METHODS FOR ANALYSIS AND PLANNING OF MODERN DISTRIBUTION SYSTEMS

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ABSTRACT

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The Principal contribution of this dissertation lies in developing an efficient optimization framework for distribution system operational and planning studies. The first part of this dissertation introduces a novel power flow model, which is equally appropriate for use at both distribution and transmission levels and can be extremely useful whenever fast, robust, and repetitive power flow solutions are required. We develop the proposed linearized AC power flow model (LACPF) based on linearization of the full set of conventional power flow equations, and therefore includes voltage magnitude solutions and reactive power flows, unlike traditional linearized power flow methods. Further, the model presented in this dissertation is non-iterative, direct, and involves no convergence issues even with ill-condition systems. We test the proposed model on several distribution systems and has found to perform with speed and accuracy appropriate for repetitive solutions.

The second part of this dissertation develops an efficient optimization framework to handle several distribution system operational and planning problems. The proposed framework uses linear programming, because linear programming based formulations tend to be flexible, reliable, and faster than their nonlinear counterparts. We consider voltage bounds, reactive power limits, and all shunt elements in the proposed optimization model. We use the proposed optimization framework to solve the problem of optimal sizing and placement of distributed generation. For this particular case, we use loss sensitivity factors and sensitivity analysis to estimate the optimal size and power factor of the candidate distributed generation units. We also perform exhaustive power flow studies to verify the sizes obtained by the proposed method. We demonstrate the

effectiveness of the method on several benchmark systems and prove that the method could lead to optimal or near- optimal global solution, which makes the proposed method very suitable to use in several optimal distribution system planning studies.

We solve the problem of optimal economic power dispatch of active distribution systems. We propose a piecewise linear model to approximate the current carrying capacities of distribution feeders. The degree of approximation in this model can be improved to the desired level by increasing the number of line segments used, without substantial affect on the main routine and the computational speed. We further develop linear models for cost functions of generating units, loads, and total power losses. We apply methods, which are developed based on nonlinear programming and conventional linear programming to evaluate the effectiveness of the proposed method. We show that the results obtained by the proposed framework correspond closely with those obtained by nonlinear means, while requiring lower computational effort.

We describe a method for solving the distribution system reconfiguration problem with an objective of reliability improvement. From practical perspective, distribution systems are reconfigured radially for best control and coordination of their protective devices. Therefore, we develop a graph theoretic method to preserve the spanning tree structure of the distribution system. We further develop an intelligent search method based on binary particle swarm optimization technique, to seek for the best combinations of sectionalizing and tie-switches that minimize the amount of total power curtailment. Since the time and computational effort spent in evaluating reliability indices are of great concern in both planning and operational stages, we propose a probabilistic reliability assessment method based on event tree analysis with higher-order contingency approximation. We demonstrate the effectiveness of the proposed method on numerous radial distribution systems and show that the amount of annual power curtailment of in-service consumers can be tremendously reduced using the proposed method.

To my late parents with love, wife Enas, and beautiful children Ali Elsaiah and Muath Elsaiah

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Chapter 1

Introduction

The electric power system is a very large and complex network consists of generating units, transmission lines, transformers, switches, loads, etc. The objective of the electric power system is to supply consumers with electric demand in a practical and reliable manner. This chapter briefly discusses the basic power system structure and its major parts. It introduces the general power flow problem and discusses the methods presented in the literature to handle the power flow problem. In addition, this chapter summarizes the common mathematical programing based methods and highlights the major contributions of this thesis.

1.1 Power System Structure

The single line diagram of a simple power system is shown below in Fig. 1.1. This system consists mainly of three regions, which are the generation region, transmission region, and distribution region. There is one voltage level in the generation region, which is the generation voltage level. However, various voltage levels are used at the other two regions.

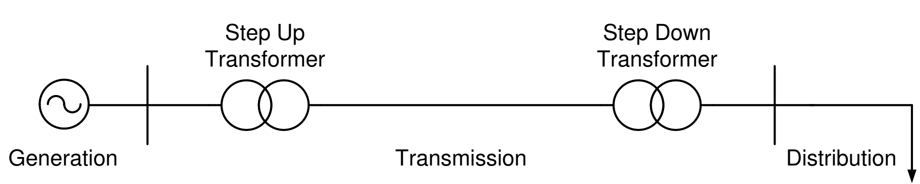

Figure 1.1: Power system single-line diagram

1.1.1 Transmission Level

The transmission level is typically different from distribution and sub-transmission levels in its characteristics and operating strategies. One distinctive feature of transmission system, for instance, is that it connects a mixture of generating units; e.g. thermal, nuclear, hydraulic, etc. Moreover, the direction of power flow in transmission systems can be in a forward or backward direction and is usually reversed to impose certain operational constraints. Further, transmission systems are characterized by high X/R ratios, which could attain a factor of 10, for high voltage networks.

1.1.2 Sub-transmission Level

The sub-transmission level receives the electrical power from the bulk power substations and transmits it to the distribution substations. The typical voltages in sub-transmission level are usually varies between 11 kV and 138 kV. Sub-transmission levels are treated as transmission systems and, sometimes, as distribution systems depending on the operating constrains and regulations used.

1.1.3 Distribution Level

The distribution system level consists of radial distribution feeders, which are fed from distribution substations through power transformers. Two distribution voltage levels are widely used in the U.S. distribution systems. These voltages are the primary voltage, which is 13.2 kV and the secondary voltage, which is 120 Volts. Distribution systems have certain distinctive features. Examples of these features include, radial structure with weakly-meshed topology, high R/X branch ratios, untransposed or rarely transposed distribution feeders, unbalanced loads along with single-phase and double-phase laterals, and dispersed generation.

1.2 Distribution System Modeling

This section highlights some modeling aspects for distribution system components. We felt that it is a quite appropriate to present few component models in this section, however detailed component models can be found in [1, 2].

1.2.1 Distribution Line Model

Fig. 1.2 shows a three-phase line section connected between bus k and bus m. The line parameters can be found by the method developed by Carson and Lewis [3]. A 4×4 sized primitive matrix, which takes into account the effect of the self-and-mutual coupling between phases can be expressed as [4],

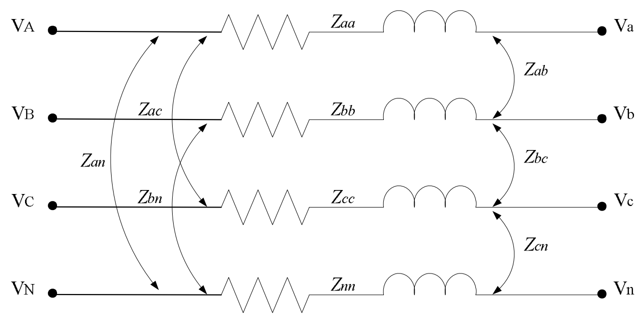

Figure 1.2: Distribution line model

However, it is convenient to represent (1.1) as a 3×3 matrix instead of the 4×4 matrix by using Kron's method [3, 4]. The effect of the ground conductor is still included in the resultant matrix. That is,

$$Z'_{abc} = \begin{bmatrix} Z_{aa} & Z_{ab} & Z_{ac} & Z_{an} \\ Z_{ba} & Z_{bb} & Z_{bc} & Z_{bn} \\ Z_{ca} & Z_{cb} & Z_{cc} & Z_{cn} \\ Z_{na} & Z_{nb} & Z_{nc} & Z_{nn} \end{bmatrix} \tag{1.1}$$

$$Z_{abc} = \begin{bmatrix} Z_{aa-n} & Z_{ab-n} & Z_{ac-n} \\ Z_{ba-n} & Z_{bb-n} & Z_{bc-n} \\ Z_{ca-n} & Z_{cb-n} & Z_{cc-n} \end{bmatrix} \tag{1.2}$$

It should be noted, however, that single-phase and two-phase line sections are most common in distribution networks. Hence, in this thesis for any phase does not present, the corresponding row and column in (1.1) will have zero entries.

1.2.2 Load Model

The active and reactive power loads on distribution networks can be represented as constant power, constant current, constant impedance, or a mixture of these types. Hence, the load model in distribution systems can be generally represented by an exponential function as,

$$P_k = P_{ref} \left(\frac{V_k}{V_{ref}} \right)^{\alpha} \tag{1.3}$$

The reactive power can be represented as,

$$Q_k = Q_{ref} \left(\frac{V_k}{V_{ref}} \right)^{\beta} \tag{1.4}$$

where, V_{ref} is the reference bus voltage, V_k is the operating voltage at bus k, P_{ref} and Q_{ref} respectively are the active and reactive power consumptions at the reference bus k, α and β are exponents by which the load characteristic can be determined. That is, constant power load model can be found by setting $\alpha = \beta = 0$. The constant power model is often used in power flow studies and has therefore been adapted in this work. Further, constant current model and constant impedance model can be obtained by setting $\alpha = \beta = 1$ or $\alpha = \beta = 2$, respectively.

1.2.3 Cogenerator Model

Cogenerators or distributed generators are small-scale energy sources, which are usually used at distribution system level to enhance the reliability and security of the system. Cogenerators can be modeled either as constant power nodes or constant voltage nodes. In accordance with the IEEE standard 1547-2003 [5] for interconnecting distributed resources with electric power systems, distributed generators are not recommended to regulate bus voltages, but strongly recommended to be modeled as constant PQ nodes. Therefore, the distributed generators used in this thesis are modeled as constant PQ nodes, with negative injections. However, the power factor of the distributed generation unit is calculated according to the application in which the distributed generator is used.

1.2.4 Shunt Capacitor Model

Capacitor banks are widely used in distribution systems to regulate bus voltages and retain reactive power limits in the desired range. In this thesis, capacitor banks are modeled as constant capacitance devices and are represented by current injections to the node at which they are connected.

1.2.5 Switch Model

Distribution systems are equipped with two types of switches; sectionalizing switches and tie-switches. The sectionalizing switches are normally closed and are used to connect various distribution line segments. The tie-switches, on the other hand, are normally open and can be used to transfer loads from one feeder to another during abnormal conditions. In this work, both types of switches are modeled as branches with zero impedance. That is, the current flow in any branch or switch in the system can be computed directly from the power flow solution and vice versa.

1.3 The Power Flow Problem

Power flow analysis is a crucial and basic tool for the steady-state analysis of any power system. The solution of the power flow problem aims at determining the steady-state voltage phase and magnitude at all buses as well as real and reactive power flows in each line, for specific loading conditions. Nonlinear models and linearized models are used in the literature to handle the power flow problem. A review of the common power flow methods is presented below in Section 1.3.1.

1.3.1 Literature Review

Power flow analysis has long been performed using full AC power flow (FACPF). The fundamental methods, which are widely used in solving power flows at transmission level are the Gauss-Seidel method, Newton-Raphson method, and Fast-Decoupled method [6, 7, 8]. The idea behind the Gauss-Seidel iterative method is very simple, however the iterative solution has a slow converge properties. It is, therefore, known as a slow-iterative problem solving technique since it constantly requires the solution of a set of nonlinear equations whose cardinality approximately equals the number of system buses. Experience with Gauss-Seidel method has shown that convergence may not be attained for all systems [2]. However, in the realistic power systems, power flow studies are carried out using per unit quantities and all bus voltages are restricted to become close to their rated values. Consequently, convergence is attained but with an extensive computational burden.

The Newton-Raphson method is a fast and robust tangential approximation technique in which line parameters and other variables are stored in the Jacobian matrix. In the Newton-Raphson method, Taylor's series is used up to the first term and the method converges very fast. The major drawback of the Newton-Raphson method, however, is that the formulation of the Jacobian matrix is computationally cumbersome in terms of execution time and storage requirement. In fact, the

Jacobian matrix needs to be recalculated and evaluated in every single iteration. More significantly, the Jacobian matrix is highly sparse and tends to be singular under certain operating conditions.

The Fast-Decoupled method [9, 10, 11], which is a modification of the Newton-Raphson method, uses an approximate and constant Jacobian that ignores the dependencies between (a) real power and voltage magnitude, and (b) reactive power and voltage angle. It is, therefore, fast and effective approach to solve power flows at transmission system level. Nevertheless, for systems with R/X branch ratios greater than 1, the standard Fast-Decoupled method does not converge well [9]. The Fast-Decoupled method is frequently used in the engineering applications in which fast power flow estimations are required.

A considerable amount of research has been presented in the literature to improve the performance of the Fast-Decoupled method. In this context, the compensation based method proposed by Rajicic and Bose [12] is probably the most popular technique that is being used to enhance the performance of the Fast-Decoupled method, in particular, for systems with high R/X branch ratios. The parallel compensation of the decoupled power flow method has been introduced in [13]. Ejebe et al [14], proposed a fast contingency screening method for voltage security analysis based on Fast-Decoupled method. The contingency analysis is performed in two stages; which are the screening stage and the solution stage. The screening stage uses a single iteration of the Fast-Decoupled method. It has been demonstrated in [14] that most of the computational time is utilized for the Q–V half iteration. Consequently, a screening method is developed in [14] in order to reduce the computational time. This screening method was accomplished using sparse vector techniques and was able to solve the Q–V half iteration only.

Numerous power flow solution methods were proposed in the literature to handle distribution systems power flow due to their special features, in particular, the high R/X branch ratios and the weakly-meshed topological structure. Some methods have used modified versions of Newton-

Raphson method and its decoupled form while others have been developed based on the backward/forward sweeping method. The latter category can be classified as current summation methods, admittance summation methods, and power summation methods.

Zimmerman and Chiang presented a fast decoupled load flow method in [15]. In this method, a set of nonlinear power mismatch equations are formulated and then solved by Newton-Raphson method. The advantage of this method is that it ordered the laterals instead of buses; hence the problem size has been reduced to the number of system's laterals. Use of laterals as variables instead of nodes makes this algorithm more efficient for a given system topology, however it may add some difficulties if the network topology is changed regularly, which is the case in distribution networks as a result of the switching operation. Baran and Wu [16] developed a method for solving distribution system power flow by solving three equations representing the voltage magnitude, real power, and reactive power. In this method, only simple algebraic equations are utilized to develop the Jacobian matrix and the power mismatches. Nevertheless, the formulation of the Jacobian matrix in every iteration tends to be computationally demanding, particularly for large-scale distribution systems.

Shirmohammadi et al. [17] presented a compensation based method for power flow analysis of balanced distribution systems. Basically, the method used KCL and KVL to obtain branch currents and bus voltages and then a forward/backward sweep is applied to obtain the power flow solution. This method has also accounted for weakly-meshed networks by breaking the given system to a number of points –breakpoints– and hence a simple radial network can be obtained. The radial network was then solved by the direct application of KCL and KVL. The effectiveness of this method diminishes as the number of breakpoints goes up. As a result, the application of this method to the weakly-meshed networks was practically restricted. An algorithm for the power flow solution of unbalanced distribution networks was developed in [18] by Cheng and

Shirmohammadi. This method can be considered as an extension to the work done in [17], but it has dealt with the modeling of voltage control buses, elaborated on the modeling aspects of various distribution system components, and was successfully applied on realistic distribution systems.

Kersting and Mandive [19, 20] suggested a method to solve the distribution system power flow problem based on Ladder-Network theory in the iterative routine. This approach has the advantage of being derivative-free and uses basic circuit theory laws. However, ladder network method assumes constant impedance loads, which is not the case in most distribution networks. Goswami and Basu presented a direct approach to obtain a solution for the distribution system power flow for both radial and meshed networks in [21]. The method was also applied to balanced and unbalanced networks. The significance of this method is that convergence is achieved for a wide range of realistic distribution systems, including weakly-meshed distribution systems. The main drawback of this method, on the other hand, is that no node in the system can serve as a junction for more than three network branches, which limits the practical use of this method.

Several distribution power flow methods have been proposed by Teng [22, 23, 24]. One method [22] is developed based on the optimal ordering scheme and triangular factorization of the bus admittance matrix. This method was developed based on the Gauss-Seidel method but has used factorization of the admittance matrix to reduce the computational burden. The method presented in [23] is developed based on the equivalent current injection technique. Amongst the advantages of this method is the constant Jacobian matrix, which needs to be converted only once. Distribution feeders reactances' have not been taken into consideration in this method by assuming that line reactance is much smaller than its resistance. However, distribution networks are characterized by a wide range of resistances and reactances, which signifies that the method may fail to converge if line reactances' are accounted for. A direct approach to obtain the distribution power flow solution has been proposed in [24]. Two matrices and direct matrix multiplication are used to obtain the distribution power flow solution. The solution involves direct matrix multiplication, and thus large memory space is needed, particularly if the method is used to handle power flows of large-scale distribution systems. Prakash and Sydulu [25] have introduced certain modifications to the method presented in [24] so that the power flow solution is obtained with lower computational burden. However, balanced conditions are only considered. The network topology based method has also been modified to include the weakly-meshed networks in [26].

It is worth noting here that all of the aforementioned power flow methods are nonlinear based methods. They have been used to carry out several power flow problems. The main drawback of many of these nonlinear based methods, however, is that they constantly converge slowly, and there exist some cases when convergence is not attended at all. More significantly, in most cases, when used in optimizing the operation of today's distribution systems, these nonlinear based methods are computationally demanding. A summary of the methods used to optimize the operation of distribution systems using nonlinear and linear optimization techniques are reviewed in the subsequent section. The challenges, advantages, and disadvantages are also highlighted.

1.4 Review of Mathematical Programming Based Methods

Optimization methods, with the broad definition, can be classified as conventional optimization methods, which are developed based on mathematical programming, and intelligent optimization methods, which are developed based on swarm intelligence and evolutionary programming. We have dealt with the latter category in Chapter 5. An overview of the former category, however, is presented in the subsequent section.

1.4.1 Nonlinear Optimization Methods

Power systems are inherently nonlinear as was discussed earlier in Section 1.3. Consequently, nonlinear optimization techniques can be used to handle power system operation and planning problems. Examples of the nonlinear optimization methods, which are widely used in the literature include, nonlinear programming, quadratic programming, and mixed-integer programming. These methods are briefly reviewed below.

In nonlinear programming based optimization, both the objective function and constraints are nonlinear. In order to handle a nonlinear programming problem, we usually start by choosing a search direction, which is obtained by finding the reduced gradient of the objective function. The crucial advantage of using nonlinear programming techniques in power system studies is partly attributed to there ability to achieve higher accuracy. However, the main disadvantage of nonlinear programming based methods is that slow convergence rate may occur, which makes these methods computationally expensive, especially for the applications in which multiple solutions are required. In addition, for a specific type of engineering applications the objective function is non-differentiable. This could limit the use of nonlinear programming based methods.

Quadratic programming can in fact be considered as a special case of nonlinear programming based technique. That is, in quadratic programming based methods the objective function is quadratic while the constraints are linear. A common objective function used in power system studies is to minimize the total generation cost or emission, which is inherently a quadratic function. The quadratic programming handles this problem efficiently, however, at the same time, the computational burden is considerably large.[1] More prominently, the standard simple form of the quadratic programming is not quite often used because convergence is not always guaranteed.

[1]In Chapter 4, we solve the optimal economic power dispatch problem of active distribution systems efficiently and we show that the computational effort can be tremendously reduced using the proposed optimization framework.

Nonlinear optimization problems can also be formulated as a mixed-integer programming using certain integer control variables. Handling optimization problems using methods based on mixed-integer programming can be computational demanding, particularly for large-scale systems.

1.4.2 Linear Optimization Methods

Linear methods are used to transform nonlinear optimization problems to linear problems. In this context, linear programming (LP) is probably the most popular technique, which is widely used to handle the engineering applications that require repetitive, prompt, and multiple solutions. Linear programming is an optimization technique introduced in the 1930s by some economists to solve the problem of optimal allocation of resources [27], [28]. Unlike nonlinear programming based methods, both the objective function and constraints are linear functions in the LP model. The advantages of using LP based methods in distribution system operation and planning include,

1. Reliability of the optimization and flexibility of the solution.

2. Rapid convergence characteristics and fast execution time.

3. Nonlinear convex curves can be handled using piecewise linear models.

4. Equality and inequality constraints can be equally handled in the basic LP routine.

Suppose we have m constraints with n variables, the standard *maximum* linear programming problem can be formulated as [29],

$$\max(\mathrm{Z}) = \sum_{j=1}^{n} c_j x_j \tag{1.5}$$

Subject to the following constraints,

$$\sum_{j=1}^{n} a_{ij}\, x_j \leq d_i \tag{1.6}$$

$$x_j \geq 0 \tag{1.7}$$

In matrix notation, the coefficients in (1.6) can be represented as,

$$A = \begin{pmatrix} a_{11} & a_{12} & \dots & a_{1n} \\ a_{21} & a_{22} & \dots & a_{2n} \\ \vdots & \vdots & \ddots & \vdots \\ a_{m1} & a_{m2} & \dots & a_{mn} \end{pmatrix} \tag{1.8}$$

The right-hand side vector d of the constraints consists of m constants,

$$d = \begin{pmatrix} d_1, & d_2, & \cdots, & d_m \end{pmatrix}^T \tag{1.9}$$

The row vector of the objective function c consists of n coefficients,

$$c = \begin{pmatrix} c_1, & c_2, & \cdots, & c_n \end{pmatrix}^T \tag{1.10}$$

The dual of this standard *maximum* problem is the standard *minimum* problem, which can be formulated as,

$$\min(\mathrm{W}) = \sum_{i=1}^{m} b_i\, y_i \tag{1.11}$$

Subject to the following constraints,

$$\sum_{j=1}^{n} a_{ij}\, y_j \geq c_j \tag{1.12}$$

$$y_i \geq 0 \tag{1.13}$$

In general, the standard linear programming can be represented as,

$$\max\ (\mathrm{Z}) = CX \tag{1.14}$$

with the equality constraints,

$$AX = d \tag{1.15}$$

$$X \geq 0 \tag{1.16}$$

Alternatively, we can use the compact form to refer to the standard maximization and minimization problems. Thus, the standard maximization problem can be stated as,

$$\text{Maximize:} \qquad \left\{c^T x \mid Ax \leq d;\ x \geq 0\right\} \tag{1.17}$$

The primal-dual standard minimization problem is stated as,

$$\text{Minimize:} \qquad \left\{y^T d \mid y^T A \geq c^T;\ y \geq 0\right\} \tag{1.18}$$

where A is a coefficient matrix as defined in (1.6) with dimensions $(i \times j)$, $c \in \mathbf{R}^j$, $x \in \mathbf{R}^j$, $d \in \mathbf{R}^i$, and $y \in \mathbf{R}^i$, and $\mathbf{R}$ is the set of real numbers.

1.5 The Necessity for New Models and Methods

The structure of distribution systems has been recently changed due to certain environmental, economic, and political reasons. This change has come through the emergence of several real-time engineering applications in both operational and planning stages. Examples of these applications include sizing and placement of distributed generators, economic power dispatch of active distribution systems, feeder reconfiguration for service restoration and reliability enhancement, and so forth. It is very well known that these applications require a power flow study at the first step of the solution. Nevertheless, and not surprisingly, the vast majority of these applications require repetitive and prompt power flow solutions. Performing full AC power flow, on one hand, gives high calculation precision but requires a quite extensive computational burden and storage requirements. On the other hand, and more prominently, the largest part of the aforementioned applications is essentially nonlinear complex combinatorial constrained optimization problems. The formulation of the nonlinear problem, however, tends to be a tedious task and computationally cumbersome in terms of execution time, storage requirements, and programming. These facts combined with the large number of distribution system components will incontestably increase the complexity of the problem. It has therefore become necessary to develop more powerful tools for both planning and operational studies not only to perform the aforementioned applications more expeditiously and efficiently, but also to handle the other new tasks, which are coming in the immediate future.

The vast majority of power system optimization problems are essentially optimal power flow problems with various objectives. Examples of the common power system optimization problems include, total loss minimization, total generation cost minimization, and total load curtailment minimization problem. The latter objective function is in fact very important objective function that is used for reliability evaluation of power systems. We have dealt with these three objectives in this thesis in Chapter 3, Chapter 4, and Chapter 5, respectively. However, we would like to elaborate here on the latter objective function, which is concerned with reliability improvement of distribution system. For every task of reliability evaluation, a power flow study is constantly performed. Toward this end, three power flow models have generally been used for reliability evaluation of power systems. These models are the full AC power flow model, the Capacity Flow model, and the DC power flow model. Experience with the FACPF model have shown, however, that when this model is incorporated in the reliability assessment framework, the task of reliability evaluation becomes extremely complex, sometimes inflexible, and oftentimes computationally intractable [**?**]. Also, the required data and storage both become high. On the other hand, the Capacity Flow model only uses the capacity constraints of the tie-lines; and thereby, generally speaking, it is not applicable for every reliability study. In view of these reasons, in many cases, it has been found to be more convenient to use the DCPF model.

The DC power flow model, which was devised more than 35 years ago, has been widely utilized in reliability assessment of power and distribution systems. It is denoted as DC power flow (DCPF), in analogy to a DC circuit fed by a DC voltage source [27, 30, 31, 32]. In fact, this model is a linearized version of the full AC power flow model, however it ignores most of the aspects of the FACPF model. The DCPF model is non-iterative, linear, and absolutely convergent, but with less accuracy than the FACPF model. The DCPF model assumes flat voltage profiles at all buses and lossless transmission lines. It is usually used whenever fast power flow solutions are required as in optimal economic power dispatch, contingency analysis, and reliability and security assessment. The DCPF model is unquestionably a powerful computational tool, however, how its assumptions are interpreted and how they can be understood is still an open question. As a matter of fact, bus voltages are mainly dependent on line parameters as well as the operating conditions, which signifies that flat voltage profiles are not always guaranteed. More significantly, voltage limits and reactive power flows are vital constraints in the realistic power systems and cannot thus be neglected. Moreover, for power system operational and planning stages, for instance, total real power losses cannot be omitted as they are typically considered as a secondary objective in several studies. Even though the DCPF model has such shortcomings, it was approximately involved in several engineering applications because of its simplicity of formulation and implementation.

The use of the DCPF model in certain reliability evaluation studies of distribution systems has been based on the assumption that adequate information about reactive power flow are unavailable in advance. Such an assumption is justified for several planning studies because reactive power is usually supplied in a form of capacitor banks, which can be treated as a separate optimization problem. However, from practical perspective, the violation of voltage bounds and insufficient reactive power support may initiate triggering events, which could in turn lead to a massive under-voltage load shedding. Therefore, it would be beneficial if a certain amount of linearity is introduced into the conventional power flow equations, without loss of generality, so that a fast and flexible solutions are obtained. Having done this, several optimization problems that require repetitive power flow estimations and optimal solutions can be formulated and solved more expeditiously and, at the same time, with a reasonable engineering accuracy.

