Locational Marginal Price Computation for Optimal Operation of Active Distribution System using Game Theory and Meta Heuristic Techniques

Thesis
Submitted in partial fulfillment of the requirements
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Dedicated to

My beloved Grandmother

Thumma Saraswathi

<u>APPROVAL SHEET</u>

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This is to certify that the thesis titled **"Locational Marginal Price Computation for Optimal Operation of Active Distribution System using Game Theory and Meta Heuristic Techniques"**, submitted by **Mr. Venkataramana Veeramsetty** (Roll No. 714120), is a bonafide work submitted to National Institute of Technology Warangal in partial fulfilment of the requirements for the award of the degree of **Doctor of Philosophy** in Electrical Engineering. To the best of my knowledge, the work incorporated in this thesis has not been submitted elsewhere for the award of any degree.

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DECLARATION

This is to certify that the work presented in the thesis entitled **"Locational Marginal Price Computation for Optimal Operation of Active Distribution System using Game Theory and Meta Heuristic Techniques"** is bonafide work done by me under the supervision of **Dr. Chintham Venkaiah**, Associate Professor, Department of Electrical Engineering, National Institute of Technology, Warangal, India and was not submitted elsewhere for the award of any degree.

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ABSTRACT

As integration of Distributed Generation (DG) into the distribution system is increasing rapidly, Distribution Companies (DISCOs) need to control private DG owners and also operate DG units in such a way that optimal operation of Active Distribution System (ADS) has been achieved in terms of reduction of active power losses, emissions and improvement of reliability. DISCO can control private DG owners and also operate the network optimally in terms of reduction of active power losses, emissions and improvement of reliability by providing proper financial incentives to DG owners. Nodal pricing is one of the most efficient and important mechanisms for providing financial incentives. Computation of Locational Marginal Price (LMP) is the most prominent mechanism among all existing policies of nodal pricing. So DISCOs require an efficient tool/algorithm to compute LMP at DG buses for optimal operation of ADS. Algorithms needs to be designed in such a way that a private DG owner will receive financial incentives based on DG unit's contribution on optimal operation of ADS. As active power load and market price are uncertain in nature, LMP computation tool which can handle uncertainties needs to be developed.

In this thesis, Proportional nucleolus theory based iterative method has been developed to compute LMP at DG buses in ADS based on active power loss reduction. Proportional nucleolus theory is a cooperative game theory solution concept which has been used for allocation of change in active power losses among DG units. Financial incentives have been provided to DG owners from reduced active power loss cost. Loss sensitivity factors have been developed to find the share of active and reactive power generation at DG bus on change in active power losses. The proposed proportional nucleolus theory based iterative method provides LMP, Reactive Power Price (RPP), zero DISCO's extra benefit due to active power loss reduction, and also estimates the state of the ADS in terms of DG units generation and active power losses. To study the robustness and effectiveness of the proposed algorithm, the proposed algorithm was implemented on 84 bus Taiwan Power Company (TPC) radial distribution system and Pacific Gas and Electric company (PG & E) 69 bus radial distribution system.

The above mentioned proportional nucleolus theory based iterative method was further extended for computing LMP at DG buses in ADS based on active power loss and emission reduction. Proportional nucleolus theory has been used to allocate change in active power losses and emissions among DG units. Financial incentives have been provided to DG owners

from reduced active power loss cost and emission penalty. The proposed proportional nucleolus theory based iterative method provides LMP, RPP, zero DISCO's extra benefit due to both active power loss and emission reduction, and it also estimates the state of ADS in terms of DG units generation and active power losses and emissions. The robustness and effectiveness of the proposed algorithm for LMP computation based on active power losses and emissions is verified by implementing it on 84 bus TPC radial distribution system and PG & E 69 bus radial distribution system.

Further, a new Hybrid Genetic Dragonfly Algorithm (HGDA) based optimal power flow (OPF) has been developed to compute LMP at DG buses in ADS based on reliability improvement. First time hybridization has been done among genetic algorithm and dragonfly algorithm to get the solution closer to the global by extracting the advantages of both. This method has been developed by considering the islanded operation when line outage has occurred. Uniform price which is equal to market price is given to all DG units as part of distribution network which is connected to substation. Load and generation scheduling has been done using HGDA based OPF to compute LMP at DG buses in that part of the network which is disconnected from substation. Expected Energy Not Supplied (EENS) has been used as a reliability measuring index. In load scheduling, the weighted sum of EENS value of various type of customers has been considered as an objective function. On the other hand, in generation scheduling, weighted sum of various objectives like DISCO's investment cost to purchase power from DG owners, active power losses and emissions in islanded portion of network has been considered as single objective function. The proposed method improves the reliability of active distribution network by providing proper incentives in terms of LMP to DG owners. The robustness and effectiveness of the proposed algorithm for LMP computation based on reliability improvement is verified by implementing the model on 38 bus and PG & E 69 bus radial distribution systems.

Further, a new method has been developed to compute Probabilistic Locational Marginal Price (PLMP) at DG buses in ADS based on active power loss reduction by handling uncertainties that exist in load and market price. Proportional Nucleolus Theory (PNT) based iterative method has been used as deterministic approach for computing LMP values. 2m+1 scheme of point estimation method (2m+1:PEM) has been used as a probabilistic approach for handling the uncertainties. The proposed mechanism provides PLMP and Probabilistic Reactive Power Price (PRPP), and also estimates the state of the ADS in terms of active power losses which are less sensitive to randomness that exist in market price and load. The robustness and effectiveness of the proposed probabilistic approach for LMP computation based on active power loss reduction is verified by implementing it on 84 bus TPC distribution system and PG & E 69 bus radial distribution systems.

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Abbreviations & Symbols

$(\Delta P_{loss})_b^i$	Change in active power loss due to change in generation of DG 'i' at bus 'b'
$(\Pi_a^t)_i^j$	Active power price of DG 'i' at hour t and iteration j in \$/MWh
$(\Pi_r^t)_i^j$	Reactive power price of DG 'i' for hour 't' and iteration 'j' in \$/MVarh
$\Delta benefit_j^t$	Extra benefit of DISCO at hour 't' and iteration 'j' in \$
ΔPG_b	Change in active power generation at bus 'b' in MW
ΔQG_b	Change in reactive power generation at bus 'b' in MVar
$\lambda_{x,j}$	j^{th} standard central moment of input variable 'x'
μ_x	Mean value of input variable 'x'
$\omega_{inv}, \omega_{emis}, \omega_{los}$	Weights corresponding to DISCO's investment,emission and loss respectively
ω_i	Weight corresponding to type 'i' loads
$\omega_{x,k}$	Weight of point k of variable x on PDF
Φ	Phase angle of DG unit
σ_x	Standard deviation of input variable 'x'
$\xi_{x,k}$	Standard location at point 'k' for input variable 'x'
a_i, b_i, c_i	Fuel cost coefficients of DG unit i
AL_i	Actual load supplying to all type i buses in kW
AL_i^{LL}	Lower limit of actual load supplying to all type i buses
AL_i^{UL}	Upper limit of actual load supplying to all type i buses
$DISCO_{inv}^{part-II}$	DISCO's investment to purchase power from DG units in part-II of network in \$

$DISCO_{inv}^{part-I}$	DISCO's investment to purchase power from grid and DG units in part-I of network in $
$DISCO_{max}^{inv}$	DISCO's investment to purchase maximum power from DG units in part-II of network in $
$EENS_{base}^{l}$	EENS value due to outage of line 'l' under base case
$EENS_{l}$	EENS value due to outage of line l with DG
$EENS_{l}^{norm}$	Normalized EENS value due to outage of line l with DG
$Emis^{part-II}$	Emission released from part-II of network in kg
$Emis^{part-I}$	Emission released from part-I of network in kg
$Emis_{max}^{part-II}$	Maximum emission released from part-II of network in kg
I_{i}^{k}	Current at bus 'i' and iteration 'k'
I_{LR}^{k}	Current injecting at receiving node of line 'L' at iteration 'k'
I_{L}^{k}	Current through line 'L' at iteration 'k'
IL_{l}^{I}	Imaginary part of current through line 'l'
IL_{l}^{R}	Real part of current through line 'l'
LD_{ren}	Matrix which has line and bus information of part-I of network after renumbering
LD_{sub}	Matrix which has line and bus information of part-I of network
LD_{ws}	Matrix which has line and bus information of part-II of network
LD_{ws}^{ren}	Matrix which has line and bus information of part-II of network after renumbering
$Line_{out}$	Outaged line
LMP_{i}	LMP value of DG unit i
$LMP_{i}^{R_b}$	LMP value of DG unit i which is located at bus 'R_b'
$Loss^{part-II}$	Active power loss in part-II of network

$Loss^{part-I}$	Active power loss in part-I of network
$Loss^{part-II}_{max}$	Base case active power loss in part-II of network
LP_{ws}	Vector having sending end nodes of each line in part-II of network
LQ_{ws}	Vector having receiving end nodes of each line in part-II of network
LR	Receiving node of line 'L'
n	Number of buses in network
$N^{part-II}_{DG}$	Number of DG units in part-II of network
n_{line}	Number of lines in network
n_{sub}	Number of buses in part-I of network
$N^{part-II}_{type}$	Different type of buses in part-II of network
n_{ws}	Number of buses in part-II of network
$nline_{sub}$	Number of lines in part-I of network
$nline_{ws}$	Number of lines in part-II of network
$Node^{part-I}_{Sorted}$	Matrix containing all buses in part-I of network in ascending order
P^{i}_{gen}	Scheduled Generation of DG unit i in kW
$P^{i}_{gen}(R_b)$	Scheduled active power of DG unit 'i' which is located at bus 'R_b'
P^{LL}_{gen}(i)	Lower generation limit of DG unit i
$P^{max}_{gen}(R_b)$	Maximim capacity of DG unit which is located at bus 'R_b'
P^{UL}_{gen}(i)	Upper generation limit of DG unit i
P^{Act}_{Load}	Vector having actual loads at each bus
$P^{Alloc}_{Load}(i)$	Allocated load to each bus i
P^{Com}_{Load}	Total commercial load in part-II of network
P^{Ind}_{Load}	Total industrial load in part-II of network

P_{Load}^{i}	Active power load at bus i
P_{Load}^{Mod}	Vector having modified loads at each bus
$P_{load}^{part-II}$	Total active power load in part-II of network
P_{load}^{part-I}	Total active power load in part-I of network
P_{Load}^{Res}	Total residential load in part-II of network
P_{min}	Minimum withdrawal of active power
P_{min}^{Bus}	Bus which has minimum withdrawal active power
P_{net}^{i}	Net active power load at bus i
PG_b	Active power generation at bus 'b' in MW
PG_i^{max}	Active power generation capacity of DG 'i'
$Pshare_i^b$	Share of active power generation of DG 'i' at bus 'b' on change in network loss
QG_b	Reactive power generation at bus 'b' in MVar
$Qshare_i^b$	Share of reactive power generation of DG 'i' at bus 'b' on change in network loss
R_b	Receiving end bus of outage line
R_l	Resistance of line 'l' in ohms
S_i	Complex power injection at bus 'i'
S_l	Apparent power flowing through line l
S_l^{max}	Thermal limit of line l
TL_i	Total load at all type i buses in kW
V_b	Complex voltage at bus 'b'
V_b^I	Imaginary part of complex voltage at bus 'b'
V_b^{LL}	Lower limit for voltage at bus b

V_b^R	Real part of complex voltage at bus 'b'
V_b^{UL}	Upper limit for voltage at bus b
V_i^{k-1}	Complex voltage at bus 'i' and iteration 'k-1'
V_{LR}^k	Voltage at receiving end node of line 'L' at iteration 'k'
V_{LS}^k	Voltage at sending end node of line 'L' at iteration 'k'
$y_{a,i}$	Actual output
$y_{c,i}$	Predicted output
Y_i	Sum of all shunt admittences at bus 'i'
Z_L	Impedance of line 'L'
${CO_2}^{DG_i}$	CO_2 released by DG unit i (kg/MW)
${CO_2}^{sub}$	CO_2 released based on load at substation bus (kg/MW)
CO^{DG_i}	CO released by DG unit i (kg/MW)
CO^{sub}	CO released based on load at substation bus (kg/MW)
${NO_x}^{DG_i}$	NO_x released by DG unit i (kg/MW)
${NO_x}^{sub}$	NO_x released based on load at substation bus (kg/MW)
${SO_2}^{DG_i}$	SO_2 released by DG unit i (kg/MW)
${SO_2}^{sub}$	SO_2 released based on load at substation bus (kg/MW)
ADS	Active Distribution System
APL	Active Power Losses
APLR	Active Power Loss Reduction
LP	Vector having sending end nodes of each line
LQ	Vector having receiving end nodes of each line
obs	Total number of observations
RDS	Radial Distribution System

Chapter 1

Introduction

Chapter 1

Introduction

1.1 General Overview

Electric power industry has been undergoing restructuring throughout the world. In the recent past, the power sector has been operating as a single utility, generating, transmitting and distributing the power. Such type of utilities are often called as vertically integrated utilities or monopolist utilities. The structure of a vertically integrated utility is as shown in Figure 1.1.

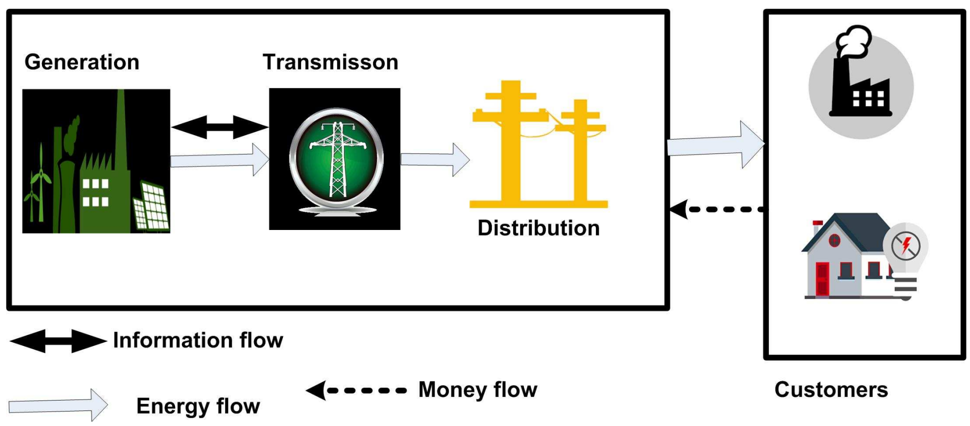


Figure 1.1: Vertically integrated electric power industry [1]

The vertically integrated electric power utilities have been undergoing a process of transition towards restructuring due to advancement of technology, the setting up of power plants near the load centers by commercial and industrial customers and operating them. As part of restructuring of electric power industry, initially transmission and distribution activities have been separated from electric power generation activities. At a later stage, competition in generation activities has been introduced by creating power pools, bilateral transactions and bidding in spot market [1]. Complete structure of restructured electric power industry is as shown in Figure 1.2.

Distribution companies (DISCOs) are one of the entities that exist in a restructured power industry. These entities own and operate the local distribution network. In general these DISCOs purchase power from generation companies either through spot market or bilateral transactions and supply power to local customers. Now a days the focus has shifted towards developing

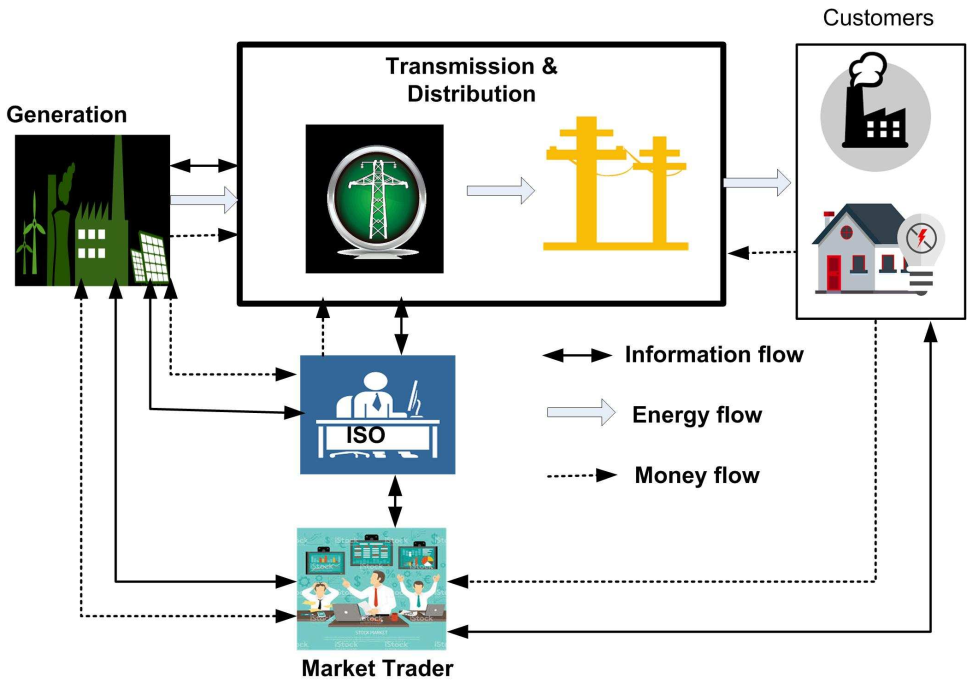


Figure 1.2: Structure of restructured electric power industry [1]

effective operating policies for efficient operation of distribution network due to increased penetration of Distributed Generation (DG). The term Distributed Generation (DG) refers to the production of electricity near the consumption place. Renewable energies and co-generation imply that simultaneous production of heat and electricity are the resources for DG [9]. Different types of DG units exist in practice, such as micro turbine, gas internal combustion engine, diesel internal combustion engines, combined cycle gas turbine, fuel cell, photo voltaic and wind power [10]. However in this thesis gas internal combustion engine, diesel internal combustion engines, combined cycle gas turbine were considered. Those who owned DG units are called DG owners. Providing the financial incentives to DG owners in terms of Locational Marginal Price (LMP) is one of the effective operating mechanisms for efficient operation of distribution network.

1.1.1 Overview of LMP Computation in Active Distribution System

In a restructured electricity market environment, Distribution company's (DISCO's) Decision Maker (DM) needs to provide equal importance to technical decisions like deployment of DG and financial decisions like development of retail competition. DISCO's DM role is very important for efficient operation of the enterprise from a technical and financial point of view, as these decisions improve market operations like competition and technical operations like reliability and service quality [11].

