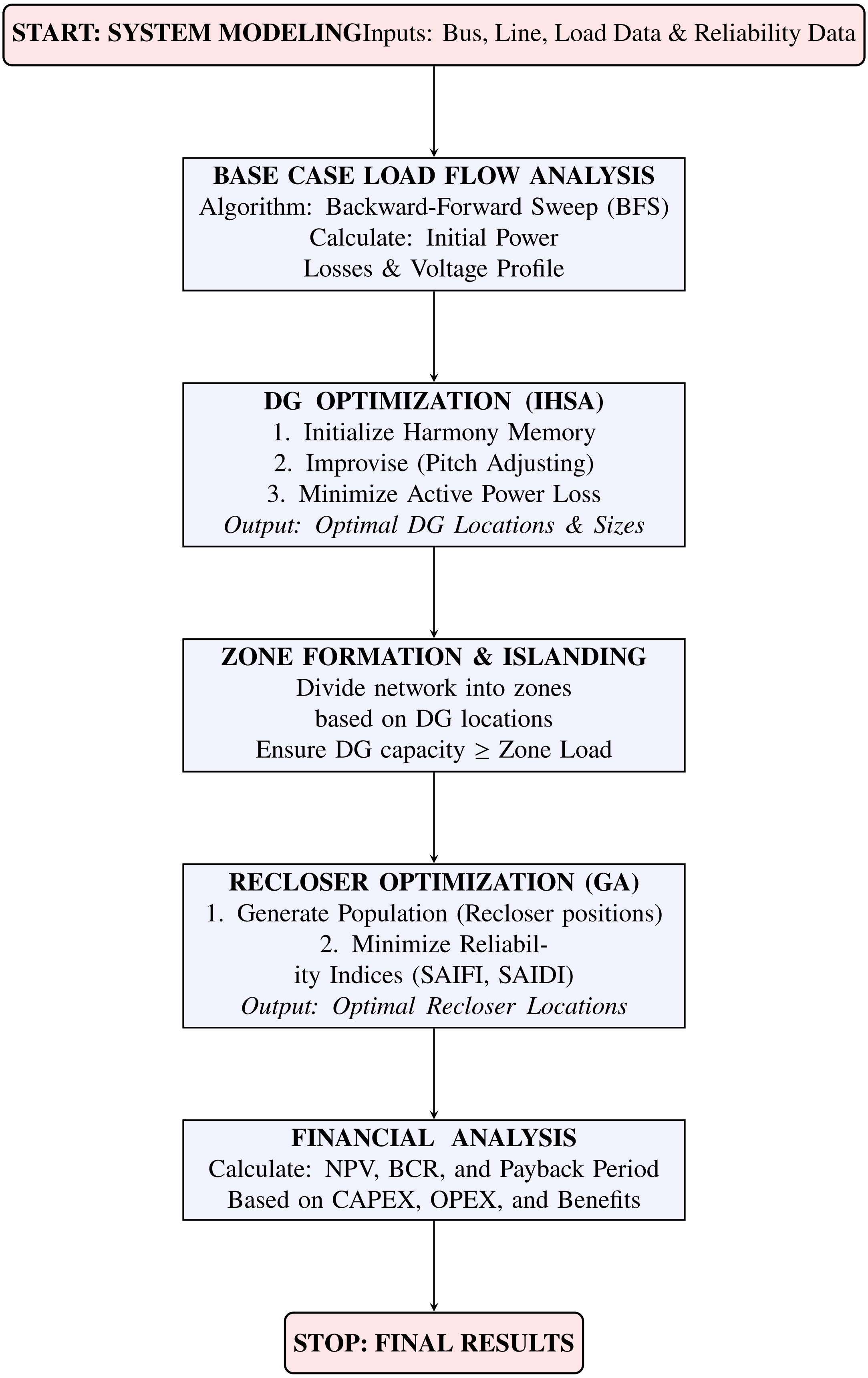


Figure 3.3: Block Diagram of the process

4. SYETEM UNDER CONSIDERATION, SOFTWARE AND TOOLS

4.1 Syestem under consideration

The research is done on a 102 Bus 11 kV real distribution Hasanpur feeder in Dhangadhi and to examine the effectiveness of methodology proposed in this thesis work, the study was carried out in IEEE 69 Bus radial distribution system. The single line diagram along with bus and branches data of the cases are shown below

Case I : IEEE 69 Bus radial distribution system.

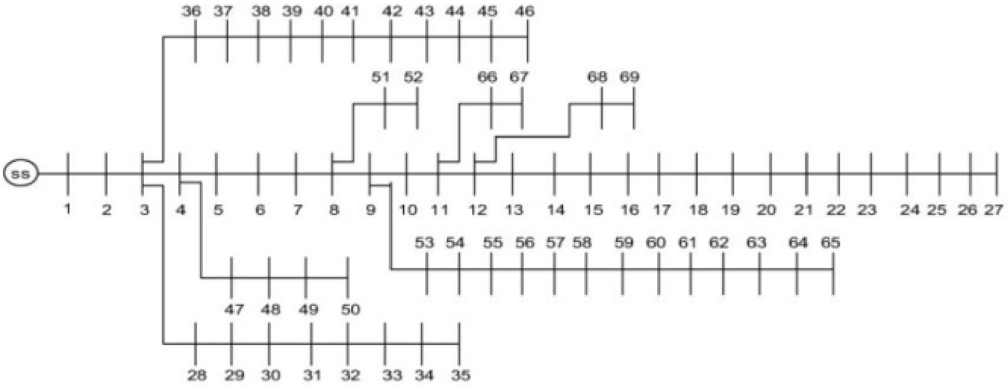


Figure 4.1: Single Line Diagram of the IEEE 69-Bus Distribution System

The line, load and reliability data of IEEE 69-Bus system is given in appendix A.

Case II : 11 kV Radial Distribution Feeder (Hasanpur Feeder).

The Parameters of the system are:

No. of buses = 102

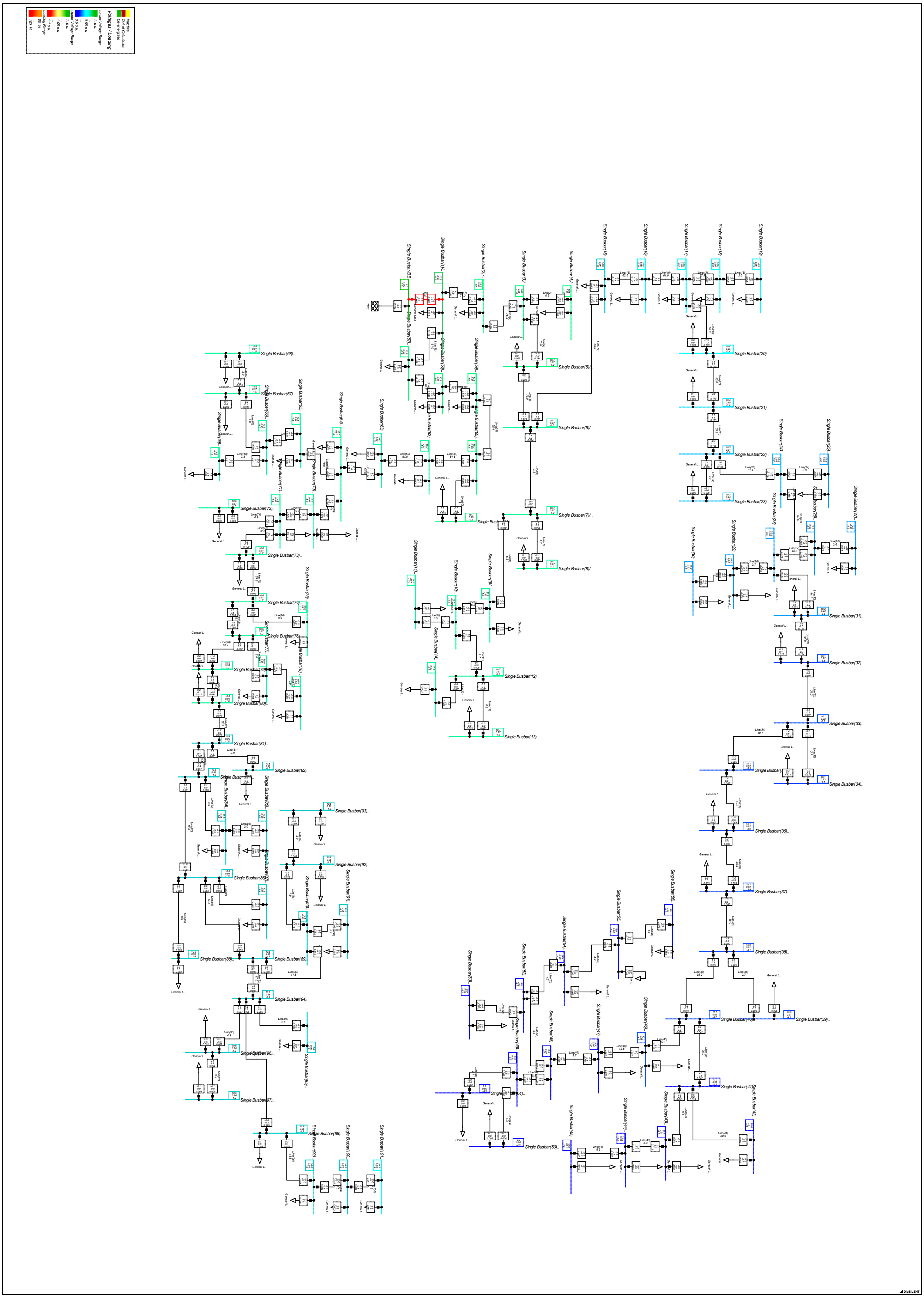
No. of branches = 101

Total line length = 23.8 km.