1.6 Overview of Contributions

The principal contribution of this work lies in developing an efficient optimization framework for distribution system operational and planning studies. This framework has been developed in the second chapter of this thesis. We first develop a fast and effective formulation for the power flow problem. The proposed linearized AC power flow model (LACPF) is developed based on linearization of the full set of conventional power flow equations, and therefore includes voltage magnitude solutions and reactive power flows, unlike traditional linearized power flow models. Hence, the technique proposed in this thesis is non-iterative, direct, and involves no convergence issues. More prominently, the model proposed in this thesis is equally appropriate for use at both distribution and transmission levels and can be extremely useful whenever fast, robust, and repetitive power flow solutions are required. Further, the modifications in case of unbalanced distribution networks are straightforward and largely lie in certain elements in the bus admittance matrix; and thus the advantages obtained with balanced operation are preserved. We test the proposed LACPF model on several balanced, unbalanced, and weakly-meshed distribution systems and found to perform with speed and accuracy appropriate for repetitive solutions. We provide and thoroughly discussed the results of various test systems, including a large-scale distribution system test case in Chapter 2. It is worth pointing out here that several test systems with various characteristics and sizes were utilized to verify the accuracy of the proposed power flow model. However, we report the results of selected systems in Chapter 2, as these systems have been used later to demonstrate the effectiveness of the proposed optimization framework.

We develop an optimization framework based on linear programming method in Chapter 2. Optimization methods, which are developed based on linear programming are compact, flexible, reliable, and faster than their nonlinear counterparts. The proposed optimization framework has the advantage of being suitable for studies that require extensive computational burden such as in reliability and security assessment and distributed generation sizing and placement. A unique feature of our development is that voltage limits and reactive power constraints have both been considered in the proposed model. These utmost constraints are entirely ignored in the traditional linearized models available in the literature. A key element in solving any optimization problem in power system is to consider the thermal capacities of transmission lines. In this context, we develop novel models to handle current limits constraints, which are involved in almost all of the realistic power system optimization problems. Toward this end, we particularly develop a generic piecewise linear model so that the inequality current constraints can be approximated by an infinite number of linear segments. The crucial advantage of this model is that the degree of approximation can be improved to any desired level by increasing the number of line segments involved, without substantial affect on the main routine and the computational speed.

As was mentioned earlier in Section 1.1.3, distribution systems are the most extensive part in the entire power system due to their spanning tree structure and the high R/X branch ratios. Therefore, we propose an analytical method for optimal placement and sizing of distributed generation units on distribution systems in Chapter 3. The objective of the analytical method presented in Chapter 3 is to minimize the distribution system losses. Analytical methods are reliable, computationally efficient, and are suitable for planning studies such as distributed generation planning. Furthermore, analytical approaches could lead to an optimal or near-optimal global solution. We first identify the penetration level of the distributed generation units. Then, we develop a priority list based on loss sensitivity factors to determine the optimal locations of the candidate distributed generation units. We perform sensitivity analysis based on the real power injection of the distributed generation units to estimate the optimal size and power factor of the candidate distributed generation units. We deal with various types of distributed generators and also propose viable solutions to reduce total system losses. We validate the effectiveness of the proposed method by applying it on the same benchmark systems used before in Chapter 2, in particular the 33 bus and the 69 bus distribution systems, since both systems have been extensively used as examples in solving the placement and sizing problem of distributed generators. We also perform exhaustive power flow routines to verify the sizes obtained by the analytical method. We validate the optimal locations and sizes obtained by the proposed analytical method by comparing them with some other analytical methods available in the literature. The test results show that the proposed analytical method could lead to an optimal or near-optimal global solution, while requiring lower computational effort.

We propose a method to solve the optimal economic power dispatch problem of active distribution systems in Chapter 4. Nonlinear programming and linear programming based methods are widely used in the literature to solve the optimal economic dispatch problem. Nevertheless, the vast majority of the linear programming based methods were developed based on the DCPF model, which has several drawbacks that we discussed earlier in Section 1.5. In Chapter 4, in addition to the piecewise linear model we have developed earlier in Chapter 2 to handle the thermal capacities of transmission lines, we develop piecewise linear models to deal with the loads, cost curves of generating units, and total power losses. We take the effect of distributed generation units in several case scenarios by considering different penetration levels. We demonstrate the effectiveness of the proposed method by performing numerous case studies. We were able to show that the results obtained by the proposed method correspond closely with those obtained by nonlinear means and is appropriate for several planning studies.

We propose a method to solve the distribution system reconfiguration problem with an objective of reliability maximization in Chapter 5. Reliability enhancement of distribution systems through feeder reconfiguration is not well studied in the literature. In the first part of Chapter 5 we introduce a complete optimization framework to handle the reliability maximization problem. Then, we proceed by discussing basic reliability concepts and introduced probabilistic reliability models. Since the time and computational effort spent in evaluating reliability indices are of great concern in both planning and operational stages, we use a probabilistic reliability assessment method based on event tree analysis with higher-order contingency approximation. Therefore, the effect of the higher-order contingencies is limited and, at the same time, the computational burden is improved. The objective function of the optimization framework used in this chapter is to minimize the total load curtailment. We choose the expected unserved energy (EUE) as the energy index that needs to be minimized. However, to know how much reliable the system is, we introduce another reliability measure, which is the energy index of unreliability (EIUR). From practical perspective, the radial topological structure has been taken as a necessary condition during the realization of this work. Therefore, we develop another constraints based on theoretical graph to preserve the spanning tree structure of the distribution system.

In the second part of this Chapter 5, we formulate the distribution system reconfiguration problem for reliability maximization. In this context, we propose an intelligent search method based on particle swarm optimization technique (PSO). Particle swarm optimization is a meta-heuristic optimization method inspired by the social behavior of flocks of birds or schools of fish, which is introduced in 1995. The advantages of using particle swarm optimization in handling the distribution system reconfiguration problem are manifold. For instance, the status of sectionalizing and tie-switches in distribution systems can be easily represented as binary numbers of (0,1). Moreover, particle swarm optimization based methods have considerably fast convergence characteristics and, generally speaking, have few parameters to tune up compared to some other meta-heuristic approaches. More prominently, particle swarm optimization has two main parameters, which are the personal best and the group best. Every particle in the swarm remembers its own personal best and at the same time its group best. Consequently, PSO based methods have considerably more memory capability than some other swarm intelligence based methods.

We demonstrate the effectiveness of the proposed method on several distribution systems and show that the amount of the annual unserved energy can be reduced using the proposed method.

1.7 Thesis Outline

This thesis presents a fast, flexible, and reliable optimization framework for distribution system operational and planning studies. The basic optimization framework is presented in Chapter 2. Chapter 3, Chapter 4, and Chapter 5, discuss in detail the applications of the proposed models and methods in modern distribution systems. Each chapter first presents the main concept of the application, and then a description of the method used in this application is exploited in detail.

Following the description of the method, comments and assumptions regarding the implementation of the method are provided.

Chapter 3 presents a method for loss reduction in distribution systems using distributed generation units. The structure of this chapter is as follows: it provides a description about the basic concepts, followed by description of the method used, and comments on the implementation. Concluding remarks are provided at the end of this chapter.

Chapter 4 proposes an effective method to solve the optimal economic power dispatch problem of power distribution systems. The main structure of this chapter is similar to the pattern of Chapter 3, discussing basic concepts, followed by a description of the method used, and comments on the implementation. Conclusion remarks are also provided at the end of this chapter.

Chapter 5 introduces a flexible and robust method for distribution system reconfiguration using particle swarm optimization based method. The main structure of this chapter is similar to the patterns of Chapter 3 and Chapter 4. Then, this chapter presents the reliability evaluation method and the proposed intelligent search method. The method of implementation, discussion, and conclusions are also provided in this chapter.

Chapter 6 highlights the conclusions drawn from the presented work and summarizes the main contributions. Possible areas of future research are outlined in this chapter.

Chapter 2

An Efficient Optimization Framework Development

In the first part of this chapter, we develop a fast, robust, and effective formulation for the power flow problem. We develop the proposed linearized AC power flow model based on linearization of the full set of conventional power flow equations, and therefore includes voltage magnitude solutions and reactive power flows, unlike traditional linearized power flow models. We test the proposed LACPF model on several distribution systems, including systems with various sizes, complexities, characteristics, and systems with weakly-meshed topologies, and found to perform with speed and accuracy appropriate for repetitive solutions.

In the second part of this chapter, we develop an efficient optimization framework to solve several distribution systems operational and planning studies. In particular, we develop formulations for power balance equations, active and reactive power constraints, and voltage limits. We develop a piecewise linear model to handle the current capacity constraints. We introduce the main constraints, which are usually used in solving any typical optimization problem. We also discuss the inclusion of additional constraints, which we are going to use in the subsequent parts of this thesis.

However, before proceeding to describe the proposed power flow model, it is imperative to touch upon the FACPF model and the DCPF model, which have both been used in this chapter to validate the effectiveness of the proposed LACPF model.

2.1 Full AC Power Flow Model

Formulation of the power flow problem requires the consideration of four variables at each bus in the system. That is, at any bus k in the system, these variables are the active power injection P_k, the reactive power injection Q_k, voltage magnitude V_k, and voltage angle δ_k. The real and reactive power flows and power losses can also be determined from the power flow solution.

Let us consider the simple transmission circuit shown in Fig. 2.1. The current injected to bus k can be calculated as,

$$I_k = \sum_{m \in \Psi_k} Y_{km} \cdot E_m \tag{2.1}$$

where Ψ_k is the set of buses adjacent to bus k, I_k is the current injected to bus k, E_m is the vector of bus voltages, and Y_{km} is the bus admittance matrix of the system.

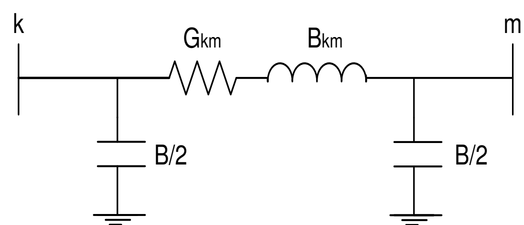

Figure 2.1: Simple transmission circuit

Let us use the rectangular and polar coordinates for admittances and bus voltages,

$$\begin{aligned} Y_{km} &= G_{km} + jB_{km} \\ E_k &= V_k \, e^{j\delta_k} \\ E_m &= V_m \, e^{j\delta_m} \end{aligned} \tag{2.2}$$

Therefore, (2.1) can alternatively be expressed as,

$$I_k = \sum_{m \in \Psi_k} (G_{km} + jB_{km}) \cdot (V_m\, e^{j\delta_m}) \tag{2.3}$$

where V_k and V_m are the voltage magnitudes at bus k and bus m, respectively. G_{km} is the real element (k,m) of the bus admittance matrix, B_{km} is the imaginary element (k,m) of the bus admittance matrix, and δ_{km} is the voltage angle difference between bus k and bus m, respectively. The complex power injected at bus k can be expressed as,

$$S_k = E_k I_k^* = (V_k\, e^{j\delta_k}) \cdot \sum_{m \in \Psi_k} (G_{km} - jB_{km}) \cdot (V_m\, e^{-j\delta_m}) \tag{2.4}$$

Therefore, the real and reactive power injections at bus k can be expressed as [8],

$$P_k = V_k \sum_{m \in \Psi_k} V_m (G_{km} \cos\delta_{km} + B_{km} \sin\delta_{km}) \tag{2.5}$$

$$Q_k = V_k \sum_{m \in \Psi_k} V_m (G_{km} \sin\delta_{km} - B_{km} \cos\delta_{km}) \tag{2.6}$$

Here (2.5) and (2.6) are the generic power flow equations. As can be seen from this formulation, in order to get a solution to the power flow equations, two of the four variables must be known in advance. Due to the nonlinear terms in the power flow equations, the solution follows iterative process in which convergence is not always guaranteed.

2.2 DC Power Flow Model

As was discussed earlier in Chapter 1, Section 1.4, some engineering applications require prompt and fast power flow estimations. The DCPF model is commonly used to preform these applications.

The DCPF model can be formulated based on the following assumptions:

1. Lossless transmission line model.

2. Flat voltage profile at all buses.

3. Voltage angle differences (lateral or sub-lateral) are assumed to be small.

Let us now consider the generic power flow equation given by (2.5) and assume that line resistance is very small compared to line reactance, that is $G_{km} = 0$, magnitudes of bus voltages are all set equal to 1.0 per unit, that is $V_k = V_m = 1.0$ per unit, and $\sin\delta_{km} \approx \delta_{km}$. Since active power injections are known in advance, the DCPF model can therefore be represented as [27, **?**, 30, 31, 32],

$$P_k = -\sum_{m=1}^{N_b} B_{km}(\delta_k - \delta_m) \tag{2.7}$$

In vector notation, the DCPF model can alternatively be represented as [**?**],

$$P_G + \hat{B}\ \delta = P_D \tag{2.8}$$

$$F = (b \times \hat{A})\ \delta \tag{2.9}$$

where N_b is the number of system buses, N_f is the number of distribution feeders, b is a diagonal matrix of distribution lines susceptances $\left(N_f \times N_f\right)$, $\hat{A}$ is the element-node incidence matrix $\left(N_f \times N_b\right)$, P_G is the vector of real power generation $\left(N_f \times 1\right)$, F is the vector of flow capacities of distribution lines $\left(N_f \times 1\right)$.

2.3 Proposed Power Flow Model

This section introduces the proposed linearized AC power flow formulation. This model is collaboratively developed by J. Mitra, S. Elsaiah, and N. Cai. We will use this formulation later on to develop an optimization framework to solve several optimal distribution systems studies.

Recall the real and reactive power injections at bus k expressed earlier by (2.5) and (2.6). That is,

$$P_k = V_k \sum_{m \in \Psi_k} V_m (G_{km} \cos \delta_{km} + B_{km} \sin \delta_{km}) \tag{2.10}$$

$$Q_k = V_k \sum_{m \in \Psi_k} V_m (G_{km} \sin \delta_{km} - B_{km} \cos \delta_{km}) \tag{2.11}$$

where Ψ_k is the set of the buses adjacent to bus k. P_k and Q_k are the real and reactive power injections at bus k. V_k and V_m are the voltage magnitudes at bus k and bus m, respectively. Also, G_{km} is the real element (k,m) of the bus admittance matrix, B_{km} is the imaginary element (k,m) of the bus admittance matrix, and δ_{km} is the voltage angle difference between bus k and bus m, respectively.

In practice, we keep bus voltages around 1.0 p.u., with a pre-specified value (usually $\pm 5\%$). Therefore, the voltage magnitude at bus k and bus m can alternatively be represented as,

$$\begin{aligned} V_k &= 1.0 \pm \Delta V_k \\ V_m &= 1.0 \pm \Delta V_m \end{aligned} \tag{2.12}$$

where ΔV_k and ΔV_m are both expected to be small quantities.

In order to approximate the power injection at bus k, let us ignore the small portion ΔV_k at bus k in (2.12). It is important to note that this is only an *approximation* that enables the linearization; it is *not* an *assumption* that the voltage magnitude equals 1.0 p.u. Therefore, (2.10) and (2.11) can be written as,

$$P_k \approx \sum_{m\in\Psi_k} V_m(G_{km}\cos\delta_{km} + B_{km}\sin\delta_{km}) \tag{2.13}$$

$$Q_k \approx \sum_{m\in\Psi_k} V_m(G_{km}\sin\delta_{km} - B_{km}\cos\delta_{km}) \tag{2.14}$$

Further, let us assume that the phase angle difference between bus (lateral or sub-lateral) k and bus m is small; (2.13) and (2.14) can be now expressed as,

$$P_k \approx \sum_{m\in\Psi_k} V_m(G_{km} + B_{km}\delta_{km}) \tag{2.15}$$

$$Q_k \approx \sum_{m\in\Psi_k} V_m(G_{km}\delta_{km} - B_{km}) \tag{2.16}$$

Eqs. (2.15) and (2.16) can be expressed as,

$$P_k \approx \sum_{m\in\Psi_k} (V_m G_{km} + V_m B_{km}\delta_{km}) \tag{2.17}$$

$$Q_k \approx \sum_{m\in\Psi_k} (V_m G_{km}\delta_{km} - V_m B_{km}) \tag{2.18}$$

As before, let us make a further approximation, $V_m \approx 1.0$ p.u., in the second term of (2.17). This implies that,

$$P_k \approx \sum_{m\in\Psi_k} (V_m G_{km} + B_{km}\delta_{km}) \tag{2.19}$$

Let us expand (2.19) as the following,

$$P_k \approx \sum_{m\in\Psi_k} V_m G_{km} + \sum_{m\in\Psi_k} B_{km}\delta_{km} \tag{2.20}$$

Alternatively, (2.19) can be rewritten as,

$$P_k \approx \sum_{m\in\Psi_k} V_m G_{km} + \sum_{m\in\Psi_k} B_{km}(\delta_k - \delta_m) \tag{2.21}$$

Now, (2.21) can be further broken to two parts as follows,

$$P_k \approx P_{ku} + P_{kv} \tag{2.22}$$

where

$$P_{ku} = \sum_{m\in\Psi_k} V_m G_{km} \tag{2.23}$$

and

$$P_{kv} = \sum_{m\in\Psi_k} B_{km}\delta_k - \sum_{m\in\Psi_k} B_{km}\delta_m \tag{2.24}$$

where

$$B_{km} = \begin{cases} \sum b_{km} + b_{kk} & \text{for} \quad m = k \\ -b_{km} & \text{for} \quad m \neq k \end{cases} \tag{2.25}$$

Here b_{kk} is the total susceptance of the shunt elements connected at bus k. It is evident from (2.25) that summing the B_{km} terms for all $m \in \psi_k$ yields,

$$\sum_{m\in\Psi_k} B_{km} = -b_{k1} - b_{k2} - \ldots + (\sum_{m\neq k} b_{km} + b_{kk}) - \ldots - b_{kN} = b_{kk} \tag{2.26}$$

Hence, (2.24) can be written as,

$$P_{kv} = -\sum_{m\neq k} B_{km}\delta_m - (B_{kk} - b_{kk})\delta_k \tag{2.27}$$

Therefore, (2.22) will have the following form,

$$P_k \approx \sum_{m \in \Psi_k} V_m G_{km} - \sum_{m \neq k} B_{km} \delta_m - (B_{kk} - b_{kk}) \delta_k \tag{2.28}$$

The reactive power equation can be expressed as,

$$Q_k \approx - \sum_{m \in \Psi_k} V_m B_{km} + \sum_{m \in \Psi_k} G_{km} (\delta_k - \delta_m) \tag{2.29}$$

Now, in a similar fashion to what we did with the real power term, (2.29) can be further broken to,

$$Q_k \approx Q_{ku} + Q_{kv} \tag{2.30}$$

where

$$Q_{ku} = - \sum_{m \in \Psi_k} V_m B_{km} \tag{2.31}$$

and

$$Q_{kv} = \sum_{m \in \Psi_k} G_{km} (\delta_k - \delta_m) \tag{2.32}$$

Now, Q_{kv} is obtained as,

$$Q_{kv} = - \sum_{m \neq k} G_{km} \delta_m - (G_{kk} - g_{kk}) \delta_k \tag{2.33}$$

where

$$G_{km} = \begin{cases} \sum g_{km} + g_{kk} & \text{for } m = k \\ \\ -g_{km} & \text{for } m \neq k \end{cases} \tag{2.34}$$

Here g_{kk} is the total conductance of the shunt elements connected at bus k. It is evident from (2.34) that summing the G_{km} terms for all $m \in \Psi_k$ yields,

$$\sum_{m \in \Psi_k} G_{km} = -g_{k1} - g_{k2} - \ldots + (\sum_{m \neq k} g_{km} + g_{kk}) - \ldots - g_{kN} = g_{kk} \tag{2.35}$$

Consequently, (2.30) will have the following form,

$$Q_k \approx -\sum_{m \neq k} G_{km}\delta_m - (G_{kk} - g_{kk})\delta_k - \sum_{m \in \Psi_k} V_m B_{km} \tag{2.36}$$

In matrix notation, the proposed LACPF model in general form can be expressed as,

$$\begin{bmatrix} P_K \\ \\ Q_K \end{bmatrix} = \begin{bmatrix} -B^{'} & G \\ \\ -G^{'} & -B \end{bmatrix} \begin{bmatrix} \delta_K \\ \\ V_K \end{bmatrix} \tag{2.37}$$

where $B^{'}$ is a modified susceptance matrix, $G^{'}$ is a modified conductance matrix, G is the conductance matrix, and G is the susceptance matrix. These matrices, which comprise the proposed power flow solution, are respectively defined as,

$$B^{'} = \begin{bmatrix} (B_{11} - b_{11}) & B_{12} & \cdots & B_{1N} \\ B_{21} & (B_{22} - b_{22}) & \cdots & B_{2N} \\ \vdots & \vdots & \ddots & \vdots \\ B_{N1} & B_{N2} & \cdots & (B_{NN} - b_{NN}) \end{bmatrix} \tag{2.38}$$

$$G' = \begin{bmatrix} (G_{11}-g_{11}) & G_{12} & \cdots & G_{1N} \\ G_{21} & (G_{22}-g_{22}) & \cdots & G_{2N} \\ \vdots & \vdots & \ddots & \vdots \\ G_{N1} & G_{N2} & \cdots & (G_{NN}-g_{NN}) \end{bmatrix} \tag{2.39}$$

$$G = \begin{bmatrix} G_{11} & G_{12} & \cdots & G_{1N} \\ G_{21} & G_{22} & \cdots & G_{2N} \\ \vdots & \vdots & \ddots & \vdots \\ G_{N1} & G_{N2} & ... & G_{NN} \end{bmatrix} \tag{2.40}$$

$$B = \begin{bmatrix} B_{11} & B_{12} & \cdots & B_{1N} \\ B_{21} & B_{22} & \cdots & B_{2N} \\ \vdots & \vdots & \ddots & \vdots \\ B_{N1} & B_{N2} & \cdots & B_{NN} \end{bmatrix} \tag{2.41}$$

2.4 Model Validation and Test Results

We test the proposed linearized power flow model on several known distribution networks; including realistic and large-scale distribution systems. We implement the proposed model on 33 bus, 69 bus, and 118 bus distribution systems. It is appropriate to point out here that these networks have been selected deliberately as they are being broadly used as examples in solving numerous problems in the area of optimal distribution system operation and planning. In addition, we implement the proposed power flow method on a practical 13 bus unbalanced network [24] and a

76 bus unbalanced distribution network [35]. Even though we implement the proposed model on numerous systems, we will focus the 33 bus system, 69 bus system, and 118 bus system since we use them throughout the rest of this thesis.

2.5 Test System I

The test system considered in this case is a 33 bus medium voltage radial distribution network [16]. The single line diagram of 33 bus system is depicted in Fig. 2.2. The 33 bus system consists of 33 buses and 32 branches. The total real and reactive power loads on this system are 3715 kW and 2300 kVAR, respectively. The base values are chosen to be 12.66 kV and 100 kVA. The 33 bus distribution system has R/X branch ratios of 3.

We use the proposed LACPF model to obtain the power flow solution of the 33 bus system and compare the results with those obtained by the FACPF model. The voltage profile obtained by the proposed LACPF model is depicted in Fig. 2.3. We also present detailed results of voltage magnitudes and voltage angles in Table 2.1. For validation purposes, we calculate the voltage vector obtained by the proposed LACPF model and that obtained by the FACPF model and compute the voltage vector error at every bus as,

$$\Delta V = \frac{\mid V_{FACPF} - V_{LACPF} \mid}{\mid V_{FACPF} \mid} \times 100\% \tag{2.42}$$

where V_{FACPF} and V_{LACPF} are the vectors of bus voltages obtained by the FACPF model and the LACPF model, respectively.

As can be seen from Fig. 2.3 and Table 2.1, the power flow results obtained by the proposed model correspond closely with those obtained by the FACPF model. It is indispensable to highlight here that the error in voltage obtained by the proposed LACPF model was less than 1% at all buses. The maximum voltage error obtained by performing the proposed model was $(-0.008 - 0.001i)$ p.u. or 0.843% and had occurred at bus 18, the farthest bus from the substation. On the other hand, the voltage error obtained by the traditional DCPF model at bus 18 is found to be 9.773%. The proposed power flow model outperforms the traditional DCPF model. Accordingly, the method reported here could handle power flows of distribution systems with high R/X branch ratios more expeditiously with a small, but acceptable, sacrifices in the engineering accuracy.