In the last decade, the penetration of Distributed Generation (DG) resources in distribution network has increased globally. The main reasons [12, 13] for increasing the penetration are as follows:

- Reliability improvement
- Emission reduction
- Improvement of electrical distribution network reinforcement horizon
- Energy resources optimization
- Supply for future load demand
- Service quality
- Utilization of non-conventional energy resources
- Loss reduction
- Avoiding the investment in large power plants and transmission lines
- Voltage support

Distribution networks have been transformed from passive state to active state like transmission system upon integration of DG units. A Distribution system with DG units is called Active Distribution System (ADS). A few operating methods like nodal pricing, which are employed in transmission network for efficient and competitive operation in restructured environment could also be employed in active distribution network. Nodal pricing is one of the mechanisms for financial incentive used by DISCO to control privately owned DG units and to encourage DG owners to carry out technical decisions like active power loss reduction, emission reduction and reliability improvement etc. LMP is the most effective method to determine nodal price in practice [14]. The computation of Locational Marginal Price (LMP) is one of the most commonly employed tools for market settlement in the deregulated power system environment. The LMP at a bus signifies the cost of supplying the next increment of load at that bus. LMP in distribution system is defined as pricing of power by the location and timing of its injection into the distribution network. The LMP is the true indicator of the marginal pricing of energy. Locational Marginal Price (LMP) in transmission system is defined as the pricing of power by the location and timing of its injection into or withdrawal from the transmission grid [15]. Similarly LMP in distribution level is defined as the pricing of power by the location and timing of its injection into the distribution network. LMP values at each DG bus were computed based on impact of power injection at that bus on distribution network performance. The performance of distribution network is identified based on reduction of active power losses, emissions and improvement reliability.

LMP values at each DG bus in active distribution network have been computed based on DG units contribution on active power loss reduction, greenhouse gas emissions reduction and reliability improvement. The computation tools for LMP computation in active distribution network can be helpful to distribution licensee and supply licensee in the following aspects:

- To maintain fair competition among the private DG owners
- To monitor state of the active distribution system
- To estimate the state of the active distribution system
- To encourage private DG owners for improving the active distribution system operation
- To estimate how much power either supply licensee or provider of last resort needs to be purchased from the pool market
- To supply electricity to customers at low price

Reduction of emissions like Sulfur dioxide (SO_2), Carbon dioxide (CO_2), Carbon monoxide (CO) and Nitrogen oxides (NO_x) from base case (or) case 1 are also considered for LMP computation. Base case (or) case 1 is referred to a distribution system without any integration of DG units. In base case, the total power drawn is from the substation bus and this power comes from thermal power plants which releases more emissions in comparison with DG units like gas internal combustion engines, diesel internal combustion engines and combined cycle gas turbine. Due to this reason the emissions released in case 2 were less in comparison with case1 (or) base case. Similarly, reduction of active power losses i.e power losses in the feeders of distribution network due to feeder resistance from base case is considered for LMP computation.

In this thesis, an iterative method was developed for computing LMP based active power loss and emission reduction. Convergence of this iterative method depends on change in the generation of DG units from previous iteration and DISCO's extra benefit. DISCO's extra benefit (or) merchandising surplus due to loss and emission reduction is defined as change in DISCO's benefit from case 2 to base case. The iterative method also provides reactive power price as an incentive for reactive power generation to each DG unit based on the contribution of DG unit's reactive power on active power losses. The proposed method can also extended by considering reactive power losses in the distribution system. The system draws some additional current for transporting reactive power back and forth. This additional current causes the system to heat up and is the cause for reactive power loss.

Reliability refers to the continuity of power supply. The distribution system is an important part of the total electric system as it provides the final link between the bulk system and the customer. In many cases these links are radial in nature. Due to this reason distribution systems are called as radial distribution system. The system is susceptible to outage in radial distribution system due to a single event. It has been stated that 80% of all interruptions occur due to failures in the distribution system [16]. Hence, improving the reliability of distribution system is very important and new methodology was developed for LMP computation based on reliability improvement.

In this thesis, the LMP value at DG buses has been calculated based on reliability improvement as an optimization problem. The optimization problem is minimization of Expected Energy Not Supplied (EENS) of various type of customers for load scheduling, and minimization of DISCO's investment cost, emissions and active power losses for generation scheduling. Global power balance equation, voltage limits and feeder thermal limits were considered as constraints in this optimization problem. In load scheduling, total active power load has been scheduled among different types of customers if total load is more the available generation in the islanded portion of network. Similarly, in generation scheduling DG unit's generation has been scheduled if the total available generation is more than the load in islanded portion of the network. A hybrid metaheuristic technique was developed using genetic algorithm (GA) and dragonfly algorithm (DA) to solve the optimization problem by extracting advantages of both GA and DA. A metaheuristic approach is defined as an iterative approach which guides a subordinate heuristic by combining intelligently different concepts for exploring and exploiting search space. They are inspired by observing the phenomena occurring in nature [17].

In this thesis, A two layer Artificial Neural Network (ANN) was developed to forecast the load on distribution system. The market price is defined as the price at which DISCO purchases the power from the grid. Back Propagation Algorithm (BPA) has been used to train the given ANN because of its flexibility, learning capabilities and is highly suitable for problems where no relationship is found between the output and input [18]. During the training of ANN, BPA adjust the weights based on error at neurons in the output layer such that input and output patterns are correlated. During the testing phase the output of trained ANN is compared with actual output. The training and testing performance of ANN was measured using Mean Absolute Percentage Error (MAPE) as represented in equation (1.1) and Root Mean Square Error (RMSE) as represented in equation (1.2).

$$MAPE = \frac{1}{obs} \sum_{i=1}^{obs} \left| \frac{y_{a,i} - y_{c,i}}{y_{a,i}} \right| * 100 \tag{1.1}$$

$$RMSE = \sqrt{\left(\frac{1}{obs} \sum_{i=1}^{obs} (y_{a,i} - y_{c,i})^2\right)} \tag{1.2}$$

Game theory looks at rational behavior when each player's well being depends on the decisions of others as well as his/her own. Game theory comprises cooperative and non-cooperative game theory. In this thesis, cooperative game theory has been used to allocate the reduced active power losses/emissions among DG units. In cooperative game, all the players are able to sign legally enforceable contracts with each other player. This assumption does not exist in non-cooperative game theory. Shapley Value method (SV), Nucleolus Theory (NT) and Proportional Nucleolus Theory (PNT) are the solution concepts for cooperative game problem. PNT has been used in this thesis for allocation of active power losses/emissions among DG units as it is superior over other methods and monotonic. One property of monotonic states is that if the value of grand coalition increases and all other sub coalition values remain constant, then each DG participant payoff should increase [19]. Fairness of the PNT solution is measured in terms of three natural properties like individual rationality, coalition rationality and collective rationality. The individual rationality states that the share of each DG unit in reduced losses/emissions must be greater than or equal to loss/emission reduction when that DG unit is operated alone. Coalition rationality states that loss/emission reduction due to any sub coalition is less than the sum of allocated loss/emission reduction to each DG unit in that sub coalition. Collective rationality states that loss/emission reduction due to coalition of all DG units is equal to the sum of allocated reduced losses/emission to each DG unit. In addition to game theory, sensitivity factors were used to measure the actual impact of active and reactive power injection at a particular bus on active power losses.

LMP values in distribution system depend on load and market price which are uncertain in nature. Due to uncertainties that exist in input variables, computed LMP values at DG buses will change. A method needs to be developed to compute probabilistic LMPs by capturing uncertainties that exist in input variables. Many probabilistic approaches are available in literature to capture the uncertainties and 2m+1 scheme of point estimation method is one of them. It provides solution with almost similar accuracy level as Monte Carlo Simulation with less computation time.

Chapter 2

Literature Review

Chapter 2

Literature Review

2.1 Introduction

In the current electric energy pricing scenario, many methods have been developed and implemented at different wholesale markets to provide pricing information to transmission and generation sectors. Retail sectors have been operating commercially, and competition among retailers has been based on operation of distribution system and how tariff structure in distribution system was developed. Hence, much concentration and focus is required to develop more efficient electricity pricing structure in distribution system. However, so far distribution systems have been operating under conventional pricing models and use very few market instruments due to constraints in technical capabilities, social considerations and regulatory perspectives [20].

Electric power wholesale markets were developed with parties like generation companies, retailers, brokers and aggregators. However, this market structure does not have active distribution systems in most of the countries. Currently electric energy price depends on the type of customers, government regulation policies, maximum load consumed, cost allocation, and court proceedings. As there has been an increase of smart grid practical applications which requires efficient pricing information, a great deal of research work on electric energy pricing is required in the near future.

It has been widely accepted that distributed generation resources can provide benefits to distribution network. Due to all these benefits, integration of DG units into the distribution system has increased rapidly over the last decade. A need was felt to put some more interest while designing tariff structure for the recovery and allocation of fixed costs and variable costs of distribution network in order to incorporate benefits of DG [21]. Distribution network with DG units considered as active network like transmission network [22]. A few methodologies which were implemented in transmission system can also be applicable in active distribution system like nodal pricing. Computation of Locational Marginal Price (LMP) is one of the most prominent methods available for nodal pricing.

The effectiveness of the pricing structure in active distribution system (ADS) depends on how investment and operation of network was performed optimally. Complete research on the pricing of electric energy in ADS till now is presented in Figure 2.1.

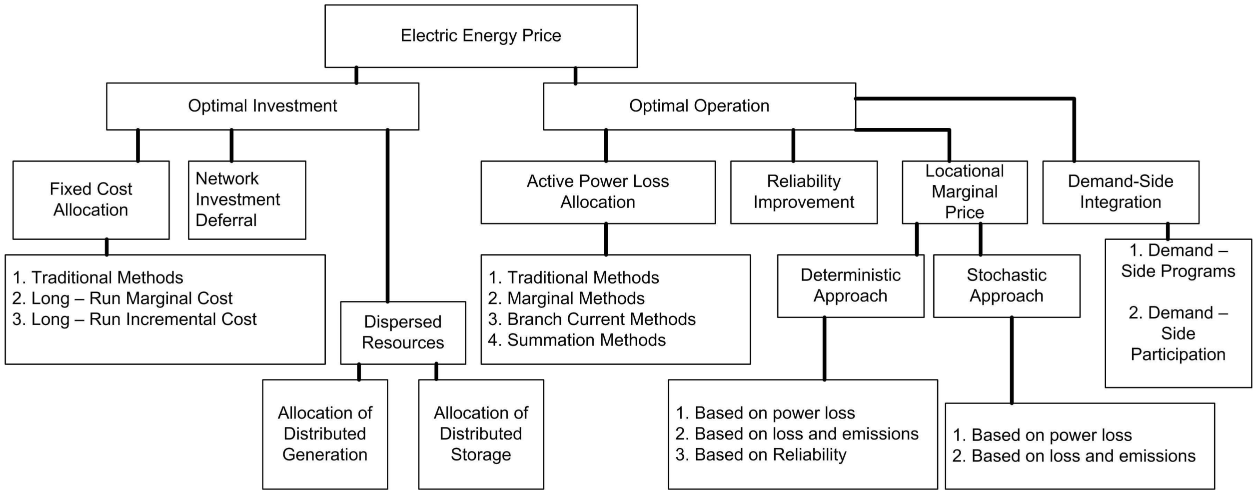


Figure 2.1: Electric Energy Pricing In Distribution System

2.2 Optimal Investment

Optimal or economic investment by DISCO on distribution system is very important. The literature that exists for optimal investment of DISCO on distribution system is based on fixed cost allocation, calculation of network investment deferral and distribution resources utilization.

2.2.1 Fixed Cost Allocation

As integration of DG units into the distribution system is increasing rapidly, more interest needs to be shown to design tariffs for the recovery and allocation of distribution network fixed costs, including capital and non-variable operation and maintenance (O & M) costs. Some well known methods available in literature for fixed cost allocation like traditional methods, calculation of long run marginal cost and long run incremental cost have been presented in this section.

2.2.1.1 Traditional methods

The general considerations involved in developing a cost of service and cost allocation methods for rural distribution system were discussed in [23]. The marginal cost of energy, reliability cost and investment costs were allocated uniformly in [24] by considering the elasticity price of demand and demand side management. Amp - Mile method was proposed in [25] for allocating the capital cost and non variable operation and maintenance costs at the medium voltage distribution level using power to current distribution factors. The main flaw of this method is that the extent of use was computed based on approximate distribution factors. Per MWh Average Charges have been computed by dividing the cost of all circuits with total active energy consumed in that network [26]. The drawback of this method is that it does not provide incentive to customers to reduce the use of congested infrastructure as it is independent of time and location of demand. The fixed charge per year of any bus was computed based on the share of load of that bus at the time of system peak which is known as coincident peak [26]. As per this method, allocation of cost is not dependent on actual usage of network.

2.2.1.2 Long Run Marginal Cost

An overview of costing and pricing terminologies in the distribution networks is presented in [27]. The distribution reinforcement model was developed to compute long run marginal cost (LRMC) for a given distribution network capacity. Area and time specific Marginal Distribution Capacity Costs (MDCC) were computed in [28] using local distribution supply plan. The computed MDCC was allocated hourly using peak capacity allocation factors (PCAFs) by assuming past peak load timing as indicative of likely future peak loads. A new MW+MVAr-Miles charging methodology was proposed in [29] for separately pricing active and reactive power at the distribution level. This method considers the distance that is used to support nodal active and reactive power injection/withdrawal, degree of support offered by the network assets and operating condition of the supporting assets in terms of power factors. Long Term Marginal Cost (LTMC) was computed using multiobjective optimization problem in [30]. In this optimization problem authors have considered long term investment, operation, and reliability related costs, congestion constraints, and load uncertainties. LRMC was computed in [31] by considering unutilized capacity within distribution network to create a forward-looking pricing message for prospective generation and demand. The unutilized capacity was used to gauge the length of time before investment to reinforce the network required. A novel method was developed in [32] for LRMC pricing methodology using sensitivity analysis for revenue reconciliation. The sensitivity analysis consists sensitivity of active power flow with respect to nodal active power increment, sensitivity of reinforcement horizon with respect to active power flow and sensitivity of present value of future reinforcement with respect to nodal active power increment.

2.2.1.3 Long Run incremental Cost

Long run incremental cost charging methodology was proposed in [33] based on unused capacity of existing network. LRIC reflects the advancing or deferring cost of future investment consequent upon the addition of generation or load at each study node on a distribution network. Long run incremental cost charging methodology was proposed in [34] based on network security. The security is reflected in the pricing through a full N-1 contingency analysis to define the maximum allowed power flow along each circuit. Long run incremental cost charging methodology was proposed in [35] based on network reliability. This pricing model reflects two reliability cost drivers like nodal unreliability tolerance mandated by security standards and stochastic nature of component reliability that reflects differing failure rates of network components. A conventional LRIC pricing methodology was proposed in [36] to reflect how a nodal increment might change the loading level of the distribution system with a negative load growth, and how this change could be translated into costs/benefits for the network. Pricing models like Distribution reinforcement model, investment related cost pricing model and LRIC pricing model were compared in terms of economic efficiency in [37]. All the long run incremental cost methodologies have not considered DISCO's extra benefit and this charging methodologies are based on the present value of future network investment cost only.

2.2.2 Network investment Deferral

A brief review of various methods used for calculating avoided costs like proxy plant method, purchase price method and marginal cost method is presented in [38]. Avoided costs reflect the expected cost of increased or decreased use of existing facilities or the expected cost of delaying or advancing additional resources. The one - year deferral method for estimating the avoided costs in transmission and distribution systems is proposed in [39]. This method was developed based on the system planner's response to small reduction in the forecasted annual peak load. A DG unit can postpone or even eliminate the need for investments on feeders or transformers. This type of strategy is known as non-wire solution. An approach for quantifying the deferral benefits created by DG on planned or scheduled network upgrade investments is developed in [40]. The capability for DG to act as an alternative solution for distribution system planning option by providing opportunities to capture the network deferment benefit is described in [41]. One of the assumptions considered in [41] is that a DG investment can be a direct substitute for "wires and poles" assets by applying the same discount rate to both. A new methodology was developed in [42] to quantify the distribution network deferment produced by DG units by considering the load growth rate and network security related investment. This methodology was developed using successive elimination algorithm together with multistage planning. This methodology was deterministic and ignored the evident uncertainties surrounding planning.

2.2.3 Distributed Resources

Proper allocation of distributed resources in distribution system is an important task if economic investment in distribution system is concerned. The literature that exist for optimal placement of DG is based on parameters like active power losses, emissions, reliability, DG investment cost and DISCO's maintenance cost. In this section the literature that is available in allocation of DG and distributed storage in distribution system is presented.

2.2.3.1 Distributed Generation (DG)

An analytical method was developed for optimal sizing and placement of DG in [43] based on active power loss reduction by considering both radial and mesh networks with time varying and time in-varying loads. An analytical approach has been developed in [44] for optimal size, location and power factor for different types of DG units based on active power loss reduction in primary distribution network. The reduction of active power losses in distribution network leads to economic investment for DISCOs. A new optimization model was developed in [45] to estimate the optimal DG capacity investment to serve peak demands optimally along with other traditional planning decisions. The optimization model was developed to minimize DG investment, operation and maintenance costs, cost of purchasing power by DISCO from the main grid, and the payments towards compensating for the active power losses.

A new heuristic approach for DG capacity investment planning from the perspective of a DISCO is proposed in [46]. This approach aims to minimize DISCO's investment and operating costs as well as payment toward active power loss compensation. This method arrives at the optimal feasible DG capacity investment plan under competitive electricity market auction as well as fixed bilateral contract scenarios. A new methodology was developed in [47] using linear programming to determine the optimal allocation of DG with respect to constraints like Thermal Constraint, Transformer Capacity, short-circuit level, short-circuit ratio and Voltage Rise Effect. Genetic algorithm based multi-objective optimization method has been developed in [48] for optimal placement of DG in distribution system by considering economic investment by DISCO. The objectives which were considered in this minimization problem are cost of network upgrading, cost of purchased energy, cost of energy losses and cost of energy not supplied.

An ordinal optimization procedure has been developed in [49] for optimal placement of DG such that the DG capacity and reduced loss cost were maximized. Here, short circuit and stability issues, and benefit of DG in deferring network upgrades were not considered. A multi-period multi-objective optimal power flow has been developed in [50] to determine optimal DG capacity. This was developed to capture the impact of varying demand levels on active power losses and other network factors and allow a more realistic estimate of the value of the loss incentive. A new methodology has been developed in [51] to evaluate the connection of DG based on long-run incremental cost indicating the forward-looking network capacity cost at each bus. In this method appropriateness of DG connecting to distribution network can be determined by comparing DG connection cost with the decrement of the network capacity cost resulting from DG capacity. In this method a heuristic approach has been used to identify the best site and size of DG.

A new method has been developed in [52] to place the DG in distribution system so that active power losses of network are reduced. This method was developed based on determination of buses that are most sensitive to voltage collapse. Continuation power-flow program has been used to determine the buses that were most sensitive to voltage collapse. A new optimization methodology using artificial bee colony (ABC) algorithm has been developed in [53] to determine the optimal DG-unit's size, power factor, and location in order to minimize the active power losses in distribution network. A probabilistic planning technique was developed in [54, 55] for optimally siting of the wind based DG units. In this optimization problem, minimization of the annual energy losses has been considered as an objective function and voltage limits, feeder capacity limit, discrete size of the available DG units, maximum investment capacity on each bus and the maximum penetration limit of the DG units were considered as technical constraints.