Total Load = 7406.03 kW

The single line diagram of the case is shown below:

Hasanpur Feeder (SLD)


Inactive
Out of Calculation
De-energized
Voltages / Loading
Lower Voltage Range
1. p.u.
...
0.95 p.u.
...
0.9 p.u.
Upper Voltage Range
1. p.u.
...
1.05 p.u.
...
1.1 p.u.
Loading Range
80. %
...
100. %
DIgSILENT

The bus and branch data of Hasanpur feeder is given in appendix B.

4.2 Software and Tools used

MATLAB's programming environment was the software used in this thesis. MATLAB stands for ”Matrix Laboratory” is a proprietary multi-paradigm programming language and numerical computing environment developed by MathWorks. MATLAB allows matrix manipulations, plotting of functions and data, implementation of algorithms, creation of user interfaces, and interfacing with programs written in other languages. Common usage of the MATLAB application involves using the ”Command Window” as an interactive mathematical shell or executing text files containing MATLAB code.

As this thesis work involves numerous power flow computations in one iteration, a time-efficient way to compute power flow results is required. MATPOWER is a package of MATLAB M-files for solving power flow and optimal power flow problems. It is intended as a simulation tool for researchers and educators that is easy to use and modify. MATPOWER is designed to give the best performance possible while keeping the code simple to understand and modify. MATPOWER was initially developed by Ray D. Zimmerman, Carlos E. MurilloS´anchez and Deqiang Gan at Cornell University under the direction of Robert J. Thomas.

5. RESULTS AND DISCUSSION

The objective of this works is to improve the reliability indices and voltage profile with optimal placements and sizing of distributed generators and autoreclosers. So, first target is to analyses the system in the base case scenario, which is without placement of the DG and reclosers. Analysis is done in IEEE 69 Bus RDS test system and Hasanpur feeder of Nepal, NEA and the parameters noted below has been studied in the base case scenario.

- Voltage profile of the system
- System Average Interruption Frequency Index (SAIFI)
- System Average Interruption Duration Index (SAIDI)
- Expected Energy Not Supplied (EENS)

5.1 IEEE 69 Bus RDS

Base Case: The IEEE 69 Bus Sytem has 69 buses in the system with total active and reactive load of 3.0829 MW and 3.403 MVar respectively. The given system was modeled in the MATLAB and with loadflow analysis done in MATPOWER, the system loss was found to be 218.0083 kW and minimum voltage as 0.9194 pu at bus 65. The detail of voltage profile is depicted in fig. 5.1 below.

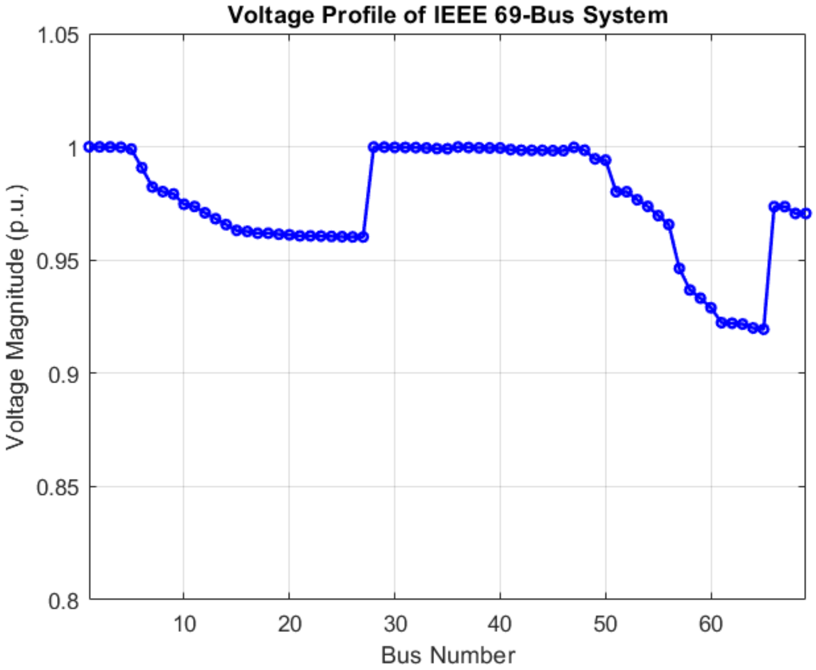


Figure 5.1: Voltage Profile of IEEE 69-Bus System

5.1.1 Reliability Indices Evaluation

The reliability indices (SAIFI, SAIDI, ENS) of the system is evaluated with the standard system reliability data for 69-Bus system and the result is depicted in the table below.

Table 5.1: Reliability Evaluation Indices for 69-Bus System

Index	Value	Unit
SAIFI	12.95	f/cust/yr
SAIDI	47.8	hr/cust/yr
EENS	147,362.62	kWh/yr

5.1.2 Placement of DG to improve voltage profile and reliability

In order to improve the reliability and voltage profile of the 69-Bus RDS, the IHSA algorithm was applied for location and sizing of DGs. Maximum number of DGs was fixed to three and the maximum capacity of individual DG was fixed to 2 MW. The result is depicted in the table below.

Table 5.2: Optimal DG Locations and Sizes

S.N.	DG Location	DG Size (MW)
1	Bus 61	1.6541
2	Bus 11	0.4652
3	Bus 21	0.3498

The result in table 5.2 shows the capacity and location of DGs. The largest size is 1.6541 MW, while the lowest capacity DG is 0.3498 MW. The active power loss of the system was reduced to 25.9541 kW and the minimum voltage increased to 0.9942 pu. The improved voltage profile of the system is depicted in the figure below.

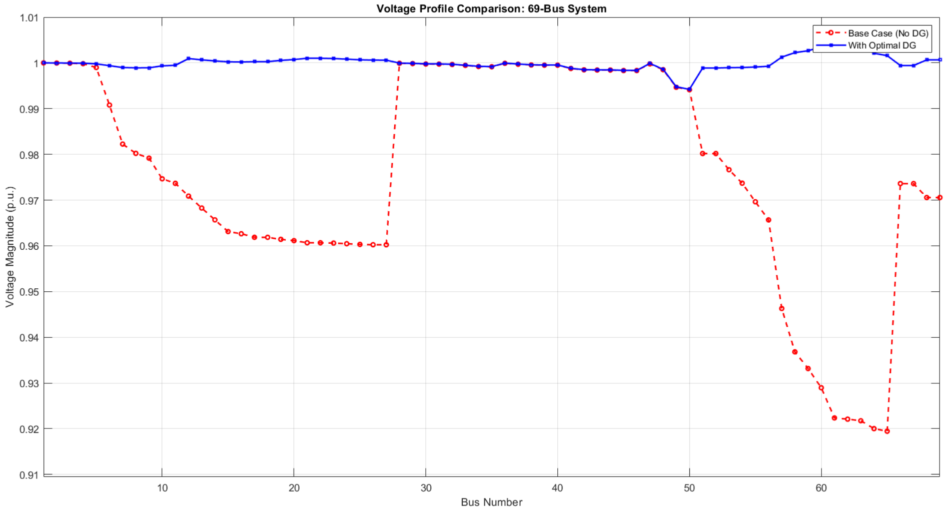


Figure 5.2: Comparison of Voltage Profiles: Base Case vs. Optimal DG Integration

In the figure above, we can see that the voltage profile of the system is improved from the minimum of 0.9194 pu to 0.9942 pu.

5.1.3 Zone formation for islanding

To improve the reliability of the system, the network is divided in different zones for islanding using autoreclosers at the zone boundaries. The number of zones is fixed to three. The largest DG is connected with Bus 1 which do not support islanding but remaining 2 DGs are grouped to form two separate islands in case of failure of main source. The result is given in the table below.

Table 5.3: Zone Formation Results

S.N.	**Zone**	**Total Buses**	**Bus Numbers**	**Boundary Switches**	**DG Loc.**
1	Zone 1	48	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 28, 29, 30, 31, 32, 33, 34, 35, 36, 37, 38, 39, 40, 41, 42, 43, 44, 45, 46, 47, 48, 49, 50, 51, 52, 53, 54, 55, 56, 57, 58, 59, 60, 61, 62, 63, 64, 65	10-11 to isolate zone 1 & 2	Bus 61
2	Zone 2	10	11, 12, 13, 14, 15, 16, 66, 67, 68, 69	16-17 to isolate zone 2 & 3	Bus 11
3	Zone 3	11	17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27	–	Bus 21

In the table above, bus numbers grouped in the respected zone are given. There are two reclosers placed at the boundaries of the zones, between bus 10-11 to isolate zone 1 and zone 2 and between bus 16-17 to isolate zone 2 and zone 3. Zone 1 does not support islanding because in order to make the complete system islanded, the size of DG would have to be larger than the total system load. The larger DGs increase the capital cost which would create the financial trouble. Remaining two zones are capable to operate in islanded mode i.e. the total load in zone 2 and 3 are less than the DGs capacity. The single line diagram of 69-Bus system after placement of Dg and zone partition is depicted in the figure below.