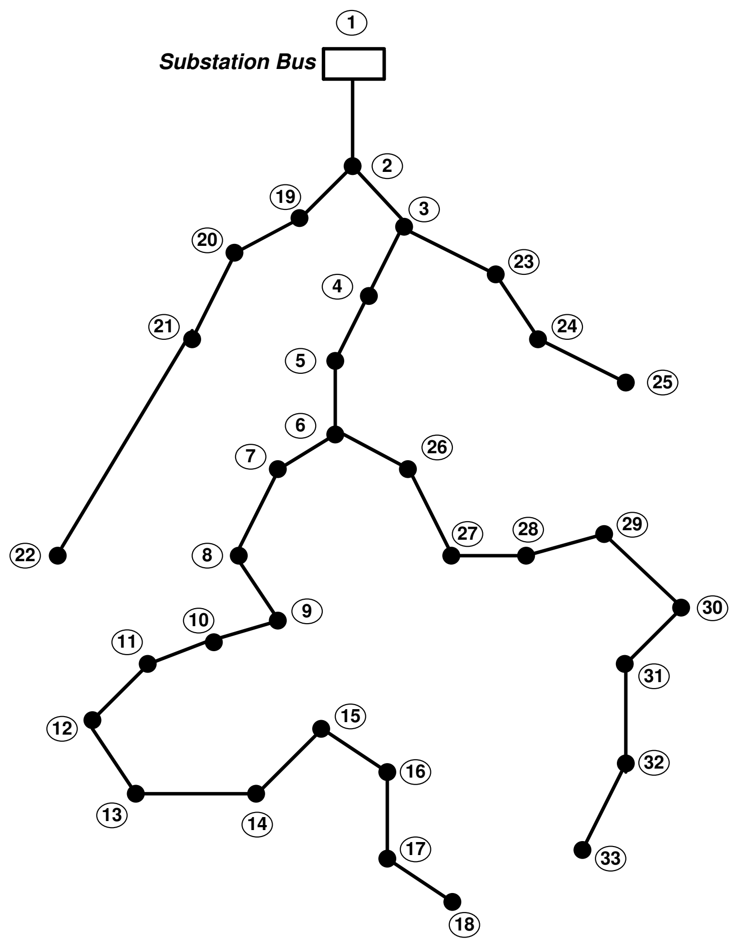

Figure 2.2: Single-line diagram of the 33 bus distribution system

Table 2.1: 33 Bus Distribution System Power Flow Results

	FACPF		LACPF		Error	
Bus	$\|V\|$ (p.u.)	Angle (radian)	$\|V\|$ (p.u.)	Angle (radian)	Vector (p.u.)	Absolute (%)
1	1	0	1	0	0	0
2	0.9970	0.0002	0.9972	0.0002	-0.000 + 0.000i	0.020
3	0.9828	0.0017	0.9839	0.0015	-0.001 + 0.000i	0.102
4	0.9753	0.0028	0.9769	0.0025	-0.002 + 0.000i	0.155
5	0.9679	0.0040	0.9700	0.0035	-0.002 + 0.000i	0.219
6	0.9494	0.0024	0.9530	0.0020	-0.004 + 0.000i	0.369
7	0.9459	-0.0017	0.9498	-0.0014	-0.004 - 0.000i	0.412
8	0.9322	-0.0044	0.9372	-0.0036	-0.005 - 0.000i	0.526
9	0.9259	-0.0057	0.9314	-0.0046	-0.006 - 0.000i	0.605
10	0.920	-0.0068	0.9261	-0.0055	-0.007 - 0.000i	0.653
11	0.9192	-0.0067	0.9253	-0.0054	-0.007 - 0.000i	0.664
12	0.9177	-0.0065	0.9239	-0.0052	-0.007 - 0.000i	0.676
13	0.9115	-0.0081	0.9183	-0.0065	-0.008 - 0.001i	0.747
14	0.9092	-0.0095	0.9162	-0.0075	-0.008 - 0.001i	0.782
15	0.9078	-0.0102	0.9149	-0.0080	-0.008 - 0.001i	0.795
16	0.9064	-0.0106	0.9137	-0.0083	-0.008 - 0.001i	0.807
17	0.9043	-0.0119	0.9118	-0.0093	-0.008 - 0.001i	0.842
18	0.9037	-0.0121	0.9113	-0.0094	-0.008 - 0.001i	**0.843**
19	0.9964	0.0001	0.9966	0.0000	-0.000 + 0.000i	0.010
20	0.9929	-0.0011	0.9931	-0.0011	-0.000 - 0.000i	0.020
21	0.9922	-0.0015	0.9924	-0.0015	-0.000 + 0.000i	0.023
22	0.9915	-0.0018	0.9918	-0.0018	-0.000 - 0.000i	0.020
23	0.9793	0.0011	0.9804	0.0010	-0.001 + 0.000i	0.113
24	0.9726	-0.0004	0.9739	-0.0005	-0.001 + 0.000i	0.134
25	0.9693	-0.0012	0.9707	-0.0012	-0.001 + 0.000i	0.145
26	0.9475	0.0031	0.9512	0.0026	-0.004 + 0.000i	0.391
27	0.9449	0.0040	0.9488	0.0034	-0.004 + 0.000i	0.403
28	0.9335	0.0055	0.9383	0.0045	-0.005 + 0.000i	0.515
29	0.9253	0.0068	0.9307	0.0056	-0.006 + 0.000i	0.585
30	0.9217	0.0087	0.9274	0.0070	-0.006 + 0.001i	0.620
31	0.9175	0.0072	0.9236	0.0059	-0.007 + 0.000i	0.655
32	0.9166	0.0068	0.9228	0.0055	-0.008 + 0.000i	0.666
33	0.9163	0.0067	0.9225	0.0054	-0.008 + 0.000i	0.666

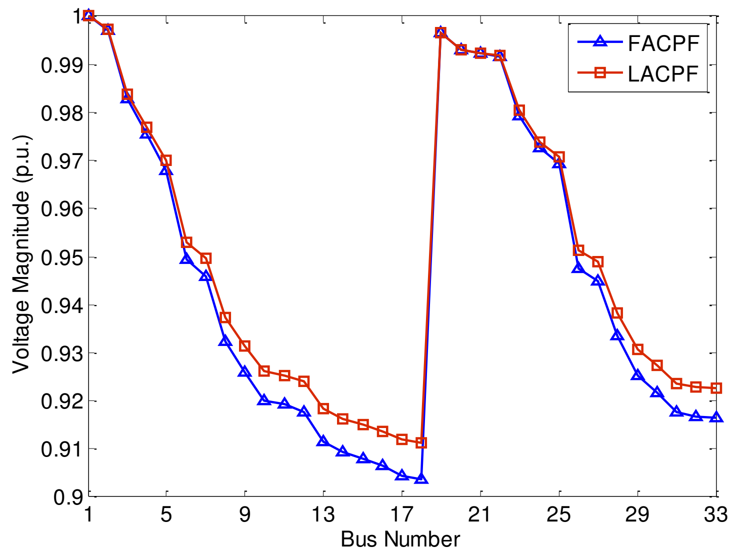

Figure 2.3: Voltage profile of the 33 bus system obtained by the proposed LACPF model and the FACPF model

2.6 Test System II

The test system considered for this case study is a 69 bus, 12.66 KV medium voltage radial distribution system [33]. The single line diagram of the 69 bus distribution system is shown in Fig. 2.4. The 69 bus system is widely used in the literature and has been considered as a relatively large-scale distribution network. The total real and reactive power loads on this system, respectively, are 3802.19 KW and 2694.06 KVAR, but the R/X ratios for some network's branches are greater than 3. We choose the base values as 12.66 kV and 100 kVA.

We use the proposed LACPF model to obtain the power flow solution of the 69 bus system and compare the results with those obtained by the FACPF model. The voltage profile obtained by the proposed LACPF model and the FACPF model is shown in Fig. 2.5. From Fig. 2.5, it is evident that the voltage profile obtained by the proposed LACPF model is almost similar to that obtained by the FACPF model. We calculate the voltage error at each bus using (2.42). It is interesting to highlight here that the error in bus voltage was less than 1% at all buses, and only few buses (exactly 10 buses) had an error between 0.27% and 0.936%. The maximum vector error was $(-0.009+0.004i)$ or 0.936% and had occurred at bus 65, which is quite far from the substation bus. On the other hand, the voltage error obtained by the traditional DCPF model at bus 65 is found to be 10.01%. The proposed power flow model outperforms the traditional DCPF model and can therefore be used for numerous engineering applications in which fast, reliable, and repetitive power flow estimations are required.

2.7 Test System III

We test the proposed power flow model on a more complicated and realistic distribution system in order to validate its feasibility in these conditions. The system used for this case study is an 11 kV, 118 bus large-scale radial distribution system [34]. This system is extensively used in the literature as a large-scale benchmark system. The single-line diagram of the 118 bus distribution system is depicted in Fig. 2.6. The total real and reactive power loads on the 118 bus distribution system are 22709.7kW and 17041.1 kVAR, respectively. Distribution feeders data, loading conditions, and other specifications of the 118 bus system can be found in [34].

The voltage error for this case study was less than 1% at all buses and the maximum voltage error obtained by the proposed LACPF method was 0.89%, which had occurred at bus 77. It is appropriate to mention here that the 118 bus large-scale distribution system has 15 tie-switches, in addition to the sectionalizing switches. The proposed LACPF model has given satisfactory results even when we close all tie switches, unlike the FACPF model, which tends to diverge when a few loops have taken place in the system. This makes the proposed model very suitable for the engineering applications in which rigid and reliable power flow estimations are required.

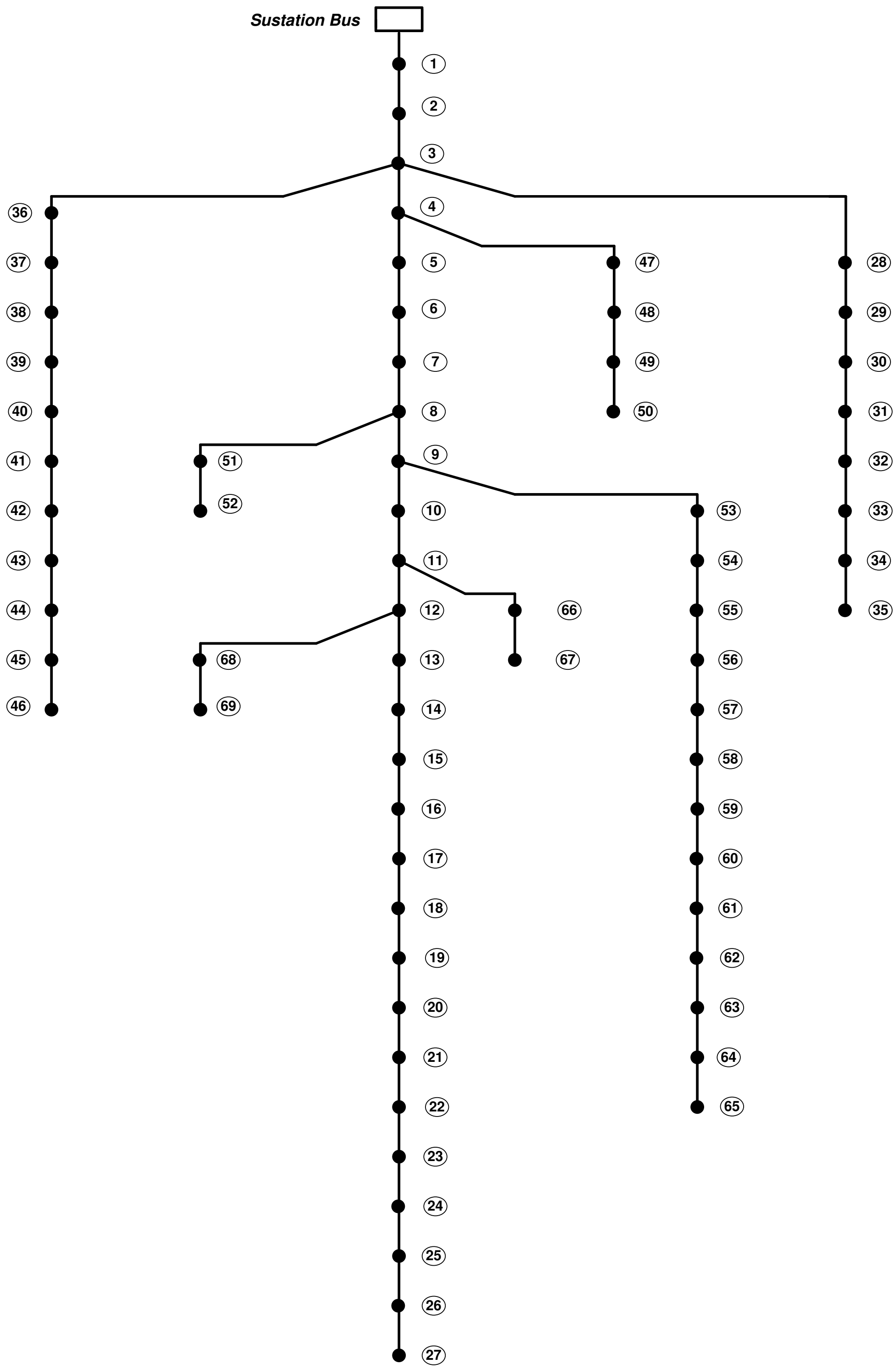

Figure 2.4: Single-line diagram of the 69 bus distribution system

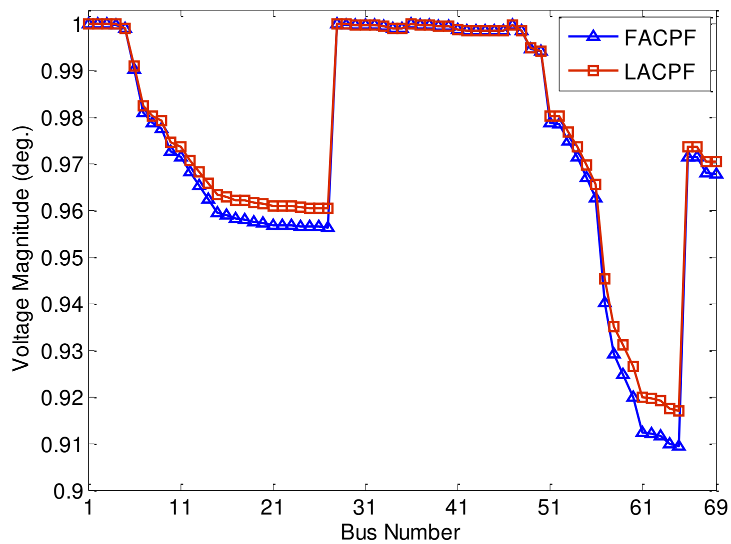

Figure 2.5: Voltage profile of the 69 bus system obtained by the proposed LACPF model and the FACPF model

2.8 Test System IV

We test the proposed LACPF model on a 76 bus distribution system with unbalanced loads [35]. Branch data and loading conditions of the 76 bus distribution system can be found in [16, 35]. This system has R/X branch ratios of 3. The maximum voltage error obtained by the proposed LACPF method, for each phase, were as follows: 0.80% for Phase A, 0.86% for Phase B, and 0.93% for Phase C. This amount of voltage error can be considered good enough for certain operational and planning engineering applications since this system has quite high R/X branch ratios.

2.9 Robustness Test of the Proposed Model

Divergence of the solution of the power flow methods usually occurs when certain ill-conditioned cases are presented in the system. As was mentioned earlier in Chapter 1, Section 1.1.3, distribution systems with high R/X branch ratios are inherently ill-conditioned power networks. Ill-conditioned

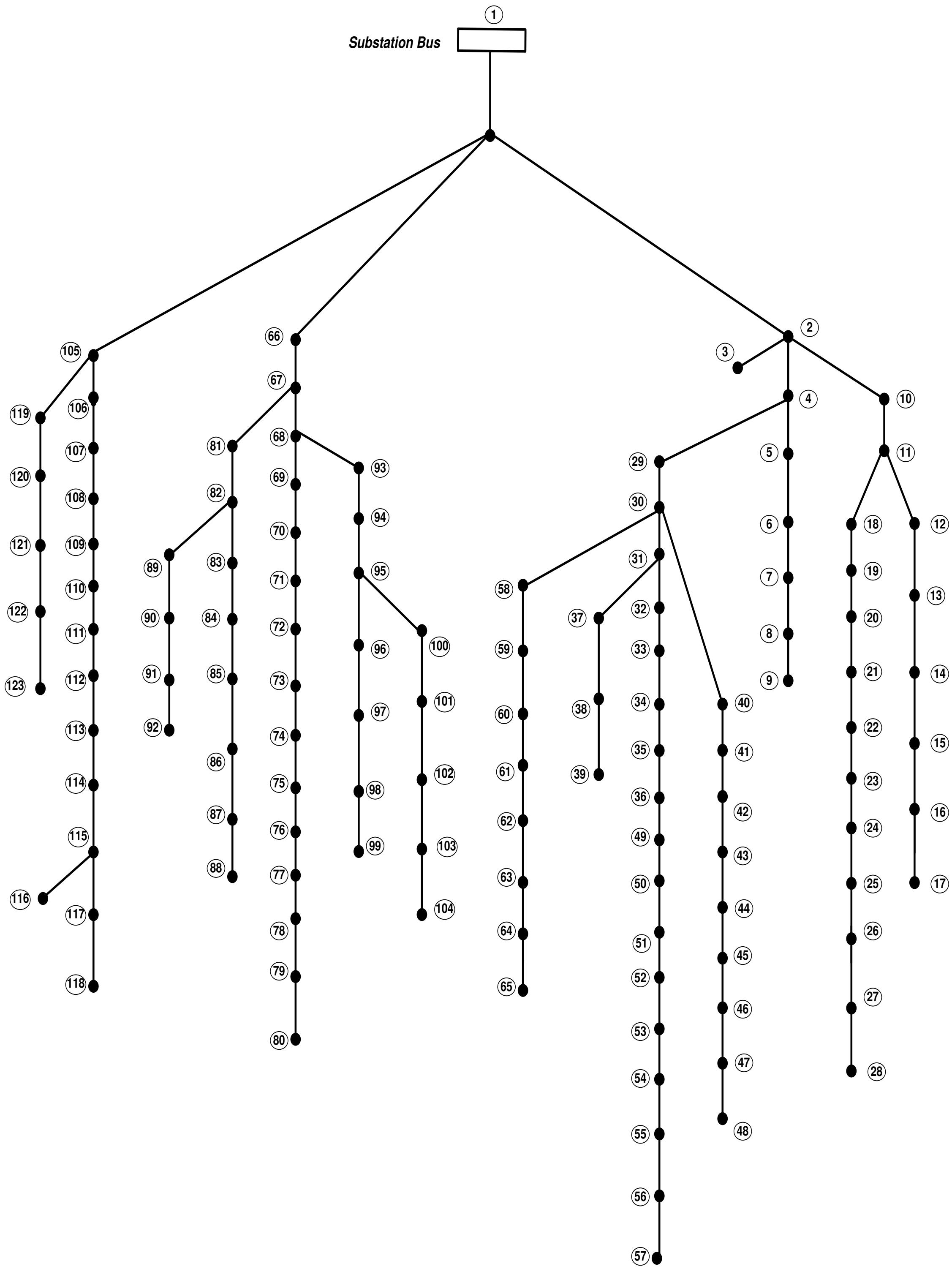

Figure 2.6: Single-line diagram of the 118 bus distribution system

cases often take place when the system involves short-lines, or even long lines, which is usually the case in most realistic and rural distribution systems. In order to show the effectiveness of the proposed LACPF model in handling such conditions, the range of the impedances in the 33 bus distribution system, which is considered as an example in this case, have been widely changed to have an ill-conditioned representation. Amongst the selected impedances, some are divided by a factor of γ, to have a short distribution line representation, while others are multiplied by the same factor to have a long line representation. When we have changed γ from 1 to 10, the test results have revealed, in fact, that the FACPF diverged for values of $\gamma \geq 3$. For these cases, some other methods such as the one reported in [17, 18], which are very computationally demanding, need to be used. On the other hand, the proposed LACPF model can handle the power flows of ill-conditioned distribution systems more expeditiously and, at the same time, with a reasonable engineering accuracy.

It is worth pointing out here that the proposed linearized power flow model is not intended to replace the powerful nonlinear power flow methods such as Newton-Raphson method [8, 7], Gauss-Seidel method [8, 7], Fast-decoupled method [9, 10, 11] and its modified versions [12, 14], or the backward/forward sweeping method [17, 18]. It rather allows us to get fast, flexible, and reliable power flow estimations, which are highly sought in many of today's engineering applications. Further, we test the proposed linearized AC power flow model on several test systems, including transmission systems, balanced and unbalanced distribution systems, weakly-meshed distribution systems, and distribution systems with distributed generation units, and under various loading conditions. In all test cases, the obtained results were promising.

2.10 Linear Programming Based Optimization

The linear programming problem is defined as the problem of maximizing or minimizing a linear function subject to linear constraints. The problem can be of equality or inequality constraints since inequality constraints can be transformed into equality constraints by introducing slack or surplus variables. As was discussed earlier, this work aims at developing an efficient optimization framework based on linear programming method. The procedures of developing the optimization framework are discussed below.

2.10.1 Objective Function Formulation

We define the minimization problem in the presented work as,

$$\text{Minimize:} \quad F(\mathbf{h},\mathbf{z},\mathbf{u}) \tag{2.43}$$

$$\text{Subject to:} \quad v(\mathbf{h},\mathbf{z},\mathbf{u}) = \mathbf{0} \tag{2.44}$$

$$w(\mathbf{h},\mathbf{z},\mathbf{u}) \leq \mathbf{0} \tag{2.45}$$

where h represents the network constraints in terms of power flow, z represents the network parameters, and u represents the control variables.

2.10.2 Power Balance Equations

Power balance equations are equality constraints represent the sum of the power at a certain bus. Basically, balance equations are derived from the linearized power flow model, which is developed earlier in Section 2.3. Mathematically, the power balance equations can be posed as,

$$
\begin{aligned}
B^{'}\delta - GV + P_G &= P_D \\
G^{'}\delta + BV + Q_G &= Q_D
\end{aligned}
\tag{2.46}
$$

Where, δ is the vector of bus voltage angles, V is the vector magnitudes of bus voltages, P_G and Q_G, respectively, are the vectors of the real and reactive power of the generators, and P_D and Q_D are the vectors of the real and reactive power of load buses, respectively.

As can be seen from (2.46), reactive power constraints and bus voltage limits have both been taken into account in the proposed optimization framework. This is a crucial advantage of the proposed optimization framework when compared to some other traditional models available in the literature, in which these vital constraints are entirely ignored.

2.10.3 Real and Reactive Power Constraints

The real power limits of generating units are constantly bounded by the available maximum and minimum power. The work presented here assumes that the output power of the generating units is adjusted in a smooth and instantaneous manner. Further, this work bounds the reactive power of each generating unit with its upper and lower limits. It is appropriate to point out here, however, that the capability curve of each generating unit can be linearized around the operating point and used to determine the reactive power constraints. However, with several and various generating units, this approach seems not only awkward to implement but also impractical. In this work, the real and reactive power constraints of the generating units are expressed as,

$$\begin{aligned} P_G^{min} \leq P_G \leq P_G^{max} \\ Q_G^{min} \leq Q_G \leq Q_G^{max} \end{aligned} \tag{2.47}$$

As can be obviously seen from (2.47), reactive power constraints have been included in the proposed optimization framework.

2.10.4 Voltage Constraints

Voltage constraints are primarily dependent on the reactive power injection to the generator bus. Conventionally, voltage limits are usually kept within a predefined range of $\pm5\%$. For practical reasons, this work bounds the upper and lower voltage limits to $\pm5\%$ so that the upper and lower voltage limits are set equal to 1.05 p.u. and 0.95 p.u., respectively. Therefore, at any bus k, the following inequality voltage constraint holds,

$$| V_k^{min} | \leq | V_k | \leq | V_k^{max} | \tag{2.48}$$

2.10.5 Line Capacity Constraints

Line capacities of distribution feeders are very important constraints that should be considered in solving any optimization problem. In particular, line capacity constraints are used to keep various system components operate within their rating and nominal values. This work proposes a piecewise linear model to calculate these inequality constraints. To formulate the current capacity constraints, let us start by calculating the current flowing out from bus k towards bus m of the transmission circuit shown in Fig. 2.1. That is,

$$\widehat{I}_{km} = \frac{\widehat{V}_k - \widehat{V}_m}{\widehat{Z}_{km}} \tag{2.49}$$

In rectangular coordinates, $\widehat{I}_{km}$ can be expressed as,

$$\widehat{I}_{km} = \frac{(V_k\ cos\ \delta_k - V_m\ cos\ \delta_m)}{\widehat{Z}_{km}} + \frac{i\,(V_k\ sin\ \delta_k - V_m\ sin\ \delta_m)}{\widehat{Z}_{km}} \tag{2.50}$$

Let us make the approximation that voltage angle difference is small and line resistance is less than its reactance. This assumption will not prevent line resistance from being included in line constraints, rather it would help in making linearization. Thus, (2.50) can be written as,

$$|\ I_{km}\ |\ \ \approx \sqrt{\left[(\delta_k - \delta_m)^2 + (V_k - V_m)^2\right]}\,/\,|\ Z_{km}\ | \tag{2.51}$$

$$\approx \sqrt{\left(I^p_{km}\right)^2 + \left(I^q_{km}\right)^2} \tag{2.52}$$

The real component of the line current is expressed as,

$$I^p_{km} = \frac{(\delta_k - \delta_m)}{|\ Z_{km}\ |} \tag{2.53}$$

The imaginary component of the line current is expressed as,

$$I^q_{km} = \frac{(V_k - V_m)}{|\ Z_{km}\ |} \tag{2.54}$$

Here I^p_{km} and I^q_{km} are the real and imaginary components of the line current, respectively. As can be obviously seen from (2.51) and (2.52) the line current can be expressed by two components, however, the magnitude of this current is still nonlinear.

Now, let us consider the circle of radius I_{km}^{max} formed by the locus of the real and imaginary components expressed by (2.53) and (2.54). The two components of the line current can be approximated by infinite number of linear segments. The degree of approximation can absolutely be improved to any desired level by increasing the number of line segments.