A new optimization framework was developed in [56] for distribution system planning by incorporating DG reactive capability and system uncertainties. An integrated solution algorithm with TRIBE Particle Swarm Optimization and ordinal optimization has been developed to determine optimal and near-optimal solutions that provide options to the system operator to compare and decide the best feasible solution for practical implementation. The total cost associated with different DG systems comprised capital cost, operation and maintenance cost, reliability cost, cost of deferred energy, and emission cost, all of which have been minimized for evaluating optimal allocation of DGs. A new method by considering load model was developed for optimal placement of DG using genetic algorithm in [57]. In this method, the weighted sum of MVA Capacity Index, Voltage Profile Index, Real and Reactive Power Loss Indices was considered as a single objective function. A new method by considering load model was developed for optimal placement of DG using particle swarm optimization in [58]. In this method, the weighted sum of Short-circuit level index, MVA Capacity Index, Voltage Profile Index, Real and Reactive Power Loss Indices were considered as a single objective function.

A new approach was developed in [59] to determine optimal capacity and location for DG units in meshed power systems. The authors have considered maximization of the system loading margin as well as DISCO's profit as objective functions and these objective functions were fuzzified as a single objective function. Fuzzy based genetic algorithm was used to solve multi-objective optimization problem. A new multi-objective model for placement of DG was developed in [60]. Minimization of the investment and operation cost of DG units, cost of active power losses and minimization of technical risks like voltage and loading constraints violation due to load uncertainty and economic risk due to electricity market price uncertainty, were considered as objectives. NSGA-II was used to solve the multi-objective optimization problem. Fuzzy logic has been used to model the uncertainties that exist in load, voltage, loading constraints and market price.

A multi-objective model was developed in [61] for determining the optimal capacity, location and investment time for DG units. Monte Carlo simulation (MCS) was used to deal with the effects of uncertainties that exist in wind power generation, electricity market price and load. In this multi-objective problem, minimization of weighted average of maximum yearly technical risk and its average value over the planning horizon, total operating costs of DG units, total grid cost, total investment cost of the DG units, total feeder reinforcement cost and total substation reinforcement cost were considered as objectives. The main drawback of the proposed method is that the computation time increases with the size of network. NSGA-II was used to solve this multi-objective optimization problem. A long-term dynamic multi-objective model for planning of distribution networks regarding the benefits of distribution network operator and distributed generation owners was developed in [62]. The proposed multi-objective model simultaneously optimizes benefits of distribution network operator and distributed generation owner. This method provides optimal schemes of sizing, placement and dynamics of investments on DG units and network reinforcements over the planning period. Point estimation method was used to capture the uncertainties that exist in load, market price and wind turbine power generation. An immune-GA-based method was utilized to solve this distribution network planning problem. A stochastic dynamic multi-objective model for integration of distributed generations in distribution networks was developed in [63]. Technical constraint dissatisfaction, costs and environmental emissions were considered as objectives. This method provides information about the optimal location, size and timing of investment for both DG units and network components. Scenario modeling was used to capture the uncertainties that exist in load, market price and wind turbine power generation. Binary particle swarm optimization was used to solve the multi-objective optimization problem.

2.2.3.2 Distributed Storage

A new methodology was developed in [64] to evaluate the impact of energy storage specific costs on net present value of energy storage installations in distribution substations. NSGA was used to solve the optimization problem. A new methodology was developed in [65] for optimally allocating energy storage systems in distribution systems with a high penetration of wind energy. In this method, wind energy generation was maximized later total electricity cost considering losses was minimized.

2.3 Optimal Operation

Optimal or economic operation of distribution system can be achieved by DISCO based on fair allocation of losses and loss cost among DG owners and customers, by designing fair reliability based charging methodology, by providing financial incentives to DG owners based on DG units performance on operation of network, and by designing proper framework for demand side management. Recent literature for loss allocation, demand side management, LMP computation at DG buses and reliability based charges has been presented in this section.

2.3.1 Loss Allocation

The allocation of active power losses of the distribution system to suppliers and consumers is a challenging issue for the deregulated electricity environment. Reasonably active power loss allocation methods have to be adopted to set up appropriate economic penalties or rewards. The allocation of active power losses depends on size, location, and time evolution of the resources connected to the distribution system. Due to increase in integration of DG units, the variety of power flows in distribution systems calls for flexible mechanisms that were able to discriminate among the contributions to increase or reduce total losses.

2.3.1.1 Traditional Methods

A new conventional methodology was developed in [66] to allocate demand and energy losses in the distribution system to customers based on the burden they impose on the system. Based on allocated losses, loss cost was assigned to customers for optimal and efficient operation of distribution system. An 'Exact Method' was developed in [67] for allocating energy losses to customers in a radial distribution system. This method was compared with 'pro rata', 'quadratic allocation' and 'proportional allocation' methods. The energy loss cost was allocated to each customer based on allocated energy losses to main optimal operation and fair charging to the customers in radial distribution system. A methodology was developed in [68] to allocate active power losses to customers before and after the network reconfiguration in a deregulated environment. Active power loss allocation was made based on 'quadratic approach'. In 'quadratic approach', real and reactive components of current flowing in each branch were identified, while losses were allocated later. An algorithm based on a heuristic rule and fuzzy multi-objective approach has been proposed to solve the network reconfiguration problem.

2.3.1.2 Marginal Methods

Marginal loss coefficient method and direct loss coefficient method were developed in [69] for allocating the active power losses. These two coefficients are location specific and varying with time. Marginal loss coefficients were calculated using load flow jacobian to trace loss variations while direct loss coefficients were calculated using Taylor series expansion to express total active power losses in terms of bus injections. Direct loss coefficients method required calculation of the elements of the Hessian matrix and also requires more computation time.

2.3.1.3 Branch Current methods

A new method was developed in [70] based on tracking the real and imaginary parts of the branch currents and had two steps. In the first step, active power losses in the distribution network in the absence of distributed generation are allocated to the customers. In the second step, the change in the active power losses that result from the influence of distributed generation are allocated to the DGs. These variations in active power losses are a measure of the avoided or added costs related to active power losses. This methodology can be used to compute DG incentives or to design tariffs for the use of the distribution network. A branch current decomposition method was developed in [71] for computing the loss allocation factors in active distribution systems. This loss allocation method is not suitable for radial unbalanced distribution systems and weakly meshed systems. The novel resistive component-based loss partitioning method was developed in [72] based on real part of the matrix impedance, for partitioning the total losses among the phase currents and for performing loss allocation in three-phase radial distribution systems with the branch current decomposition loss allocation method [71] adapted to three-phase systems.

2.3.1.4 Summation Methods

A new method for active power loss allocation in active distribution system has been developed in [73] based on the power summation algorithm. This method establishes direct relationship between active power losses in each branch of the network and injected active and reactive power in the buses. A new method for energy loss allocation in active distribution system has been developed in [74] based on the energy summation algorithm. This method is based on the branch oriented approach and utilizes statistical information of daily load and generation curves.

2.3.2 Reliability Based Charges

The ability of a power system to provide adequate and secure supply of electrical energy at any point in time is referred to as the reliability of a system. A coherent method for computing the customer benefits based on reliability investment was developed in [75]. A generalized analytical approach and a time sequential monte-carlo simulation technique was developed in [76] for evaluating the customer interruption cost in complex radial distribution systems. The reliability differentiated pricing policy based on outage cost was developed in [77]. This method provides differentiated prices for various customer classes based on their respective outage costs. A policy for optimal pricing of non-utility generated power is developed in [78]. An optimal pricing policy provides benefits for utility, industry, and the utility's other customers. Optimal pricing policy for non-utility generated power is achieved using reliability differentiated real-time pricing. A new mathematical model was developed in [79] to quantify the effects of demand-side management on the chronological hourly load curve. This model was used to investigate the impact of demand-side management on the reliability cost and reliability worth approach. The impact of non-utility generation on the adequacy and reliability cost indices and the cost of customer interruptions were discussed in [80]. The application of index probability distribution concepts to establish an appropriate balance between reliability improvement and cost saving strategies to power utilities subjected to performance-based rates was discussed in [81]. Here, the contract between a customer and a utility in the form of customer service disruption payments was analysed using appropriate index probability distributions. A new method was developed in [82] to determine the optimal operating strategy by considering hourly reliability of the distribution system. Hourly reliability worth was computed using sequential Monte-Carlo Simulation. A supply interruption model was developed in [83] to compute the penalty payments for failing to sustain the minimum level of required reliability. A value-based economic evaluation method for distribution automation has been proposed in [84]. This method considers customer interruption costs in the benefit analysis and uses the present-worth analysis to perform economic evaluation of projects.

2.3.3 Demand-Side integration

Elevating the capability of the demand for electricity to respond to price signals would benefit not only consumers who want to actively participate in electricity markets, but also help markets operate more efficiently and satisfactorily. Electricity markets become more efficient and competitive if more active participation comes from demand side. It will promote more optimal allocation of economic resources. The unusual economic attributes of the demand for electrical energy and the issues that must be addressed if the demand side is to participate actively in the market were discussed in [85]. Incentive contract for demand management was developed in [86] depending on customers willingness and load locations. A new methodology suitable to aggregators and large customers for generation of bids and offers from demand side was developed in [87]. The ability of self organized maps to classify customers and their response potential from distributor or customer electrical demand databases is discussed in [88]. An optimal and automatic residential energy consumption scheduling methodology that aims to achieve a trade-off between minimizing the payment and the waiting time for the operation of each household appliance based on the needs declared by users is discussed in [89]. A pilot study of demand response from household customers utilizing smart metering, remote load control and pricing based on the hourly spot price combined with a time of day network tariff was provided in [90]. Demand-side participation is mostly offered as an effective solution to increase market efficiency when hockey-stick-type offer curves are present. Modeling and simulation of demand-side participation in wholesale market was developed in [91]. A Monte Carlo-based algorithm was developed in [92] to formulate multiple purchase offers in the day-ahead energy market by coalitions in which consumers vary in their sensitivity to demand response programs.

2.3.4 Locational Marginal Price (LMP)

Very few researchers are working in the area of LMP (or) Dynamic Pricing computation at DG buses in active distribution system. DG bus is defined as bus or node in distribution system where DG unit injects the power into the network. The first time LMP values at DG buses were computed in [93] based on impact of power injection at DG buses on active power losses of network. Here marginal loss coefficients were developed to measure the impact of power injection at DG buses on active power losses of network. These marginal loss coefficients were used to compute active and reactive power price at each DG bus in active distribution system.

The main limitations of this method are non zero and non-controllable merchandising surplus due to loss reduction and this method estimates state of the network only for current operating conditions. LMP values at DG buses in active distribution system were computed based on active power losses of network using reconciliated marginal loss coefficients in [26]. In this method reconciliated marginal loss coefficients were used to compute the share of power injection at each DG bus on active power losses of active distribution system. The main limitations of this approach are non-controllable merchandising surplus due to loss reduction, lack of estimation of the state of the network for next operating condition, and lack of fairness in allocating active power losses among DG units.

Nodal prices were computed in [94] based on optimal allocation of DG units in active distribution system using genetic algorithm. The objectives which were considered for this problem are minimizing active power losses and maximizing the voltage and savings in electricity bill in the presence of DG units. Nodal real and reactive power prices were computed in [95] for identifying optimal location of DG and optimal number of DG units using mixed integer non linear programming. The real and reactive power prices were computed using lagrangian multiplier value of the real and reactive power flow equations. The values of lagrangian multiplier were computed by solving first-order necessary condition of lagrangian and partial derivatives of the lagrangian with respect to every variable concerned. The main limitations of these methods are non zero and non controllable merchandising surplus. These methods cannot estimate the state of the network for the next operating condition.

LMP values at each DG bus were computed in [3] based on active power loss reduction. Iterative algorithm was developed to compute LMP of each DG in active distribution system based on DG unit's contribution in loss reduction. The main short comings of this method were that the authors used shapley value method for allocation of reduced active power losses among DG units. Shapley value method suffers from flaws such as the solution may not lie inside the core. In this method the authors have not considered DISCO's extra benefit in convergence of iterative algorithm, with DISCO incurring financial loss because of this. Incentives have been computed based on wholesale market price that leads to high incremental price which may reduce DG units profit. The authors have not considered actual contribution of reactive power of DG units on active power losses while computing reactive power payments. LMP values at any bus were computed in [96] using market price, marginal loss cost, congestion and utilization of renewable resources. The main shortcomings of this approach are non controllable and non zero merchandising surplus due to loss reduction, and this method cannot estimate the state of the system for the next operating condition.

Probabilistic LMP values were computed for each DG unit in [97] using nucleolus based cooperative game theory and point estimation method. Deterministic LMP values at each DG bus were computed in [4] based on active power losses and emissions using nucleolus based cooperative game theory. Probabilistic LMP values were computed for each DG unit in [98] using shapley value based cooperative game theory and point estimation method. In this method, the authors have used 2m scheme of point estimation method. In 2m scheme of point estimation method, the accuracy of solution depends on the number of input variable. If the number of input variables increases then the calculated points of each input move away from the mean value which leads to reduction of accuracy of the solution. The main limitation of these approaches is that computation of DISCO's extra benefit is not effective and to offset that the authors have used nucleolus game theory to allocate loss and emission reduction. However nucleolus game theory suffers from some flaws such as not being monotonic and in this method the authors have calculated incentives using market price that provides high incremental price. Computation of LMP at DG buses like this may lead to loss of DG unit's profit.

A robust bi-level decision-making framework is presented in [99] for DG owning retailers to supply electricity to price-sensitive customers. The optimal selling price and the retailer's energy-supply strategy are modeled in the lower sub-problem. According to the proposed selling price, the optimal energy consumption of price sensitive clients is determined in the upper sub-problem. A bi - level optimization problem was developed in [100] to compute optimal contract pricing for dispatchable DG units. A multi leader and follower game theory concept was used where DG units act as leaders and DISCO as a follower. Maximization of DG units profit was considered as an upper level optimization problem, whereas minimization of electricity supply cost of DISCO was considered as a lower - level problem. DG units provide offering prices to DISCO and DISCO determines the amount of power purchased from wholesale market and DG owners for different contract periods. As DISCO operates the network based on prices offered by DG units, the main limitation of these approaches is that DISCO cannot control private DG owners and operate the network effectively. This method also had shortcomings like non zero and non controllable merchandising surplus due to loss reduction.

A new approach was developed in [101] for calculating the guaranteed energy purchase price for each DG unit. Here, Monte carlo simulation was used to handle the uncertainty that exists in load, market price and DISCO future investment. The main shortcoming of the Monte Carlo Simulation is that it requires a lot of number of samples and takes large computation time. A Meta-heuristic modified honey bee mating optimization algorithm was developed in [102] to compute LMP values for each DG unit in active distribution system based on active power losses. Here, Minimization of active power losses is considered as an objective function. LMP values and power factor of each DG unit was considered as control variables for this optimization problem. 2m scheme of point estimation method was used to handle uncertainty that exist in market price and load. The main limitation of this approach is that the reactive power price was not considered while computing LMP based on loss reduction. A new approach was developed in [103] to compute LMP at DG buses based on active power losses. In this method, the authors have used loss factors and linear optimal power flow for computing LMP at DG buses. The main limitations of this approach are non zero and non controllable merchandising surplus due to loss reduction.

2.4 Motivation

Many effective mechanisms exist for transmission pricing/LMP calculation in deregulated environment to improve transmission network operation, but very few mechanisms exist in active distribution system for its operation. This is the motive for research into computation of LMP in active distribution system.

Distribution companies (DISCOs) have not received the desired technological support as in transmission and generation, despite 30% to 40% of total investment in electric power sector going to electric power distribution systems. In general 3% to 6% of active power losses exist in electric power sector. The total distribution active power losses in developed countries are not greater than 10% of total active power losses in electric power sector. However, these active power losses are around 20% in developing countries like India. Due to this reason electric power utilities in developing countries are trying to reduce active power losses by effective operating mechanisms like providing financial incentives. To manage active power losses in distribution network, an efficient and effective computation tools has to be developed. This was the inspiration to develop an efficient tool to compute LMP at DG buses in active distribution system based on active power losses.

As per the statistics, energy sector is responsible for 70% of overall greenhouse gas emissions due to burning coal. Hence, more focus will be required in this sector. If the distribution companies are able to use low emission coefficient generators available as DG units in distribution network, then the amount of power purchased from thermal plants will be reduced. This leads to reduction of burning of coal and greenhouse gas emissions. Hence, there is a need to develop a robust computation tool for optimal utilization of DG units in active distribution system based on the reduction of greenhouse gas emissions.

Increasing population and economic improvement have increased the demand for electricity in India. Existing power systems are under pressure to meet the load requirements in India. This leads to power imbalance and thus affects the customers with power interruption and unbalanced voltages. Generating more power either by installing more power plants or increasing the local generation in distribution level is the only solution to avoid these problems. Distribution network's contribution is more in terms of nonavailability of supply to the users from power generation plants. It means that most of the failures occur in the distribution networks. The statistics emphasize that there is a need for reassessment of available strategies to improve the electrical services by improving the reliability of network. Now it is time to develop active distribution networks which will be helpful to meet increasing demand and to provide reliable power in the case of a power plant breakdown. The role of DISCO decision maker (DM) is very important to control private DG owners in such a way that the reliability of the network is improved. Private DG owners can be controlled effectively by providing financial incentives based on DG's contribution in reliability improvement. An effective tool is required to control private DG owners for improving the reliability of active distribution network. Hence, there is a need to develop a robust computation tool for optimal utilization of DG units in active distribution system based on reliability improvement.

The problem of LMP computation in active distribution system is subject to uncertainty due to inherent randomness in load and market price. If any LMP computation method is able to tackle uncertainty, then it will allow DISCO's decision maker to propose a solution for optimal operation of active distribution system, which is less sensitive to randomness in load and market price. From this discussion there is a need to develop an efficient computation tool which is less sensitive to uncertainties that exist in load and market price for computing LMP at DG buses in an active distribution system.

As per the limitations that exist in the literature of LMP computation at DG buses in active distribution system and government policies, there is a need to develop a tool for computing LMP values at DG buses in active distribution system by considering following parameters.

- Active power loss reduction
- Emission reduction
- Reliability improvement
- Capturing uncertainties that exist in load and market price
- Zero merchandising surplus
- Controllable merchandising surplus
- Estimating the state in current and next operating conditions
- Fair allocation of losses and emissions

- Fair allocation of incentives for active and reactive power generation

2.5 Contribution

In this work the main contributions are as follows:

√ LMP at each DG bus in active distribution network has been computed based on change in active power losses using proportional nucleolus based cooperative game theory. Proportional nucleolus based cooperative game theory [104] has been used for the first time for allocating change in active power losses among DG units. Loss sensitivity factors have been developed to measure the impact of active and reactive power generation at each DG bus on active power losses. Incentives have been given to each DG unit based on its contribution in change in active power losses. These incentives have been given to each DG unit from the reduced active power loss cost. The proposed method has been implemented on 84 bus TPC distribution system [5] and PG & E 69 bus distribution system [7]. The accuracy and validity of the proposed method has been verified by comparing it with shapley value based iterative method [3].