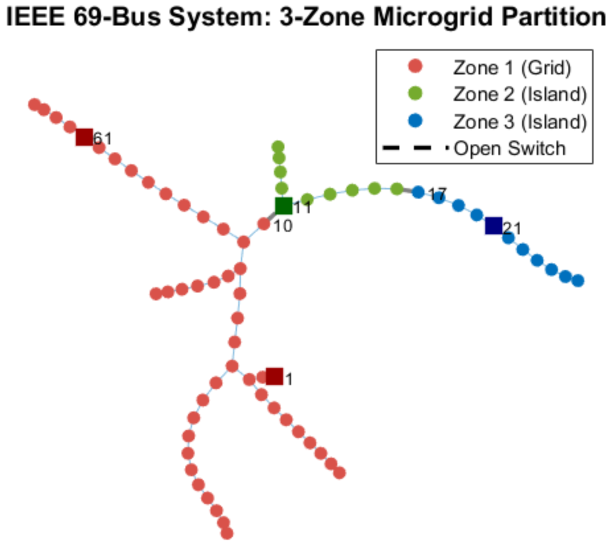


Figure 5.3: Single line diagram of zone formation and islanding in 69-Bus RDS

The improvement in reliability indices after DG placement and zone partitioning are depicted in the table below.

Table 5.4: Reliability Indices Comparison: Base Case vs. DG & Zoning

Indices	Base Case (No Protection)	DG & Zoning (3 Zones)	Improvement
SAIFI (int/cust/yr)	12.95	6.54	49.5%
SAIDI (hr/cust/yr)	47.80	24.21	49.4%
ENS (kWh/yr)	147,362.62	87,213.22	40.8%

So in the above table we can see that SAIFI and SAIDI of the system after DG placement and zone islanding, improved by 49.5% whereas ENS improved by 40.8%.

5.1.4 Auto recloser placement

To improve the reliability further, autoreclosers are placed at different locations to minimize and isolate the faulty section while maintaining the remaining section healthy. The number and locations of autoreclosers obtained by performing Genetic algorithm optimization technique is listed in the table below.

Table 5.5: Optimal Recloser Locations (Total: 7)

S.N.	**Location**
1	Bus 2-3
2	Bus 7-8
3	Bus 3-28
4	Bus 39-40
5	Bus 47-48
6	Bus 8-51
7	Bus 54-55

After placement of the reclosers, the reliability of the system is further improved which is depicted in the table below.

Table 5.6: Reliability Indices Comparison

Metric	Base Case	DG and Zoning Case	Optimal Recloser Case	Improvement vs Base
SAIFI (int/cust/yr)	12.95	6.54	3.48	73.13%
SAIDI (hr/cust/yr)	47.80	24.21	12.63	73.58%
ENS (kWh/yr)	147,362.62	87,213.22	30,407.61	79.37%

The data clearly shows that the reliability was improved to 49.5% after DG placement and zone islanding which futher improved and reached to 73% after addition of 7 reclosers.

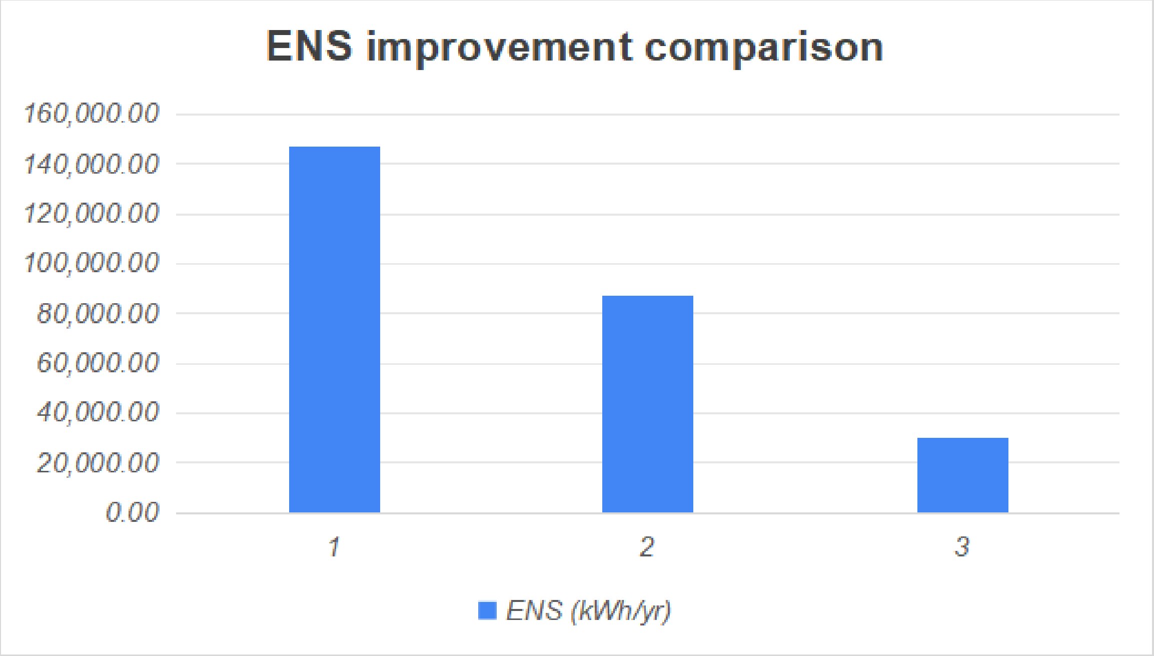


Figure 5.4: ENS comparison for different case

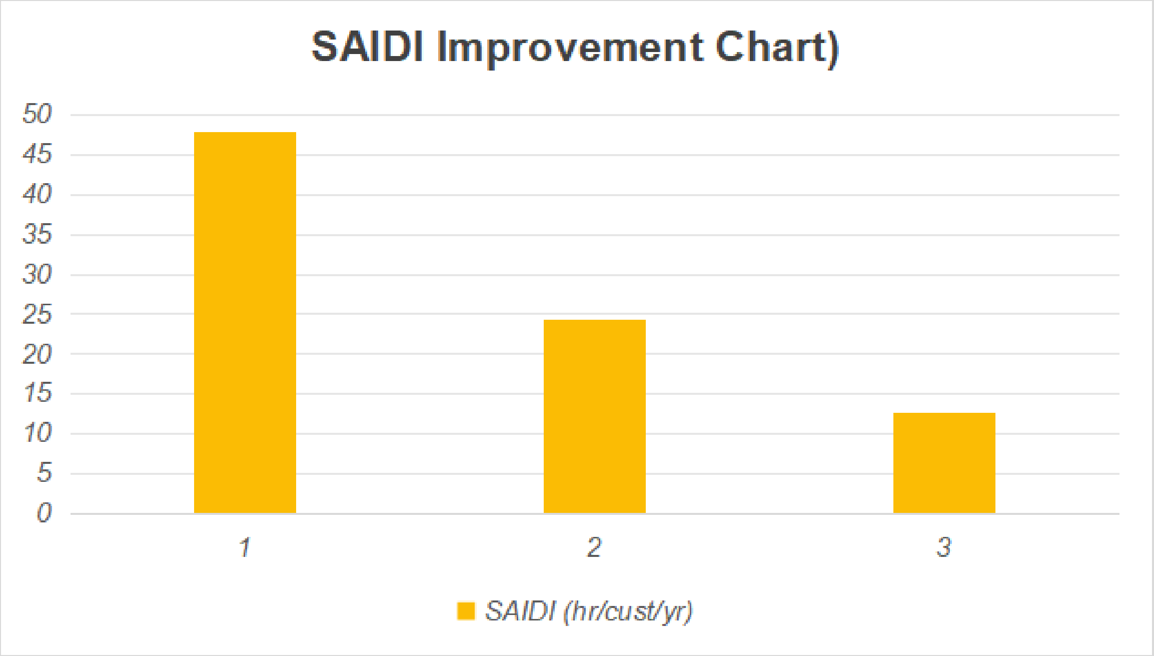


Figure 5.5: Comparison of SAIDI for different cases in 69-Bus RDS.