Figure 2.7: Piecewise approximation of line capacity constraints

Fig. ?? shows the locus of the real and reactive components of the line current I_{km}^{p} and I_{km}^{q}, respectively. Let us now draw our attention to the straight line segment shown in Fig. 2.8. The straight line equation joins the two points $(0,x)$ and $(y,0)$ can be simply expressed as,

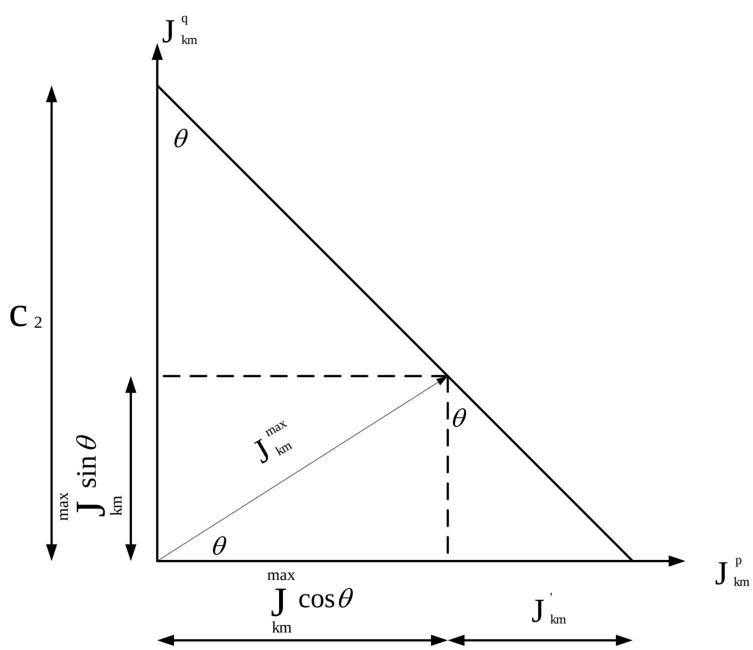

Figure 2.8: Piecewise approximation of line capacity constraints

$$I_{km}^{q} = c_1 \, I_{km}^{p} + c_2 \tag{2.55}$$

From Fig. 2.8, it is obvious that the diameter I_{km}^{max} is perpendicular to the straight line connects

$(0, y)$ and $(x, 0)$. Therefore, (2.55) can be expressed as,

$$I^{q}_{km} = \frac{-1}{tan\ \theta_l} + c_2 \tag{2.56}$$

Also,

$$c_2 = \frac{1}{tan\ \theta_l} \times (I^{max}_{km}\ cos\ \theta_l + I'_{km}) \tag{2.57}$$

where

$$I'_{km} = I^{max}_{km} \cdot\ sin\ \theta_l \cdot\ tan\ \theta_l \tag{2.58}$$

Therefore, the intended straight line equation can be formulated as,

$$I^{q}_{km} = \frac{-1}{tan\ \theta_l} \times \left[I^{p}_{km} + I^{max}_{km}\left(\ cos\ \theta_l +\ sin\ \theta_l \cdot\ tan\ \theta_l\right)\right] \tag{2.59}$$

Let us multiply both sides of (2.55) by $\tan\theta_l$ and rearrange. The current carrying capacity of any feeder in the distribution system can be formulated as,

$$I^{max}_{km} = I^{p}_{kml}\ cos\ \theta_l + I^{q}_{kml}\ sin\ \theta_l \tag{2.60}$$

where l=1, 2, ..., m

The current limit constraints in the proposed optimization framework can be expressed as,

$$\begin{aligned} bA'\ \delta + bA''\ V \leq &\ \ I^{max}_{f} \\ -bA'\ \delta - bA''\ V \leq &\ \ I^{max}_{r} \end{aligned} \tag{2.61}$$

where b is a diagonal matrix of the distribution feeders admittances $\left(N_f \times N_f\right)$, V is the vector of bus voltage magnitudes $(N_b \times 1)$, δ is the vector of node voltage angles $(N_b \times 1)$, A is the element-node incidence matrix $\left(N_f \times N_b\right)$ and,

$$\begin{aligned} A' = &\quad A\ cos\ \theta_l \\ A'' = &\quad A\ sin\ \theta_l \end{aligned} \tag{2.62}$$

It is important to point out here that power flows are conventionally used to specify the current capacity constraints. Nevertheless, in distribution systems the current limits are constantly represented in terms of Amperes. This clearly justifies our use of current instead of power. Technically, the line current limits are often denoted as current carrying capacities of distribution feeders.

2.10.6 The Proposed Optimization Framework

The entire optimization framework is presented in this section. Suppose F is the function to be minimized. Mathematically, the minimization problem can be posed as,

$$\mathrm{C} = \min\left(\sum_{i=1}^{N_b} F_i\right) \tag{2.63}$$

Subject to

1. Real and Reactive Power Injections

$$\begin{aligned} B^{'}\delta - GV + P_G = P_D \\ G^{'}\delta + BV + Q_G = Q_D \end{aligned} \tag{2.64}$$

2. Real and Reactive Power Constraints

$$\begin{aligned} P_G^{min} \leq P_G \leq P_G^{max} \\ Q_G^{min} \leq Q_G \leq Q_G^{max} \end{aligned} \tag{2.65}$$

3. Feeder Capacity Constraints

$$\begin{aligned} bA' \; \delta + bA'' \; V \leq I_f^{max} \\ -bA' \; \delta - bA'' \; V \leq I_r^{max} \end{aligned} \tag{2.66}$$

4. Voltage Bound Constraints

$$\mid V_k^{min} \mid \leq \mid V_k \mid \leq \mid V_k^{max} \mid \tag{2.67}$$

5. Angle Constraints

$$\delta \text{ is unrestricted} \tag{2.68}$$

where N_b is number of buses, and N_f is number of distribution feeders $B^{'}$, B, $G^{'}$ and G are as given in Chapter 2, Section 2.3 with dimensions of $(N_b \times N_b)$, δ is the vector of node voltage angles $(N_b \times 1)$, V is the vector of bus voltage magnitudes $(N_b \times 1)$, P_G and Q_G are the vectors of real and reactive power generation $(N_b \times 1)$, P_C and Q_C are the vectors of real and reactive load curtailments $(N_b \times 1)$, P_D and Q_D are the vectors of bus real and reactive loads $(N_b \times 1)$, P_G^{max} and Q_G^{max} are the vectors of maximum available real power generation $(N_b \times 1)$, P_G^{min} and Q_G^{min} are the vectors of minimum available real power generation $(N_b \times 1)$, I_f^{max} and I_r^{max} are the vectors of forward and reverse flow capacities of distribution lines $\left(N_f \times 1\right)$, V^{max} and V^{min} are the vectors of maximum and minimum allowable voltages $(N_b \times 1)$, b is a diagonal matrix of the distribution feeder admittances $\left(N_f \times N_f\right)$, and A is the node-branch incidence matrix $\left(N_f \times N_b\right)$.

2.10.7 Additional Network Performance Constraints

We will utilize the proposed optimization framework to handle different applications in modern distribution systems. Thus, we will consider different and numerous practical constraints for each problem. For instance, if the problem aims at finding the optimal locations and sizes of distributed generation units, as will be seen later in Chapter 4, other constraints, which considers the step sizes of the distributed generation units will be added to the solution framework. However, if the problem aims at maximizing the reliability of the distribution system through the minimization of total load curtailment of the consumers, which is the aim of Chapter 5, additional network constraints such as the load curtailments will be considered in the power balance injections and the constraints. Moreover, other constraints, which are developed based on theoretical graph will be included in the optimization framework. To summarize, we will introduce appropriate additional network constraints according to the application we are dealing with and the problem on hand.

2.11 Summary

In the first part of this chapter we have developed a fast and effective model for the power flow problem. We have developed this model based on linearization of the full set of conventional power flow equations, and therefore it includes voltage magnitude solutions and reactive power flows, unlike traditional linearized power flow models. The technique proposed in this chapter is non-iterative, direct, and involves no convergence issues. Further, the proposed power flow model is equally appropriate for use at both distribution and transmission levels and can be extremely useful whenever fast, robust, and repetitive power flow solutions are required. We have tested the proposed LACPF model on numerous balanced, unbalanced, and weakly-meshed distribution systems and found to perform with speed and accuracy appropriate for repetitive solutions. We have reported several test cases and discussed the results in the first part of this chapter.

In the second part of this chapter we have introduced an optimization framework based on the proposed power flow model and linear programming. Linear programming based methods are more compact, flexible, reliable, and faster than their nonlinear counterparts. The proposed optimization framework developed in this chapter is very robust and can therefore be used whenever repetitive and prompt solutions are required. The optimization framework developed in this chapter has the following main features:

1. We have developed this framework based on a novel linearized AC power flow model, in which the coupling between active power and voltage magnitude as well as the coupling between reactive power and voltage angle is maintained.

2. The proposed linearized model can handle power flows of a wide range of distribution systems including, balanced, weakly-meshed, and unbalanced distribution systems. The modifications in case of unbalanced distribution networks are straightforward and largely lie in certain elements in the bus admittance matrix; thus the advantages obtained with balanced operation are preserved.

3. We have taken into consideration both voltage limits and reactive power constraints, which have been totally neglected in the traditional linearized methods available in the literature such as the DCPF model, for instance.

4. We have introduced a piecewise linear model to handle the current carrying capacities of distribution feeders. The proposed linear model allows us to approximate the current capacity constraints and include them in the optimization framework. A key feature of the proposed piecewise model is that we could improve the degree of approximation to the desired desired

level by increasing the number of line segments used, without substantial affect on the main routine and computational speed.

Chapter 3

Distributed Generation Sizing and Placement

This chapter introduces an analytical method for placement and sizing of distributed generation units on distribution systems. The objective of the analytical method presented in this chapter is to minimize the distribution system losses. Analytical methods are reliable, computationally efficient, and are suitable for off-line distribution system planning studies. More prominently, analytical methods could lead to an optimal or near-optimal global solution. In this chapter, we start by determining the penetration level of the distributed generation units. Then, we develop a priority list based on loss sensitivity factors to determine the optimal locations of the candidate distributed generation units. We perform sensitivity analysis based on the real power injection of the distributed generation units to estimate the optimal size and power factor of the candidate distributed generation units. In this chapter, we have dealt with various types of distributed generators and have also proposed viable solutions to reduce total system losses. We validate the effectiveness of the proposed method by applying it on 33 bus and 69 bus distribution systems, which are extensively used as examples in solving the problem of placement and sizing of distributed generators. We perform exhaustive power flow routines to verify the sizes obtained by the analytical method. We validate the optimal sizes and locations obtained by the analytical method by comparing them with some other analytical methods available in the literature. We also report on the effect of distributed generation units on the overall voltage profile of the distribution system. The test results show that total losses can be reduced and voltage profile can be tremendously improved by the proper placement and sizing of distributed generation units. More significantly, the test results reveal that the proposed analytical method could lead to an optimal or near-optimal global solution, and is very appropriate to use for several distribution systems planning studies.

3.1 Distributed Generation Placement and Sizing Problem

Distribution systems have been operated in a vertical and centralized manner for many years, for best control and coordination of their protective devices. In addition, distribution systems are characterized by high R/X branch ratios with radial or weakly-meshed topological structure [1, 4, 35, 36]. In fact, the radial topological structure makes distribution systems the most extensive part in the entire power system. The poor voltage regulation and the high line resistance both play a significant role in increasing total power losses of distribution systems. In this context, minimization of power losses of distribution systems is constantly achieved by feeder reconfiguration based techniques [37, 38, 39, 40, 41, 42]. However, distributed generators (DG) [43] have been recently proposed in the literature to minimize distribution system power losses. The potential benefits of distributed generators installation on distribution networks include total system losses reduction, voltage profile improvement, peak load shaving, and reliability enhancement [43, 44, 45]. Given these tremendous advantages, distributed generators can play vital role in reducing losses and improving voltage profile; and thereby increasing the reliability and security of distribution systems, if they are properly located, sized, and their penetration level is also identified.

3.2 Overview of Existing Work

The problem of placement and sizing of distribution generation is essentially a nonlinear complex mathematical optimization problem. Multiple solutions, with various scenarios, are constantly sought while handling the problem of placement and sizing of distributed generators. A great variety of solution techniques are proposed in the literature to handle the problem of placement and sizing of distributed generators on distribution systems. These solution techniques can be broadly classified as population based optimization methods or heuristics and analytical based techniques. Population based optimization methods may include genetic algorithms [46, 47], artificial bee colony algorithm [48], tabu search [49], particle swarm optimization [50], and evolutionary programming [51]. Population based optimization methods are widely adapted in both operational and planning studies and have given satisfactory results over the years.

Over the past years, there has been great interest in using analytical approaches to handle the placement and sizing problem of distributed generators [52, 53, 54, 55]. A common objective function used in these approaches is distribution system losses reduction and voltage profile improvement. The vast majority of the analytical methods available in the literature were developed based on the exact loss formula developed by Elgerd [6]. The exact loss formula is an equation relating voltage magnitude and voltage angle at a bus with the active power and reactive power injections to that bus in a highly nonlinear fashion. One of the major drawbacks of using the exact loss formula is the process of updating the power loss constants, which are very nonlinear complex functions. As a matter of fact, analytical approaches are less complicated than some of the heuristic techniques mentioned above. However, exhaustive power flows are still being performed in the solution procedures. The number of power flows performed in distributed generators placement and sizing based on analytical approaches, for instance, could possibly attain $(n_s - 1)$ for a radial system with n_s buses. Using nonlinear based methods, on one hand, gives high calculation precision but requires a quite extensive computational burden and storage. On the other hand, with the distinctive properties of distribution systems such as high R/X branch ratios, there is a good chance that the power flow solution might fail to converge. Nevertheless, the method proposed in this chapter does not encounter convergence problems and allows us to get fast and reliable power flow estimations, which are highly sought in numerous applications that require repetitive and reliable solutions such as optimal distributed generation units placement and sizing problem.

3.3 Detailed Solution Procedures

This section first presents the objective function and constraints. It develops a priority list based on loss sensitivity factors to determine the candidate buses for DG placement. Further, DG injection based sensitivity analysis is performed to determine the optimal sizes of the DG units. A method to select the corresponding optimal power factor is also provided in this section.

3.3.1 Objective Function and Constraints

The objective function of the problem aims at minimizing the real power loss and improving the voltage profile at all system buses. Mathematically, the problem can be posed as,

$$\text{Total Loss} = \min\left(\sum_{i=1}^{N_b} |I_k^2| \times R_k\right) \tag{3.1}$$

Subject to

1. Real and Reactive Power Injections

$$B^{'}\delta - GV + P_G = P_D$$
$$G^{'}\delta + BV + Q_G = Q_D \tag{3.2}$$

2. Feeder Capacity Constraints

$$bA'\ \delta + bA''\ V \leq I_f^{max}$$
$$-bA'\ \delta - bA''\ V \leq I_r^{max} \tag{3.3}$$

3. Voltage Bound Constraints

$$\mid V_k^{min} \mid \leq \mid V_k \mid \leq \mid V_k^{max} \mid \tag{3.4}$$

4. Distributed Generators Sizes

$$S_{DG}^{min} \leq S_{DG} \leq S_{DG}^{max} \tag{3.5}$$

where N_b is number of buses, I_k is the current flowing out of branch k, R_k is the resistance of branch k. S_{DG}^{min} and S_{DG}^{max} represent the available real and reactive power capacities of the distributed generation units. Other abbreviations are as defined earlier in Chapter 2, Section 2.10.

3.3.2 Identification of Penetration Level

In this work, we define the penetration level of the distributed generation as,

$$\text{Penetration Level} = \frac{S_{DG}}{S_{TD}} \times 100\% \tag{3.6}$$

where S_{DG} and S_{TD} are the output power of the distributed generation unit and the total system demand, respectively.

3.3.3 Selection of Optimal Location: A priority list

In this work, the active power loss sensitivity factor λ_p has been identified and used to determine the optimal locations for the distributed generation units for total power loss reduction. To estimate this sensitivity factor, let us consider the simple radial distribution feeder shown in Fig. 3.1. From Fig. 3.1, the line power losses can be calculated as,

$$P_{loss} = \frac{(P^2_{Lk,eff} + Q^2_{Lk,eff})}{\mid V_k^2 \mid} \times R_k \tag{3.7}$$

where $P_{Lk,eff}$ and $Q_{Lk,eff}$ are the effective real and reactive power loads beyond bus k.

We define the active power loss sensitivity factor λ_p as [56],

$$\lambda_p = \frac{\partial P_{loss}}{\partial P_{Lk,eff}} = \frac{2 \times P_{Lk,eff} \times R_k}{\mid V_k^2 \mid} \tag{3.8}$$

The active power loss sensitivity factor is calculated using (3.8) for all buses, and then the calculated values are arranged in a priority list with a descending order so that buses with high λ_p are considered first for allocating the available distributed generation units.

3.3.4 Selection of Optimal Size

To determine the optimal size of the candidate distributed generation unit, let us start by considering the distribution feeder depicted in Fig. 3.1. As shown in Fig. 3.1, a distributed generation unit of size P_{DG} and Q_{DG} is arbitrarily placed at bus k of the system. Before the installation of this distributed generation unit, the power losses in the line section $k, k-1$ is estimated as in (3.7). That is,

$$P_L^- = \frac{(P_{Lk,eff}^2 + Q_{Lk,eff}^2)}{|V_k^2|} \times R_k \tag{3.9}$$

However, after the DG is installed at bus k, power losses in the line section $k, k-1$ can be estimated as,

$$P_L^+ = \left[\frac{(P_{DG} - P_{Lk,eff})^2}{|V_k^2|} + \frac{(Q_{DG} - Q_{Lk,eff})^2}{|V_k^2|}\right] \times R_k \tag{3.10}$$

Alternatively, (3.10) can be represented as,

$$P_L^+ = \left[\frac{P_{DG}^2 - 2 \cdot P_{DG} \cdot P_{Lk,eff} + P_{Lk,eff}^2}{|V_k^2|} + \frac{Q_{DG}^2 - 2 \cdot Q_{DG} \cdot Q_{Lk,eff} + Q_{Lk,eff}^2}{|V_k^2|}\right] \times R_k \tag{3.11}$$

Consequently, the difference in power losses before and after the installation of the DG unit at bus k can be estimated as,

$$\Delta P_L = P_L^+ - P_L^- \tag{3.12}$$

Alternatively, (3.12) can be written as,

$$\Delta P_L = \left[\frac{P_{DG}^2 + Q_{DG}^2 - 2 \cdot P_{DG} \cdot P_{Lk,eff} - 2 \cdot Q_{DG} \cdot Q_{Lk,eff}}{|V_k^2|}\right] \times R_k \tag{3.13}$$

Therefore, for the total real power losses to be minimum in the feeder section $(k-1, k)$, the first derivative of (3.12) with respect to the active power injected by the distributed generation unit at this particular bus should be driven to zero. That is,

$$\frac{\partial \Delta P_L}{\partial P_{DG}} = 0 \tag{3.14}$$

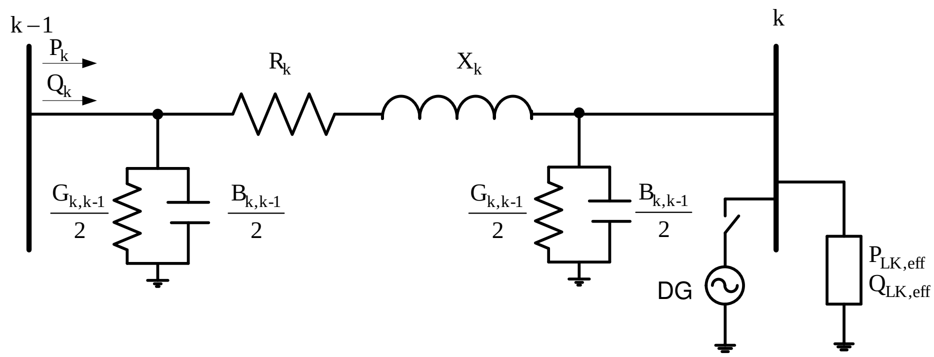

Figure 3.1: A simple radial distribution feeder

Hence, after performing the partial derivatives of (3.13) and rearranging, the optimal size of the DG unit can be written as,

$$S_{DG} = \sqrt{P_{DG}^2 + Q_{DG}^2} \tag{3.15}$$

The optimal DG size in Watt is given below as,

$$P_{DG} = \frac{P_{Lk,eff} + \alpha \cdot Q_{Lk,eff}}{1+\alpha^2} \tag{3.16}$$

The optimal DG size in Var is given as,

$$Q_{DG} = \frac{P_{Lk,eff} + \alpha \cdot Q_{Lk,eff}}{\alpha+\beta} \tag{3.17}$$

where α and β are respectively defined as,

$$\alpha = \tan\theta = \frac{Q_{DG}}{P_{DG}} \tag{3.18}$$

$$\beta = \cot\theta = \frac{P_{DG}}{Q_{DG}} \tag{3.19}$$

where θ is the power factor angle of the candidate DG unit.

From (3.15)–(3.17) the optimal DG sizes are obtained. Conventionally, the DG size is represented in VA and this has been given by (3.15). As a rule of thumb, it was determined that the total losses of the system are minimum when the size of the distributed generation unit matches the effective load connected to that bus. In fact, this concurs with our derivations in (3.16) and (3.17). For instance, if the selected distributed generation unit was a photovoltaic that supplies real power only i.e. the power factor of the distributed generation unit is unity, according to (3.16) the optimal size of the distributed generation unit in Watt (P_{DG}) will be equal to that of the total effective load connected to that bus. The optimal size of the distributed generation unit in Var (Q_{DG}) will be equal to zero in this case. On the other hand, if the selected distributed generation unit was a synchronous condenser that regulates the bus voltage by injecting reactive power only, according to (3.17), the optimal size of this distributed generation unit in Var (Q_{DG}) will be equal to that of the total effective load connected to that bus. However, the optimal size of this distributed generation unit in Watt (P_{DG}) will be equal to zero in this case. The same principle applies for various distributed generation units as can be seen from (3.15)–(3.17).

3.3.5 Selection of Optimal Power Factor

As can be clearly seen for the formulation given by (3.15)–(3.17), the power factor of the distributed generation unit plays a significant role in determining its optimal size. However, estimating the optimal power factor that contributes to minimizing the total system losses is not an easy task. For instance, distributed generation units should operate at practical power factors to maintain the upper and lower voltage constraints; and thereby contribute in a reduction of the total real power losses. However, the majority of the DG units used at distribution system level are not dispatched and not well-controlled since their dispatch could possibly lead to certain operational problems in the protection system of the distribution network. More importantly, according to the IEEE regulations and standards, in particular standard 1547–2003 [5] for interconnecting distributed resources with electric power systems, distributed generators are not recommended to regulate bus voltages at the installation node. The strategy that is widely used to keep bus voltages within the permissible range is through capacitor banks. Nonetheless, even when capacitor banks are presented, violations of voltage limits happen commonly in distribution systems.

The vast majority of the methods used to estimate the optimal power factor of distributed generators are developed based on expert systems. For instance, the optimal power factor of the distributed generators has been assumed to be equal to that of the load connected to the same bus with reverse operating strategy in [48]. Further, the optimal power factor of the distributed generators was assumed to be equal to that of the total downstream load at which the distributed generation unit is connected in [54]. It has been demonstrated in [54] that the losses of the distribution system are minimum when the power factor of the distributed generator is selected to be equal to that of the total load downstream. In fact, this assumption seems to be more realistic, and hence, it is adapted in this work. Depending on their capabilities of injecting active and reactive power, distributed generators can be classified as [54],

1. DG Type I: This DG is capable of injecting active and reactive power such as synchronous generators.

2. DG Type II: This DG is capable of injecting active power but absorbs reactive power from the system such as induction generators.

3. DG Type III: This DG is capable of injecting active power only such as photovoltaic.

4. DG Type IV: This DG is capable of injecting reactive power only such as synchronous condensers.

The sign of the power factor has also been acquired from [54]. That is, α will be considered positive if the DG injects reactive power, as in Type I and Type II, for instance. Thus, if a DG unit is going to be installed at bus k of the distribution feeder shown in Fig.1, the power factor of this unit is calculated as,

$$PF_{DG} = \frac{P_{Lk,eff}}{\sqrt{P_{Lk,eff}^2 + Q_{Lk,eff}^2}} \tag{3.20}$$

3.4 Demonstration and Discussion

In order to demonstrate the effectiveness of the proposed analytical method, we test it on different distribution systems. We provide the results of the 33 bus distribution system and the 69 bus distribution system in this section.

3.5 33 Bus System Optimal Locations and Sizes

The optimal results of placement and sizing of the DG units on the 33 bus distribution system using the proposed analytical solution are presented in this section. These results are also verified by performing exhaustive power flow routines.

3.5.1 Analytical Method

We utilize the LACPF model, which is developed earlier in Chapter 2 to determine the optimal location, size, and power factor of the candidate DG units for the 33 bus distribution system. We perform sensitivity analysis based on real power losses; and thereby we find the loss sensitivity factors λ_p, at each bus using (3.8), to determine the optimal locations of the candidate DG units. The results of the loss sensitivity factors are depicted in Fig. 3.2. As can be seen from Fig. 3.2, the optimal location for the first DG unit is found to be at bus 6. The power factor of the downstream load at bus 6 is also obtained from the power flow solution and was found to be equal to 0.8907 lagging. Even though this work is concerned with active power losses minimization, the four DG types mentioned earlier in Section 4.3.5 have been sized according to (3.15)–(3.17) and installed at bus 6, one at a time, to select the DG type which has much impact on total loss reduction. As expected, DG Type I and DG Type II contributed significantly to losses reduction not only because both of them inject active power to the system, but also the DG locations were selected in accordance to active power losses reduction. The number of DG units used for loss reduction will be limited to two distributed generation units of Type I and Type II and the results of these types will be presented and discussed in the subsequent section.

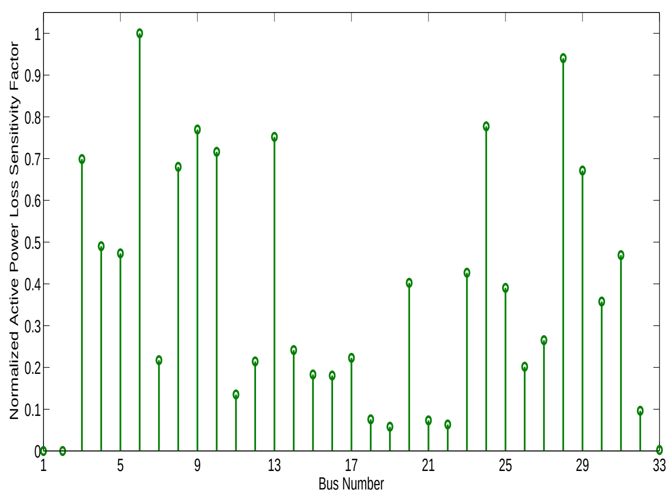

Figure 3.2: Active power loss sensitivity factors of the 33 bus system

The results obtained by the proposed method are presented in Table 3.1 and Table 3.2, respectively. We perform exhaustive power flows to verify the sizes obtained by the analytical method. All simulations are carried out using Matlab 7.9 on an Intelcore, 4GB, 800 MHz computer.

Table 3.2 shows the results obtained by both methods for the case of DG Type I. This DG type injects both real and reactive power to the bus at which it is connected. When a single DG is selected to be installed at bus 6, the optimal size obtained by the proposed analytical approach is 2486 kVA. The reduction in power losses due to this injection was 62.08%. As indicated previously, we are interested in locating and sizing of two DG units in the presented work, thus another DG of the same type is connected at bus 28, which is identified from sensitivity analysis as an optimal location for the second DG unit as can be seen from Fig. 3.2. The DG size for this case is given below in Table 3.1. The total reduction in total power losses achieved by installing the second DG is 69.32%. It is worth mentioning here that once we determine the size of the DG unit from the analytical solution, we change the obtained DG size in a stepwise fashion and then select the size that yields to total minimum power losses. It is also important to point out here that while refining the size of the DG size we almost got the nearest integer size obtained by the analytical method as we have chosen small step size to change the size of the DG units. During the entire search process, if any of the constraints listed in Section 4.3.1 is violated, we consider the next available DG location for further evaluation.

Table 3.2 shows the results obtained by the analytical method and the exhaustive power flow routines for the case of Type II DG, which injects real power only. As expected, the reduction in power losses when this DG type is used is less than that obtained by deploying Type I DG. Using the proposed analytical method, the total loss reduction when a single DG is utilized is 43.79%, while that obtained by using two DG units is 45.46%.