The main features of the proposed approach are as follows:

- Zero and controllable merchandising surplus due to change in active power losses
- Estimation of the system for current and next operating condition
- Provision of encouragement to private DG owners to participate in loss reduction
- Creating facility for trade off of DISCO among active power losses and extra benefit

√ LMP at each DG bus in active distribution network has been computed based on change in active power losses and emissions using Proportional nucleolus based cooperative game theory. Proportional nucleolus based cooperative game theory [104] has been used for the first time for allocating change in active power losses and change in emissions simultaneously among DG units. Incentives have been given to each DG unit based on its contribution in change in active power losses and emissions. These incentives have been given to each DG from reduced active power loss cost and emissions penalty. The proposed method has been implemented on 84 bus TPC distribution system [5] and PG & E 69 bus distribution system [7]. The accuracy and validity of the proposed method has been verified by comparing it with marginal loss method [93], shapley value based iterative method [3] and nucleolus based iterative method [4].

The main features of the proposed approach are as follows:

- Zero and controllable merchandising surplus due to change in active power losses and emissions
- Estimation of the state of the system for current and next operating condition
- Encouragement to private DG owners to participate in loss and emission reduction.
- Provision of flexibility to DISCO's decision maker to choose priority among active power losses and greenhouse gas emissions in terms of weights ω_1 and ω_2 respectively.

√ LMP at each DG bus in active distribution network has been computed based on reliability improvement. The islanded mode of operation has been considered for active distribution system upon outage of line either due to failure or maintenance. Hybrid genetic and dragonfly algorithm has been developed for load and generation scheduling in active distribution system. Load scheduling has been considered if the total load is more than available generation in islanded portion of the network; otherwise generation scheduling has been initiated. This method has been implemented on 38 bus radial distribution system [6] and PG & E 69 bus distribution system [7]. The proposed method is compared with uniform price method [3, 4], GA [105] and DA [106]. The uniform price which is equal to market price has been considered for all DGs in part of network which was connected to the substation.

The main features of the proposed approach are as follows:

- First time reliability has been considered for LMP computation in active distribution system
- First time hybridization has been done between genetic algorithm and dragonfly algorithm to extract the advantages of both methods that provide better results in comparison with individual method.
- DISCO can trade off among different types of loads in the islanded portion of active distribution network using weights ω_1, ω_2 and ω_3 during load scheduling.
- In generation scheduling, DISCO can trade off among emissions, active power losses and cost of power purchased from DGs in islanded portion of active distribution network using weights ω_{emis}, ω_{loss} and ω_{inv} respectively.
- DISCO can estimate the state of the system under single contingency
- Developed some prerequisite algorithms for identification of nodes beyond a particular bus and renumbering buses based on the position of slack bus in both parts of active distribution system.

√ Probabilistic LMP at each DG bus in active distribution network has been computed based on active power loss reduction. 2m+1 scheme of point estimation method [107] has been used to capture the uncertainties that exist in load and market price. The proposed method has been implemented on 84 bus TPC distribution system [5] and PG & E 69 bus distribution system [7]. The proposed method for computing probabilistic LMP is compared with other probabilistic frameworks like Monte Carlo Simulation [108] and 2m scheme of point estimation method [107]. The proposed method has also been compared with shapley value based iterative method [3] and marginal loss method [93] in probabilistic framework.

The main features of the proposed approach are as follows:

- DISCO can provide active and reactive power prices which are less sensitive to uncertainties that exist in market and load.
- DISCO can trade off among active power losses and extra benefit
- DISCO can estimate the state of the active distribution system, which is less sensitive to uncertainties that exist in market and load.
- DISCO Provides zero and controllable merchandising surplus due to change in active power losses irrespective of uncertainties that exist in market and load.

2.6 Thesis Organization

The thesis has been organized into seven chapters.

Chapter 1 briefly introduces restructured power systems and LMP computation in active distribution system.

Chapter 2 presents literature review relevant to the proposed research work. A comprehensive bibliographical review on LMP computation in active distribution system is presented. Finally, it presents the motivation for the research work carried out in this thesis.

Chapter 3 describes LMP computation at DG buses based on active power loss reduction to operate the active distribution system optimally. In this method proportional nucleolus based cooperative game theory has been used for the first time to allocate the change in active power losses among DG units in active distribution system. Financial incentives have been provided to DG units based on their contribution in reduction of active power losses. Financial incentives to each DG unit are derived from reduced active power loss cost in active distribution system. The proposed method has been implemented on 84 bus TPC distribution network [5] and PG & E 69 bus distribution system [7]. In order to identify the robustness and effectiveness of the proposed algorithm, the results obtained are compared with shapley value based iterative method [3].

Chapter 4 addresses the LMP computation at DG buses based on the reduction of active power losses and emissions to operate the active distribution system optimally. In this method, a proportional nucleolus based cooperative game theory [104] has been used for the first time to allocate the change in active power losses and emissions simultaneously among DG units in active distribution system. Financial incentives have been provided to DG units based on its contribution in reduction of active power losses and emissions. Financial incentives to each DG unit is derived from reduced active power loss cost and emission penalty in active distribution system. The proposed method has been implemented on 84 bus TPC distribution network [5] and PG & E 69 bus distribution system [7]. In order to identify the robustness and effectiveness of the proposed algorithm, the results obtained are compared with uniform price method [3, 4], marginal loss method [93], shapley value based iterative method [3] and nucleolus based iterative method [4].

Chapter 5 presents the LMP computation at DG buses based on reliability improvement to operate the active distribution system optimally. Hybridization has been done between genetic algorithm and dragonfly algorithm to extract advantages of both to get better results. Hybrid genetic dragonfly algorithm has been used for load and generation scheduling in islanded portion of the active distribution system. Load scheduling has been initiated if the total load is more than available generation in islanded portion of active distribution system, otherwise generation scheduling is initiated. The proposed method has been implemented on 38 bus radial distribution network [6] and PG & E 69 bus distribution system [7]. In order to validate the robustness and effectiveness of the proposed algorithm, the results obtained are compared with uniform price method [3, 4], genetic algorithm [105] and dragonfly algorithm [106].

Chapter 6 describes the probabilistic LMP computation at DG buses based on active power loss reduction to operate the active distribution system optimally. 2m+1 scheme of point estimation method [107] has been used for capturing the uncertainties that exist in load and market price. Proportional nucleolus based cooperative game theory [104] has been used to allocate the change in active power losses among DG units. The proposed method provides active and reactive power price for each DG, and extra benefit to DISCO which is less sensitive to uncertainties that exist in market price and load. The proposed method has been implemented on 84 bus TPC radial distribution network [5] and PG & E 69 bus distribution system [7]. In order to validate the robustness and effectiveness of the proposed algorithm, the results obtained are compared with uniform price method [3, 4], marginal loss method [93] and shapley value based iterative method [3] in both probabilistic and deterministic framework.

Finally, **Chapter 7** highlights the main findings of the research work reported in this thesis and suggests scope for future work.

2.7 Summary

In this chapter a comprehensive bibliographical review on locational marginal price computation at DG buses for optimal operation of active distribution system has been presented. The short comings of all existing approaches have been discussed. Finally, the motivation and for contribution to research have been presented.

Chapter 3

Computation of Locational Marginal Price at DG buses in active distribution system based on Active Power Loss Reduction

Chapter 3

Computation of Locational Marginal Price at DG buses in active distribution system based on Active Power Loss Reduction

3.1 Introduction

Distribution companies (DISCOs) have not received the desired technological support in transmission and generation, despite 30% to 40% of total investment in electric power sector going to electric power distribution systems. In general 3% to 6% of active power losses exist in electric power sector. Total distribution active power losses in developed countries are not greater than 10% of total active power losses in electric power sector. However these active power losses are around 20% in developing countries like India. Due to this reason electric power utilities in developing countries are trying to reduce active power losses by effective operating mechanisms like providing financial incentives [109]. To manage active power losses in distribution network, efficient and effective computation tools have to be developed.

In this chapter a method to compute Locational Marginal Price (LMP) at DG buses in active distribution network by allocating reduced losses among DG units using Proportional Nucleolus Theory (PNT) has been presented. PNT is one of the most efficient solution methods for cooperative game theory problem. The financial savings of DISCO due to loss reduction from base case have been allocated as an incentive to each DG unit based on DG unit's contribution in loss reduction. The allocated incentive of each DG unit is again shared among active and reactive power generation of that DG unit based on contribution of these parameters in loss reduction. The impact of active and reactive power of DG unit on loss reduction has been computed based on sensitivity analysis. The reactive power price has been computed for each DG unit based on actual contribution of generated reactive power on reduction of active power losses of network. Even though reactive power does not provide any effective work on the system, the reactive power cannot be avoided due to its concern in maintaining network stability and reliability [110].

The original contributions of this chapter are as follows:

- Fair allocation of reduced losses among DG units using PNT for the first time.
- Financial Incentive to each DG unit has been computed by sharing financial savings of DISCO due to loss reduction
- Allocation of financial incentive to each DG unit shared among active and reactive power of that particular DG unit based on sensitivity factors.
- Enabling the DISCO's decision maker to handle trade off among loss reduction and DISCO's extra benefit.
- Making merchandising surplus controllable
- Developing a new approach to compute loss sensitivity factors with respect to active and reactive power generation of DG units for the first time

The proposed method can be employed by DISCO in order to :

- Operate the network with low active power losses.
- Estimate the state of network in terms of LMP, generation, active power loss and voltage at each bus.
- Control private DG owners
- Maintain fair competition among DG owners

3.2 Problem Formulation

An iterative method has been developed to compute LMP at DG buses in radial distribution system based on two ideas like :

- Allocation of reduced active power loss of network among DG units using cooperative game theory
- Calculation of LMP at DG bus based on its contribution in loss reduction.

The load at each hour of the day need to be forecast to estimate the LMP at each DG bus. A two layer Artificial Neural Network has been used to forecast the load.

3.2.1 Load forecasting

The system operator must forecast the system load at each hour of the following day in order to compute LMP at each DG bus. Artificial Neural Network (ANN) based load forecasting has been used in this chapter because of its efficient performance in forecasting [111]. Back Propagation Algorithm (BPA) has been used to train the given ANN because of its flexibility, learning capabilities and is highly suitable for problems where no relationship is found between the output and input [18].

ANN has been trained by considering 'D' day 't' hour load L(t,D) as output and (t-1), (t-2), (t-3), (t-4) hours load of 'D' day and 't' hour load of (D-1),(D-2) days as input data. Because of this, ANN can predict the next hour load based on the last four hours load and the load of the same hour of previous two days. After training, the ANN has been tested by 24 hours load data as testing data. ANN has been trained and tested by taking nine months practical load data from [2]. The testing performance of the network was measured by using Mean Absolute Percentage Error (MAPE) and Root Mean Square Error (RMSE) [112]. Topology of ANN used for forecasting the load is as shown in Figure3.1.

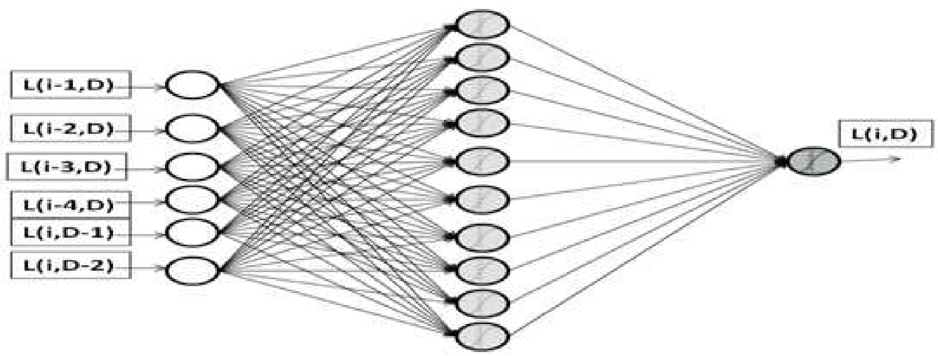


Figure 3.1: Topology of Feed Forward Neural Network

ANN structure was designed by considering the following guidelines :

- ANN has been used to forecast the load on particular hour of the day. So only one neuron/node is considered in output layer
- ANN has been designed to forecast the load on particular hour of the day based on previous four hours of load data, and load data on same hour for previous two days. So total six neurons/nodes have been considered in input layer.
- Number of neurons/nodes considered in hidden layer are 1.5 times of number of neurons/nodes in input layer.

In this study, LMP at DG buses were computed based on DG units contribution in reduction of active power losses, emissions and improvement of reliability. All these parameters depends on load on the substation. Hence, there is a need of proper training of ANN. Properly trained ANN will give the information about load on substation with less forecast error. If the forecasting error has low value, then all estimated system performance parameters like active power losses , emissions and reliability are very close to actual values. Hence, the estimated LMP values of each DG unit will reflect the actual contribution of that DG unit on distribution system performance.

3.2.2 Computation of loss reduction

An iterative distribution load flow algorithm is implemented in two cases based on forecast load (L(t,D)) and active power price ($(\Pi_a^t)_i^j$) at hour 't' of day in order to compute change in active power loss. In this chapter backward and forward sweep algorithm [113] has been utilized as shown in Figure F.1 in Appendix-F to take complete advantage of ladder structure of distribution network, achieve high speed, robust convergence and enable low memory requirements [114, 115]. In this load flow solution, simultaneous control of PQ modeled [116] DG has been used.

Case 1: Base case - No DG unit is connected to the system.

Case 2: DG units inject the power into the system.

Generation of each DG unit based on cost coefficient of that generator and active power price ($(\Pi_a^t)_i^j$) at DG bus has to be computed using equations (3.1) and (3.2). The loss reduction has to be computed using equation (3.3) with reference to the base case.

$$CF_i = a_i((PG^t)_i^j)^2 + b_i(PG^t)_i^j + c_i \tag{3.1}$$

$$(PG^t)_i^j = \frac{(\Pi_a^t)_i^j - b_i}{2a_i} \tag{3.2}$$

$$\Delta Ploss = {Ploss_0}^t - {Ploss_{DG}}^t \tag{3.3}$$

Cooperative game theory is then applied to allocate the reduced losses among DG units. In this chapter PNT is used as a solution method for allocation.

3.2.3 Proportional Nucleolus Theory (PNT)

The restructured power system undergoes a continuous by challenging issue such as allocation of active power loss of network among players. These players are market participants in the transmission system and DG owners in the distribution system. As active power loss of either transmission system or distribution system is highly non linear and non separable, allocation of active power loss among players is a difficult task. In this chapter, cooperative game theory has been used for loss allocation for the following reasons:

- It is a well founded economic framework to qualitatively study allocation of active power loss [117]
- It provides well behaved solution with economic features for assessing the interaction of different participants in competitive market for resolving the conflicts among participants [118]
- It revisits the decisions when player's actions directly influences each other. It keeps the equilibrium of these decisions as well [119]

DISCO has control over DG owners in distribution network. If all DG units operate in a cooperative manner then the network will be operating with low active power loss. Due to DISCOs command over DG owners and to exploit advantages of cooperative operation, DISCOs enable all players to work as a group. It is assumed that all DG units in the distribution system are acting as a group and the DG units are players in this cooperative game problem. Proportional Nucleolus Theory (PNT) is one of the solution concept for cooperative game theory problem. In this study, PNT has been chosen to allocate the active power losses among DG units due to its features like

- It provides effective decision/solution when one player (DG unit) influence the other players (DGs) on system performance (like reduction of active power losses and emissions in distribution system)
- It can expand the core to obtain a unique solution.
- It satisfies all the properties like individual rationality, coalition rationality and collective rationality.
- It always provides an effective solution

The number of coalitions existing in a cooperative game problem consisting of n players is equal to $(2^n - 1)$. All players in a coalition inject the power into the system at the same time. The allocation of active power loss among DG units corresponds to the allocation of payoffs among DG units in the coalition. The problem of active power loss allocation turns into the equilibrium point in game theory.

Extended core concept has been introduced in order to compute solution for cooperative games under empty core environment. The main characteristics of extended core is always non empty and the solution concept coincides in cases where the core is non empty. An imputation chooses from an extended core in PNT like nucleolus which chooses an imputation from the core. The PNT differs from nucleolus theory in the formation of definition of excess concerned with coalitions [104]. As a measure of inequity of an imputation y for a coalition S is defined as excess. In proportional nucleolus theory the excess is defined as shown in equation (3.4). Which measures the amount by which coalition S falls short of its potential $v^l(S)$ in the coalition y. Since core is defined as the set of imputations such that $\sum y_i \geq v^l(S)$ An imputation x for all coalitions of S is within the core only if all its excess values are negative or zero.

$$e(Y:S) = \frac{v^l(S) - \sum_{i \varepsilon S} y_i}{v^l(S)} \tag{3.4}$$

PNT can grow the core to obtain a unique solution in empty core and large core cases. Thus PNT can provide better solution in extended core and core selection problem. This ability of proportional nucleolus to select an imputation is another advantage of extended core solution concept. The solution has been obtained based on PNT concept by solving the following linear programming problem as shown in equation (3.5).

$$\begin{aligned} & & min\ \varepsilon \\ S.t & \qquad & \frac{v^l(S) - \sum_{i \varepsilon S} y_i}{v^l(S)} \leq \varepsilon \\ & & \sum_{i \varepsilon N} y_i = v^l(N) \end{aligned} \tag{3.5}$$

Where ε is a small arbitrary real value.

PNT is explained legibly in the following example. Let us assume that three DG units were integrated into the network with base case active power loss of 440 kW and assume that the generation of each DG unit is 0.5 MW, 0.75 MW and 1 MW. Table.3.1 presents losses and reduced losses from base case due to each coalition of DG units.