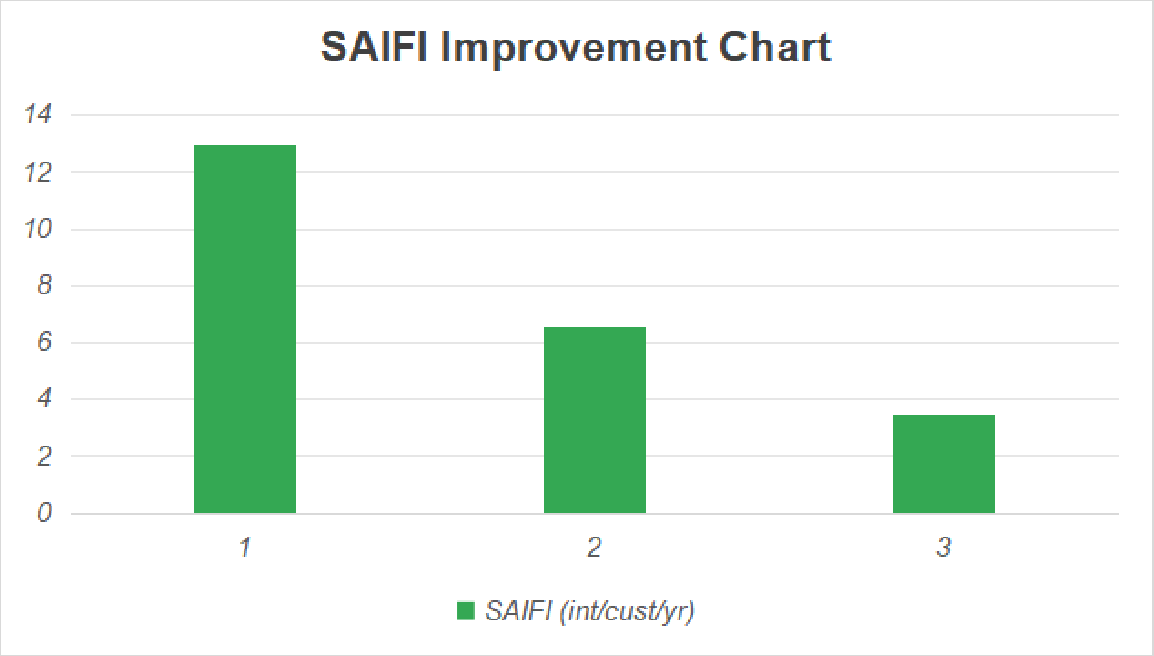


Figure 5.6: Comparison of SAIFI for different cases in 69-Bus RDS.

In the above graphs, index 1 is used for base case where no changes in the IEEE 69 Bus RDS has been done. Index 2 is used for the case in which DGs are introduced at three different locations and three zones created for islanding operation in order to improve reliability. Index 3 is used for the case in which extra 7 reclosers are added in the network to improve the reliability further.

5.1.5 Financial Calculation

Technical Input Parameters

Parameter	Value	Unit	Remarks
Total DG Capacity	2,469.1	kW	
Annual Operating Hours	5,000	hrs	
Total Annual Generation	12,345,500	kWh	$2,469.1$ kW × $5,000$ hrs
Power Loss Reduction	192.05	kW	Saved active power losses
ENS Improvement	116,955	kWh	

Economic Assumptions

Parameter	Value	Unit	Remarks
Grid Tariff (Sales)	\$0.09	/kWh	
Value of Lost Load (C_E)	\$0.50	/kWh	
Biomass Fuel Cost	\$0.045	/kWh	Rice Husk: \$0.03/kg × 1.5 kg/kWh
DG O&M Cost	\$0.02	/kWh	Standard Biomass Maintenance
Recloser Maint. Rate	2.0%	/yr	
Discount Rate	8.0	%/yr	
Project Life	20	yr	

Initial Capital Expenditure (CAPEX)

Item	Quantity	Unit Cost	Total Cost (\$)
Biomass DG Units	2,469.1 kW	\$1,400 / kW	3,456,740
Automatic Reclosers	7 Units	\$15,000 / unit	105,000
Zone Boundary Switches	2 Units	\$15,000 / unit	30,000
TOTAL CAPEX			**3,591,740**

Annual Operating Expenditure (OPEX)

Item	Calculation Detail	Annual Cost (\$)
Fuel Cost (Rice Husk)	$12,345,500$ kWh × \$0.045	555,548
DG O&M Cost	$12,345,500$ kWh × \$0.020	246,910
Protection System Maint.	2% of (\$105,000 + \$30,000)	2,700
TOTAL ANNUAL OPEX		**805,158**

Annual Benefits (Revenue & Savings)

Benefit Stream	**Calculation Detail**	**Annual Value ($)**
A. Energy Generation Sales	12,345,500 kWh × $0.09	1,111,095
B. Loss Reduction Savings	192.05 kW × 5,000 hrs × $0.09	86,424
C. Reliability Savings (ENS)	116,955 kWh × $0.50	58,478
TOTAL ANNUAL BENEFITS	*A + B + C*	**1,255,997**

Final Financial Indicators

Metric	**Formula**	**Result**
Net Annual Cash Flow	Total Benefits − Total OPEX	**$450,839**
Annuity Factor	@8% for 20 year	9.818
Present value of inflows	Net Annual Cash-Flow * Annuity Factor	$4,426,337
NPV	Present value of inflows - CAPEX	**$834,597**
IRR		**10.99%**
Payback Period	Total CAPEX / Net Annual Cash Flow	**7.97 Years**

5.2 Hasanpur Feeder (Practical Feeder)

Base Case: The Hasanpur Feeder, NEA, Nepal has 102 buses in the system with total active and reactive load of 7.406 MW and 2.89 MVar respectively. The given system was modeled in the MATLAB and with loadflow analysis done in MATPOWER the system loss was found to be 277.33 kW. The minimum voltage was 0.9014 pu at bus no. 57. The detail of voltage profile is depicted in the figure below.

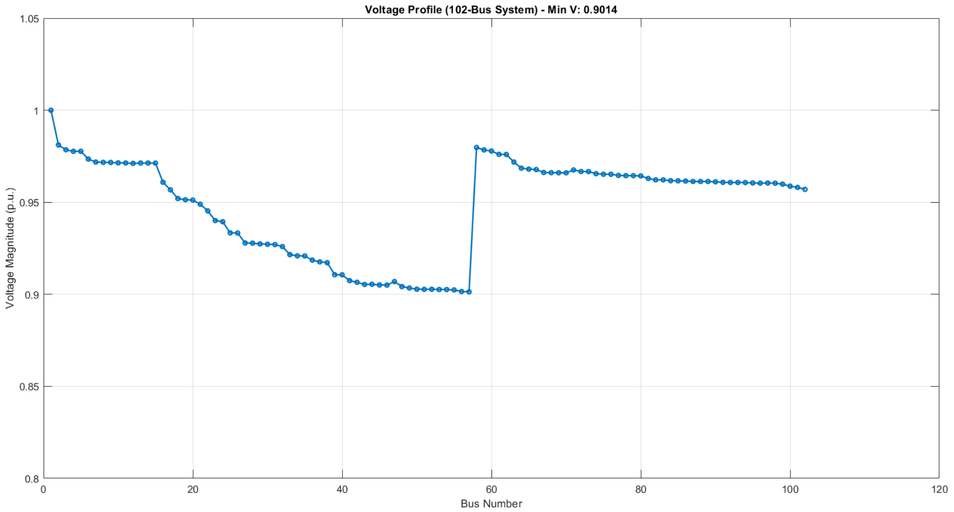


Figure 5.7: Voltage Profile of the Hasanpur feeder (Base case)

The figure above describes the voltage at different buses. We can see that the lowest voltage is 0.9014 pu at bus no. 57 and the maximum voltage is 1 pu at bus no. 1.

5.2.1 Reliability Indices Evaluation

The reliability indices (SAIFI, SAIDI, ENS) of the system is evaluated with the failure rate of the line taken as 0.065 f/km./yr., repair rate 240 hours and total consumer at any individual bus equal to the active load at that bus in kw. The result is depicted in the table below.

Table 5.7: Reliability Evaluation at Initial Condition

Index	Value	Unit
SAIFI	1.547	failures / customer / yr
SAIDI	6.188	hours / customer / yr
ENS	45828.49	kWh / yr

5.2.2 Placement of DG to improve voltage profile and reliability

In order to improve the reliability and voltage profile of the 11 kV Hasanpur feeder, the IHSA algorithm was applied to find the location and sizing of DGs. Maximum number of DGs was fixed to three and the maximum capacity of individual DG was fixed to 3 MW. The result is depicted in the table below.

Table 5.8: DG Optimization Results

S.N.	Optimal Location of DG (Bus No.)	Capacity of DG (MW)
1	81	2.2756
2	27	1.6376
3	42	1.3002
Total Capacity (MW)		5.2134

The result in table 5.8 shows the capacity and location of DGs. The largest size is 2.2756 MW, while the lowest capacity DG is 1.3002 MW. The active power loss of the system was reduced to 19.3891 kW and the minimum voltage of the system increased to 0.9909 pu. The improved voltage profile of the system is depicted in the figure below.

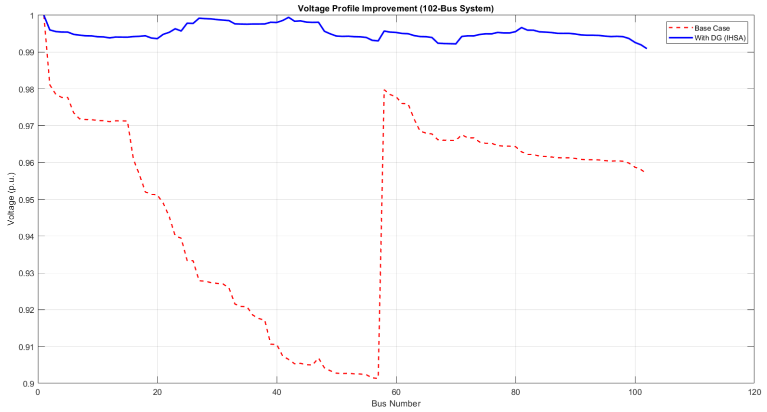


Figure 5.8: Voltage Profile Improvement with DG Integration

In the figure above, we can see that the voltage profile of the system is improved from the minimum of 0.9014 pu to 0.9909 pu.