The general solution procedures of the analytical method are summarized as [57],

1. Enter the number and the type of candidate DG units.

2. Obtain the initial system loss using the LACPF.

3. Use the loss sensitivity factors and setup a priority list to determine the optimal locations of the candidate DG units.

4. Use (3.15)–(3.19) and the LACPF to determine the optimal DG size and the corresponding power factor.

5. Change the optimal DG size obtained in step (4) in small stepwise fashion to estimate the suitable size. Choose the size that gives minimum losses.

6. Check constraints. If any of the constraints given in Section 4.3.1 is violated, consider the next available DG location.

3.5.2 Exhaustive Power Flow

To verify the sizes of the DG units obtained by the proposed analytical method, we compare them with those obtained by performing exhaustive power flow solutions. In this case, we first identify the penetration level of the DG units using (3.6). We assume a penetration level of 15%–60%. Accordingly, the allowable minimum and maximum DG output power for the 33 bus system varies between 556 kVA and 2620 kVA. Since DG sizes are given in discrete values, we change the DG sizes in small steps and install the candidate DG units at bus 6, which is identified from sensitivity analysis as an optimal location for DG installation. We perform power flow solution several times and determine the DG size that gives minimum losses. This size is found to be 2485 kVA, which gives a reduction in total losses of 62.03%. The same procedures are repeated for the second DG (Type II), which is connected at bus 28 according to the sensitivity analysis. The DG size obtained for this case is also given below in Table 3.1. Further, the total loss reduction achieved in this case is 69.17%.

As can also be seen from Table 3.1 and Table 3.2, the results obtained by the proposed analytical method correspond closely with those obtained by performing exhaustive power flow solutions. It is worth noting here that while the results obtained from both methods were almost similar, the proposed analytical method is shown to be considerably faster than the exhaustive power flow as it requires few power flow solutions to determine the optimal size.

Table 3.1: Results of The 33 Bus Distribution System–DG Type I

Method	Analytical Method		Exhaustive Power Flow	
Item	Single DG	Two DG	Single DG	Two DG
Optimal Location	6	28	6	28
S_{DG} (KVA)	2487	1204	2485	1200
Power Loss (KW)	69.01	55.85	69.00	55.73
% Loss Reduction	62.08	69.32	62.03	69.17

Table 3.2: Results of The 33 Bus Distribution System–DG Type II

Method	Analytical Method		Exhaustive Power Flow	
Item	Single DG	Two DG	Single DG	Two DG
Optimal Location	6	28	6	28
P_{DG} (kW)	2215	785	2214	785
Power Loss (kW)	102	99	102	97
% Loss Reduction	43.79	45.46	43.8	45.4

3.6 69 Bus System Optimal Locations and Sizes

The optimal results of placement and sizing of the DG units on the 69 bus distribution system using the proposed analytical solution are presented in this section. These results are also verified by performing exhaustive power flow routines.

3.6.1 Analytical Method

We use the proposed power flow model to determine the optimal locations and sizes of DG units for the 69 bus distribution system. Then, we perform sensitivity analysis; and from which we find the loss sensitivity factors λ_p, at each bus using (3.8), to determine the optimal locations of the candidate DG units. The results of the loss sensitivity factors are depicted in Fig. 3.3. The optimal location for the first DG unit is found to be at bus 61. The power factor of the downstream load at bus 61 is also obtained from the power flow solution and was found to be equal to 0.82 lagging. Table 3.3 shows the results obtained by the proposed analytical method and those obtained by performing exhaustive power flow solutions for the case of DG Type I. This DG type injects both real and reactive power to the bus at which it is connected. As can be seen from Table 3.3, the DG sizes obtained by the proposed analytical method correspond closely to those obtained by the exhaustive power flow routines, while requiring lower computational effort.

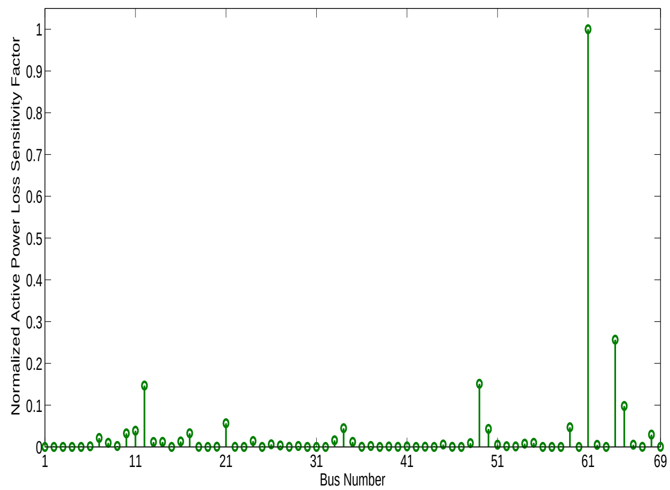

Figure 3.3: Active power loss sensitivity factors of the 69 bus system

As can be seen from Table 3.3, when a single DG is concerned, the percentage loss reduction achieved by the analytical method is 86.86%. The percentage reduction in losses by performing exhaustive power flows is almost the same. The DG sizes for this case study are also given in Table 3.3. Now, a second DG of type I and of size 945 kVA is connected at bus 49, which is identified from the sensitivity analysis as an optimal location for DG installation. The total loss reduction obtained by the analytical approach is 88.10%.

Table 3.4 shows the results obtained by both methods for the case of Type II DG, which injects real power only. As expected, total loss reduction when such DG type has been used is less than that obtained by deploying Type I DG. The total loss reduction when a single DG is utilized is 57.06% . On the other hand, when two DG units are installed at the specified buses, the total loss reduction obtained by the proposed analytical method is 87.91%.

Table 3.3: Results of The 69 Bus Distribution System–DG Type I

Method	Analytical Method		Exhaustive Power Flow	
Item	Single DG	Two DG	Single DG	Two DG
Optimal Location	61	49	61	49
S_{DG} (kW)	1918	945	1916	945
Power Loss (kW)	23.92	21.63	23.90	21.63
% Loss Reduction	86.86	88.10	86.87	88.09

3.6.2 Exhaustive Power Flow

In order to verify the sizes of the DG units obtained by the proposed analytical expressions, we have compared them with those obtained by performing exhaustive power flow solutions. In this case, we first identify the penetration level of the DG units using (3.6). We assume a penetration level of 15%–60% for this case study. Accordingly, the allowable minimum and maximum DG output power for the 69 bus system is varying between 700 kVA and 2795 kVA. Since DG sizes are given in discrete values, we change the DG sizes in small steps and installed the candidate DG units at bus 61, which is identified as an optimal location for DG installation from sensitivity analysis. We perform power flow solution several times and determine the size that gives minimum loss. This size is found to be 1918 kVA, which gives a reduction in total losses of 86.86%. The same procedures are repeated for the second DG (Type II), which is connected at bus 49 according to the sensitivity analysis. The optimal locations and sizes of the distributed generation units for this case study are given in Table 3.4. It is worth to note here that if any of the constraints listed in Section 3.3.1 is violated during the search for the optimal DG size, this DG unit is omitted from the list and the following DG unit location is considered for further evaluation.

Table 3.4: Results of The 69 Bus Distribution System–DG Type II

Method	Analytical Method		Exhaustive Power Flow	
Item	Single DG	Two DG	Single DG	Two DG
Optimal Location	61	49	61	49
P_{DG} (kW)	1580	760	1580	760
Power Loss (kW)	78	22	78	22
% Loss Reduction	57.06	87.91	57.06	87.91

3.7 Voltage Profile Improvement

Amongst the potential advantages of installing distributed generation units on distribution systems is their ability to improve the overall voltage profile of the system. In this section, we study the influence of the distributed generation units on the system. Table 3.5 depicted below shows the minimum bus voltages obtained before and after the installation of the distributed generation units, for the 33 bus system and the 69 bus system, respectively. In the context of voltage profile improvement, the minimum bus voltage of the 33 bus system before the introduction of the distributed generation units was 0.9113 p.u. and had occurred at bus 18. The maximum bus voltage was equal 1.0 p.u., which is the substation bus voltage. The minimum bus voltage of the 33 bus distribution system has been boosted to 0.9509 p.u. when a single DG of Type I is installed. However, the minimum bus voltage has been boosted to 0.9693 p.u. when two DG units of Type I are installed. These minimum bus voltages had occurred at bus 18 for both cases. In fact, this signifies that the improvement in the overall voltage profile of the 33 bus system is about 4.35% when a single distributed generation unit is installed and almost 6.36%, when two distributed generation units have been installed on the 33 bus distribution system.

For the 69 bus distribution system, the minimum bus voltage was 0.9170 p.u. and had occurred at bus 65 while the maximum bus voltage was equal to 1.0 p.u., which is the substation bus voltage. After the installation of a single distributed generation unit, and two DG units of Type I, the minimum bus voltage of the 69 bus distribution system becomes 0.9728 p.u. This means the improvement in the overall voltage profile of the 69 bus system is almost 6.09%. On the other hand, the maximum bus voltage after the installation of these DG units becomes 1.011 p.u. and occurs at bus 27. Table 3.5 shows detailed results for these case studies.

Table 3.5: Minimum Bus Voltages Before and After DG Installation

Item	DG Type I		DG Type II	
Test System	Single DG	Two DG	Single DG	Two DG
33 Bus Distribution System	0.9509	0.9693	0.9411	0.9516
Voltage Improvement (%)	4.35	6.36	3.27	4.42
69 Bus Distribution System	0.9728	0.9729	0.9695	0.9697
Voltage Improvement (%)	6.09	6.10	5.73	5.75

3.8 Comparative Study

To test the effectiveness of the proposed analytical method, we compare the performance of the proposed analytical method with some other analytical methods presented in the literature.We consider the 33 bus system for this comparative study. The comparison results are shown below in Table 3.6. As can be clearly seen from Table 3.6, the proposed analytical method has led to a global optimal solution, while requiring lower computational effort.

Table 3.6: Performance Comparison of The Proposed Method

Method and Item	Method Ref. [53]	Method Ref. [54]	Proposed Analytical Method	
			Based FACPF	Based LACPF
Optimal Location	6	6	6	6
Optimal Size (kW)	2490	2601	2236	2215
% Loss Reduction	47.33	47.39	46.30	43.79
Iterations/Power flow	5	5	5	–
NET (ms)/Power flow	290.52	287.50	295.87	51.23

3.9 Summary

This chapter has proposed an analytical method for placement and sizing of distributed generators on power distribution systems with an objective of loss reduction. Analytical approaches could lead to optimal or near-optimal global solution and are very appropriate for optimal distribution system planning studies. We have determined the penetration level of the candidate distributed generation units. Then, we have used the power flow model, which we developed earlier in Chapter 2, to perform sensitivity analysis to determine the optimal location, size, and power factor of the candidate distributed generator unit. The main features of the work presented in this chapter include the following,

1. The use of sensitivity analysis to select the appropriate locations of the candidate distributed generation units; and thereby reducing the search space and computational burden.

2. This work is different from that presented in the literature in the sense that it proposes direct and understandable expressions to estimate the optimal, or near-optimal, size of the distributed generation units. The work presented herein does not utilize the complicated exact loss formula.

3. This work considers various types of distributed generators and incorporates the optimal power factor in the sizing problem. The vast majority of the work presented in the literature assumes unity power factor for the candidate distributed generator units.

4. The proposed analytical method could lead to optimal or near-optimal global solution, while requiring lower computational effort. The method reported here is suitable for several distribution system planning studies.

Chapter 4

Optimal Economic Power Dispatch of Active Distribution Systems

This chapter describes a method for solving the optimal economic power dispatch problem of active distribution systems. In this chapter, we develop piecewise linear models to deal with the cost curves of generating units and total power losses. We consider distributed generators of constant power type and unity power factor similar to those which have been dealt with in Chapter 3, however, we assume various penetration levels. To show the effectiveness of the proposed method, we compare its performance with two other methods, which are widely used in the literature to solve the optimal economic power dispatch problem. Namely, these methods are the full AC power flow based economic dispatch and the DC power flow based economic dispatch. We show through simulations that the proposed method outperforms the DC power flow based economic dispatch method and the results obtained by the proposed method correspond closely with those obtained by nonlinear means, while requiring lower computational effort. Further, We hold a comparison with some other methods, which are available in the literature, to validate the consistency of the proposed method in finding the optimal or near-optimal global solution. The results show that the proposed method could lead to optimal or near-optimal global solution, and is appropriate to use for several power system operational and planning studies.

4.1 Optimal Economic Power Dispatch Problem

For about half a century, the optimal economic power dispatch problem has been the subject of intensive research all around the world. It is a crucial tool in the operation and planning stages of any power system. The optimal power flow problem was first formulated and introduced as a network constrained economic dispatch problem (ED) in 1962 by Carpentier [58] and was defined later as an optimal power flow problem by Dommel and Tinney [59]. The task of performing optimal power flow aims essentially at determining the optimal settings of the given power network by optimizing certain functions, e.g. minimization of total generation cost, total power losses, or total emission, while satisfying a set of operating and technical constraints. Numerous control variables that include generators' real power, transformers' tap changers and phase shifters, static and dynamic VAR compensators are also involved in optimizing the objective function.

4.2 Overview of Existing Work

The solution of the optimal economic power dispatch problem is very important for several power system operational and planning studies. The solution the optimal ED problem was mainly devoted to transmission systems. Nevertheless, due to the liberalization of energy markets and the introduction of non-utility generation, the solution of ED problem at distribution system level has increasingly become of great interest in recent years. A great variety of solution techniques have been proposed in the literature to solve the optimal economic dispatch problem since its inception. Momoh et al. presented a review of optimal power flow methods selected in [60, 61]. The challenges to optimal power flows are reported by Momoh et al. in [62]. Examples of some common methods, which are used in the literature to solve the optimal power flow problem include, nonlinear programming [63, 64, 65, 66], quadratic programming [67], Newton's method [68, 69], heuristic and swarm intelligence [70, 71, 72, 73], interior point method [74, 75], and linear programming (LP) based methods [76, 77, 78, 79]. Amongst these methods, LP based methods are recognized as viable and promising tools in solving the constrained economic dispatch problem. The earliest versions of the LP based economic power dispatch were developed based on the pure DC power flow model [8, 30, 80]. Lately, the constraints in the LP models were linearized and treated by nonlinear power flows in order to impose them precisely. The inherent features of the LP based economic power dispatch methods include reliability of optimization, flexibility of the solution, rapid convergence characteristics, and fast execution time [29].

Several approaches have been recently proposed in the literature to solve the economic dispatch problem in the presence of distributed generators. A heuristic method based an optimal dynamic power dispatch with renewable energy sources is presented in [71]. The problem of economic power dispatch in the presence of intermittent wind energy sources is carried out using linear programming in [81]. The problem of optimal economic power dispatch in the presence of intermittent wind and solar generators is carried out using sequential quadratic programming in [82]. Sequential quadratic programming is able to handle the convex cost curves of generating units efficiently since the latter is inherently a quadratic function. Nonetheless, quadratic programming requires considerable computational effort. More significantly, the standard simple form of the quadratic programming is not often used because convergence is not always guaranteed. The optimal power dispatch in the presence of distributed generators has also been proposed in [83, 84, 85].

4.3 Development of Models and Methods

This section reviews some modeling aspects to handle the optimal economic power dispatch problem. It develops piecewise linear models for the cost functions of generators. It also develops linear model for transmission line losses so that they can be included in the proposed method.

4.3.1 Cost Functions of Generators

The cost function of a conventional generator i is usually expressed as a second-order quadratic polynomial as,

$$F_i(P_{Gi}) = \alpha_i + \beta_i\, P_{Gi} + \gamma_i\, P_{Gi}^2 \tag{4.1}$$

The work adapted the linearization model developed in [30]. Thus, the nonlinear cost function can be approximated by a series of straight-line segments as depicted in Fig. 4.1. The three linear segments shown in Fig. 4.1 are represented as P_{i1}, P_{i2}, and P_{i3}. Further, the slope of each linear segment is given as μ_1, μ_2, and μ_3, respectively.

The cost function can therefore be represented as [30],

$$F_i(P_{G_i}) = F_i(P_{G_i^{min}}) + \mu_1 P_{i1} + \mu_2 P_{i2} + \mu_3 P_{i3} \tag{4.2}$$

with,

$$0 \leq P_{ih} \leq P_{ih}^{+} \quad , \quad h = 1,2,3 \tag{4.3}$$

The cost function is obtained by including all the linear segments in the P_{ih}. That is,

$$P_{G_i} = P_{G_i^{min}} + P_{i1} + P_{i2} + P_{i3} \tag{4.4}$$

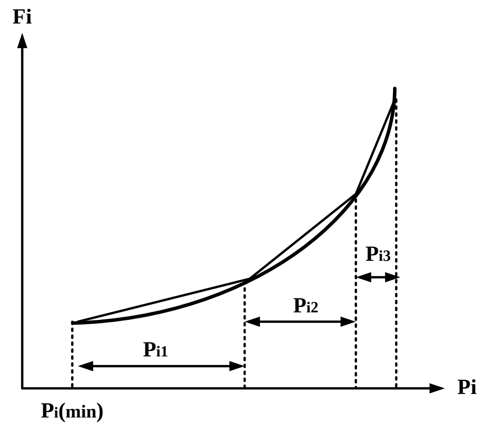

Figure 4.1: Linearization of cost function

4.3.2 Inclusion of Losses

The proposed LACPF model, which is developed earlier in Sec. 2.3, is lossless model as can be seen from (2.38). This section presents a piecewise linear model to include the losses in the proposed framework. Let us consider the simple circuit shown in Fig. 4.2. The real and reactive power flowing out from bus k towards bus m can be calculated as [8],

$$P_{km} = V_k^2\, g_{km} - V_k\, V_m\, g_{km} \cos\delta_{km} - V_k\, V_m\, b_{km} \cos\delta_{km} \tag{4.5}$$

$$Q_{km} = -V_k^2\, b_{km} + V_k\, V_m\, b_{km} \cos\delta_{km} - V_k\, V_m\, g_{km} \sin\delta_{km} \tag{4.6}$$

The real and reactive power flowing out from bus m towards bus k can be obtained in a similar manner. That is,

$$P_{mk} = V_m^2\, g_{km} - V_k\, V_m\, g_{km} \cos\delta_{km} - V_k\, V_m\, b_{km} \cos\delta_{km} \tag{4.7}$$

$$Q_{mk} = -V_m^2\, b_{km} + V_k\, V_m\, b_{km} \cos\delta_{km} - V_k\, V_m\, g_{km} \sin\delta_{km} \tag{4.8}$$

Therefore, the real and reactive power losses can be obtained as,

$$P_L = g_{km}\ (V_k^2 + V_m^2 - 2V_k\ V_m \cos\delta_{km}) \tag{4.9}$$

$$Q_L = -b_{km}\ (V_k^2 + V_m^2 - 2V_k\ V_m \cos\delta_{km}) \tag{4.10}$$

Let us use the approximations $V_k \approx 1.0$ p.u., $V_m \approx 1.0$ p.u., and $\cos\delta_{km} \approx 1 - \frac{\delta_{km}^2}{2}$, the approximate real and reactive power losses formulas can be written as,

$$P_L^{\triangle} = g_{km}\ \delta_{km}^2 \tag{4.11}$$

$$Q_L^{\triangle} = -b_{km}\ \delta_{km}^2 \tag{4.12}$$

Eqs. (4.11) and (4.12) indicate that the active and reactive power losses are quadratic forms of δ_{km}. Therefore, in order to include the losses in the proposed method, the angles δ_k and δ_m are obtained from the base power flow solution and the initial losses are computed. These losses are then added to system loads and a power flow solution is executed to obtain the exact losses.

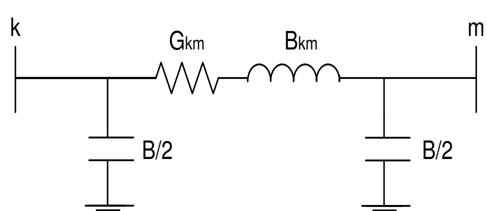

Figure 4.2: Transmission line π model

4.3.3 The Proposed Framework

In this section, we present the entire optimization framework for solving the optimal ED problem. The objective function used here is to minimise the total generation cost. The minimisation problem is formulated as,

$$\text{Total Cost} = \min\left(\sum_{i=1}^{N_g} F_i\left(P_{Gi}\right)\right) \tag{4.13}$$

Subject to

1. Real and Reactive Power Injections

$$\begin{aligned} B^{'}\delta - GV + P_G &= P_D \\ G^{'}\delta + BV + Q_G &= Q_D \end{aligned} \tag{4.14}$$

2. Real and Reactive Power Constraints

$$\begin{aligned} P_G^{min} \leq P_G \leq P_G^{max} \\ Q_G^{min} \leq Q_G \leq Q_G^{max} \end{aligned} \tag{4.15}$$

3. Line Capacity Constraints

$$\begin{aligned} bA'\ \delta + bA''\ V &\leq I_f^{max} \\ -bA'\ \delta - bA''\ V &\leq I_r^{max} \end{aligned} \tag{4.16}$$

4. Voltage Bound Constraints

$$|V^{min}| \leq |V| \leq |V^{max}| \tag{4.17}$$

5. Angle Constraints

$$\delta \text{ is unrestricted} \tag{4.18}$$

4.4 DCPF Based Optimal Economic Dispatch

To demonstrate the effectiveness of the proposed optimal ED method, we compare its performance with some other methods, which have been extensively used in the literature. We compare the proposed optimal ED method with the the DCPF based economic dispatch and the full AC power flow based economic dispatch method. We implement the DCPF based economic dispatch method and use Matpower simulator package [87] to find the results of the full AC power flow based economic dispatch method. For the sake of completeness, these two methods are briefly reviewed in the subsequent section.

The traditional DC power flow based economic dispatch can be formulated as,

$$\text{Total Cost} = \min\left(\sum_{i=1}^{N_g} F_i\left(P_{Gi}\right)\right) \tag{4.19}$$

Subject to

1. Real Power Injections

$$B^{'}\delta + P_G = P_D \tag{4.20}$$

2. Real Power Constraints

$$P_G^{min} \leq P_G \leq P_G^{max} \tag{4.21}$$

3. Feeder Capacity Constraints

$$\begin{aligned} b\hat{A}\,\delta &\leq I_f^{max} \\ -b\hat{A}\,\delta &\leq I_r^{max} \end{aligned} \tag{4.22}$$

4. Angle Constraints

$$\delta \text{ is unrestricted} \tag{4.23}$$

4.5 FACPF Based Optimal Economic Dispatch

The full AC power flow based economic dispatch method used in this work is formulated as,

$$\text{Total Cost} = \min\left(\sum_{i=1}^{N_g} F_i\left(P_{Gi}\right)\right) \tag{4.24}$$

Subject to

1. Nonlinear Power Flow Injections

$$g(\mathbf{h},\mathbf{z}) = \mathbf{0} \tag{4.25}$$

2. Real and Reactive Power Constraints

$$\begin{gathered} P_G^{min} \leq P_G \leq P_G^{max} \\ Q_G^{min} \leq Q_G \leq Q_G^{max} \end{gathered} \tag{4.26}$$

3. Feeder Capacity Constraints

$$\begin{gathered} I_f \leq I_f^{max} \\ I_r \leq I_r^{max} \end{gathered} \tag{4.27}$$

4. Voltage Bound Constraints

$$|V^{min}| \leq |V| \leq |V^{max}| \tag{4.28}$$

5. Angle Constraints

$$\delta \text{ is unrestricted} \tag{4.29}$$

where $g(\mathbf{h},\mathbf{z})$ represents the nonlinear power flow equations. Other abbreviations are as defined in Section 4.4

4.6 Demonstration and Discussion

The effectiveness of the proposed optimal economic power dispatch method is demonstrated on a modified 30 bus system [86]. The modified 30 bus system consists of 30 buses, 41 transmission lines, and 2 shunt capacitors, which are placed at bus 5 and bus 24, respectively. This system has six generators, which are placed at bus 1, bus 2, bus 13, bus 22, bus 23, and bus 27, respectively. The total real and reactive power peak loads on the modified 30 system are 189.2 MW and 107.2 MVar, respectively. We use four methods to solve the optimal ED problem. These methods are the FACPF based ED (FACPF based ED), LACPF based ED (LACPF based ED) including losses, LACPF based ED (LACPF based ED) lossless model, and the DCPF based ED (DCPF based ED). The results of the FACPF based ED are obtained using Matpower simulation package [87]. Three case scenarios are performed and discussed in detail in the subsequent section.

4.6.1 Case Scenario I

The purpose of this case scenario is to validate the methods and models developed in this chapter. Therefore, no distributed generators are considered in this case scenario. The real power and voltage magnitudes of the generators of the modified 30 bus system, which are obtained using the proposed method are, respectively, presented in Table 4.1. As can be seen from Table 4.1, the results of the optimal economic power dispatch of the 6 generators, which are obtained by the LACPF based ED (lossy model), correspond closely with those obtained by the FACPF based ED. Furthermore, voltage magnitudes obtained by the LACPF based ED (lossy model) are also correspond closely with those obtained by the FACPF based ED. In this context, the percentage of voltage errors obtained by the proposed method at buses 1, 2, 13, 22, 23, and 27, respectively, are 0.00%, 0.88%, 4.39%, 0.88%, 0.58%, and 3.91%, which are less than 5% at all buses.

The total generation cost, total generation, and total losses of the modified 30 bus system are also given in Table 4.1. As can be seen from Table 4.1, the results obtained by the proposed LACPF based ED (lossy model) correspond closely with those obtained by the FACPF based ED. The results of the total generation cost, total generation, and total losses, which are obtained by both methods were almost similar. The results presented in this case study show that the proposed method can handle the optimal ED problem more efficiently than some other traditional linearized methods, which are developed based on the DCPF model.