Table 3.1: Active power loss reduction in kW for different Coalitions

Coalition (S)	Losses	Loss Reduction($v^l(S)$)
S={DG1=0.5MW}*	420.95	19.05
S={DG2=0.75MW}*	387.95	52.05
S={DG3=1MW}*	418.1	21.9
S={DG1=0.5MW& DG2=0.75MW }*	335	105
S={DG1=0.5MW& DG3=1MW }*	378.8	61.2
S={DG2=0.75MW& DG3=1MW }*	354.95	85.05
N={DG1=0.5MW& DG2=0.75MW & DG3=1MW}#	271.85	168.15

* represents sub coalition S # represents grand coalition N

Objective function:

$$\min \ 0*y_1+0*y_2+0*y_3+1*\varepsilon$$

Equality constraint:

$$1*y_1+1*y_2+1*y_3+0*\varepsilon = 168.15$$

Inequality constraints:

$$\begin{gathered}
-1*y_1+0*y_2+0*y_3-19.05*\varepsilon \leq \text{-19.05} \\
0*y_1-1*y_2+0*y_3-52.05*\varepsilon \leq \text{-52.05} \\
0*y_1+0*y_2-1*y_3-21.9*\varepsilon \leq \text{-21.9} \\
-1*y_1-1*y_2+0*y_3-105*\varepsilon \leq \text{-105} \\
-1*y_1+0*y_2-1*y_3-61.2*\varepsilon \leq \text{-61.2} \\
0*y_1-1*y_2-1*y_3-85.05*\varepsilon \leq \text{-85.05}
\end{gathered}$$

By solving the above linear programming problem that is formulated using equation (3.5), the share of each DG unit in loss reduction is y_1=53.4753kW, y_2 =85.6559kW and y_3=29.0188kW. Fairness of the above solution is measured in terms of three natural properties like individual rationality, coalition rationality and collective rationality.

- Individual Rationality:
  Share of each DG unit in reduced losses must be greater than or equal to loss reduction when that DG unit is operated alone.

$v^l(1) \leq y_1 \Rightarrow 19.05 \leq 53.4753$
$v^l(2) \leq y_2 \Rightarrow 52.05 \leq 85.6559$
$v^l(3) \leq y_3 \Rightarrow 21.90 \leq 29.0188$

- Coalition Rationality:
  Loss reduction due to any sub coalition is less than sum of allocated loss reduction to each DG unit in that sub coalition.

  $v^l(1,2) \leq y_1 + y_2 \Rightarrow 105 \leq 53.4753+85.6559$
  $v^l(1,3) \leq y_1 + y_3 \Rightarrow 61.2 \leq 53.4753+29.0188$
  $v^l(2,3) \leq y_2 + y_3 \Rightarrow 85.05 \leq 85.6559+29.0188$

- Collective Rationality:
  Loss reduction due to coalition of all DG units is equal to sum of allocated reduced losses to each DG unit.

  $v^l(1,2,3) = y_1 + y_2 + y_3$
  $\Rightarrow 168.15 = 53.4753+85.6559+29.0188$

As discussed previously main feature of PNT is extended core. Extended core is inter sectional area formed in triangle by all equality and inequality constraints. This is done by pretending that the plane of the plot is the plane $y_1 + y_2 + y_3$ = 168.15, and giving each point on the plane three coordinates which add to 168.15. The equilateral triangle with extended core which is the region where all the points satisfies all the equality and inequality constraints is shown in Figure 3.2.

3.2.4 DISCO Extra benefit

DISCO extra benefit is defined as difference between DISCO benefit with and without DG units. DISCO benefit without and with DG is calculated using equations (3.6) and (3.7) respectively.

$$benefit_0^t = \Pi^c L(t,D) - ((L(t,D) + Ploss_0^t)\lambda^t \tag{3.6}$$

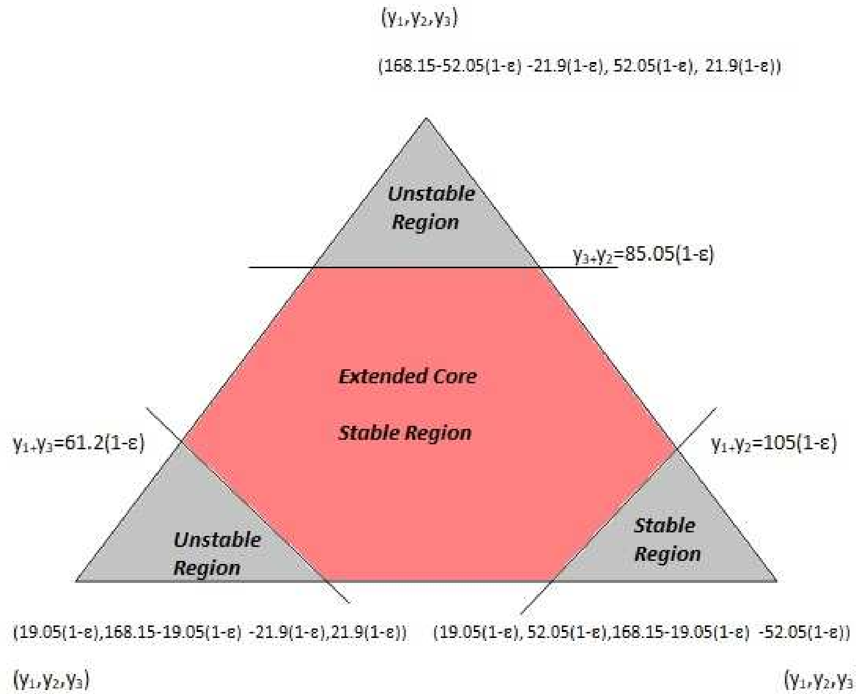


Figure 3.2: Formation of extended Core

$$benefit_j^t = \Pi^c L(t,D) - \sum_{i=1}^{N_{DG}} ((PG^t)_i^j)(\Pi_a^t)_i^j - \sum_{i=1}^{N_{DG}} (QG^t)_i^j (\Pi_r^t)_i^j - (L(t,D) + Ploss_{DG}^t - \sum_{i=1}^{N_{DG}} (PG^t)_i^j)\lambda^t \tag{3.7}$$

The final expression of extra benefit obtained by subtracting (3.6) from (3.7) is as shown in equation (3.8).

$$\Delta benefit_j^t = (Ploss_0^t - Ploss_{DG}^t)\lambda^t - \sum_{i=1}^{N_{DG}} (QG^t)_i^j (\Pi_r^t)_i^j - \sum_{i=1}^{N_{DG}} (PG^t)_i^j ((\Pi_a^t)_i^j - \lambda^t) \tag{3.8}$$

3.2.5 Impact of Active and Reactive power Generation on active power loss of radial distribution system

The single line diagram of six bus system as shown in Figure 3.3 has been considered for deriving the expressions for identifying the following:

- Sensitivity of generation at any bus on active power loss of radial distribution system
- Share of active and reactive power generation of any DG unit on change in losses due to injection of that DG unit.

It is assumed that the considered system has generators with lagging power factor at buses 4 and 5.

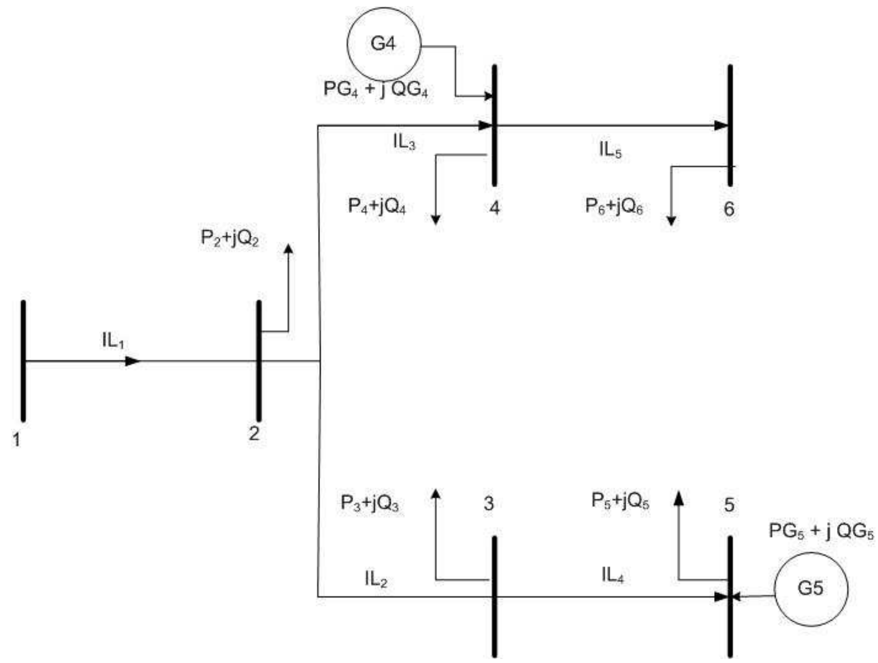


Figure 3.3: Single line diagram of six bus distribution system

A matrix called Bus Incident Beyond Line (BIBL) has been developed in such a way that if node ”b” connected is beyond line ”l” then set BIBL(l,b)=1 otherwise set BIBL(l,b)=0. BIBL matrix for the above six bus system is represented in Table 3.2.

Table 3.2: Bus Incident Beyond Line (BIBL) Matrix

	Bus1	Bus2	Bus3	Bus4	Bus5	Bus6
Line1	0	1	1	1	1	1
Line2	0	0	1	0	1	0
Line3	0	0	0	1	0	1
Line4	0	0	0	0	1	0
Line5	0	0	0	0	0	1

The current drawn at each bus has been computed based on net withdrawal complex power and voltage at that bus. The final expression for current at each bus is as shown in equation (3.9).

$$
\begin{aligned}
I_2 &= \frac{P_2 + jQ_2}{V_2^*} \\
I_3 &= \frac{P_3 + jQ_3}{V_3^*} \\
I_4 &= \frac{(P_4 - PG_4) + j(Q_4 - QG_4)}{V_4^*} \\
I_5 &= \frac{(P_5 - PG_5) + j(Q_5 - QG_5)}{V_5^*} \\
I_6 &= \frac{P_6 + jQ_6}{V_6^*}
\end{aligned} \tag{3.9}
$$

The current through each line in the six bus distribution network has been computed by applying KCL at each bus and the final expression of current through each line is shown in equation (3.10).

$$
\begin{aligned}
IL_1 = I_2 + IL_2 + IL_3 &= \frac{P_2 + jQ_2}{V_2^*} + IL_2 + IL_3 \\
IL_2 = I_3 + IL_4 &= \frac{P_3 + jQ_3}{V_3^*} + IL_4 \\
IL_3 = I_4 + IL_5 &= \frac{(P_4 - PG_4) + j(Q_4 - QG_4)}{V_4^*} + IL_5 \\
IL_4 = I_5 &= \frac{(P_5 - PG_5) + j(Q_5 - QG_5)}{V_5^*} \\
IL_5 = I_6 &= \frac{P_6 + jQ_6}{V_6^*}
\end{aligned} \tag{3.10}
$$

All line currents shown above are complex quantities. After rearranging real and imaginary parts complex line currents are shown in equation (3.11).

$$
\begin{aligned}
IL_1 &= IL_1^R + jIL_1^I \\
IL_2 &= IL_2^R + jIL_2^I \\
IL_3 &= IL_3^R + jIL_3^I \\
IL_4 &= IL_4^R + jIL_4^I \\
IL_5 &= IL_5^R + jIL_5^I
\end{aligned} \tag{3.11}
$$

where the real and imaginary parts of each line current are shown in equation (3.12) and equation (3.13) respectively.

$$\begin{aligned}
IL_1^R = \frac{P_2V_2^R+Q_2V_2^I}{|V_2|^2}+\frac{P_3V_3^R+Q_3V_3^I}{|V_3|^2}+\frac{(P_4-PG_4)V_4^R+(Q_4-QG_4)V_4^I}{|V_4|^2}+ \\
\frac{(P_5-PG_5)V_5^R+(Q_5-QG_5)V_5^I}{|V_5|^2}+\frac{P_6V_6^R+Q_6V_6^I}{|V_6|^2} \\
IL_2^R = \frac{P_3V_3^R+Q_3V_3^I}{|V_3|^2}+\frac{(P_5-PG_5)V_5^R+(Q_5-QG_5)V_5^I}{|V_5|^2} \\
IL_3^R = \frac{(P_4-PG_4)V_4^R+(Q_4-QG_4)V_4^I}{|V_4|^2}+\frac{P_6V_6^R+Q_6V_6^I}{|V_6|^2} \\
IL_4^R = \frac{(P_5-PG_5)V_5^R+(Q_5-QG_5)V_5^I}{|V_5|^2} \\
IL_5^R = \frac{P_6V_6^R+Q_6V_6^I}{|V_6|^2}
\end{aligned} \tag{3.12}$$

$$\begin{aligned}
IL_1^I = \frac{P_2V_2^I+Q_2V_2^R}{|V_2|^2}+\frac{P_3V_3^I+Q_3V_3^R}{|V_3|^2}+\frac{(P_4-PG_4)V_4^I+(Q_4-QG_4)V_4^R}{|V_4|^2}+ \\
\frac{(P_5-PG_5)V_5^I+(Q_5-QG_5)V_5^R}{|V_5|^2}+\frac{P_6V_6^I+Q_6V_6^R}{|V_6|^2} \\
IL_2^I = \frac{P_3V_3^I+Q_3V_3^R}{|V_3|^2}+\frac{(P_5-PG_5)V_5^I+(Q_5-QG_5)V_5^R}{|V_5|^2} \\
IL_3^I = \frac{(P_4-PG_4)V_4^I+(Q_4-QG_4)V_4^R}{|V_4|^2}+\frac{P_6V_6^I+Q_6V_6^R}{|V_6|^2} \\
IL_4^I = \frac{(P_5-PG_5)V_5^I+(Q_5-QG_5)V_5^R}{|V_5|^2} \\
IL_5^I = \frac{P_6V_6^I+Q_6V_6^R}{|V_6|^2}
\end{aligned} \tag{3.13}$$

Active power loss of system can be computed using equation (3.14). Change in active power losses with respect to change in active power generation at bus 4 is nothing but sensitivity of losses with respect to active power generation at bus 4 is as shown in equation (3.15).

$$P_{loss} = |IL_1|^2R_1+|IL_2|^2R_2+|IL_3|^2R_3+|IL_4|^2R_4+|IL_5|^2R_5 \tag{3.14}$$

$$\begin{aligned}\frac{\partial P_{loss}}{\partial PG_4} &= -2IL_1^R R_1 \frac{V_4^R}{|V_4|^2} - 2IL_1^I R_1 \frac{V_4^I}{|V_4|^2} \\ &\quad -2IL_3^R R_3 \frac{V_4^R}{|V_4|^2} - 2IL_3^I R_3 \frac{V_4^I}{|V_4|^2} \\ &= -2\frac{[BIBL(:,4)]^T (IR^{Real} V_4^R + IR^{Imag} V_4^I)}{|V_4|^2}\end{aligned} \tag{3.15}$$

Similarly sensitivity of losses with respect to reactive power generation at bus 4 with the DG having lagging power factor is shown in equation (3.16) and with the DG having leading power factor is shown in equation (3.17).

For DG having lagging power factor:

$$\begin{aligned}\frac{\partial P_{loss}}{\partial QG_4} &= -2IL_1^R R_1 \frac{V_4^I}{|V_4|^2} + 2IL_1^I R_1 \frac{V_4^R}{|V_4|^2} \\ &\quad -2IL_3^R R_3 \frac{V_4^I}{|V_4|^2} + 2IL_3^I R_3 \frac{V_4^R}{|V_4|^2} \\ &= -2\frac{[BIBL(:,4)]^T (IR^{Real} V_4^I - IR^{Imag} V_4^R)}{|V_4|^2}\end{aligned} \tag{3.16}$$

For DG having leading power factor:

$$\begin{aligned}\frac{\partial P_{loss}}{\partial QG_4} &= 2IL_1^R R_1 \frac{V_4^I}{|V_4|^2} - 2IL_1^I R_1 \frac{V_4^R}{|V_4|^2} \\ &\quad +2IL_3^R R_3 \frac{V_4^I}{|V_4|^2} - 2IL_3^I R_3 \frac{V_4^R}{|V_4|^2} \\ &= -2\frac{[BIBL(:,4)]^T (IR^{Imag} V_4^R - IR^{Real} V_4^I)}{|V_4|^2}\end{aligned} \tag{3.17}$$

In general the sensitivity of active power losses with active power generation is shown in equation (3.18) and the sensitivity of active power loss with reactive power generation for the DGs having lagging and leading power factor are shown in equations (3.19) and (3.20) respectively.

$$\frac{\partial P_{loss}}{\partial PG_b} = -2\frac{[BIBL(:,4)]^T (IR^{Real} V_b^R + IR^{Imag} V_b^I)}{|V_b|^2} \tag{3.18}$$

For generator having lagging power factor:

$$\frac{\partial P_{loss}}{\partial QG_b} = -2\frac{[BIBL(:,b)]^T(IR^{Real}V_b^I - IR^{Imag}V_b^R)}{|V_b|^2} \tag{3.19}$$

For generator having leading power factor:

$$\frac{\partial P_{loss}}{\partial QG_b} = -2\frac{[BIBL(:,b)]^T(IR^{Imag}V_b^R - IR^{Real}V_b^I)}{|V_b|^2} \tag{3.20}$$

where IR^{Real} matrix is shown in equation (3.21) and IR^{Imag} matrix is as shown in equation (3.22).

$IR^{Real}=$

$$\begin{bmatrix} IL_1^R R_1 & IL_2^R R_2 & IL_3^R R_3 & IL_4^R R_4 & \dots & IL_{nline}^R R_{nline} \end{bmatrix}^T \tag{3.21}$$

$IR^{Imag}=$

$$\begin{bmatrix} IL_1^I R_1 & IL_2^I R_2 & IL_3^I R_3 & IL_{nline}^I R_4 & \dots & IL_{nline}^I R_{nline} \end{bmatrix}^T \tag{3.22}$$

Total change in active power loss of radial distribution system due to change in active and reactive power generation of DG 'i' at bus 'b' is shown in equation (3.23). The share of active and reactive power generations of DG unit 'i' at bus 'b' on system active power loss are shown in equations (3.24) and (3.25) respectively. Where Φ is phase angle corresponding to power factor of DG 'i'.

$$(\Delta P_{loss})_b^i = \frac{\partial P_{loss}}{\partial PG_b}\Delta PG_b + \frac{\partial P_{loss}}{\partial QG_b}\Delta QG_b \tag{3.23}$$

$$Pshare_i^b = \frac{\frac{\partial P_{loss}}{\partial PG_b}}{\frac{\partial P_{loss}}{\partial PG_b} + \frac{\partial P_{loss}}{\partial QG_b}tan(\Phi)} \tag{3.24}$$

$$Qshare_i^b = \frac{\frac{\partial P_{loss}}{\partial QG_b}}{\frac{\partial P_{loss}}{\partial PG_b}cot(\Phi) + \frac{\partial P_{loss}}{\partial QG_b}} \tag{3.25}$$

3.2.6 PNT based iterative Algorithm

The PNT based iterative algorithm to compute LMP values at each DG bus is shown in Algorithm 1. PNT has been used in this algorithm for fair allocation of reduced losses among

DG units.