5.2.3 Zone formation for islanding

To improve the reliability of the system, the network is divided into different zones for islanding using autoreclosers at the zone boundaries. The number of zones is fixed to three. The largest DG is connected with Bus 1 which do not support islanding but remaining 2 DGs are grouped to form two separate islands in case of failure of main source. The result is given in the table below.

Table 5.9: Zone Formation Results

S.N.	Zone	Total	Buses	Switches	DG
1	Zone 1	65	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 58, 59, 60, 61, 62, 63, 64, 65, 66, 67, 68, 69, 70, 71, 72, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 84, 85, 86, 87, 88, 89, 90, 91, 92, 93, 94, 95, 96, 97, 98, 99, 100, 101, 102	18-21 to isolate zone 1 & 2	Bus 81
2	Zone 2	18	21, 22, 23, 24, 25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36, 37, 38	38-39 to isolate zone 2 & 3	Bus 27
3	Zone 3	19	39, 40, 41, 42, 43, 44, 45, 46, 47, 48, 49, 50, 51, 52, 53, 54, 55, 56, 57	-	Bus 42

In the table above, bus numbers grouped in the respected zone are given. There are two reclosers placed at the boundaries of the zones, between bus 18-21 to isolate zone 1 and zone 2 and between bus 38-39 to isolate zone 2 and zone 3. Zone 1 does not support islanding because in order to make the complete system islanded, the size of DG would have to be larger than the total system load. The larger DGs increase the capital cost which would create the financial trouble. Remaining two zones are capable to operate in islanded mode i.e. the total load in zone 2 and 3 are less than the DGs capacity. The single line diagram of the Hasanpur feeder after placement of Dg and zone partition is depicted in the figure below.

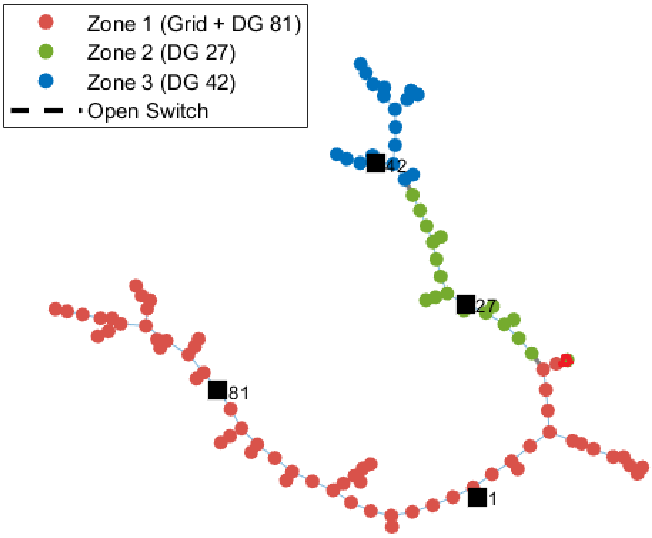


Figure 5.9: Zone Formation Diagram

The improvement in reliability indices after DG placement and zone partitioning are depicted in the table below.

Table 5.10: Reliability Evaluation after DG Installation and Zone Formation

Index	Value	Unit	Improvement
SAIFI	0.5992	failures / customer / yr	61.27%
SAIDI	2.397	hours / customer / yr	61.26%
ENS	17397.92	kWh / yr	62.04%

So in the above table we can see that SAIFI and SAIDI of the system after DG placement and zone islanding, improved by 61% whereas ENS improved by 62%.

5.2.4 Auto recloser placement

To improve reliability further, autoreclosers are placed at different locations to minimize and isolate the faulty section while maintaining the remaining section healthy. The number and locations of autoreclosers obtained by performing Genetic algorithm optimization technique is listed in the table below.

The single line diagram after placement of additional reclosers is shown in figure below.

After placement of the reclosers, the reliability of the system is further improved which is depicted in the table below.

Table 5.11: Autorecloser Optimization Result

S.N.	Branch Number	From Bus	To Bus
1	3	3	4
2	26	25	27
3	46	41	47
4	57	2	58
5	75	75	76
6	76	75	77
7	99	99	100
8	100	100	101

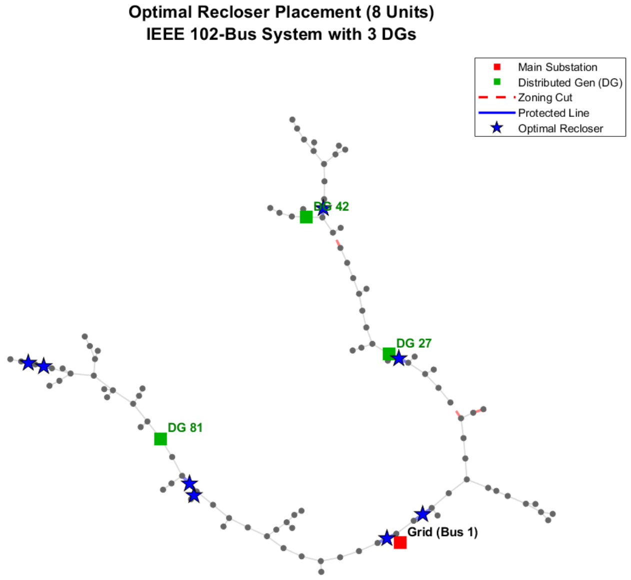


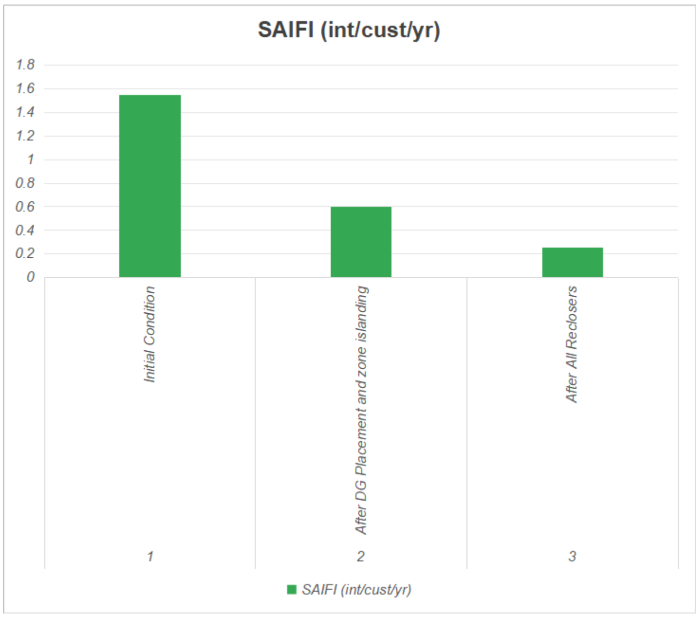
Figure 5.10: Final SLD after DG and reclosers placement

The data clearly shows that the reliability was improved to 61% after DG placement and zone islanding which futher improved and reached to 84% after addition of 8 reclosers.

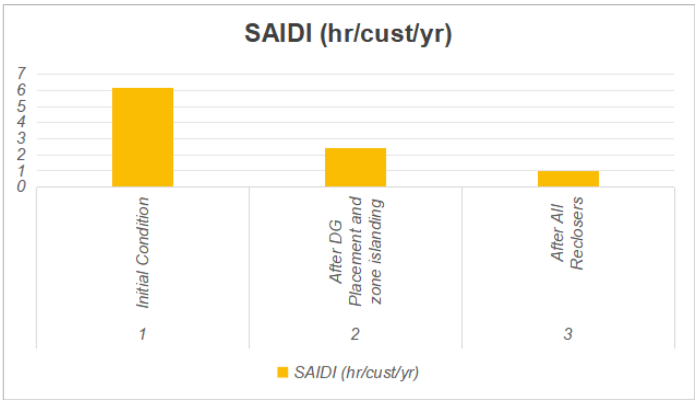
The comparison of the indices at different conditions is shown in the figure below.

Table 5.12: Reliability Indices Result

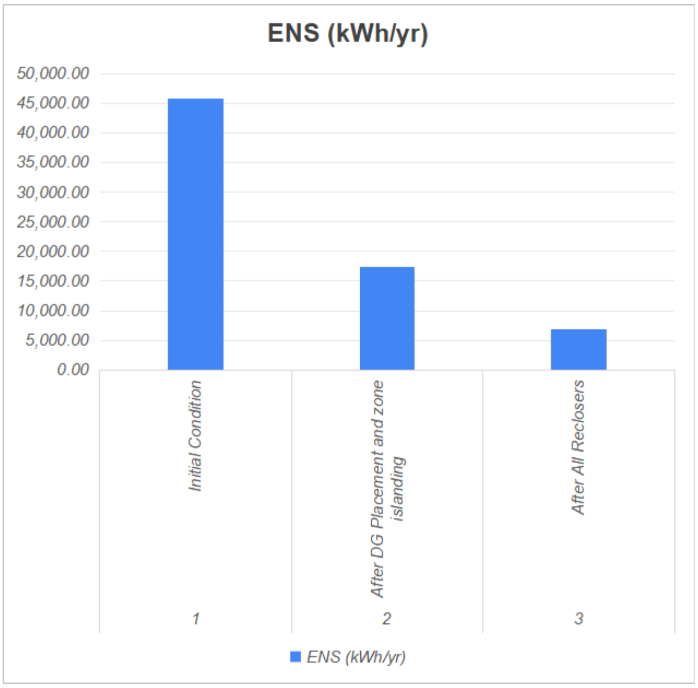
S.N.	**Scenario**	**SAIFI**	**SAIDI**	**ENS**	**Imp. ENS (%)**	**Imp. SAIDI (%)**	**Imp. SAIFI (%)**
1	Initial Condition	1.5470	6.1880	45828.49	0.00	0.00	0.00
2	After DG Placement and zone islanding	0.5992	2.3970	17397.92	62.04	61.26	61.27
3	After All Reclosers	0.2521	1.0082	6946.57	84.84	83.71	83.70