Table 4.1: ED Results of the Modified 30 Bus System – Case Scenario I

Power (MW) Voltage (p.u.)	FACPF Based ED	LACPF Based ED		DCPF Based ED
		Model I	Model II	
P_{G1}	39.92	45	45	45
P_{G2}	53.03	48.958	47.20	47.884
P_{G13}	14.96	15	15	15
P_{G22}	22.46	21	21	21
P_{G23}	16.06	16	16	16
P_{G27}	45.58	45	45	44.316
V_1	1.050	1.050	1.050	1.0
V_2	1.028	1.037	1.036	1.0
V_{13}	1.048	1.002	1.003	1.0
V_{22}	1.019	1.010	1.011	1.0
V_{23}	1.026	1.020	1.022	1.0
V_{27}	1.050	1.009	1.008	1.0
T. Cost ($/hr)	576.92	579.72	572.95	572.95
T. Gen. (MW)	192.06	190.96	189.20	189.20
T. Losses (MW)	2.86	2.84	0	0

4.6.2 Case Scenario II

In this case scenario, we solve the optimal ED problem in the presence of distributed generators. As has been discussed in Chapter 3, the advantages of distributed generation sources include total loss reduction, voltage profile improvement, peak load shaving, and reliability and security enhancement. The distributed generators used in this work are modeled as constant PQ nodes with

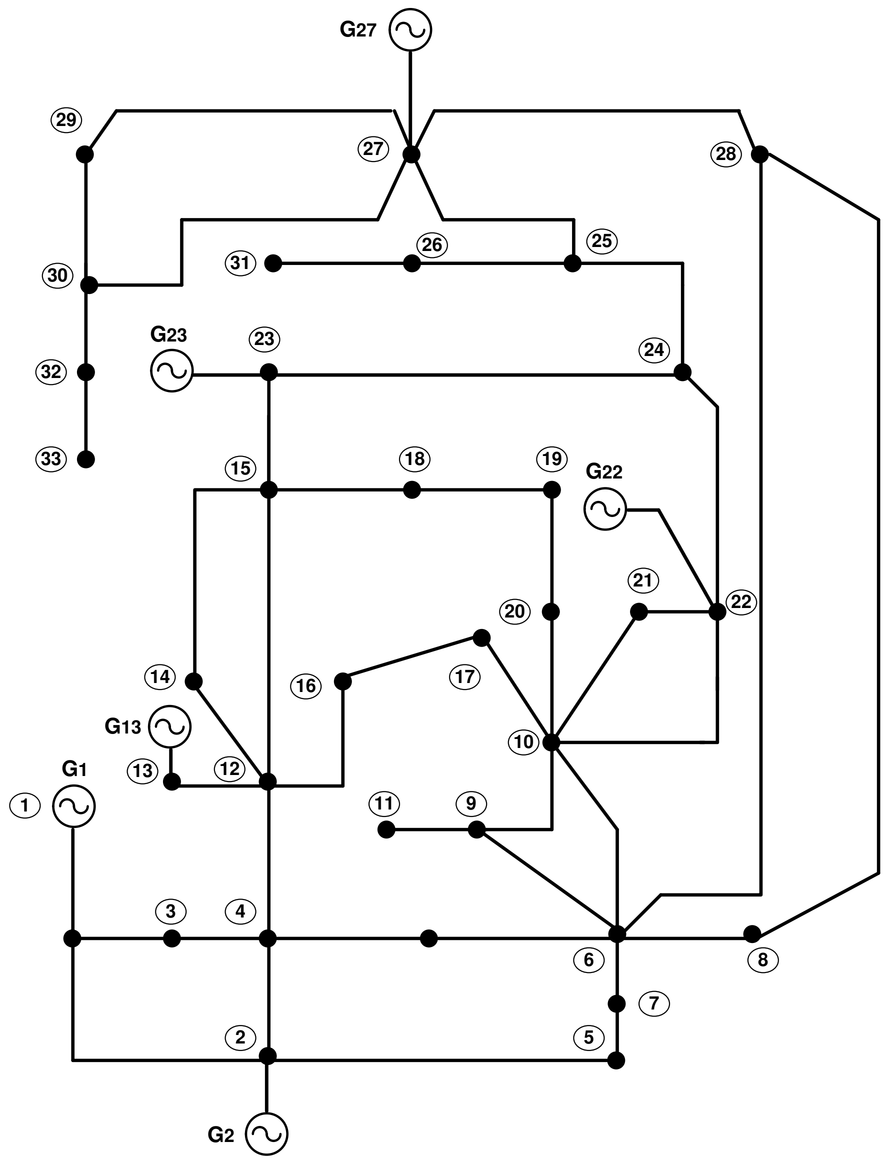

Figure 4.3: Modified 30 Bus Distribution System

negative injections. This assumption concurs with the IEEE standard 1547-2003 [5] for interconnecting distributed resources with electric power systems, which emphasizes that distributed generators are not recommended to regulate bus voltages; and thereby they should be modeled as PQ nodes not PV nodes. Further, distributed generators operated at unity power factor have been assumed in this work.

When dealing with distributed generators, it is customary to define their penetration level in the distribution system. Therefore, we define the penetration level of the distributed generators (η_p) in the system as [81],

$$\eta_p = \frac{1}{P_D} \sum_{m=1}^{N_r} P_m \tag{4.30}$$

where P_D represents the total system demand, P_m represents the output power of the distributed generators, and N_r represents the number of the distributed generators.

It is noteworthy to highlight here that we only consider the penetration level of the distributed generation units in this work. The problem of determining the optimal locations and sizes of distributed generation units is not germane to the presented work. In accordance to the Electric Power Research Power Institute (EPRI) and other studies, the penetration level of the distributed generators in distribution systems was in the vicinity of 20% in 2010. In this work, we consider two penetration levels of distributed generators. In the first case, which is discussed here, we assume a penetration level of 10%, which is equivalent to approximately 18.92 MW. We place six distributed generation units at buses 4,7,15,21,24, and 31, respectively. These locations are selected based on the peak load densities. Each distributed generation unit is rated at approximately 3.15 MW.

The real power and voltage magnitudes of the generators of the modified 30 bus system are, respectively, presented in Table 4.2. As can be seen from Table 4.2, the results of the optimal economic power dispatch of the generators, which are obtained by the LACPF based ED (lossy model), correspond closely with those obtained by the FACPF based ED. Furthermore, voltage magnitudes obtained by the LACPF based ED (lossy model) are also correspond closely with those obtained by the FACPF based ED. This case study has shown that the proposed method is appropriate to handle the optimal ED problem of active distribution systems efficiently and can be used for optimal distribution system planning studies.

The total generation cost and total generation of the modified 30 bus system are given in Table

4.2. As can be seen from Table 4.2, the results obtained by the proposed LACPF based ED (lossy model) correspond closely with those obtained by the FACPF based ED. The results of the total generation cost, total generation, and total losses, which are obtained by both methods were almost similar. The results presented in this case study show that the proposed method can handle the optimal ED problem more efficiently than some other traditional linearized methods, which are developed based on the DCPF model.

Table 4.2: ED Results of the Modified 30 Bus System – Case Scenario II

Power (MW) Voltage (p.u.)	FACPF Based ED	LACPF Based ED		DCPF Based ED
		Model I	Model II	
P_{G1}	39.30	45	45	45
P_{G2}	51.64	40	40	40
P_{G13}	13.46	15	15	15
P_{G22}	21.56	21	21	21
P_{G23}	13.56	16	16	16
P_{G27}	34.33	34.625	33.3	33.3
V_1	0.968	1.050	1.050	1.0
V_2	0.965	1.036	1.036	1.0
V_{13}	1.055	0.997	0.997	1.0
V_{22}	1.008	1.011	1.011	1.0
V_{23}	1.016	1.023	1.023	1.0
V_{27}	1.049	1.009	1.008	1.0
T. Cost ($/hr)	505.13	505.1568	500.468	500.468
T. Gen. (MW)	172.84	171.526	170.3	170.3

4.6.3 Case Scenario III

In this case scenario the penetration level of the wind turbine generators is assumed to be 20%. This penetration level is approximately equivalent to 37.84 MW. Similar to Case Scenarion II, we place six distributed generation units at buses 4,7,15,21,24, and 31, respectively. These locations have been selected based on the peak load densities. In this case scenario, each distributed generation unit is assumed to be rated at approximately 6.13 MW.

The real power and voltage magnitudes of the generators of the modified 30 bus system are, respectively, presented in Table 4.3. As can be seen from Table 4.3, all bus voltages are within the permissible range. The results of the optimal economic power dispatch of the 6 generators, which are obtained by the LACPF based ED (lossy model), correspond closely with those obtained by the FACPF based ED. Furthermore, voltage magnitudes obtained by the LACPF based ED (lossy model) are also correspond closely with those obtained by the FACPF based ED. This case study has shown that the proposed method is appropriate to handle the optimal eD problem of active distribution systems efficiently and can be used for optimal distribution system planning studies.

The total generation cost and total losses of the modified 30 bus system are given in Table 4.3. As can be seen from Table 4.3, the results obtained by the proposed LACPF based ED (lossy model) correspond closely with those obtained by the FACPF based ED. The results of the total generation cost and total losses, which are obtained by both methods were almost similar. The results presented in this case study show that the proposed method can handle the optimal ED problem more efficiently than some other traditional linearized methods, which are developed based on the DCPF model.

4.7 Performance Analysis of the Proposed Method

In this section, we compare the performance of the proposed optimal ED method with some other methods available in the literature. Firstly, we compare the maximum error in the computed total cost and total generation cost obtained by the proposed method with those obtained by the full AC based ED and the DCPF based ED methods. Then, we demonstrate the effectiveness and the consistency of the proposed method in finding the optimal or near-optimal global solution by comparing its performance with two other methods available in the literature.

Table 4.3: ED Results of the Modified 30 Bus System – Case Scenario III

Power (MW) Voltage (p.u.)	FACPF Based ED	LACPF Based ED		DCPF Based ED
		Model I	Model II	
P_{G1}	34.61	45	45	45
P_{G2}	47.33	40	40	40
P_{G13}	10.58	10.356	10	10
P_{G22}	20.40	21	21	21
P_{G23}	11.01	12	12	12
P_{G27}	33.78	24	23.4	23.4
V_1	0.964	1.050	1.050	1.0
V_2	0.961	1.036	1.036	1.0
V_{13}	1.063	1.000	1.000	1.0
V_{22}	1.014	1.010	1.010	1.0
V_{23}	1.021	1.021	1.021	1.0
V_{27}	1.045	1.014	1.014	1.0
T. Cost ($/hr)	451.55	433.2579	429.8162	429.8162
T. Gen. (MW)	157.72	152.356	151.4	151.4

4.7.1 Comparison of the Maximum Error

The errors in the total generation and total generation cost obtained by the studied case scenarios are presented in this section and the results are summarized in Table 4.4. As can be noticed from Table 4.4, the percentage errors in the total generation and total generation cost obtained by the proposed LACPF based ED method are much lower than those obtained by the DCPF based ED method. This makes the proposed method very suitable not only to handle the optimal ED problem of active distribution systems, but also to solve several other optimal distribution system operational and planning problems, in which repetitive optimal solutions are highly sought.

4.7.2 Comparison of the Optimal Solution

To test the consistency of the proposed LACPF based ED method in finding the optimal or near optimal global solution, it has been compared with some other methods, which are presented in the literature. We use a method, which is developed based on hybrid particle swam optimization

Table 4.4: Comparison of Total Cost and Total Generation Errors Obtained by the Proposed LACPF based ED method and the DCPF based ED method

System / Model	DCPF based ED		LACPF based ED	
Case Scenarios	Cost Error (%)	Gen. Error (%)	Cost Error (%)	Gen. Error (%)
Case Scenario I	4.45	1.61	0.04	0.19
Case Scenario II	1.46	0.92	0.55	0.25
Case Scenario III	1.94	1.28	0.08	0.14

[72], and also a method, which is developed based on SQP using Matpower simulation package [87]. We consider the modified 30 bus system in this comparative study. The comparison results are shown in Table 4.5. As can be seen from Table 4.5, the proposed LACPF based ED method could lead to optimal or near-optimal global solution similar to that solution, which is obtained using nonlinear means.

Table 4.5: Comparison of Method Performance

Comparison Item	Method Ref. [72]	Method Ref. [87]	Proposed Method
Total Cost ($/hr)	575.41	578.29	579.72
Total Gen. (MW)	191.85	192.01	190.96
Total Losses (MW)	2.86	2.81	2.84

4.8 Summary

This chapter has presented a method for solving the optimal economic power dispatch problem of active distribution systems. The method presented in this paper is developed based on linear programming and a linearized network model in which voltage magnitudes and reactive power flows have both been accounted for, unlike traditional linearized power flow methods. Some features of the work presented in this chapter include the following,

1. We have developed piecewise linear models to handle the thermal capacities of transmission

lines, loads, cost curves of generating units, and line losses. We show the effectiveness of the proposed method on a modified 30 bus system.

2. We have considered three case scenarios in this chapter. In the first case scenario, we have assumed no distributed generation units are present in the same. The objective of this case scenario is to validate the accuracy of the proposed methods and models in handling the optimal ED problem.

3. We have considered different penetration levels in Case Scenario II and Case Scenario III. We have assumed two penetration levels of distributed generators. In Case Scenario II, we assume a penetration level of 10%, which is approximately equivalent to 18.92 MW. We have placed six distributed generation units at buses 4,7,15,21,24,and 31, respectively. These locations are selected based on the peak load densities. Each distributed generation unit is approximately rated at 3.15 MW.

4. We have also assumed a penetration level of distribution generation units of 20% Case Scenario III. This penetration level is approximately equivalent to 18.92 MW. Similar to Case Scenario II, we have placed six distributed generation units at buses 4,7,15,21,24, and 31, respectively. These locations are selected based on the peak load densities. In this case scenario, each distributed generation unit is assumed to be rated at approximately 6.13 MW.

5. We have compared the performance of the proposed optimal ED method with some other methods available in the literature. Further, in order To test the consistency of the proposed LACPF based ED method in finding the optimal or near optimal global solution, we have compared its performance with some other methods presented in the literature. We use a method, which is developed based on hybrid particle swam optimization [72], and also a method, which is developed based on SQP using Matpower simulation package [87].

6. We show that the proposed LACPF based ED method could lead to optimal or near-optimal global solution similar to that solution, which is obtained using nonlinear means, and can be used to handle several optimal power system planning and operational studies.

Chapter 5

Reliability-constrained Optimal Distribution System Reconfiguration

This chapter presents a method to solve the distribution system reconfiguration problem with an objective of reliability enhancement. In the first part of this chapter, we introduce the basic reliability concepts, identify the state space of the problem, and report on reliability measures. We then discuss probabilistic reliability models and introduce a probabilistic reliability assessment method based on event tree analysis. From practical perspective, it is unnecessary to enumerate all events to compute the exact values of probabilities; and thereby calculate the reliability indices. Therefore, we improve the computational performance of the probabilistic reliability assessment method by introducing a criterion so that the effect of the higher-order contingencies is limited and the time and computational effort spent in evaluating the reliability indices are greatly reduced.

The objective function of the method proposed in this chapter is to minimize the total load curtailment. We choose the expected unserved energy (EUE), which is alternatively known as the loss of energy expectation (LOEE), as the reliability index that needs to be minimized. We introduce a formula to calculate EUE reliability index based on the expected demand not supplied (EDNS) index, which represents the total load curtailment in this case. We utilize the energy index of unreliability (EIUR) to evaluate the overall reliability of the given distribution system.

In the second part of this chapter, we formulate the distribution system reconfiguration problem for reliability enhancement. We propose an intelligent search method based on particle swarm optimization method (PSO) to seek all possible combinations of the switches that improve the distribution system reliability. Particle swarm optimization is a meta-heuristic optimization method inspired by the social behavior of flocks of birds or schools of fish, which is introduced in 1995 by [88, 89]. The advantages of using particle swarm optimization in handling the distribution system reconfiguration problem are manifold. For instance, the status of sectionalizing and tie-switches in distribution systems can be easily represented as binary numbers of (0,1). Moreover, particle swarm optimization based methods have considerably fast convergence characteristics and, generally speaking, have few parameters to tune up compared to some other meta-heuristic approaches.

We demonstrate the effectiveness of the proposed reliability enhancement method on the 33 bus system, 69 bus system, and 118 bus large-scale distribution system, which have been dealt with earlier in Chapter 2, as these systems are extensively used in the literature as examples in solving the distribution feeder reconfiguration problem. We consider the effect the voltage security limits in numerous case scenarios. The test results show that amount of the annual unserved energy and customers interruptions can be significantly reduced using the proposed reliability-based optimal distribution system reconfiguration method.

5.1 Distribution System Reconfiguration Problem

In this section we discuss the reasons for distribution system reconfiguration. We review and discuss the work presented in the literature to solve this problem and briefly discuss the significance of considering reliability constraints while reconfiguring the distribution network.

5.1.1 Reasons for Distribution Feeder Reconfiguration

The vast majority of power distribution systems are characterized by radial topological structure and poor voltage regulation. The radial topology is necessary in order to facilitate the control and coordination of the protective devices used at the distribution system level. However, with that radial structure, the failure of any single component between the load point and the source node would cause service interruptions and may result in disconnecting several load points. Distribution systems are equipped with two types of switches, which are sectionalizing switches and tie-switches. The sectionalizing switches are normally closed and are used to connect various distribution line segments. The tie-switches, on the other hand, are normally open and can be used to transfer loads from one feeder to another during abnormal and emergency conditions. Distribution feeder reconfiguration is one of the several operational tasks that are performed frequently on distribution systems. Basically, it denotes to the process of changing the topological structure of distribution networks by altering the open/close status of the sectionalizing and tie-switches to achieve certain objectives. Of these objectives, reliability and security enhancement, voltage profile improvement, peak load shaving, and loss minimization are of most concern.

5.1.2 Review of Existing Work

The first approach to solve the distribution system reconfiguration problem was introduced by Merlin and Back [37] in 1975. The objective of the work presented in [37] was to search for the minimum loss operating spanning tree configuration. The work presented in [37] starts by closing all switches (tie-switches and sectionalizing switches) so that the distribution system is converted to a meshed network. Then, based on predefined current indices, both sectionalizing and tie-switches are open in a subsequent fashion in order to restore the original radial topology of the distribution system. Since then, several methods are proposed in the literature to solve the distribution feeder reconfiguration problem. Shirmohammadi and Hong [38] proposed a heuristic method to minimize the resistive losses of distribution feeders. In the method reported in [38], an optimal power flow pattern is used to solve the optimal distribution feeder reconfiguration problem. Baran and Wu [33] presented a network reconfiguration method with an objective of loss reduction and load balancing. In [33], two approximate power flow solutions and a load index were proposed to find the minimum loss configuration of the distribution system. Methods based on swarm intelligence have also been recently proposed in the literature to handle the distribution feeder reconfiguration problem [39, 40, 90, 91, 92]. Despite such a great variety of solution techniques, the vast majority of the work presented in the literature was devoted to distribution system loss reduction and voltage profile improvement. Surprisingly, other significant objectives such as reliability and security enhancement and service restoration of in-service consumers have got less attention in the literature, and have not thus been fully addressed.

In recent years, there has been an increasing interest in improving distribution system reliability using distribution system reconfiguration. The expected energy not supplied (EENS), expected demand not supplied (EDNS), and the expected outage cost (ECOST) are some examples of the reliability measures used in the literature. In [93], a reliability worth enhancement based distribution system reconfiguration is proposed. Analytical and heuristic methods have been proposed for reliability worth enhancement. A reliability cost-worth model of the distribution system is built up and from which the ECOST and the EENS are obtained. The interrupted energy assessment rate (IEAR), which is proposed by Goel and Billinton [94], has also been used in [93] to relate the interruption cost and the expected energy not supplied for every feasible configuration. A distribution system reconfiguration for reliability worth analysis based on simulated annealing is proposed in [95]. The work reported in [95] used the same reliability indices and the same customer damage function as in [93]. However, several conclusions about the final system configuration are drawn as the ECOST and the EENS were both considered as objectives in the optimization problem. Reliability improvement of power distribution systems using distributed generation has also been proposed in the literature [96, 97, 98].

Swarm intelligence based optimization methods or meta-heuristic methods have been recently proposed in the literature to handle the distribution system reconfiguration problem for reliability enhancement. Amongst these methods, particle swarm optimization based methods are recognized as viable tools in solving the distribution system reconfiguration problem for reliability improvement. Chakrabarti et al. presented a reliability based distribution system reconfiguration method in [99]. The objective of the work presented in [99] was to minimize the loss of load expectation (LOLE) and the loss of energy expectation (LOEE). In addition, Monte Carlo simulation and particle swarm optimization have both been used in [99]. Amanulla el al [100] extended the work presented in [99] and proposed a cut set based analytical method to improve the service reliability of distribution systems. It is worth mentioning here that in all the studies, which are carried out in [99, 100, 101], the number of sectionalizing switches have been restricted and priory assigned in order to speed up the computational burden and reduce the search space. In addition, first-order cut-sets have only been considered in the work proposed in [99, 100, 101].

Elsaiah et al. [102, 103, 104] recently proposed methods for solving the optimal distribution feeder reconfiguration for reliability improvement. In [102, 103], a fast method for reliability improvement of power distribution system via feeder reconfiguration is proposed. The work presented in [102, 103] is developed based on a linearized network model in the form of DC power flow and linear programming model, in which current carrying capacities of distribution feeders and real power constraints have been considered. The optimal status of sectionalizing and tie-switches are identified using an intelligent binary particle swarm optimization based search method. The probabilistic reliability assessment is conducted using a method based on high probability order approximation. Several case studies are carried out in [102, 103] on a small 33 bus radial distribution system, which is extensively used as an example in solving the distribution system reconfiguration problem. The effect of embedded generation has also been considered in one case scenario. The results show that the proposed method yields a tremendous reduction in the EDNS reliability index and services interruptions of in-service consumers. The work presented in [102, 103] has been extended in [104] to improve the reliability of Microgrids, which is basically a distribution system or part thereof. The probabilistic reliability was conducted using a first-cut set based method. Moreover, a graph theoretic method is developed in [104]to preserve the radial topological structure of the Microgrid. The penetration of the distribution generators is obtained using a hybrid optimization model, which is developed based on Homer software package [105]. The method is tested on a large-scale Microgrid with renewable energy resources, in particular wind turbine induction generators, and different load scenario are considered in [104].

The problem of optimal switch placement in power distribution systems is conducted using trinary particle swarm optimization in [106]. The use of ant colony optimization for placement of sectionalizing switches in distribution systems is presented in [107]. The work presented in [107] only considered the failure rates of the distribution feeders and assumed that the other distribution system components such as transformers, circuit breakers, etc are to be perfectly reliable, which is not the case in realistic distribution systems. Further, the work presented in [107] has just considered the placement of a single switch on the distribution system and one case scenario is performed in this study.

5.1.3 Importance of Enhancing Distribution Systems Reliability

The majority of today's distribution systems are being stressed and operated at heavy loading conditions due to the rapid increase in electricity demand as well as certain economic and environmental constraints. More prominently, several of the present power distribution systems are subject to numerous power quality constraints such as the mitigation of voltage dips, flicking, and service interruptions, which have not been of full consideration in the old days. In this context, statistics have shown that the vast majority of service outages have taken place at distribution system level [108, 109]. A study conducted by the Power System Outage Task Force (PSOTF) [110] after the massive blackout of the US and Canada took place on August 14th-15th 2003, has indicated that stressed and unsecured systems can be a major source for blackouts that happened in recent years and could happen in future. Brown [109] has reported that distribution systems contribute for up to 90% of overall consumers reliability problems. The annual cost of these service interruptions could attain billion of dollars according to the Electric Power Research Institute (EPRI) and the US Department of Energy (DOE) [111]. These concerns combined with the complexities of the modern power distribution systems has motivated us to consider the reliability and security constraints while handling the problem of optimal distribution feeder reconfiguration.

5.2 Development of Models and Methods

This section presents probabilistic models for various distribution system components. It also provides a probabilistic reliability assessment method based on higher-order contingency approximation, the reliability indices utilized in this work, and the complete optimization framework.

5.2.1 Probabilistic Reliability Indices

Reliability of distribution system can be simply defined as the ability of the distribution system to satisfy its consumers load demand under certain operating conditions [112]. This work uses the expected demand not supplied and the expected unserved energy to evaluate the reliability of the distribution system. We use the loss of load probability reliability index (LOLP) to calculate the amount of the total load curtailment. In addition, we have used the energy index of unreliability to know how secure the system is. We define the reliability indices used in this work as [108],

1. Expected Unserved Energy (EUE): The expected number of megawatt hours per year that the system can not supply to consumers. Alternatively, it is known as the expected energy not supplied (EENS).
2. Loss of Load probability (LOLP): The probability that the system will not be able to supply the load demands under certain operating scenarios.
3. Energy Index of Unreliability (EIUR): The fraction of the energy demand that the system is not able to meet.

5.2.2 The State Space

The state space of the problem presented in this chapter is defined as the set of all possible combinations of generators N_g, distribution feeders N_f, sectionalizing switches N_{ss}, tie-switches N_{ts}, buses N_b, circuit breakers N_{cb}, and distribution transformers N_{tr}. Consequently, the dimension of the state space can be expressed as $\Phi_s = \left\{N_g + N_f + N_{ss} + N_{ts} + N_b + N_{cb} + N_{tr}\right\}$.[1] Probabilistic models of the aforementioned components are addressed in the subsequent section.

[1] From practical perspective, the radial topological structure of the distribution system is taken as a necessary condition during the realization of the presented work. Therefore, the substation bus is assumed to be perfectly reliable for all case scenarios performed herein.

5.2.3 Probabilistic Models of Components

Distribution system modeling aims at translating the physical network into a reliability network based on series, parallel, or a combination of series/parallel component connections. Probabilistic modeling techniques are used to represent various system components. Hence, every single component in the distribution system is assigned a probability of being available (P) or unavailable (Q) so that $P+Q=1$. The availability of any component i in the system can be represented as [108],

$$P_i = \frac{1/\lambda_i}{1/\lambda_i + 1/\mu_i} = \frac{\mu_i}{\mu_i + \lambda_i} \tag{5.1}$$

where λ_i is the failure rate of component i and μ_i is the repair rate of component i, respectively.

Eq. (5.1) can alternatively be represented as,

$$P_i = \frac{MTTF_i}{MTTF_i + MTTR_i} \tag{5.2}$$

where MTTF$_i$ and MTTR$_i$ are the Mean Time To Failure and the Mean Time To Repair of component i, respectively.

In this work, we assume that each component in the distribution system can only reside in an up-state (available) or down-state (unavailable). Therefore, the two-state Markovian model shown in Fig. 5.1 is used to model the transformers, circuit breakers, switches, and buses. However, for distribution system feeders, a discrete probability density function has been constructed for every distribution line. If a distribution feeder is tripped for certain system state, the distribution feeder is removed from the bus admittance matrix and its capacity is set equal to zero.