Algorithm 1 PNT based iterative Algorithm

Inputs

1: Read hour (t) of the day (D) and λ^t
2: Read Forecasted load L(t,D)

Steps

1: Run the load flow and compute base case losses with forecasted load L(t,D)
2: Set iteration j=1, $(\Pi_a^t)_i^j$=λ^t, and $(PG^t)_i^0$=0 where i=1,2,...N_{DG}
3: i=1 ▷ i represents DG number
4: **while** $i \neq N_{DG}+1$ **do**
Compute Generation using equations (3.2) and (3.26)

$$(QG^t)_i^j = (PG^t)_i^j * \frac{\sqrt{1-(cosdg^i)^2}}{cosdg^i} \tag{3.26}$$

▷ If calculated generation using equation (3.2) exceeds maximum capacity of DG unit then DG generation is set to generation upper limit. The constraint considered for DG generation is as shown in equation (3.27)

$$0 \leq (PG^t)_i^j \leq PG_i^{max} \tag{3.27}$$

5: $i \leftarrow i+1$
6: **end while**
7: Run the load flow and compute change in active power losses due to coalition of all DG units ($v^l(N)$) based on generation computed using equations (3.2) and (3.26).
8: Run the load flow and compute losses due to each sub coalition of DG units ($v^l(S)$) based on generation computed using equations (3.2) and (3.26).
9: Compute DISCO extra benefit ($\Delta benefit_j^t$) using equation (3.8) and set error=max($(PG^t)_i^j - (PG^t)_i^{j-1}$) where i=1,2,...$N_{DG}$
10: **if** $\Delta benefit_j^t \leq \varepsilon_1$ OR $\Delta Pmax \leq \varepsilon_2$ **then**
11: $GoTo \rightsquigarrow Step20$
12: **else**
13: $GoTo \rightsquigarrow$ Step 15
14: **end if**

▷ Where ε_1 and ε_2 are small values

Algorithm 1 (Continued) PNT based iterative Algorithm

15: Compute share of each DG unit in loss reduction (y_i) using PNT as shown in section 3.2.3
16: Compute incentive provided to each DG unit as shown in equation (3.28).

$$DG_{inc}^{i} = \frac{y_i}{v^l(N)} * \lambda^t v^l(N) = y_i * \lambda^t \tag{3.28}$$

17: Distribute incentive of each DG unit among active and reactive power generation as shown in equation (3.29).

$$\begin{aligned} DG_{inc}^{P}(i) &= DG_{inc}^{i} * Pshare_i^b \\ DG_{inc}^{Q}(i) &= DG_{inc}^{i} * Qshare_i^b \end{aligned} \tag{3.29}$$

18: Compute active and reactive power price for next iteration using equations (3.30) and (3.31) respectively.

$$((\Pi_a^i)_t^{j+1} - \lambda^t)\frac{(\Pi_a^i)_t^{j+1} - b_i}{2a_i} = DG_{inc}^{P}(i) \tag{3.30}$$

$$(\Pi_r^i)_t^{j+1} = \lambda^r + \frac{DG_{inc}^{Q}(i)}{(QG^t)_i^j} \tag{3.31}$$

▷ Reactive power price at substation bus is less than 1% of active power price [120], and so the value of λ^r is set to zero.

19: Increment iteration j=j+1 and go to Step 3.
20: Stop iterative algorithm for hour 't' and take print out of required data.

3.3 Analytical Studies

3.3.1 Case Study - 1

The proposed method was implemented on 84 bus Taiwan Power Company (TPC) distribution network as shown in Figure A.1 in Appendix-A. Table 3.3 represents the location of 15 DG units of various types operating at 0.9 lagging power factor with 1 MW capacity. The cost coefficients of each type of DG are represented in Table 3.4. The proposed method has been simulated under MATLAB [121] environment on realistic price data drawn from [2] and the TPC distribution system data captured from [5] and presented in Table G.1 of Appendix-A.

3.3.1.1 Load forecasting

TPC distribution system's load for the next day has been forecast using historical data and by employing ANN as explained in section 3.2.1.

Table 3.3: Type and Location of 1 MW capacity DG units [4]

Unit	Type	Location	Unit	Type	Location
1	1	4	9	2	20
2	1	65	10	2	47
3	1	25	11	3	11
4	1	35	12	3	60
5	1	84	13	3	41
6	2	55	14	3	30
7	2	12	15	3	76
8	2	72			

Type 1: Combined Cycle Gas Turbine

Type 2: Gas Internal Combustion Engine

Type 3: Diesel Internal Combustion Engine

Table 3.4: DG units cost coefficients [4]

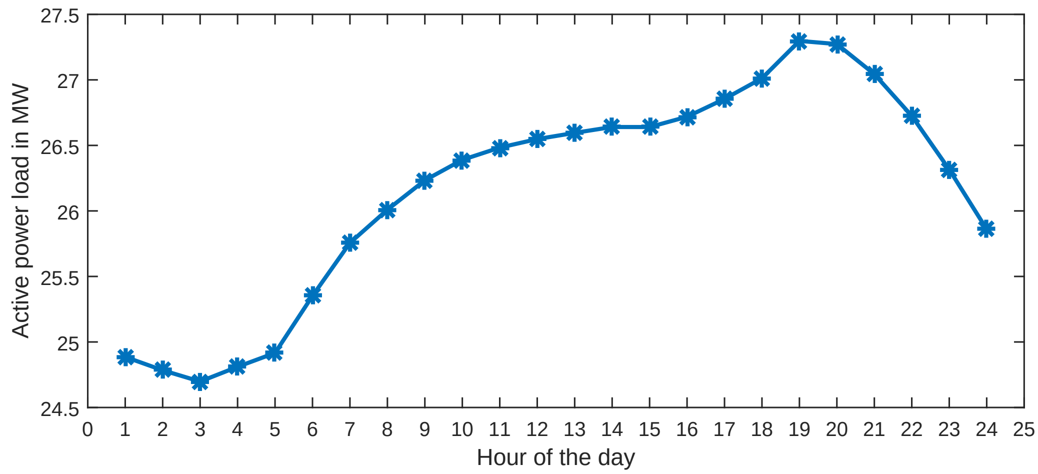
Type	a (\$/MW^2h)	b (\$/MWh)	c (\$/h)
1	5.8	21	0
2	5.3	20	0
3	5.0	20	0

- Mean Absolute Percentage Error (MAPE) and Root Mean Square Error (RMSE) based on testing of network are found to be 1.3424 and 0.0094 respectively.
- The predicted load for the next 24 hours for TPC distribution network is shown in Figure 3.4.

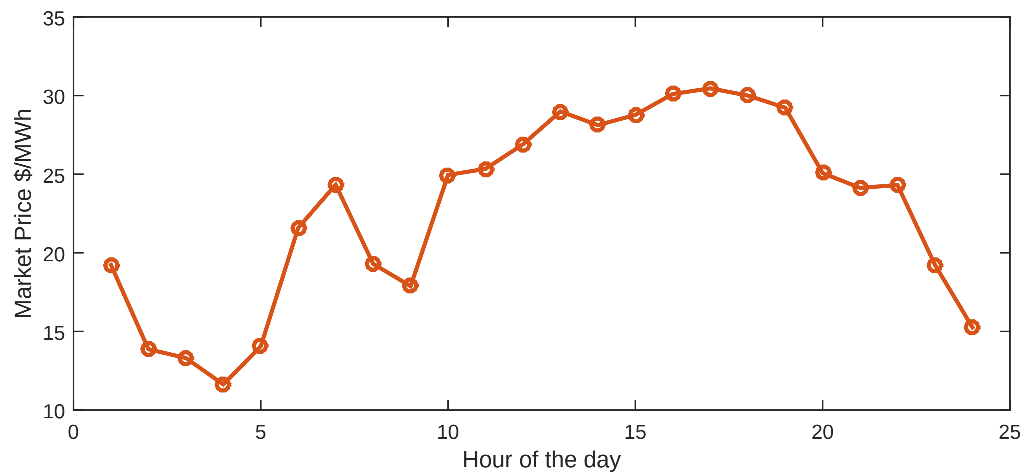
3.3.1.2 Impact of market price (λ^t) on LMP of DG units

Table 3.5 presents LMP values for each DG bus at market price of 19.23 \$/MWh, 21.59 \$/MWh and 25.07 \$/MWh.

- When the market price is 19.23 \$/MWh all DG units are off as market price is less than 'b' coefficient value of generator.
- Hence there is reduction in active power loss of network and there are no incentives to DG units. LMP value at each DG bus is equal to market price only.



(a)



(b)

Figure 3.4: (a) Forecasted load curve [2] (b) Market Price Curve [2] for 84 bus TPC radial distribution system

- On the other hand, LMP values at DG buses for market prices of 21.59 \$/MWh and 25.07 \$/MWh are based on DG's contribution in loss reduction.

- As DG11 has high impact on loss reduction, LMP of DG11 unit is more when compared with remaining DG units.

Table 3.5: LMP in \$/MWh at DG buses for different market prices

DG Unit	λ^t=19.23(\$/MWh)	λ^t=21.59(\$/MWh)	λ^t=25.07(\$/MWh)
DG1	19.23	22.30	25.82
DG2	19.23	22.04	25.44
DG3	19.23	22.06	25.54
DG4	19.23	22.10	25.58
DG5	19.23	22.22	25.80
DG6	19.23	22.04	25.59
DG7	19.23	21.65	25.14
DG8	19.23	22.18	25.76
DG9	19.23	21.97	25.49
DG10	19.23	21.66	25.10
DG11	19.23	22.62	26.21
DG12	19.23	21.94	25.36
DG13	19.23	22.13	25.55
DG14	19.23	21.88	25.39
DG15	19.23	21.77	25.26

3.3.1.3 Impact of market price (λ^t) on Generation of DG units

Table 3.6 shows generation of DG units for different market prices.

- When the market price is 19.23 \$/MWh, all DG units are not able to generate power as wholesale market price is less than 'b' coefficient of DG units.

- However DG unit's generation at market prices of 21.59 \$/MWh and 25.07 \$/MWh depends on the incentive provided by DISCO.

- As DG11 receives more incentive from DISCO due to its huge contribution in loss reduction, it has more generation when market prices are either 21.59 \$/MWh or 25.07 \$/MWh.

3.3.1.4 Impact of market price (λ^t) on reactive power price of DG units

The impact of market price on reactive power price of DG units is as shown in Table 3.7.

Table 3.6: DG unit's generation in kW for different market prices

DG Unit	λ^t=19.23($/MWh)	λ^t=21.59($/MWh)	λ^t=25.07($/MWh)
DG1	0	112	416
DG2	0	90	383
DG3	0	92	391
DG4	0	94	395
DG5	0	105	413
DG6	0	192	527
DG7	0	156	485
DG8	0	205	543
DG9	0	186	518
DG10	0	156	482
DG11	0	262	621
DG12	0	194	536
DG13	0	213	556
DG14	0	188	539
DG15	0	177	526

- When the market price is 19.23 $/MWh, DG units can not generate power as market price is less than 'b' coefficient. Hence, the reactive power price is as shown in Table 3.7 and is equal to reactive power price at substation bus, that is zero.
- When the market price is 21.59 $/MWh and 25.07 $/MWh, reactive power price of each DG unit is assigned based on DG unit's reactive power contribution in loss reduction.
- DG11 has high reactive power price due to the reactive power contribution in loss reduction.

Table 3.7: DG unit's reactive power price in $\$/MVarh$ for different market prices

DG Unit	λ^t=19.23($/MWh)	λ^t=21.59($/MWh)	λ^t=25.07($/MWh)
DG1	0	0.5387	0.6333
DG2	0	0.3435	0.4100
DG3	0	0.3726	0.4495
DG4	0	0.4086	0.4850
DG5	0	0.4680	0.5806
DG6	0	0.2986	0.3670
DG7	0	0.0454	0.0567
DG8	0	0.4645	0.5818
DG9	0	0.2996	0.3645
DG10	0	0.0643	0.1059
DG11	0	0.7774	0.9501
DG12	0	0.2683	0.3302
DG13	0	0.4506	0.5742
DG14	0	0.2118	0.2607
DG15	0	0.1390	0.1724

3.3.1.5 Variation in active power loss of network during iterative algorithm for different market prices

Figure 3.5 shows the variation in active power loss of network as iterations increase in the proposed method at different market prices.

- Active power loss of network decreases as iterations increase.
- This is due to the increasing of incentive to DG units thereby increasing the generation that have positive impact on loss reduction.

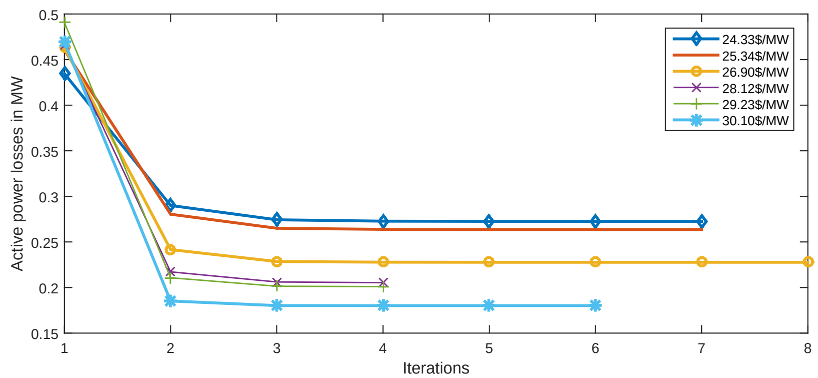


Figure 3.5: Variation in active power loss for different market prices

3.3.1.6 Variation in extra benefit of DISCO during iterative algorithm for different market prices

Variation in extra benefit of DISCO as iterations progress in proposed method is as shown in Figure 3.6.

- In a deregulated environment, zero extra benefit is nothing but zero merchandising surplus.
- This can be achieved by the proposed method and is shown in Figure 3.6.
- The proposed method provides incentive to each DG unit based on unit's contribution in loss reduction.
- These incentives are given from financial savings of DISCO due to loss reduction until DISCO's extra benefit reaches to zero.

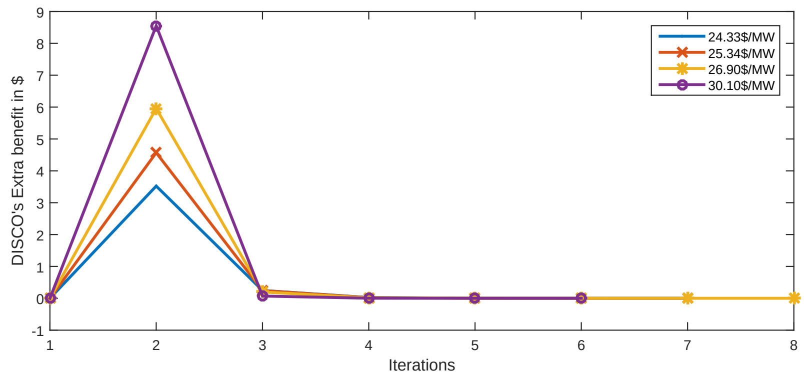


Figure 3.6: DISCO's Extra benefit variation for different market prices

3.3.1.7 Comparison of active power loss of network between shapley value based iterative method [3] and the proposed method

The proposed method is compared with shapley value based iterative method as mentioned in [3] in terms of losses during 24 hours of the day. As shown in Figure 3.7

- Proposed method and existing method provide equal losses which is equal to base case losses at hours of the day where the market price is less than 'b' coefficient of all DG units.

- At remaining hours of the day, the proposed method enables DISCO to operate the distribution system with low active power losses in comparison with the existing method.

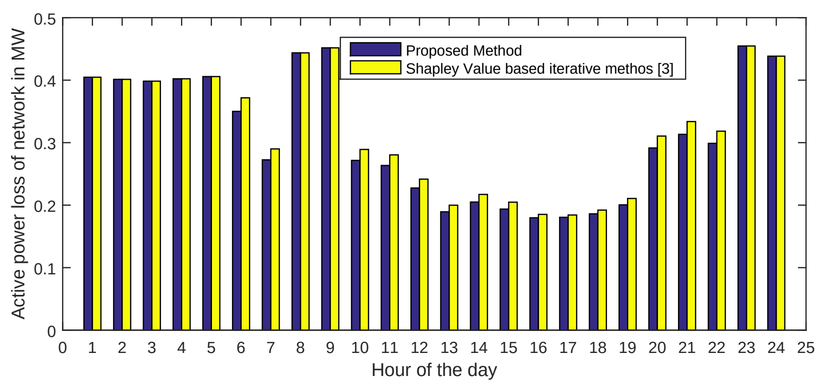


Figure 3.7: Comparison of active power loss of network between shapley value based iterative method [3] and the proposed method

3.3.1.8 Comparison of DG units profit between shapley value based iterative method [3] and the proposed method

Figure 3.8 shows a comparison of the proposed method with shapley value based iterative method [3] in terms of profit of DG units per hour at a market price 24.95 $/MWh. DG profit is computed as the difference between total amount paid by DISCO for both active and reactive power generation and total generation cost.

- The proposed method provides more profit to DG owners as incentives are provided from DISCO's financial savings due to loss reduction.
- As DG11 has high positive impact on loss reduction, it gets more profit in comparison with the remaining DG units.