(a) SAIFI comparison for different case



(b) SAIDI comparison for different case



(c) ENS comparison for different case

Figure 5.11: Comparison of Reliability Indices

5.2.5 Financial Calculation

Technical Input Parameters

Parameter	Value	Unit	Remarks
Total DG Capacity	5,213.4	kW	
Annual Operating Hours	5,000	hrs	
Total Annual Generation	26,067,000	kWh	$5,213.4$ kW × $5,000$ hrs
Power Loss Reduction	257.94	kW	Saved active power losses
ENS Improvement	38,755	kWh	

Economic Assumptions

Parameter	Value	Unit	Remarks
Grid Tariff (Sales)	\$0.09	/kWh	
Value of Lost Load (C_E)	\$0.50	/kWh	
Biomass Fuel Cost	\$0.045	/kWh	Rice Husk: $\$0.03/\text{kg} \times 1.5$ kg/kWh
DG O&M Cost	\$0.02	/kWh	Standard Biomass Maintenance
Recloser Maint. Rate	2.0%	/yr	
Discount Rate	8.0	%/yr	
Project Life	20	yr	

Initial Capital Expenditure (CAPEX)

Item	Quantity	Unit Cost	Total Cost (\$)
Biomass DG Units	5,213.4 kW	\$1,400 / kW	7,298,760
Automatic Reclosers	8 Units	\$15,000 / unit	120,000
Zone Boundary Switches	2 Units	\$15,000 / unit	30,000
TOTAL CAPEX			**7,448,760**

Annual Operating Expenditure (OPEX)

Item	Calculation Detail	Annual Cost (\$)
Fuel Cost (Rice Husk)	$26,067,000$ kWh × \$0.045	1,173,015
DG O&M Cost	$26,067,000$ kWh × \$0.020	521,340
Protection System Maint.	2% of (\$120,000 + \$30,000)	3,000
TOTAL ANNUAL OPEX		**1,697,355**

Annual Benefits (Revenue & Savings)

Benefit Stream	**Calculation Detail**	**Annual Value ($)**
A. Energy Generation Sales	$26,067,000$ kWh × \$0.09	2,346,030
B. Loss Reduction Savings	257.94 kW × $5,000$ hrs × \$0.09	116,073
C. Reliability Savings (ENS)	$38,755$ kWh × \$0.50	19,377
TOTAL ANNUAL BENEFITS	$A + B + C$	**2,481,480**

Final Financial Indicators

Metric	**Formula**	**Result**
Net Annual Cash Flow	Total Benefits − Total OPEX	**$784,126**
Annuity Factor	@8% for 20 year	9.818
Present value of inflows	Net Annual Cash-Flow * Annuity Factor	$7,698,661
NPV	Present value of inflows - CAPEX	**$249,901**
IRR		**8.44%**
Payback Period	$\frac{\text{Total CAPEX}}{\text{Net Annual Cash Flow}}$	**9.50 Years**

5.2.6 Sensitivity Analysis

Sensitivity analysis with the change in the Value of Lost Load (VOLL) to \$ 0.2, \$ 0.5, and \$ 0.8 per kWh is depicted in the table below.

Table 5.13: Sensitivity Analysis: Impact of Value of Lost Load

Value of Lost Load ($/kWh)	**Reliability Benefit** ($/yr)	**Net Annual Cash Flow** ($)	**NPV @ 8% Discount Rate** ($)	**IRR** (%)	**Payback Period** (Years)
0.2	7751	772499	135749	8.24	9.64
0.5 (Base)	19378	784126	249900	8.45	9.5
0.8	31004	795752	364050	8.65	9.36

Results obtained from the sensitivity analysis performed with respect to the change in the value of lost load, shows that there is minor deviation in the financial indicators. From the result it is clear that the impact of reliability improvement on project finance is negligible. The main beneficial parameter is sale of energy which generates revenue in million and is very high compared to the improvement in energy not supplied.

6. CONCLUSIONS AND RECOMENDATIONS

6.1 Conclusions

The optimal sizing and location of the DG units and optimal location of reclosers is evaluated based on the reliability and performance of radial distribution system following the proposed algorithms. The reliability indices for IEEE-69 RDS and for the Hasanpur distribution feeder have been calculated first for the base case along with active power loss and voltage profile to compare the effectiveness of the algorithm before and after injection of the DG units, making zones for islanding and adding additional reclosers. The corresponding performance indices are evaluated, and the difference is found with the nominal case scenario. Also, the financial analysis is carried out taking the initial installation cost of DG, operation maintenance cost, installation and o m cost of reclosers, outage cost, income from selling of the energy with proposed DG, income from the loss reduction, income from the reduction in interruption cost and income from the reduction in energy not supplied.

For IEEE-69 bus system the values of reliability indices such as SAIFI, SAIDI and ENS for the base case is found to be 12.95 fault/customer/year, 47.8 hrs/customer/year and 147,362.62 kWh/year respectively. The active power loss is 218.0083 kW, reactive power loss is 99.1228 MVAr and the lowest voltage is found as 0.9194 pu at bus 65. With the proposed algorithm, the location and size of the three DGs to improve the voltage profile and reliability are 1.6541 MW at bus 61, 0.4652 MW at bus 11 and 0.3498 MW at bus 21. After placement of DGs the active power loss of the network is reduced to 25.9541 kW where as the minimum voltage of the network has been improved to 0.9942 pu. Further, three zones are created for islanding to improve reliability. DG 1 is connected with main grid but the DG itself cannot survive for islanding. The compromise is done on the basis of the financial investment required for the bulky DG required to make zone 1 as independent island. Zone 1 contains bus no. 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 28, 29, 30, 31, 32, 33, 34, 35, 36, 37, 38, 39, 40, 41, 42, 43, 44, 45, 46, 47, 48, 49, 50, 51, 52, 53, 54, 55, 56, 57, 58, 59, 60, 61, 62, 63, 64 and 65. The total load of zone 1 is 2.4668 MW. Similarly, Zone 2 groups bus no. 11, 12, 13, 14, 15, 16, 66, 67, 68 and 69 and the total active power of this zone is 0.4435 MW. In the same way, Zone 3 groups bus no. 17, 18, 19, 20, 21, 22, 23, 24, 25, 26 and 27 and the total active power of this zone is 0.296 MW. Zone 2 and 3 is capable to operate in islanded mode. After placement of the three DGS and zone formation the reliability indices such as SAIFI, SAIDI and ENS is improved by 49.5%, 49.4%.and 40.8% respectively. To improve the reliability further additional 7 reclosers are added, the location of which is optimized using GA. The locations of the reclosers are line no. 2-3, 7-8, 3-28, 39-40, 47-48, 8-51 and 54-55. After addition of these reclosers, the reliability indices (SAIFI, SAIDI and ENS) improved to 73.13%, 73.58% and 79.37% respectively.

The financial indicators such as NPV, IRR and payback period for integration of biomass DGs and reclosers is \$834,597.00, 10.99% and 7.97 year respectively, which indicates that the project is financially feasible.

For Hasanpur feeder, the values of reliability indices such as SAIFI, SAIDI and ENS is found to be 1.547 fault/customer/year, 6.188 hrs/customer/year and 45,828.49 kWh/year respectively. The active power loss is 277.33 kW and the lowest voltage is found as 0.9014 pu at bus 57. With the proposed algorithm, the location and size of the three DGs to improve the voltage profile and reliability are 2.2756 MW at bus 81, 1.6376 MW at bus 27 and 1.3002 MW at bus 42. After placement of DGs the active power loss of the network is reduced to 19.3891 kW where as the minimum voltage of the network has been improved to 0.9909 pu. Further, three zones are created for islanding to improve reliability. DG 1 is connected with main grid but the DG itself cannot survive for islanding. The compromise is done on the basis of the financial investment required for the bulky DG required to make zone 1 as independent island. Zone 1 contains bus no. 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 58, 59, 60, 61, 62, 63, 64, 65, 66, 67, 68, 69, 70, 71, 72, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 84, 85, 86, 87, 88, 89, 90, 91, 92, 93, 94, 95, 96, 97, 98, 99, 100, 101 and 102. The total load of zone 1 is 4.588 MW. Similarly, Zone 2 groups bus no. 21, 22, 23, 24, 25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36, 37 and 38 and the total active power of this zone is 1.6305 MW. In the same way, Zone 3 groups bus no. 39, 40, 41, 42, 43, 44, 45, 46, 47, 48, 49, 50, 51, 52, 53, 54, 55, 56 and 57 and the total active power of this zone is 1.2812 MW. Zone 2 and 3 is capable to operate in islanded mode. After placement of the three DGS and zone formation the reliability indices such as SAIFI, SAIDI and ENS is improved by 61%, 61%.and 62% respectively. To improve the reliability further additional 8 reclosers are added, the location of which is optimized using GA. The locations of the reclosers are line no. 3-4, 25-27, 41-47, 2-58, 75-76, 75-77, 99-100 and 100-101. After addition of these reclosers, the reliability indices (SAIFI, SAIDI and ENS) improved to 83.7%, 83.7% and 84.8% respectively. The financial indicators such as NPV, IRR and payback period for integration of biomass DGs and reclosers is \$249,901.00, 8.44% and 9.5 years respectively, which indicates that the project is financially feasible.