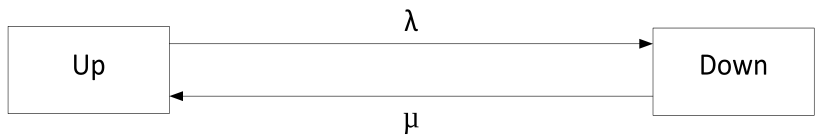

Figure 5.1: Two state model representation

5.2.4 Probabilistic Reliability Assessment

Since the time and computational effort spent in evaluating system indices are of great concern in both planning and operational stages, the work reported in this chapter uses a probabilistic reliability assessment method based on the event tree analysis [108, 115, 116]. Basically, event tree analysis can be considered as a binary form of a decision tree, which is utilized to obtain the probabilities of the different possible outcomes of the system after an event takes place. Amongst the advantages of using event tree analysis in the reliability evaluation of distribution systems is attributed to its ability to model complex systems, such as distribution systems, in an understandable manner [115].

Now, let us consider Fig. 5.2 [116], which depicts an event tree with various success and failure probabilities. The probability of occurrence of each path is obtained by multiplying the probabilities of occurrence of the events forming that path. That is [112],

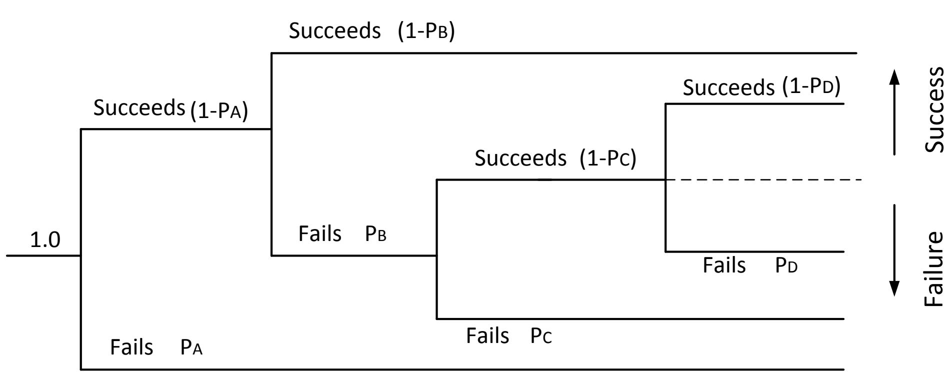

Figure 5.2: Concept of event tree analysis

$$\text{System Reliability} = \sum \text{probabilities of all successful paths} \tag{5.3}$$

The probability of success of the event tree shown above in Fig. 5.2 is calculated as,

$$\begin{aligned} P = 1 - (P_A) - [(P_B)\cdot(P_C)] + [(P_A)\cdot(P_B)\cdot(P_C)] \\ + [(P_A)\cdot(P_B)\cdot(P_D)] + [(P_B)\cdot(P_C)\cdot(P_D)] \\ - [(P_B)\cdot(P_D)] - [(P_A)\cdot(P_B)\cdot(P_C)\cdot(P_D)] \end{aligned} \tag{5.4}$$

As can be seen from (5.4) the probability of success of the event tree shown above in Fig. 5.2 can be represented with various individual probabilities P_A, P_B, P_C, and P_D, up to forth-order probability.

5.2.5 Higher-order Contingencies Based Event Tree Analysis

Enumerating all events using (5.4) to compute the exact values of probabilities; and thereby the reliability indices, can sometimes be unnecessary and impractical. In practice, probabilities of occurrence of various events are approximated up to certain order. This work uses the event tree analysis method with higher-order contingency approximation to calculate the reliability indices of the distribution system. The basic concept behind such an approximation is that if the contingency level does not have much impact on the system's reliability, we can ignore this contingency level without substantial effect on the required precision [113, 114]. Now, suppose we have three events E_A, E_B, and E_C with individual probabilities of P_A, P_B, and P_C, respectively. Therefore, the compound event probability can always be expressed as a polynomial comprising the three probabilities P_A, P_B, and P_C. For instance, let us consider the compound probability of the event $(E_A \cap E_B) \cup E_C$, which can be expressed as,

$$(E_A \cap E_B) \cup E_C = (P_C) + (P_A)\cdot(P_B) - (P_A)\cdot(P_B)\cdot(P_C) \tag{5.5}$$

As can be seen from (5.5), this compound probability consists of three terms: (P_C) with a first order probability , $[(P_A)\cdot(P_B)]$ with a second order probability, and $[(P_A)\cdot(P_B)\cdot(P_C)]$ with a third order probability. If we assume that the individual probabilities P_A, P_B, and P_C have, approximately, same order magnitude, the order of magnitude of each product term will depend on how many probabilities are involved in each product term. It is worth pointing out here that the probability of failure of most power system components is quite small, typically $\leq 1\%$ per year [114]. With that being said, the effect of higher-order events such as second-order and above can be limited using certain probability or frequency criterion.

Therefore, in the example given above, if the individual probabilities P_A, P_B, and P_C are very small, then the event $(E_A \cap E_B) \cup E_C$ can be approximated with $[(P_C)+(P_A)\cdot(P_B)]$ or even with (P_C) [114]. During the realization of the presented work, the effect of any contingency level with a frequency of occurrence less than 10^{-10} has been neglected.

5.2.6 Reliability Evaluation Model

In this section, we present an optimization framework to solve the distribution system reconfiguration problem. The objective of this optimization framework is to minimize the total load curtailment. The constraints in the proposed model are the spanning tree constraints, voltage bounds, real and reactive power limits, generation capacity constraints, and distribution feeders thermal capacities.

The total load curtailment minimization problem can be posed as,

$$\text{Loss of Load} = \min\left(\sum_{i=1}^{N_b} P_{Ci}\right) \tag{5.6}$$

Subject to:

1. Real and Reactive Power Injections

$$B^{'}\delta - GV + P_G + P_C = P_D \tag{5.7}$$

$$G^{'}\delta + BV + Q_G + Q_C = Q_D \tag{5.8}$$

2. Real and Reactive Power Constraints

$$P_G^{min} \leq P_G \leq P_G^{max} \tag{5.9}$$

$$Q_G^{min} \leq Q_G \leq Q_G^{max} \tag{5.10}$$

3. Feeder Capacity Constraints

$$bA'\ \delta + bA''\ V \leq I_f^{max} \tag{5.11}$$

$$-bA'\ \delta - bA''\ V \leq I_r^{max} \tag{5.12}$$

4. Load Curtailment Constraints

$$0 \leq P_C \leq P_D \tag{5.13}$$

$$0 \leq Q_C \leq Q_D \tag{5.14}$$

5. Voltage Bound Constraints

$$|V^{min}| \leq |V| \leq |V^{max}| \tag{5.15}$$

6. Angle Constraints

$$\delta \quad \text{unrestricted} \tag{5.16}$$

7. Spanning Tree Constraints

$$\varphi(l) = 0 \tag{5.17}$$

where P_C is the vector of real load curtailments $(N_b \times 1)$ and Q_C is the vector of reactive load curtailments $(N_b \times 1)$. Other abbreviations are as previously defined in Chapter 2.

It is worth mentioning here that all network constraints are considered in (5.6). Further, (5.7) and (5.8) are augmented by fictitious generators, which are equivalent to the required load curtailment. Moreover, in order to obtain a feasible solution for (5.6), we assume that one of the bus angles equals zero in the constraints.

5.2.7 Implementation of the Spanning Tree Constraints

One of the practical aspects of the presented work is that it retains the radial structure of the distribution system. We develop this condition based on a theoretic graph method [117, **?**] and impose it by adding constraint (5.17) to the optimization framework. The procedures of formulating this constraint are explained as follows: suppose we have a graph $G(V,E)$ with n vertices (nodes) $V = \{v_1, v_2, \cdots, v_n\}$ and m edges (branches) $E = \{e_1, e_2, \cdots, e_m\}$. We define the $(n \times m)$ vertex-edge incidence matrix $A\left[a_{ij}\right]$ of this graph as,

$$A = \begin{cases} 1, & \text{if an edge runs from vertex } i \text{ to vertex } j \\ -1, & \text{if an edge runs from vertex } i \text{ to vertex } j \\ 0, & \text{if vertex } i \text{ is not connected to vertex } j \end{cases} \tag{5.18}$$

From (5.18), it is evident that there are exactly two ones in every column of A. Consequently, we could obtain any row of A from the remaining rows, which signifies that A is linearly dependent. If we take out any row from A, the rank of the resultant matrix should be $\leq n$, which, in other words, means that the resultant matrix is linearly independent. Such matrix is denoted as the reduced incidence matrix A_r, and whose dimensions of $(n-1)\times m$ and a rank of $n-1$. The algorithm used in this work is developed based on the following theorem [117, 118].

Theorem: Any sub-matrix in A_r with dimensions $(n-1)\times(n-1)$, is non-singular if and only if the $n-1$ edges corresponding to the $n-1$ columns of this matrix constitutes a spanning tree.

Therefore, for every possible configuration, we evaluate the determinant of the reduced incidence matrix, or any sub-matrix in it, so that, if $\det[A_r]=\pm 1$, this means that the radial topology is preserved. On the other hand, if $\det[A_r]=0$, this means that the system has at least one loop and, therefore, the configuration is infeasible. We obtain the number of loops in every configuration, $\varphi(l)$, form Euler's formula [117] as,

$$\text{Number of Loops} = 1 - \text{Number of Vertices } + \text{Number of Edges} \tag{5.19}$$

To better understand the spanning tree algorithm developed herein, let us consider the graph shown in Fig. 5.3. This graph consists of 4 vertices and 5 edges. The incidence matrix described this graph has one column for each vertex and one row for each edge of the graph. The incidence matrix of the graph depicted in Fig. 5.3 can thus be represented as,

$$A = \begin{bmatrix} -1 & 1 & 0 & 0 \\ 0 & -1 & 1 & 0 \\ -1 & 0 & 1 & 0 \\ -1 & 0 & 0 & 1 \\ 0 & 0 & -1 & 1 \end{bmatrix} \tag{5.20}$$

Let us draw our attention to the loop forms by the vertices V_1, V_2, and V_3 and the edges E_1, E_2,

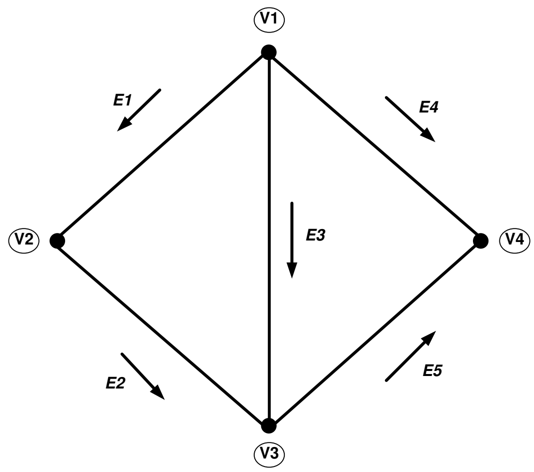

Figure 5.3: A graph with $n = 4$ vertices and $m = 5$ edges

and E_3, respectively. The matrix describes these vertices and edges can be expressed as,

$$A = \begin{bmatrix} -1 & 1 & 0 & 0 \\ 0 & -1 & 1 & 0 \\ -1 & 0 & 1 & 0 \end{bmatrix} \tag{5.21}$$

As can be seen from (5.21), the summation of the first two rows yields to the third row, which indicates that the matrix described by (5.21) is linearly dependent. The number of loops in the graph shown in Fig. 5.3 can be determined using (5.19), which is in this case equal to 2.

5.2.8 Calculation of Reliability Indices

From the formulation given above in (5.6)–(5.16), it is evident that (5.7) and (5.8) are augmented by fictitious generators, which is equivalent to the required curtailment since the problem aims at minimizing the total load curtailment. Further, in order to get a feasible solution for this standard minimization problem, one of the bus angles is assumed to be equal to zero. From a practical point of view, we take the radial network topology is taken as a necessary constraint during the realization of the presented work. We thus apply the algorithm presented in Section 3.2.7 to impose the radial topology constraints on all possible configurations.

Using the formulation giving in (5.6), the expected demand not supplied is calculated as,

$$EDNS = \sum_{h=1}^{Nc} LOL(h) \times Prob(h) \tag{5.22}$$

The expected unserved energy over a period of one year is calculated as,

$$EUE = 8760 \times EDNS \tag{5.23}$$

The energy index of unreliability (EIU) can therefore be estimated as [96, 97],

$$EIUR = \frac{LOEE}{E_T} \tag{5.24}$$

where T is the period of study in hours, $LOL(h)$ is the load curtailment of state h, $Prob(h)$ is the probability of state h, N_c is number of contingencies, and E_T is the total energy demand.

5.3 Formulation of the Optimal Distribution System Reconfiguration Problem

As was mentioned earlier in Section 5.1, this work proposes a method based on particle swarm optimization to search for the best set of the sectionalizing and tie-switches that maximizes the service reliability of the distribution network. Nevertheless, before proceeding to describe the proposed intelligent search method, it is indispensable to touch upon the fundamentals of the particle swarm optimization technique, its potential advantages, disadvantages, and the reasons behind choosing it as a searching tool during the realization of the presented work.

5.3.1 Particle Swarm Optimization

Particle swarm optimization is a population-based optimization technique inspired by the social behavior of flocks of birds or schools of fish, which is described in detail by Kennedy and Eberhart in [88, 89]. In particle swarm optimization, the positions and velocities of the particles are initialized with a population of random feasible solutions and search for optima by updating generations. The advantages of using particle swarm optimization technique in distribution system reconfiguration studies include the following:

1. Distribution systems are generally equipped with two kinds of switches, which are the sectionalizing switches and tie-switches. The sectionalizing switches are normally closed and used to connect various distribution feeders segments. On the other hand, the tie-switches are normally open and used to transfer loads during abnormal and emergency conditions. These switches can be better represented by digital numbers 0 and 1, which are easy to implement using binary particle swarm optimization.

2. Particle swarm optimization has two main parameters, which are the personal best and the group best. Every particle in the swarm remembers its own personal best and at the same time the group best. Consequently, PSO based methods have considerably more memory capability than some other swarm intelligence based methods.

3. Particle swarm based optimization only needs few parameters to tune up, unlike some other swarm intelligence.

4. Particle swarm optimization can handle a wide range of nonlinear and non-differentiable

functions in an efficient and effective manner.

5. Unlike some other swarm intelligence based methods, particle swarm optimization has better convergence characteristics, which is not largely affected by the problem dimensions, non-linearity, and size.

6. Particle swarm optimization could lead to optimal or semi-optimal global solution for a wide range of practical problems.

In particle swarm optimization, the movement of the particles, which represent the potential solutions, is governed by the weighting factors, the individual best, and the group best. Using these three components, a vector that determines the direction and magnitude of each particle in the swarm can therefore be represented as,

$$v_i = v_{i-1} + \varphi_1 \times rand \times (Ppbest_i - x_i) + \varphi_2 \times rand \times (Pgbest - x_i) \tag{5.25}$$

where *rand* is a uniformly distributed random number between [0,1], $Ppbest_i$ is the particle best position from the probability of a state prospective particle i has ever encountered, *Pgbest* is the group of particles best position from the probability of a state prospective the group has ever encountered. Further, φ_1 and φ_2 are acceleration factors. These acceleration factors are usually chosen so that $\varphi_1 + \varphi_2 = 4$, with $\varphi_1 = \varphi_2 = 2$.

The change in particles positions can be defined by a sigmoid limiting transformation function and a uniformly distributed random number in [0,1] as the following,

$$x_{id} = \begin{cases} 1, & \text{rand(0,1)} < S(v_{id}) \\ 0, & \text{otherwise} \end{cases} \tag{5.26}$$

where, x_{id} is the d^{th} component of particle i and $S(v_{id})$ is the sigmoid function of d^{th}'s component of particle i which can be expressed as,

$$S(v_{id}) = \frac{1}{1+e^{(-v_{id})}} \tag{5.27}$$

5.3.2 The Search Space of the Problem

In the presented distribution system reconfiguration problem for service reliability improvement, the solution space being searched by the intelligent BPSO method is defined as the space of all possible network configurations. Suppose the number of sectionalizing switches is N_{ssn} and the number of and tie-switches is N_{tsn}, respectively. The solution space would be of the form Ω_s=$\{N_{ss1}, N_{ss2}, \cdots, N_{ssn}\} \cup \{N_{ts1}, N_{ts2}, \cdots, N_{tsn}\}$. Here, N_{ssi} and N_{tsi} describe the open/close status of the sectionalizing switch, or tie-switch, i, respectively.

5.3.3 Detailed Solution Algorithm

The solution algorithm explains the flow of the procedures of evaluating the reliability indices and finding the optimal configuration. The steps of the reliability assessment and finding the optimal distribution system configuration are summarized as follows,

1. Initialize the positions and velocities of the particles, x_i and v_i respectively. Particle's positions are initialized using uniformly distributed random numbers; switches that are in the closed state are represented by 1's and switches that are in the open state are represented by 0's. The length of a vector dimension equals the number of system switches. One of the particles is chosen to represent the original configuration of the system, that is, all tie-switches are in open state.

2. Check if there are identical particles. If so, discard the identical ones and save the rest of the particles in a temporary array vector by converting the binary numbers to decimal numbers.

3. Check if there are particles already exist in the database, if so, set load curtailments of the existing particles to the system peak load to decrease the chance of visiting these configurations again. Then, save the rest in the database and go to the next step.

4. Check the radiality condition for each particle, if the radiality condition is met, go to next step, otherwise set load curtailments of the particles that represent infeasible configurations to the system peak load to decrease the chance of visiting these configurations again.

5. Set system parameters and update the status of the system components (sectionalizing witches, tie-switches, circuit breakers, etc.), for every particle.

6. Perform reliability evaluation for each particle by solving the linear programming optimization problem for every system state to calculate the expected load curtailment for each particle.

7. Determine and update personal best and global best configuration based on minimum load curtailments.

8. Check for convergence. After few iterations, if no new better configurations were discovered, terminate the algorithm.

9. Update particle's velocities using (5.25) and update particle's positions using (5.26) and (5.27), and go to step 3.

The solution procedures of reliability evaluation and finding the optimal configuration using the proposed BPSO based search method are depicted in the flow chart shown in Fig 5.4.

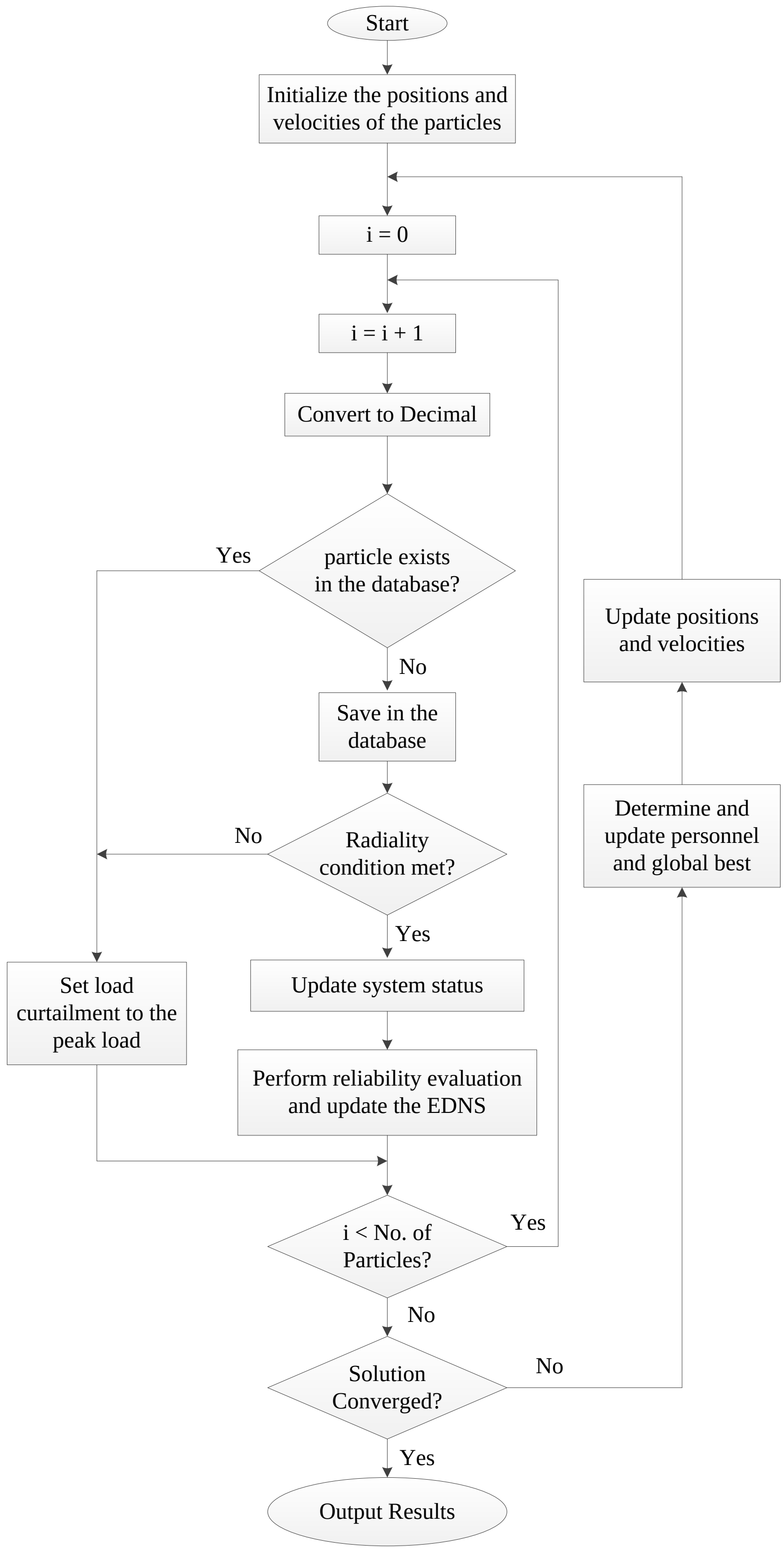

Figure 5.4: Flowchart of the proposed method

5.4 Demonstration and Discussion

In order to demonstrate the effectiveness of the proposed method and the search method of optimal distribution system reconfiguration, we test the proposed method on three different distribution systems. We provide the results, assumptions, and discussion in the subsequent section.

5.4.1 Modified 33 Bus Distribution System Test Case

The 33 bus system is a 12.66 kV radial distribution system, which has been widely used as a benchmark system in solving the distribution system reconfiguration problem [16]. The single-line diagram of the 33 bus system is depicted in Fig. 5.5. The total real and reactive power loads on this system are 3715 KW and 2300 KVAR, respectively. As shown in Fig. 5.5, this system consists of 33 buses, including the substation bus, 32 branches, 3 laterals, and 5 tie-lines. For the initial configuration, the normally open switches (tie-lines) are {S33, S34, S35, S36, S37}, which are represented by dotted lines. The normally closed switches are denoted as S1 to S32 and are represented by solid lines.

The reliability data used in this work are acquired from [101] and are given in Table 5.1. The reliability indices used in this paper are the expected unserved energy EUE and the energy index of unreliability EIUR. The parameters of the proposed BPSO based search method are given in Table 5.2. We conduct several case studies on the 33 bus system and other systems, which are provided hereafter. It is imperative to mention here that we consider various loading conditions that include light loading conditions in which the total load is reduced by 50%, rated or nominal loading conditions in which peak loads are considered, and heavy loading conditions in which the total load is increased by 50%. The results of the nominal (peak) loading conditions are discussed in the subsequent sections.

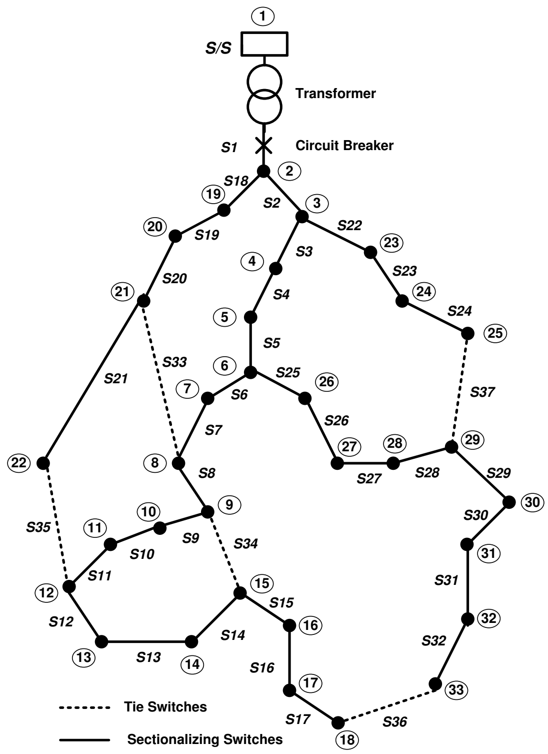

Figure 5.5: Single-line diagram of the modified 33 bus distribution system

Table 5.1: Reliability Data for the Test Systems

Component Name	Failure rate (failure/year)	Repair Rate (hr)
Transformer	0.05882	144
Bus	0.0045	24
Circuit Breaker	0.1	20
Distribution Line	0.13	5
Sectionalizing Switch	0.2	5

5.4.1.1 Case Scenario I

In this case scenario, circuit breakers, switches, and the distribution transformer are assumed to be perfectly reliable. The failure rates of distribution lines are only considered in this case study. It has been assumed that every distribution line has a sectionalizing switch. The optimal status of the sectionalizing and tie-switches is obtained using the BPSO given in Section 3.3.4. As depicted in Table 5.2, the parameters of the BPSO based search method have been chosen so that: number of particles = 50, acceleration factors $\varphi_1 = 2$, and $\varphi_2 = 2$, with $\varphi_1 + \varphi_2 = 4$, and the maximum number of iterations = 1000. It is worth pointing out here that these parameters were obtained after carrying out several independent runs and found to provide best performance in terms of execution time and solution.

Table 5.2: Parameters of the BPSO

Parameter	Proposed Value
Number of Particles	50
Social Constant (φ_1)	2
Social Constant (φ_1)	2
Max. Number of iterations	1000

For comparison purposes, the proposed method of distribution system reconfiguration for reliability maximization has been first applied on the initial configuration shown in Fig. 5.5. The optimal set of the sectionalizing and tie-switches that yield minimum load curtailment were {S6, S10, S13, S27, S36}. The results of this case study are summarized below in Table 5.8.

For the nominal load scenario, as can be seen from Table 5.8, the EUE is reduced from 17521.3 kWh/year for the initial configuration to 13536.6 kWh/year after reconfiguration. This is about 22.74% reduction in the annual expected unserved energy.