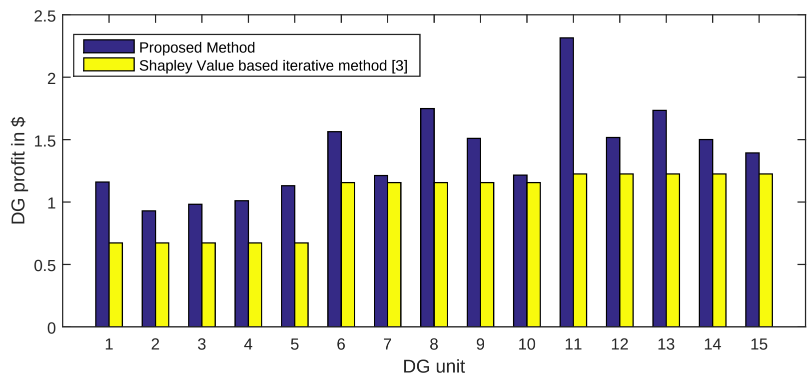
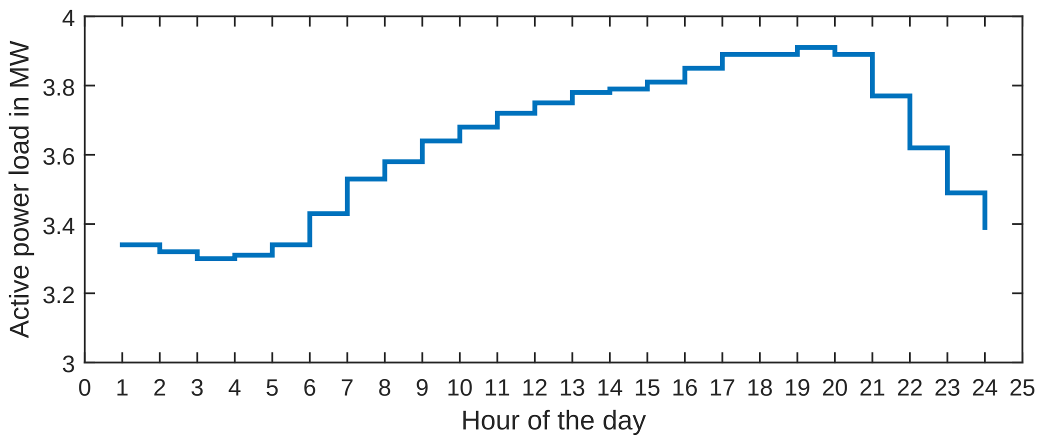


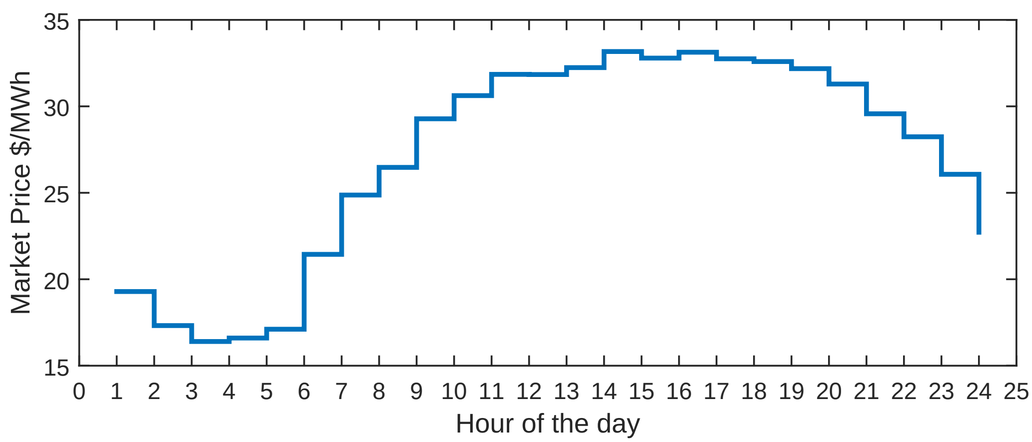
Figure 3.8: Comparison of DG units profit between shapley value based iterative method [3] and the proposed method

3.3.2 Case Study - 2

The proposed method was implemented on PG & E 69 bus radial distribution system as shown in Figure C.1 in Appendix-C. Table 3.8 represents the location of 3 DG units of various types operating at 0.9 lagging power factor with 1 MW capacity. The cost coefficients of each type of DG are represented in Table 3.4. The proposed method has been simulated under MATLAB [121] environment on realistic price and load data drawn from [2] and presented in Figure 3.9. The PG & E 69bus radial distribution system data captured from [7] and presented in Table C.1 in Appendix-C.



(a)



(b)

Figure 3.9: (a) Average load curve [2] (b) Average Market Price Curve [2] for PG & E 69 bus radial distribution system

Table 3.8: Type and Location of 1 MW capacity DG units for PG & E 69 bus radial distribution system

DG Unit	Type	Location	Engine Type
DG 1	1	61	Combined Cycle Gas Turbine
DG 2	2	53	Gas Internal Combustion Engine
DG 3	3	11	Diesel Internal Combustion Engine

3.3.2.1 Impact of market price (λ^t) on LMP of DG units in PG & E 69 bus active distribution system

Table 3.9 presents LMP values for each DG bus at different market price and loading conditions.

- When the market price is 19.29 $/MWh, 17.2 $/MWh, 16.40 $/MWh, 16.60 $/MWh and 17.11 $/MWh, all DG units are off as the market price is less than 'b' coefficient value of generator.
- Hence there is reduction in active power loss of network and no incentives to DG units. LMP value at each DG bus is equal to market price only.
- LMP values at DG buses for market prices of 21.44 $/MWh, 24.87 $/MWh and 26.47 $/MWh are based on DG's contribution in loss reduction.
- DG1 has more LMP value in comparison with remaining DG units. This is due to DG1's greater contribution in active power loss reduction at given market price and loading conditions.
- When market prices are 32.75 $/MWh, 33.17 $/MWh, 32.79 $/MWh, and 33.13 $/MWh, all DG units operate at their maximum capacity and they cannot increase generation even if DISCO provides incentives.
- Due to this reason all DG units at these market prices have LMP values same as market price.

3.3.2.2 Impact of market price (λ^t) on Generation of DG units for PG & E 69 bus active distribution system

Table 3.10 presents active power generation for each DG unit at different market prices and loading conditions.

Table 3.9: LMP in \$/MWh at DG buses for different market prices for PG & E 69 bus active distribution system

λ^t (\$/MWh)	Load (MW)	DG1	DG2	DG3	λ^t (\$/MWh)	Load (MW)	DG1	DG2	DG3
19.29	3.34	19.29	19.29	19.29	26.47	3.58	28.85	27.04	27.03
17.32	3.32	17.32	17.32	17.32	24.87	3.53	27.34	25.52	25.55
16.40	3.30	16.40	16.40	16.40	32.75	3.78	32.75	32.75	32.75
16.60	3.31	16.60	16.60	16.60	33.17	3.79	33.17	33.17	33.17
17.11	3.34	17.11	17.11	17.11	32.79	3.81	32.79	32.79	32.79
21.44	3.43	24.02	22.13	22.21	33.13	3.85	33.13	33.13	33.13

- When the market price is 19.29 \$/MWh, 17.2 \$/MWh, 16.40 \$/MWh, 16.60 \$/MWh and 17.11 \$/MWh, all DG units are not able to generate power as the market price is less than 'b' coefficient value of generator.

- Hence active power generation from DG units at these market prices is equal to zero.

- The active power generation from DG units for the market prices of 21.44 \$/MWh, 24.87 \$/MWh and 26.47 \$/MWh is based on the amount of incentives received in terms of LMP from DISCO.

- When market prices are 32.75 \$/MWh, 33.17 \$/MWh, 32.79 \$/MWh, and 33.13 \$/MWh all DG units operate at their maximum capacity of 1000 kW.

3.3.2.3 Impact of market price (λ^t) on reactive power price of DG units for PG & E 69 bus active distribution system

The impact of market price on reactive power price of DG units is as shown in Table 3.11. When the market price is 19.29 \$/MWh, 17.2 \$/MWh, 16.40 \$/MWh, 16.60 \$/MWh and 17.11 \$/MWh

- All DG units are not able to generate power as the market price is less than 'b' coefficient value of generator.

- Active power generation from DG units at these market prices is equal to zero, and the distribution system is operating as in base case (No DG units).

Table 3.10: Active power generation in kW at different market prices for PG & E 69 bus active distribution system

λ^t ($/MWh)	Load (MW)	DG1	DG2	DG3	λ^t ($/MWh)	Load (MW)	DG1	DG2	DG3
19.29	3.34	0	0	0	26.47	3.58	676.7	664.2	703.0
17.32	3.32	0	0	0	24.87	3.53	546.6	520.8	555.6
16.40	3.30	0	0	0	32.75	3.78	1000	1000	1000
16.60	3.31	0	0	0	33.17	3.79	1000	1000	1000
17.11	3.34	0	0	0	32.79	3.81	1000	1000	1000
21.44	3.43	260.3	200.9	221.0	33.13	3.85	1000	1000	1000

- The reactive power price for each DG unit is equal to the reactive power price at a substation bus which is equal to zero,

Whereas the reactive power price for each DG unit at the market prices of 21.44 $/MWh, 24.87 $/MWh and 26.47 $/MWh is based on the contribution of reactive power of that DG unit on active power loss reduction.

- As the reactive power of DG1 has more contribution on active power loss reduction at these market price and loading conditions, it receives more reactive power price value in comparison with the remaining DG units.

When the market prices are 32.75 $/MWh, 33.17 $/MWh, 32.79 $/MWh, and 33.13 $/MWh all DG units operate at their maximum capacity 484.3 kVar and they cannot increase reactive power generation.

- DISCO cannot provide incentives to DG units for reactive power generation.
- Reactive power price for all these DG units at these market prices and loading conditions is equal to the reactive power price at substation bus which is equal to zero.

3.3.2.4 Variation in active power loss of network during iterative algorithm for different market prices for PG & E 69 bus active distribution system

Figure 3.10 shows the variation in active power loss of network as iterations increase in the proposed method at different market prices.

Table 3.11: Reactive power price in \$/MVarh at different market prices for PG & E 69 bus active distribution system

λ^t (\$/MWh)	Load (MW)	DG1	DG2	DG3	λ^t (\$/MWh)	Load (MW)	DG1	DG2	DG3
19.29	3.34	0	0	0	26.47	3.58	2.325	0.894	1.015
17.32	3.32	0	0	0	24.87	3.53	2.197	0.707	0.776
16.40	3.30	0	0	0	32.75	3.78	0	0	0
16.60	3.31	0	0	0	33.17	3.79	0	0	0
17.11	3.34	0	0	0	32.79	3.81	0	0	0
21.44	3.43	1.991	0.541	0.604	33.13	3.85	0	0	0

- Active power loss of network decreases as iteration increases.
- This is due to the increasing of incentive to DG units, thereby increasing the generation that has a positive impact on loss reduction.

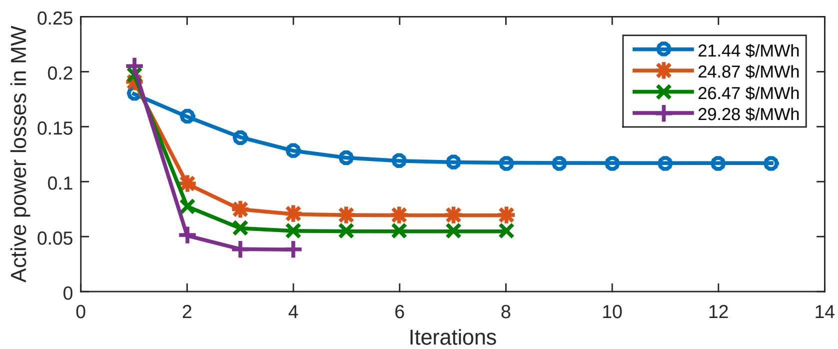


Figure 3.10: Variation in active power loss for different market prices for PG & E 69 bus active distribution system

3.3.2.5 Variation in extra benefit of DISCO during iterative algorithm for different market prices for PG & E 69 bus active distribution system

The variation in extra benefit per hour of DISCO as iterations progress in the proposed method is shown in Figure 3.11. In a deregulated environment, zero extra benefit is nothing but zero merchandising surplus is essential. This can be achieved by the proposed method and is shown in Figure 3.11.

- The proposed method provides incentive to each DG unit based on the unit's contribution in loss reduction.
- These incentives are given from the financial savings of DISCO due to loss reduction until DISCO's extra benefit reaches zero.

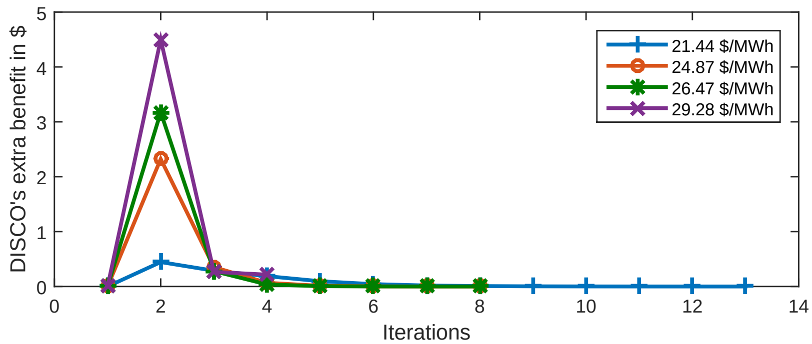


Figure 3.11: DISCO's Extra benefit variation for different market prices for PG & E 69 bus active distribution system

3.3.2.6 Comparison of proposed method in terms of Active power losses for PG & E 69 bus active distribution system

The proposed method is compared with shapley value based iterative method as mentioned in [3] in terms of losses during 24 hours of the day. As shown in Figure 3.12

- The proposed method and existing method provide equal losses that is equal to base case losses at those hours of the day where the market price is less than 'b' coefficient value of all DG units.
- When market prices are 33.17 $/MWh, 32.79 $/MWh, 33.13 $/MWh, 32.75 $/MWh and 32.59 $/MWh, all DG units are operating at their maximum capacity at initial price (market price) in both proposed and shapley value based iterative method [3].
- Due to this reason both methods are operating the network with same active power losses.
- At remaining hours of the day in the proposed method enables DISCO to operate the distribution system with less active power loss in comparison with existing shapley value based iterative method [3].

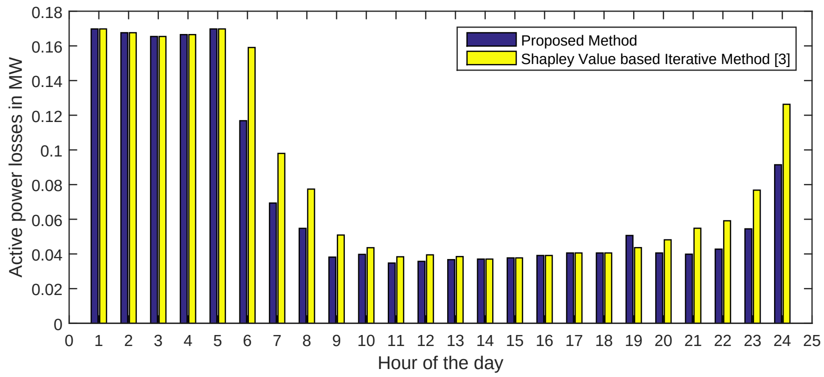


Figure 3.12: Comparison in terms of active power loss of network for PG & E 69 bus active distribution system

3.3.2.7 Comparison of proposed method in terms of DG profit

Table 3.12 shows a comparison of the proposed method with shapley value based iterative method [3] in terms of profit of DG units at different market prices. DG profit is computed as the difference between total amount paid by DISCO for both active and reactive power generation and total generation cost.

- The proposed method provides more profit to DG owners as incentives provided from DISCO's financial savings due to loss reduction.
- As DG1 has high positive impact on loss reduction, DG1 gets more profit in comparison with the remaining DG units in the proposed method.

Table 3.12: Comparison in terms of DG units profit for PG & E 69 bus active distribution system

λ^t	Proposed Method			Shapley Value based iterative method [3]		
($/MWh)	DG1	DG2	DG3	DG1	DG2	DG3
21.44	0.644	0.267	0.306	0.008	0.098	0.104
24.87	2.349	1.663	2.077	0.635	1.104	1.170
26.47	3.407	2.565	2.570	1.283	1.974	2.096

3.4 Summary

The proportional nucleolus theory (PNT) based iterative method has been developed to compute LMP at DG buses based on loss reduction. DG units which have a high positive impact of loss reduction received more incentive. PNT was used for the first time for computing LMP at DG buses based on loss reduction. Sensitivity factors were developed to identify the share of active and reactive power generation of each DG unit on change in losses of network due to injection of DG. Incentives were provided to DG units from DISCO's financial savings due to loss reduction.

This method provides controllable MS and an opportunity to DISCO to handle trade off among losses and extra benefit. This method can be helpful to DISCO decision maker to control private DG owners and help operate network optimally in terms of losses, and to estimate the state of network. Fair allocation of loss reduction among DG units was achieved by PNT and the proposed method is also helpful to society/customers for getting quality power. As there will be an increase of DG penetration into the network in future, this method may resolve many problems related to distribution system planning and operation.

Chapter 4

Computation of Locational Marginal Price at DG buses in active distribution system based on Active Power Loss and Emission Reduction

Chapter 4

Computation of Locational Marginal Price at DG buses in active distribution system based on Active Power Loss and Emission Reduction

4.1 Introduction

In this chapter, an iterative method for computing locational marginal price (LMP) at DG buses in active distribution system based on reduction of active power losses and emissions is presented. Here, DISCO provides incentives to DG owners in terms of LMP from financial savings due to loss and emission reduction. The allocated financial incentive of each DG unit is again shared among active and reactive power of that particular DG unit based on power factor. The proposed method computes nodal prices at DG buses in order to provide financial incentives to DG owners only, whereas for customers, a uniform price has been considered as in [122]. In this proposed iterative method there is no change in price for customers. The important part of the iterative algorithm is allocation of reduced active power losses and emissions among DG units using proportional nucleolus theory (PNT) which is monotonic unlike nucleolus solution concept. The share of DG unit in active power loss reduction and emission reduction has been used for calculating LMP in next iteration. Weight parameters will be changed based on the decision maker's priority of loss reduction and emission reduction. After converging iterative algorithm based on chosen weights, the final LMP values depends on the decision maker's choice in DISCO extra benefit.

The original contributions of this chapter are as follows :

- PNT has been used for the first time to compute LMP based on loss and emission reduction
- A novel mathematical modeling has been developed to compute financial incentives to DGs for their contribution in reduction of active power losses and emissions.
- DISCOs have been empowered to operate the network optimally.
- A novel tool has been developed to enable DISCOs to control private DG owners.

The applications of the proposed method are follows:

- DISCO's decision maker can use this method to maintain fair competition among DG owners
- DISCO's decision maker can handle the trade off among losses, emissions, DG benefits and DISCO's extra benefit.
- This proposed method can be helpful to DISCO's decision maker to estimate the state of the network in terms of LMP, generation, active power losses and emissions in day ahead operation.

4.2 Problem Formulation

The proposed PNT method has been developed based on two ideas :

- Allocation of the share of reduced losses and emissions among DG units.
- Financial incentive to DG unit based on its share in loss and emission reduction.

PNT has been used for the allocation of reduced losses and emissions among DG units and new iterative algorithm has been developed to compute financial incentive to each DG unit based on their contribution in reduction of losses and emissions.

4.2.1 Computation of change in Active power loss and emission

An iterative distribution load flow algorithm has been implemented in two cases for computing change in active power loss and emission. In this method backward and forward sweep algorithm [113] has been used as shown in Figure F.1 in Appendix-F. This algorithm utilizes to complete advantage the ladder structure of distribution network, to achieve high speed, robust convergence and has low memory requirements [114, 115]. In this load flow solution, simultaneously controlled PQ modeled [116] DG has been used.

Case 1: Base case - No DG was integrated into the system. Total load was supplied from substation bus.

Case 2: DG units were integrated into the system. Total load was supplied from substation bus and DG units

Generation of each unit has been computed based on cost coefficients of that generator and LMP at DG bus using equations (3.1) and (3.2); loss reduction from base case has been computed using equation (3.3).

Total emissions under Case 1 and Case 2 have been computed using equations (4.1) & (4.2) respectively and the change in emission has been computed using equation (4.3)

$$Emn_0{}^t = (SO_2{}^{Sub} + CO_2{}^{Sub} + CO^{Sub} + NO_x{}^{Sub})P_{Sub}{}^t \tag{4.1}$$

Compute emission cost using equations (4.4) and (4.5) under Case 1 and Case 2 respectively based on penalty price of respective greenhouse gas emission.