6.2 Recomendations

From this study, the optimum sizing and allocation of multi-DG units as well as optimal location of autoreclosers were performed based on improvement of reliability and voltage profile. For the improvement of voltage profile, capacitor units along with standby diesel generators operating only for outage duration can also be an alternate option. The detailed modeling of each DG can be done considering intermittency, and work can be further expanded to detail stability analysis. Moreover, further works can be investigated in relay and protection coordination.

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Appendices

A Line and Load data for IEEE 69-Bus RDS

Table A.1: Line and Load Data for IEEE 69-Bus RDS

Branch No.	**Send Node**	**Receive Node**	**R (Ω)**	**X (Ω)**	P_L **(kW)**	Q_L **(kVAr)**
1	1	2	0.0005	0.0012	0	0
2	2	3	0.0005	0.0012	0	0
3	3	4	0.0015	0.0036	0	0
4	4	5	0.0251	0.0294	0	0
5	5	6	0.3660	0.1864	2.6	2.2
6	6	7	0.3811	0.1941	30	40.4
7	7	8	0.0922	0.0470	54	75
8	8	9	0.0493	0.0251	30	22
9	9	10	0.8190	0.2707	19	28
10	10	11	0.1872	0.0619	145	104
11	11	12	0.7114	0.2351	104	145
12	12	13	1.0300	0.3400	5	8
13	13	14	1.0440	0.3450	5.5	8
14	14	15	1.0580	0.3496	0	0
15	15	16	0.1966	0.0650	45.5	30
16	16	17	0.3744	0.1238	35	60
17	17	18	0.0047	0.0016	35	60
18	18	19	0.3276	0.1083	0	0
19	19	20	0.2106	0.0690	0.6	1
20	20	21	0.3416	0.1129	114	81
21	21	22	0.0140	0.0046	3.5	5
22	22	23	0.1591	0.0526	0	0
23	23	24	0.3463	0.1145	20	28
24	24	25	0.7488	0.2475	0	0
25	25	26	0.3089	0.1021	14	10
26	26	27	0.1732	0.0572	10	14
27	3	28	0.0044	0.0108	18.6	26
28	28	29	0.0640	0.1565	18.6	26
29	29	30	0.3978	0.1315	0	0
30	30	31	0.0702	0.0232	0	0
31	31	32	0.3510	0.1160	0	0

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Table A.1 – continued from previous page

Branch No.	Send Node	Receive Node	R (Ω)	X (Ω)	P_L (kW)	Q_L (kVAr)
32	32	33	0.8390	0.2816	10	14
33	33	34	1.7080	0.5646	14	9.5
34	34	35	1.4740	0.4873	4	6
35	3	36	0.0044	0.0108	26	18.55
36	36	37	0.0640	0.1565	18.55	26
37	37	38	0.1053	0.1230	0	0
38	38	39	0.0304	0.0355	17	24
39	39	40	0.0018	0.0021	17	24
40	40	41	0.7283	0.8509	1.2	1
41	41	42	0.3100	0.3623	0	0
42	42	43	0.0410	0.0478	4.3	6
43	43	44	0.0092	0.0116	0	0
44	44	45	0.1089	0.1373	26.3	39.22
45	45	46	0.0009	0.0012	26.3	39.22
46	4	47	0.0034	0.0084	0	0
47	47	48	0.0851	0.2083	56.4	79
48	48	49	0.2898	0.7091	384.7	274.5
49	49	50	0.0822	0.2011	384.7	274.5
50	8	51	0.0928	0.0473	28.3	40.5
51	51	52	0.3319	0.1114	2.7	3.6
52	9	53	0.1740	0.0886	4.35	3.5
53	53	54	0.2030	0.1034	19	26.4
54	54	55	0.2842	0.1447	17.2	24
55	55	56	0.2813	0.1433	0	0
56	56	57	1.5900	0.5337	0	0
57	57	58	0.7837	0.2630	0	0
58	58	59	0.3042	0.1006	100	72
59	59	60	0.3861	0.1172	0	0
60	60	61	0.5075	0.2585	888	1244
61	61	62	0.0974	0.0496	23	32
62	62	63	0.1450	0.0738	0	0
63	63	64	0.7105	0.3619	162	227
64	64	65	1.0410	0.5302	59	42
65	11	66	0.2012	0.0611	18	13

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Table A.1 – continued from previous page

Branch No.	**Send Node**	**Receive Node**	**R (Ω)**	**X (Ω)**	P_L **(kW)**	Q_L **(kVAr)**
66	66	67	0.0047	0.0014	13	18
67	12	68	0.7394	0.2444	28	20
68	68	69	0.0047	0.0016	20	28

Table A.2: System Reliability Data for 69-Bus System

Feeder Section	**Failure Rate (f/yr)**	**Repair Time (hrs)**
F1	0.1	4
F2	0.15	5
F3	0.2	6
F4	0.25	3
F5	0.3	2
F6	0.1	4
F7	0.15	5
F8	0.2	6
F9	0.25	3
F10	0.3	2
F11	0.1	4
F12	0.15	5
F13	0.2	6
F14	0.25	3
F15	0.3	2
F16	0.1	4
F17	0.15	5
F18	0.1	2
F19	0.1	4
F20	0.15	5
F21	0.2	6
F22	0.25	3
F23	0.3	2
F24	0.1	4
F25	0.15	5
F26	0.2	6

Continued on next page

Table A.2 – continued from previous page

Feeder Section	Failure Rate (f/yr)	Repair Time (hrs)
F27	0.25	3
F28	0.3	2
F29	0.1	4
F30	0.15	5
F31	0.2	6
F32	0.25	3
F33	0.3	2
F34	0.1	4
F35	0.15	2
F36	0.1	2
F37	0.1	4
F38	0.15	5
F39	0.2	6
F40	0.25	3
F41	0.3	2
F42	0.1	4
F43	0.15	5
F44	0.2	6
F45	0.25	3
F46	0.3	2
F47	0.1	4
F48	0.15	5
F49	0.2	6
F50	0.25	3
F51	0.3	2
F52	0.1	4
F53	0.15	5
F54	0.2	6
F55	0.25	3
F56	0.3	2
F57	0.1	4
F58	0.15	5
F59	0.2	6
F60	0.25	3

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Table A.2 – continued from previous page

Feeder Section	Failure Rate (f/yr)	Repair Time (hrs)
F61	0.3	2
F62	0.1	4
F63	0.15	5
F64	0.2	6
F65	0.25	3
F66	0.3	2
F67	0.1	4
F68	0.15	5

B Bus and Branch data for Hasanpur Feeder

Table B.1: Bus Data for Hasanpur Feeder

S.N.	**Bus**	**P(kW)**	**Q(kVAR)**
1	1	0	0
2	2	186.3151	72.7096
3	3	46.5788	18.1774
4	4	0	0
5	5	46.5788	18.1774
6	6	93.1576	36.3548
7	7	0	0
8	8	0	0
9	9	93.1576	36.3548
10	10	46.5788	18.1774
11	11	0	0
12	12	186.3151	72.7096
13	13	0	0
14	14	46.5788	18.1774
15	15	46.5788	18.1774
16	16	186.3151	72.7096
17	17	46.5788	18.1774
18	18	23.2894	9.0887
19	19	186.3151	72.7096
20	20	93.1576	36.3548
21	21	46.5788	18.1774
22	22	93.1576	36.3548
23	23	0	0
24	24	93.1576	36.3548
25	25	0	0
26	26	46.5788	18.1774
27	27	0	0
28	28	186.3151	72.7096
29	29	0	0
30	30	93.1576	36.3548
31	31	46.5788	18.1774
32	32	372.6303	145.4191
33	33	279.4727	109.0643

Table B.1: Bus Data for Hasanpur Feeder

S.N.	**Bus**	**P(kW)**	**Q(kVAR)**
34	34	0	0
35	35	186.3151	72.7096
36	36	0	0
37	37	46.5788	18.1774
38	38	46.5788	18.1774
39	39	0	0
40	40	93.1576	36.3548
41	41	0	0
42	42	0	0
43	43	465.7878	181.7739
44	44	23.2894	9.0887
45	45	46.5788	18.1774
46	46	139.7363	54.5322
47	47	93.1576	36.3548
48	48	93.1576	36.3548
49	49	0	0
50	50	0	0
51	51	93.1576	36.3548
52	52	46.5788	18.1774
53	53	0	0
54	54	46.5788	18.1774
55	55	46.5788	18.1774
56	56	46.5788	18.1774
57	57	46.5788	18.1774
58	58	46.5788	18.1774
59	59	232.8939	90.8870
60	60	23.2894	9.0887
61	61	0	0
62	62	46.5788	18.1774
63	63	186.3151	72.7096
64	64	23.2894	9.0887
65	65	93.1576	36.3548
66	66	93.1576	36.3548
67	67	0	0
68	68	93.1576	36.3548