According to the Energy Data via World Energy Council (enerdata) [119, 120], the typical household power consumption in the US is about 11,700 kWh each year. This is for an average household size closer to 2.5 people. Further, according to [119, 120] each American uses about 4,500 kWh per year in his home. We use these figures here to calculate the average number of the affected households before and after reconfiguration. Therefore, for Case Scenario I, for nominal loading conditions, the average number of the affected households before reconfiguration is estimated to be 1.5 households. The number of the affected consumers before reconfiguration was 3.89 consumers. However, these figures have been respectively reduced to 1.16 and 3, after the system has been reconfigured. This has been the case for the light and heavy loading conditions as can be clearly seen from Table 5.8.

As an example of the effectiveness of the proposed method in minimizing the EIU, for the case of nominal load, the EIU has been reduced from 0.00054 before reconfiguration to 0.00042 after the system has been reconfigured.

5.4.1.2 Case Scenario II

In this case scenario, we take the failure rates of all distribution system components such as circuit breakers, switches, buses, distribution lines, and transformer into consideration. In addition, we assume that every distribution line has a sectionalizing switch. The optimal set of the sectionalizing and tie-switches that yield minimum load curtailment are {S6, S10, S13, S27, S36}. For comparison purposes, the proposed method of distribution system reconfiguration for reliability maximization has been first applied to the initial configuration shown in Fig. 5.5. The results of this case scenario are summarized below in Table 5.9.

As can be obviously seen from Table 5.9, the EUE has been reduced from 85692.2 kWh/year for the initial configuration to 74235.6 kWh/year after reconfiguration. This is about 13.4% reduction in the expected unserved energy. Moreover, in Case Scenario II, for nominal loading conditions, the average number of the affected households before reconfiguration is estimated to be 7.32 households. The number of the affected consumers before reconfiguration was 19.04 consumers. However, these figures have been respectively reduced to 6.34 and 16.5, after the system has been reconfigured. The This case scenario has shown the effect of taking the failure rates of all system components into the optimization problem.

As an example of the effectiveness of the proposed method in minimizing the EIU, for the case of nominal load, the EIU has been reduced from 0.00263 before reconfiguration to 0.00228 after the system has been reconfigured.

5.4.1.3 Case Scenario III

In realistic distribution systems, the number of sectionalizing switches are sometimes limited due to certain operational and economic reasons. Therefore, this case scenario is similar to case scenario II except that the number of sectionalizing switches have been limited and their locations are assigned. For this case scenario, the number of sectionalizing switches has been assumed 11 switches, in addition to the 5 tie-switches. The positions of these sectionalizing switches are assumed to be {S7, S8, S9, S11, S12, S14, S17, S28, S29, S32, S24}. The results of this case scenario are summarized below in Table 5.5.

Table 5.5 shows the set of switches that had to be opened to minimize the total load curtailment. This set include {S9, S14, S17, S28, S33}. As can be seen from Table 5.5, the EUE has been reduced from 85692.2 kWh/year for the initial configuration to 76107.7 kWh/year after reconfiguration. This is about 11.2% reduction in the expected unserved energyd. Moreover, in Case Scenario III, for nominal loading conditions, the average number of the affected households before reconfiguration is estimated to be 7.32 households. The number of the affected consumers before reconfiguration was 19.04 consumers. However, these figures have been respectively reduced to 6.5 and 16.91, after the system has been reconfigured. The This case scenario has shown the effect of taking the failure rates of all system components into the optimization problem. As expected, the amount of power curtailed is going to increase if the number of sectionalizing switches is constrained.

As an example of the effectiveness of the proposed method in minimizing the EIU, for the case of nominal load, the EIU has been reduced from 0.00263 before reconfiguration to 0.00234 after the system has been reconfigured.

5.4.1.4 Case Scenario IV

This case scenario is similar to case scenario III except that the failure rates of distribution feeders are increased by 20% and the failure rates of sectionalizing switches are increased by 10%. Again, the positions of these sectionalizing switches are assumed to be {S7, S8, S9, S11, S12, S14, S17, S28, S29, S32, S24}. The results of this case scenario are summarized below in Table 5.6.

Table 5.6 shows the set of switches that had to be opened to minimize the total load curtailment. This set include {S9, S14, S17, S28, S33}. As can be seen from Table 5.6, the EUE has been reduced from 91778.3 kWh/year for the initial configuration to 80972.4 kWh/year after reconfiguration. This is about 11.77% reduction in the expected unserved energy. Moreover, in Case Scenario IV, for nominal loading conditions, the average number of the affected households before reconfiguration is estimated to be 7.84 households. The number of the affected consumers before reconfiguration was 20.4 consumers. However, these figures have been respectively reduced to 6.92 and 18, after the system has been reconfigured.

As an example of the effectiveness of the proposed method in minimizing the EIU, for the case of nominal load, the EIU has been reduced from 0.00282 before reconfiguration to 0.00248 after the system has been reconfigured.

5.4.2 Modified 69 Bus Distribution System Test Case

The 69 bus system is a 12.66 kV distribution system with total real and reactive power loads of 3802.19 kW and 2694.06 kVar, respectively [33]. The single-line diagram of the 69 bus system is depicted in Fig. 5.6. For the initial configuration, the normally open switches are {S69, S70, S71, S72, S73}.

The proposed reliability based distribution system reconfiguration method is applied on the

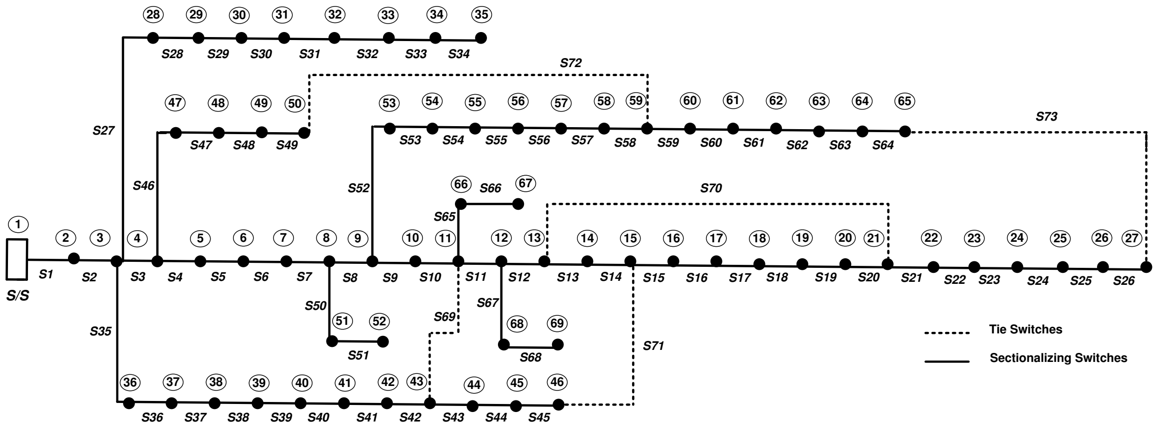

Figure 5.6: Single-line diagram of the 69 bus distribution system

69 bus system and the EUE reliability index is calculated for every feasible configuration. We consider the nominal loading conditions in this case scenario. It is appropriate to mention here that various case studies were conducted on the 69 bus system, however, owing to space constraints, the results of one case scenario, in which the failure rates of all distribution feeders are considered, are presented in Table 5.7. As can be seen from Table 5.7, the amount of the annual unserved energy is reduced from 31498.4 kWh/year for the initial network topology to 23124.5 kWh/year after reconfiguration. This is equivalent to 26.58% reduction in the annual unserved energy.

For nominal loading conditions, the average number of the affected households before reconfiguration is estimated to be 2.96 households. The number of the affected consumers before reconfiguration was 7 consumers. However, these figures have been respectively reduced to 1.98 and 5.14, after the system has been reconfigured. Moreover, the EIU has been reduced from 0.00095 before reconfiguration to 0.00069 after the system has been reconfigured.

5.4.3 Modified 118 Bus Distribution System Test Case

The proposed framework has been applied to a more complicated and realistic distribution system to validate its feasibility in such conditions. The system under consideration is an 11 kV, 118-

nodes large-scale radial distribution system [121]. The single-line diagram of the 118 bus system is depicted in Fig. 5.7.This system consists of 117 branches and has 15 tie-lines. The results of one case scenario performed on this system are presented. The failure rates of distribution feeders are considered in this case. For the initial configuration, the EUE has been calculated using the proposed algorithms and was found 111.29 MW/year. The EUE has been reduced to 108.75 MW/year after the network being reconfigured.

For nominal loading conditions, the average number of the affected households before reconfiguration is estimated to be 9.51 households. The number of the affected consumers before reconfiguration was 24.73 consumers. However, these figures have been respectively reduced to 9.29 and 24.16, after the system has been reconfigured.

5.4.4 Voltage Profile Improvement

We discuss the effect of the reconfiguration on improving the overall voltage profile of the distribution system in this section. We consider the 33 bus, 69 bus, and 118 bus system in this case study. However, we provide the results of the basic case scenario in which circuit breakers, switches, and the distribution transformer are assumed to be perfectly reliable except distribution feeders. Further, we assume that every distribution line has a sectionalizing switch. As can be seen from Table 5.9, all bus voltages have become within the pre-specified limit, which is assumed to be 5% in this work. This is a key advantage of the proposed method of reliability enhancement since keeping bus voltages within the predetermined limits relive loads, reduce the possibility of load shedding; and thereby minimize service interruptions.

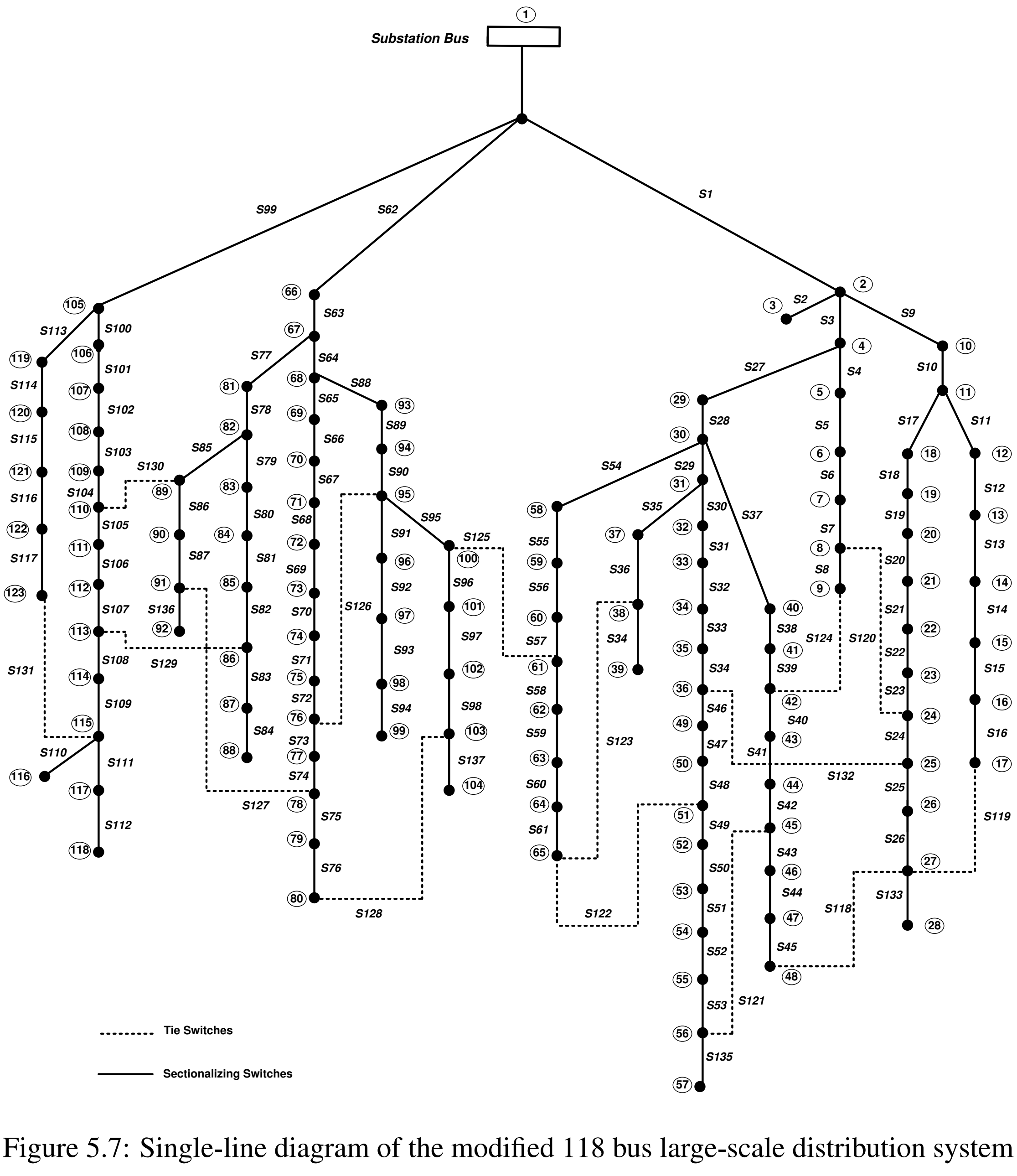

Figure 5.7: Single-line diagram of the modified 118 bus large-scale distribution system

5.5 Summary

This chapter has proposed a framework for distribution system reconfiguration with an objective of reliability maximization. The main features of the work described above include:

1. The framework is developed based on a novel linearized power flow model, in which the coupling between active power and voltage magnitude as well as the coupling between reactive power and voltage angle is maintained.

2. Voltage magnitudes, reactive power flows, and all shunt elements have been taken into consideration in the proposed model.

3. The current limits constraints can be approximated using piecewise linear model. Therefore, the degree of approximation can be improved to the desired level by increasing the number of line segments used, without substantial affect on the main routine.

4. The framework presented in this paper is generic in the sense that it can be used for solving several power system optimization problems such as the constrained economic power dispatch for active distribution systems and energy market simulations, in which repetitive solutions are required.

5. The probabilistic reliability evaluation was conducted using the event tree analysis with higher-order contingency approximation, hence the computational burden has been tremendously reduced when compared to some other approaches available in the literature, which sometimes tend to be infeasible even for off-line planning studies.

Table 5.3: Results of Case Scenario I

Network Status & Loading Conditions		Best Set of Tie & Sectionalizing Switches	EUE kWh/year	Affected Households	Affected Consumers
Nominal	Initial Conf.	S33, S34, S35, S36, S37	17521.3	1.5	3.89
	Optimal Conf.	S6, S10, S14, S27, S36	13536.6	1.16	3.0
Light	Initial Conf.	S33, S34, S35, S36, S37	7008.54	0.60	1.56
	Optimal Conf.	S6, S10, S14, S27, S36	5414.63	0.46	1.20
Heavy	Initial Conf.	S33, S34, S35, S36, S37	24529.9	2.10	5.45
	Optimal Conf.	S7, S10, S13, S27, S36	18951.2	1.62	4.21

Table 5.4: Results of Case Scenario II

Network Status & Loading Conditions		Best Set of Tie & Sectionalizing Switches	EUE kWh/year	Affected Households	Affected Consumers
Nominal	Initial Conf.	S33, S34, S35, S36, S37	85692.2	7.32	19.04
	Optimal Conf.	S6, S10, S13, S27, S36	74235.6	6.34	16.49
Light	Initial Conf.	S33, S34, S35, S36, S37	34276.9	2.93	7.62
	Optimal Conf.	S7, S10, S14, S27, S36	29694.2	2.54	6.60
Heavy	Initial Conf.	S33, S34, S35, S36, S37	119969	10.25	26.65
	Optimal Conf.	S7, S10, S13, S27, S36	103930	8.88	23.10

Table 5.5: Results of Case Scenario III

Network Status & Loading Conditions		Best Set of Tie & Sectionalizing Switches	EUE kWh/year	Affected Households	Affected Consumers
Nominal	Initial Conf.	S33, S34, S35, S36, S37	85692.2	7.32	19.04
	Optimal Conf.	S9, S17, S28, S33, S34	76107.7	6.50	16.91
Light	Initial Conf.	S33, S34, S35, S36, S37	34276.9	2.93	7.62
	Optimal Conf.	S9, S17, S28, S33, S34	30443.1	2.60	6.77
Heavy	Initial Conf.	S33, S34, S35, S36, S37	119969	10.25	26.65
	Optimal Conf.	S9, S14, S17, S28, S33	106551	9.11	23.68

Table 5.6: Results of Case Scenario IV

Network Status & Loading Conditions		Best Set of Tie & Sectionalizing Switches	EUE kWh/year	Affected Households	Affected Consumers
Nominal	Initial Conf.	S33, S34, S35, S36, S37	91778.3	7.84	20.40
	Optimal Conf.	S9, S17, S28, S33, S34	80972.4	6.92	18
Light	Initial Conf.	S33, S34, S35, S36, S37	36711.3	3.14	8.16
	Optimal Conf.	S9, S17, S28, S33, S34	32389.0	2.77	7.20
Heavy	Initial Conf.	S33, S34, S35, S36, S37	128490	10.98	28.55
	Optimal Conf.	S9, S14, S17, S28, S33	113361	9.69	25.19

Table 5.7: Results of 69 Bus System

Network Status	Best Set of Tie & Sectionalizing Switches	EUE kWh/year	Affected Households	Affected Concumers
Initial Conf.	S69, S70, S71, S72, S73	31498.4	2.96	7
Final Conf.	S14, S18, S24, S56, S69	23124.5	1.98	5.14

Table 5.8: Results of 118 Bus System

Network Status	Best Set of Tie & Sectionalizing Switches	EUE MWh/year	Affected Households	Affected Concumers
Initial Conf.	S33, S34, S35, S36, S37	108.75	9.51	24.73
Final Conf.	S6, S10, S14, S27, S36	111.29	9.29	24.16

Table 5.9: Comparison of Bus Voltages Before and After Reconfiguration

Test System	Min. Voltage Before Reco.	Max. Voltage Before Reco.	Min. Voltage After Reco.	Max. Voltage After Reco.
33 Bus System	0.9113 @ 18	1.0 @ 1	0.95 @ 25	1.0474 @ 1
69 Bus System	0.9175 @ 64	1.0 @ 1	0.9654 @ 65	1.01 @ 1
118 Bus System	0.8844 @ 77	1.0 @ 1	0.9528 @ 77	1.0414 @ 1

Chapter 6

Conclusions and Future Work

6.1 Conclusions

Electric power distribution systems have been operated in a vertical and centralized manner for several years. However, due to certain environmental, economic, and political reasons, this structure has been changed and several real–time engineering applications in both operational and planning stages have emerged. Examples of these applications include optimal sizing and placement of distributed generation units, optimal power flow of active distribution systems, and feeder reconfiguration for reliability enhancement and service restoration, and so forth. It is very well known that these applications require a power flow study at the first step of the solution. Nevertheless, the vast majority of these applications require repetitive and prompt power flow solutions. Performing full AC power flow, on one hand, gives high calculation precision but requires a quite extensive computational burden and storage requirements. On the other hand, and more prominently, the largest part of the aforementioned applications is essentially nonlinear complex combinatorial constrained optimization problems. The formulation of the nonlinear problem tends to be a tedious task and computationally cumbersome in terms of execution time, storage requirements, and programming. These constraints combined with the large number of nodes, branches, and switches of distribution system will incontestably increase the complexity of the problem. It has therefore become necessary to develop more powerful tools for both planning and operational studies not only to accompany the aforementioned applications, but also to handle the other new tasks, which are coming in the immediate future.

The first part of this dissertation developed a novel power flow model, which is equally appropriate for use at both distribution and transmission levels and can be extremely useful whenever fast, robust, and repetitive power flow solutions are required. We developed the proposed linearized AC power flow model (LACPF) based on linearization of the full set of conventional power flow equations, and therefore includes voltage magnitude solutions and reactive power flows, unlike traditional linearized power flow methods. The model developed in this dissertation is non-iterative, direct, and involves no convergence issues even with ill-conditioned systems and systems with high R/X branch ratios. The modifications in case of unbalanced distribution networks are straightforward and largely lie in certain elements in the bus admittance matrix; and thus the advantages obtained with balanced operation are preserved. We tested the proposed LACPF model on several balanced, unbalanced, and weakly-meshed distribution systems and found to perform with speed and accuracy appropriate for repetitive solutions. We provided and thoroughly discussed the results of various test distribution systems, including a large-scale system test case, in Chapter 2.

The second part of this dissertation developed an efficient optimization framework to handle several distribution system operational and planning problems. The proposed framework uses linear programming since linear programming based formulations tend to be flexible, reliable, and faster than their nonlinear counterparts. We considered voltage bounds, reactive power limits, and all shunt elements in the proposed optimization model. As was discussed in Chapter 1, distribution systems are the most extensive part in the entire power system due to their spanning tree structure and the high R/X branch ratios. Therefore, we proposed a new analytical method for optimal placement and sizing of distributed generation units on distribution systems in Chapter 3. The objective of the analytical method presented in Chapter 3 is to minimize the distribution system losses. Analytical methods are reliable, computationally efficient, and are suitable for planning studies such as distributed generation planning. Furthermore, analytical approaches could lead to an optimal or near-optimal global solution. We developed a priority list based on loss sensitivity factors to determine the optimal locations of the candidate distributed generation units, after identifying the penetration level of the distributed generation units. We performed sensitivity analysis based on the real power injection of the distributed generation unit to estimate the optimal size and power factor of the candidate distributed generation units. We considered various types of distributed generators and also proposed viable solutions to reduce total system losses. We validated the effectiveness of the proposed method by applying it on the same benchmark systems used before in Chapter 2, in particular the 33 bus and the 69 bus distribution systems, since both systems have been extensively used as examples in solving the placement and sizing problem of distributed generators. In addition, we performed exhaustive power flow studies to verify the sizes obtained by the analytical method. We validated the optimal locations and sizes obtained by the proposed analytical method by comparing them with some other analytical methods available in the literature. We show that the proposed analytical method could lead to an optimal or near-optimal global solution, while requiring lower computational effort.

We proposed a new method to solve the optimal economic power dispatch problem of active distribution systems in Chapter 4. Nonlinear programming and linear programming based methods are widely used in the literature to solve the optimal economic dispatch problem. Nevertheless, the vast majority of the linear programming based methods were developed based on the DCPF model, which has several drawbacks were discussed earlier in Section 1.5. In Chapter 4, in addition to the piecewise linear model we have developed earlier in Chapter 2 to handle the thermal capacities of transmission lines, we developed piecewise linear models to deal with the exponential loads, cost curves of generating units, and total power losses. We take the effect of distributed generation units in several case scenarios by considering different penetration levels. We demonstrated the effectiveness of the proposed method by performing numerous case studies. We were able to show that the results obtained by the proposed method correspond closely with those obtained by nonlinear means, while requiring lower computational effort.

We proposed a method to solve the distribution system reconfiguration problem with an objective of reliability improvement in Chapter 5. Reliability enhancement of distribution systems through feeder reconfiguration is not well studied in the literature. In the context, we introduced a complete optimization framework to handle the reliability maximization problem. Since the time and computational effort spent in evaluating reliability indices are of great concern in both planning and operational stages, we used a probabilistic reliability assessment method based on event tree analysis with higher-order contingency approximation. Therefore, the effect of the higher-order contingencies is limited and, at the same time, the computational burden is improved. We select the expected unserved energy as the energy index that needs to be minimized. However, to know how much reliable the system is, we introduced another reliability measure, which is the energy index of unreliability. From practical perspective, the radial topological structure has been taken as a necessary condition during the realization of this work. Therefore, we developed another constraints based on theoretic graph to preserve the spanning tree structure of the distribution system. We proposed a search method based on particle swarm optimization technique. We demonstrate the effectiveness of the proposed method on several distribution systems and show that the amount of the annual unserved energy, the number of affected households, and the affected number of consumers can be tremendously reduced using the proposed method.

6.2 Future Work

As with any research topic, the models and methods presented in this dissertation can be extended in several directions. Some other research directions are summarized here.

In Chapter 3, we addressed the problem of optimal placement and sizing of distributed generation units using analytical techniques. We proposed formulas for both the optimal location and optimal size of the candidate distributed generation units. We considered one load scenario, in which peak loads are assumed. In fact, the work presented in Chapter 3 can be extended in different directions. For instance, the problem can be solved using the proposed optimization framework in addition to a method, which can be developed based on swarm intelligence such as particle swarm optimization or genetic algorithms. We anticipate that both the analytical and the swarm intelligence based method would eventually lead to similar results. However, the latter method will be more appropriate in case that different load scenarios are sought.

In Chapter 4, we proposed a method for solving the problem of optimal economic power dispatch of active distribution systems. We assumed a constant power distributed generation units while performing this study. In fact, in a related work [122], we considered intermittent wind turbine induction generators based distributed generators to account for penetration of the distributed generators. However, the study we conducted in [122] was completely developed based on the DCPF model. The work presented in Chapter 4 can be extended using intermittent distributed generation units such wind turbine induction generators and solar generators. The intermittency of the distributed generators can be accounted for using a hybrid optimization model such as Homer [105], for instance, which has been used in [122]. Other constraints can also be added to the optimization framework in order to perform some other optimal operation and planning studies.

We proposed a new method to solve the distribution system reconfiguration problem with an objective of reliability improvement in Chapter 5. In the context, we introduced a complete optimization framework to handle the reliability maximization problem. We used a probabilistic reliability assessment method based on event tree analysis and selected the expected unserved energy as the energy index that needs to be minimized. We developed another constraints based on theoretical graph to preserve the spanning tree structure of the distribution system. we proposed a search method based on particle swarm optimization technique. However, in Chapter 5 we did not concentrate on the fault location and isolation. The work presented in Chapter 5 can be extended to solve the problem of service restoration in distribution systems. In this context, the objective function has to be modified so that the expected unserved energy and the number switching operations have to be minimized simultaneously. In order to increase the amount of the total restored load, distributed generation units can be added to the system. The amount of the total restored load can be significantly increased by means of distributed generation units. For further load restoration, sensitivity analysis can be performed to select the optimal size and location of these distributed generators, which would result in minimizing of the total load curtailment of in-service consumers.

In Chapter 5, we used the energy index of unreliability to measure the overall reliability of the system. We incorporated the number of affected households and affected consumers in the performed study. The work is now being extended so that these indices to combine to propose a more realistic reliability index.

In [123], we solved the problem of distribution system reconfiguration for loss reduction and voltage profile improvement using. The optimization framework presented in Chapter 5 can be modified to solve the same problem. In doing so, transmission losses have to linearized in order to include them in the model.

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