Table B.1: Bus Data for Hasanpur Feeder

S.N.	**Bus**	**P(kW)**	**Q(kVAR)**
69	69	93.1576	36.3548
70	70	186.3151	72.7096
71	71	46.5788	18.1774
72	72	186.3151	72.7096
73	73	46.5788	18.1774
74	74	279.4727	109.0643
75	75	0	0
76	76	46.5788	18.1774
77	77	0	0
78	78	93.1576	36.3548
79	79	46.5788	18.1774
80	80	23.2894	9.0887
81	81	186.3151	72.7096
82	82	0	0
83	83	46.5788	18.1774
84	84	0	0
85	85	46.5788	18.1774
86	86	46.5788	18.1774
87	87	0	0
88	88	93.1576	36.3548
89	89	46.5788	18.1774
90	90	0	0
91	91	0	0
92	92	93.1576	36.3548
93	93	93.1576	36.3548
94	94	93.1576	36.3548
95	95	0	0
96	96	93.1576	36.3548
97	97	23.2894	9.0887
98	98	93.1576	36.3548
99	99	93.1576	36.3548
100	100	93.1576	36.3548
101	101	46.5788	18.1774
102	102	186.3151	72.7096

Table B.2: Branch Data for Hasanpur Feeder

From Bus	To Bus	Length (Meter)	Resistance	Reactance
1	2	600	0.2733	0.511506
2	3	150	0.2733	0.511506
3	4	50	0.2733	0.511506
4	5	50	0.2733	0.511506
4	6	250	0.2733	0.511506
6	7	100	0.2733	0.511506
7	8	100	0.2733	0.511506
8	9	100	0.2733	0.511506
8	10	200	0.2733	0.511506
10	11	50	0.2733	0.511506
11	12	350	0.2733	0.511506
11	13	100	0.2733	0.511506
13	14	100	0.2733	0.511506
13	15	200	0.2733	0.511506
7	16	750	0.2733	0.511506
16	17	300	0.2733	0.511506
17	18	350	0.2733	0.511506
18	19	350	0.5426	0.51118258
19	20	300	0.5426	0.51118258
18	21	250	0.2733	0.511506
21	22	300	0.2733	0.511506
22	23	450	0.2733	0.511506
23	24	1050	0.5426	0.51118258
23	25	600	0.2733	0.511506
25	26	300	0.2733	0.511506
25	27	500	0.2733	0.511506
27	28	150	0.2733	0.511506
27	29	50	0.2733	0.511506
29	30	350	0.2733	0.511506
30	31	750	0.2733	0.511506
29	32	150	0.2733	0.511506
32	33	550	0.2733	0.511506
33	34	100	0.2733	0.511506
34	35	50	0.2733	0.511506

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From Bus	To Bus	Length (Meter)	Resistance	Reactance
34	36	250	0.5426	0.51118258
36	37	100	0.5426	0.51118258
37	38	50	0.5426	0.51118258
38	39	750	0.5426	0.51118258
39	40	100	0.5426	0.51118258
39	41	400	0.5426	0.51118258
41	42	200	0.5426	0.51118258
42	43	250	0.9077	0.52734102
42	44	500	0.9077	0.52734102
44	45	200	0.9077	0.52734102
45	46	50	0.9077	0.52734102
41	47	150	0.5426	0.51118258
47	48	950	0.5426	0.51118258
48	49	350	0.5426	0.51118258
49	50	450	0.9077	0.52734102
50	51	100	0.9077	0.52734102
50	52	100	0.9077	0.52734102
49	53	650	0.5426	0.51118258
53	54	150	0.5426	0.51118258
53	55	250	0.5426	0.51118258
55	56	900	0.9077	0.52734102
56	57	350	0.9077	0.52734102
2	58	100	0.2733	0.511506
58	59	100	0.2733	0.511506
59	60	50	0.2733	0.511506
60	61	150	0.2733	0.511506
61	62	150	0.9077	0.52734102
61	63	350	0.2733	0.511506
63	64	300	0.2733	0.511506
64	65	50	0.2733	0.511506
65	66	50	0.9077	0.52734102
66	67	450	0.9077	0.52734102
67	68	50	0.9077	0.52734102
68	69	50	0.9077	0.52734102
67	70	100	0.9077	0.52734102

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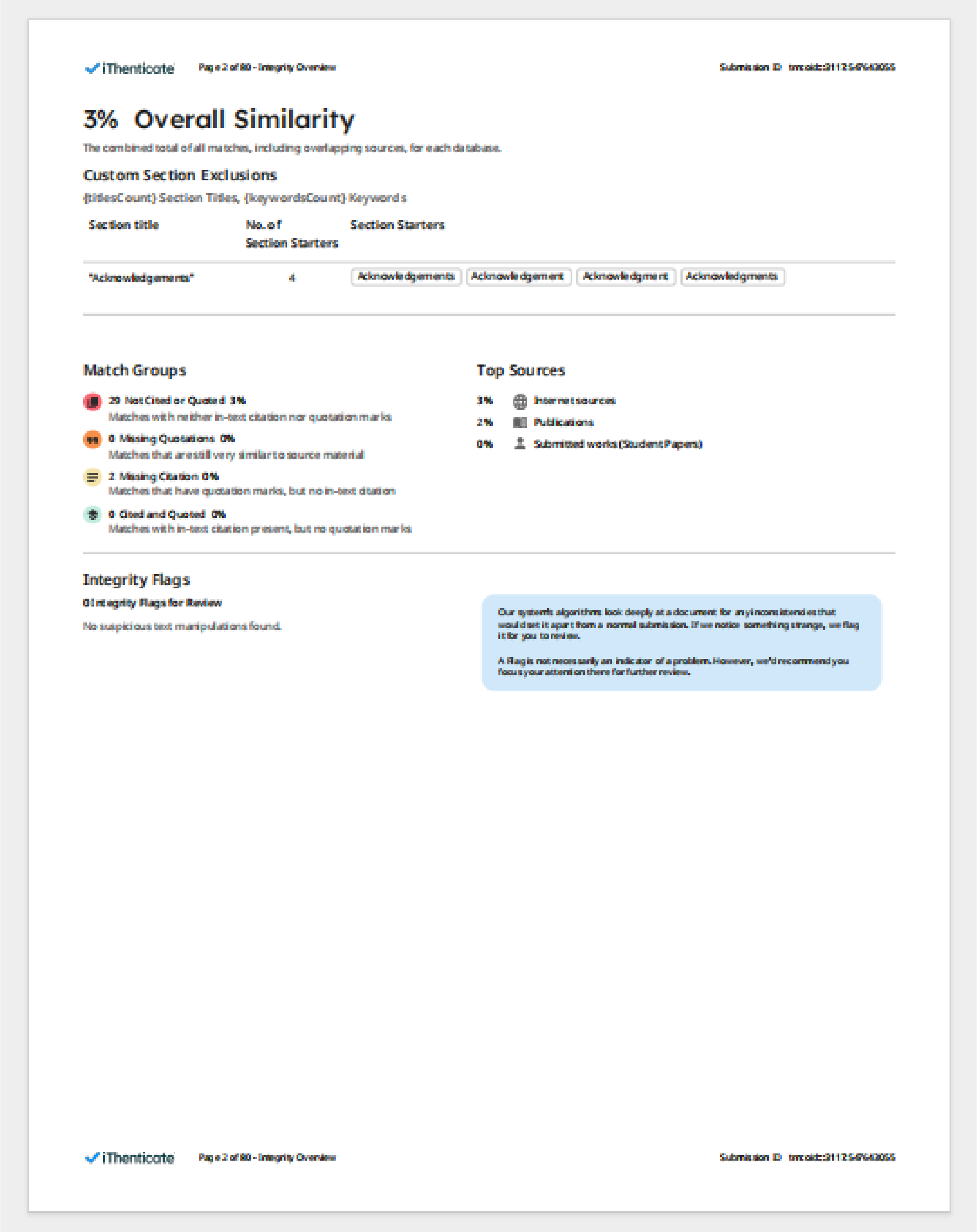
From Bus	**To Bus**	**Length (Meter)**	**Resistance**	**Reactance**
65	71	50	0.2733	0.511506
71	72	100	0.2733	0.511506
72	73	50	0.2733	0.511506
72	74	150	0.2733	0.511506
74	75	50	0.2733	0.511506
75	76	50	0.2733	0.511506
75	77	100	0.2733	0.511506
77	78	250	0.2733	0.511506
78	79	50	0.2733	0.511506
77	80	50	0.2733	0.511506
80	81	250	0.2733	0.511506
81	82	150	0.2733	0.511506
82	83	100	0.2733	0.511506
82	84	100	0.2733	0.511506
84	85	100	0.9077	0.52734102
85	86	250	0.9077	0.52734102
84	87	100	0.2733	0.511506
87	88	50	0.2733	0.511506
87	89	50	0.2733	0.511506
87	90	50	0.2733	0.511506
90	91	100	0.9077	0.52734102
91	92	100	0.9077	0.52734102
91	93	50	0.9077	0.52734102
93	94	50	0.9077	0.52734102
90	95	150	0.5426	0.51118258
95	96	200	0.5426	0.51118258
95	97	50	0.9077	0.52734102
97	98	100	0.9077	0.52734102
95	99	250	0.5426	0.51118258
99	100	350	0.9077	0.52734102
100	101	450	0.5426	0.51118258
101	102	600	0.9077	0.52734102



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