A cooperative game theory is required to identify the contribution of each DG unit on change in system losses and emissions. In this chapter PNT has been used for allocation of change in losses and emissions among DG units.

$$Emn_{DG}{}^t = \sum_{i=1}^{N_{DG}} (SO_2{}^{DG_i} + CO_2{}^{DG_i} + CO^{DG_i} + NO_x{}^{DG_i})(PG^t)_i^j + (SO_2{}^{Sub} + CO_2{}^{Sub} + CO^{Sub} + NO_x{}^{Sub})(P_{Load}{}^t + Ploss_j{}^t - \sum_{i=1}^{N_{DG}} (PG^t)_i^j) \tag{4.2}$$

$$\Delta Emn = Emn_0{}^t - Emn_{DG}{}^t \tag{4.3}$$

$$EC_0{}^t = (SO_2{}^{Sub}P_{SO_2} + CO_2{}^{Sub}P_{CO_2} + CO^{Sub}P_{CO} + NO_x{}^{Sub}P_{NO_x})P_{Sub}{}^t \tag{4.4}$$

$$EC_{DG}{}^t = \sum_{i=1}^{N_{DG}} (SO_2{}^{DG_i}P_{SO_2} + CO_2{}^{DG_i}P_{CO_2} + CO^{DG_i}P_{CO} + NO_x{}^{DG_i}P_{NO_x})(PG^t)_i^j + (SO_2{}^{Sub}P_{SO_2} + CO_2{}^{Sub}P_{CO_2} + CO^{Sub}P_{CO} + NO_x{}^{Sub}P_{NO_x}) * (P_{Load}{}^t + Ploss_j{}^t - \sum_{i=1}^{N_{DG}} (PG^t)_i^j) \tag{4.5}$$

4.2.2 DISCO's Extra benefit

DISCO's benefit is defined as the difference between total revenue collected from the customers and the sum of total amount paid to purchase power from DG buses and substation bus and the penalty due to emission, which is as shown in equations (4.6) and (4.7)

$$benefit_0{}^t = \pi^c D - ((PLoad^t + Ploss_0{}^t)\lambda^t + EC_0{}^t \omega_e) \tag{4.6}$$

DISCO's extra benefit is defined as the difference between base case benefit and benefit after DGs inject power into the distribution system. As per the definition, extra benefit is obtained by subtracting equation (4.6) from equation (4.7) and the final expression is shown in equation (4.8).

$$\begin{split} benefit_j{}^t = \pi^c D - (\sum_{i=1}^{N_{DG}} (PG^t)_i^j (\pi_a^t)_i^j + \sum_{i=1}^{N_{DG}} (QG^t)_i^j (\pi_r^t)_i^j + (PLoad^t + Ploss_j{}^t - \\ \sum_{i=1}^{N_{DG}} (PG^t)_i^j)\lambda^t + EC_j{}^t \omega_e) \end{split} \tag{4.7}$$

$$\begin{split} \Delta benefit_j{}^t = (Ploss_0^t - Ploss_j^t)\lambda^t - \sum_{i=1}^{N_{DG}} (PG^t)_i^j * ((\pi_a^t)_i^j - \lambda^t) - \\ \sum_{i=1}^{N_{DG}} (QG^t)_i^j (\pi_r^t)_i^j + (EC_0{}^t - EC_j{}^t)\omega_e \end{split} \tag{4.8}$$

DISCO's extra benefit has been increased due to loss and emission reduction in the presence of DG units. DISCO's extra benefit is nothing but merchandising surplus obtained from loss and emission reduction. In general this merchandising surplus is greater than zero. Minimization of this merchandising surplus is required for fair competition [3]. The expression for DISCO's extra benefit in terms of merchandising surplus is shown in equation (4.9) that has been derived using loss reduction in equation (4.10) and emission reduction in equation (4.11).

$$\Delta benefit_j{}^t = (MS^t)_{loss}^j + (MS^t)_{Emn}^j \tag{4.9}$$

where

$$(MS^t)_{loss}^j = (Ploss_0^t - Ploss_j^t)\lambda^t - \sum_{i=1}^{N_{DG}} (PG^t)_i^j ((\pi_a^t)_i^j - \lambda^t) - \sum_{i=1}^{N_{DG}} (QG^t)_i^j (\pi_r^t)_i^j \tag{4.10}$$

$$(MS^t)_{Emn}^j = (EC_0{}^t - EC_j{}^t)\omega_e \tag{4.11}$$

In [123], a penalty has been allocated to DISCO for emission while serving the customers. The main aim of this strategy is to reduce emissions. As per this proposed strategy, DISCO which delivers electricity from high emission releasing generators receives a high penalty price. As the penalty is more, the customer price leads to high value. On the other hand, DISCO which delivers electricity from low emission releasing generators receives low penalty price. Since penalty is less, customer price will be low. The parameter ω_e shown in equations (4.7) (4.8) and (4.11) represents the share of DISCO and generators in total system penalty price for emission. Based on this discussion ω_e value is set to 0.5 in this chapter, but the final value is determined by the decision maker's choice.

4.2.3 PNT based iterative Algorithm

A PNT based iterative algorithm to compute LMP at each DG bus and then estimate the generation based on their contribution for reduction in active power losses and emissions is explained in Algorithm 2. DISCO predicted generation as an economic signal for DG units to achieve optimal operation of network.

In Algorithm 2 convergence has been checked in Step 10 by using $\Delta benefit_j^t$ and $\Delta Pmax$ values. The condition based on $\Delta Pmax$ would be satisfied if there is no considerable change in loss and emission because of increase in generation. In such a case incremental price related to loss and emission reduction is very small so that there was no significant change in LMP values and generation. Incentive provided to each generator from extra benefit of DISCO until $\Delta benefit_j^t$ is lower than the small value ε_1.

Algorithm 2 PNT based iterative Algorithm

Inputs

1: Hour (t) of the day (D)
2: Forecasted load L(t,D)
3: Market price λ^t

Steps

1: Run the load flow and compute base case loss with forecasted load L(t,D)
2: Set iteration j=1, $(\pi_a^i)_t^j = \lambda^t$, and PG_i^0=0 where i=1,2,...N_{DG}
3: i=1 ▷ i represents DG number
4: **while** $i \neq N_{DG} + 1$ **do**
    Compute Generation using equations (3.2) and (3.26)
    ▷ If calculated generation using equation (3.2) exceeds maximum capacity of DG unit then DG generation is set to generation upper limit. The constraint considered for DG generation is as shown in equation (3.27)
5:     $i \leftarrow i + 1$
6: **end while**
7: Run the load flow and compute loss ($v^l(N)$), emission ($v^e(N)$) due to coalition (N) of all DG units based on generation computed in Step 4.

Algorithm 2 (Continued) PNT based iterative Algorithm

8: Run the load flow and compute loss ($v^l(S)$), emission ($v^e(S)$) due to each sub coalition (S) of all DG units based on generation computed in Step 4.
9: Compute DISCO extra benefit ($\Delta benefit_j{}^t$) using equation (4.8) and set $\Delta Pmax$=max($PG_i^j - PG_i^{j-1}$)
10: **if** $\Delta benefit_j{}^t \leq \varepsilon_1$ OR $\Delta Pmax \leq \varepsilon_2$ **then** ▷ ε_1 and ε_2 are small values for checking convergence
11: *GoTo* ⇝ Step 20
12: **else**
13: *GoTo* ⇝ Step 15
14: **end if**
15: Compute share of each DG unit in loss reduction xLoss(i) and in emission reduction xEmn(i) using PNT as shown in section 3.2.3
16: Compute financial incentive of each DG unit for it's contribution in loss reduction using equation (4.12) and emission reduction using equation (4.13)

$$DGgain_{loss}^i = \omega_1 \frac{((Ploss_0^t - Ploss_j^t)\lambda^t + (MS^t)_{Emn}^j)xLoss(i)}{Ploss_0^t - Ploss_j^t} \tag{4.12}$$

$$DGgain_{Emn}^i = \omega_2 \frac{((Ploss_0^t - Ploss_j^t)\lambda^t + (MS^t)_{Emn}^j)xEmn(i)}{Emn_0^t - Emn_j^t} \tag{4.13}$$

17: Distribute incentive of each DG unit among active and reactive power generation as shown in equation (4.14).

$$\begin{aligned} DGgain_P^i &= DGgain_{loss}^i * (cosdg^i)^2 + DGgain_{Emn}^i \\ DGgain_Q^i &= DGgain_{loss}^i * (1 - (cosdg^i)^2) \end{aligned} \tag{4.14}$$

18: Compute active and reactive power price for next iteration using equations (4.15) and (4.16).

$$((\pi_a^i)_t^{j+1} - \lambda^t)\frac{(\pi_a^i)_t^{j+1} - b_i}{2a_i} = DGgain_P^i \tag{4.15}$$

$$(\pi_r^i)_t^{j+1} = \lambda^r + \frac{DGgain_Q^i}{QG_i^j} \tag{4.16}$$

Reactive power price at substation bus is less than 1% of active power price [120]. Hence λ^r value is considered as zero.
19: Increment iteration j=j+1 and go to Step 3.
20: Stop iterative algorithm for hour 't' and take print out of required data.

ω_1 and ω_2 represent weights for loss and emission reduction respectively. These values depends on DISCO's decision maker priority among loss reduction and emission reduction. If the decision maker decides to give top priority to loss reduction, then assign ω_1=1 and ω_2=0. Similarly, if the decision maker decides to operate network with lower emission, then assign ω_1=0 and ω_2=1. The values of ω_1 and ω_2 vary between 0 and 1 based on the decision maker choice.

4.3 Analytical Studies

4.3.1 Case Study - 1

The proposed PNT based iterative algorithm has been implemented on Taiwan Power Company (TPC) distribution network as shown in Figure A.1 in Appendix-A. TPC distribution network consists of 84 buses and 11 feeders. The complete information of TPC distribution system has been considered from [5] and presented in Table G.1 in Appendix-A. This is assuming that fifteen DG units with 0.9 lagging power factor have been connected to the TPC distribution network. The type and locations of 1 MW DG units are shown in Table 3.3. The cost coefficients of each type of DG are presented in Table 3.4.

The results in this section were obtained from simulation in MATLAB [121] environment on i7 processor, 3.4GHz and 4GB RAM machine. Complete information about emission coefficients of DG units and substation bus and cost coefficients of DG units have been taken from [4]. All the simulation results shown in this section are based on the forecast load and market price shown in Figure 3.4.

4.3.1.1 Impact of ω_1 and ω_2 on the DG unit's generation, Active power prices, Reactive Power Price, Active power losses and Emissions for TPC active distribution system

Table 4.1 and Table 4.2 present results obtained by the proposed PNT based iterative method at a market price of λ^t=25.34 \$/MW and λ^t=13.31 \$/MW respectively using different values of ω_1 and ω_2 for TPC distribution system.

As shown in Table 4.1 ,

- When the market price is λ^t=25.34 \$/MW, TPC distribution system power loss increase continuously as ω_2 increases, which means that DISCO wants to encourage DG units which have high impact on emission reduction.

- For example DG6, DG7, DG8, DG9 and DG10 with smaller emission coefficients compared to other DG units have increased their generation as ω_2 increases.

- Similarly, the emission increases as ω_1 increases, which means that DISCO wants to encourage DG units which have high impact on loss reduction like DG11.

- When the market price is 13.31 \$/MW, all DG units in TPC distribution systems are off because the market price is less than 'b' coefficient in cost function of DG units. In such a case, active power loss and emission are the same as base case.

Table 4.1: Impact of ω_1 and ω_2 on the DG unit's Generation (kW), loss (kW) and Emission (kg)

		λ^t=25.34 \$/MW			λ^t=13.31 \$/MW		
Type	ω_1	0.75	0.5	0.25	0.75	0.5	0.25
	ω_2	0.25	0.5	0.75	0.25	0.5	0.75
	DG1	513	497	481	0	0	0
	DG2	461	460	459	0	0	0
1	DG3	467	465	462	0	0	0
	DG4	478	473	466	0	0	0
	DG5	493	484	473	0	0	0
	DG6	619	635	650	0	0	0
	DG7	554	589	623	0	0	0
2	DG8	648	655	662	0	0	0
	DG9	613	631	647	0	0	0
	DG10	552	587	622	0	0	0
	DG11	755	728	699	0	0	0
	DG12	624	634	644	0	0	0
3	DG13	656	657	657	0	0	0
	DG14	614	628	640	0	0	0
	DG15	594	613	632	0	0	0
Loss(kW)		243.24	243.91	244.99	398.39	398.39	398.39
Emission(kg)		22732	22680	22634	24404	24404	24404

As shown in Table 4.2,

- When the market price is 25.34 \$/MW, LMP values of all type 2 units in TPC distribution system increase with increase in value of ω_2 as these units have more impact on emission with low emission coefficients.

- Similarly LMP values of the remaining DG units vary based on their contribution to loss and emission reduction.
- LMP of DG11 increases consistently with ω_1 which means that it has much impact on loss of TPC distribution system.
- When the market price is 13.31 \$/MW, all DG units are inactive as the market price is less than 'b' coefficient for all DG units and their LMP values are equal to market price.

Table 4.2: Impact of ω_1 and ω_2 on the DG unit's LMP (\$/MW), Loss (kW) and Emission (kg)

		λ^t=25.34 \$/MW			λ^t=13.31 \$/MW		
Type	ω_1	0.75	0.5	0.25	0.75	0.5	0.25
	ω_2	0.25	0.5	0.75	0.25	0.5	0.75
1	DG1	26.95	26.77	26.58	13.31	13.31	13.31
	DG2	26.35	26.34	26.33	13.31	13.31	13.31
	DG3	26.42	26.39	26.36	13.31	13.31	13.31
	DG4	26.55	26.49	26.41	13.31	13.31	13.31
	DG5	26.72	26.61	26.48	13.31	13.31	13.31
2	DG6	26.56	26.73	26.89	13.31	13.31	13.31
	DG7	25.87	26.24	26.61	13.31	13.31	13.31
	DG8	26.87	26.95	27.01	13.31	13.31	13.31
	DG9	26.50	26.68	26.86	13.31	13.31	13.31
	DG10	25.85	26.22	26.59	13.31	13.31	13.31
3	DG11	27.55	27.28	26.99	13.31	13.31	13.31
	DG12	26.24	26.34	26.44	13.31	13.31	13.31
	DG13	26.56	26.57	26.57	13.31	13.31	13.31
	DG14	26.14	26.28	26.40	13.31	13.31	13.31
	DG15	25.94	26.13	26.32	13.31	13.31	13.31
Loss(kW)		243.24	243.91	244.99	398.39	398.39	398.39
Emission(kg)		22732	22680	22634	24404	24404	24404

Table 4.3 shows the reactive power prices of each DG unit by implementing the proposed PNT based iterative method on TPC distribution system with different weight parameter combinations, when the market prices are 25.34 \$/MW and 13.31 \$/MW respectively.

- When the market price is 13.31 \$/MW, all DG units are off as market price is less than 'b' coefficient of DG units.
- In such a case the reactive power price is equal to the market price of reactive power, which is zero.
- When the market price is 25.34 \$/MW, the reactive power price of each DG unit is based on its contribution in loss reduction and is as shown in Table 4.3.
- Reactive power price of each DG unit decreases with decrease in ω_1.

Table 4.3: Impact of ω_1 and ω_2 on the DG unit's reactive power price (\$/MVar), Loss and Emission

		TPC distribution system					
		λ^t=25.34 \$/MW			λ^t=13.31 \$/MW		
Type	ω_1	0.75	0.5	0.25	0.75	0.5	0.25
	ω_2	0.25	0.5	0.75	0.25	0.5	0.75
1	DG1	0.651	0.440	0.223	0	0	0
	DG2	0.368	0.248	0.125	0	0	0
	DG3	0.402	0.271	0.137	0	0	0
	DG4	0.464	0.313	0.159	0	0	0
	DG5	0.546	0.369	0.187	0	0	0
2	DG6	0.380	0.255	0.128	0	0	0
	DG7	0.056	0.037	0.019	0	0	0
	DG8	0.526	0.354	0.179	0	0	0
	DG9	0.351	0.236	0.119	0	0	0
	DG10	0.044	0.028	0.014	0	0	0
3	DG11	0.906	0.614	0.313	0	0	0
	DG12	0.289	0.194	0.097	0	0	0
	DG13	0.438	0.295	0.149	0	0	0
	DG14	0.242	0.162	0.082	0	0	0
	DG15	0.148	0.099	0.050	0	0	0
Loss(kW)		243.24	243.91	244.99	398.39	398.39	398.39
Emission(kg)		22732	22680	22634	24404	24404	24404

4.3.1.2 Impact of ω_1 and ω_2 on DG units LMP:

Figure 4.1 represents computed LMP values of each DG unit by implementing PNT based iterative algorithm on specified test system with weights ω_1=0 and ω_2=1.

- When spot price of substation bus is 24.95 \$/MW. Since more weight is provided by the decision maker to emission reduction, DG units which release low emission would get more price for generation.
- DG units 6, 7, 8, 9 and 10 received more incentive compared to other DGs because of their low emission coefficients.

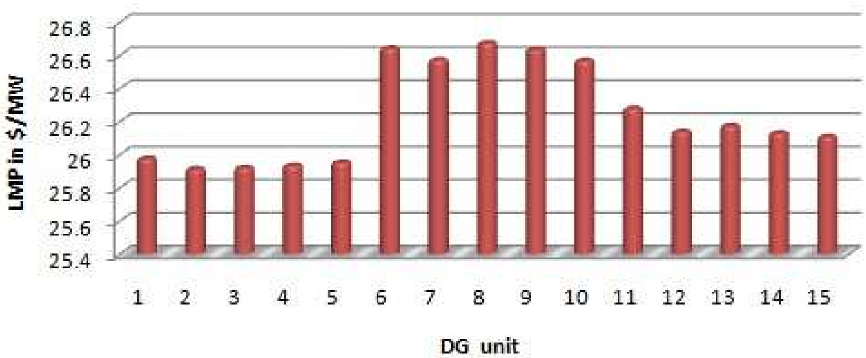


Figure 4.1: LMP values of each DG unit at ω_1=0 and ω_2=1

Figure 4.2 represents variation in LMP values of all type2 (low emission coefficients) DG units with various ω_1 and ω_2 values were used when the spot price of substation bus is 24.95 \$/MW for TPC distribution system.

- LMP values of all type 2 DG units increases with ω_2 as these are low emission coefficient generators.

4.3.1.3 Variation in Extra benefit of DISCO:

Figure 4.3 shows variation in DISCO's extra benefit with proposed PNT based iterative algorithm at different market prices when ω_1=0.5 and ω_2=0.5 for TPC distribution system.

- Proposed iterative algorithm will provide zero extra benefit at all market prices.
- This is happening as DISCO operator provides some financial incentives to DG unit based on its contribution to active power loss and emission reduction for DISCO's extra benefit.

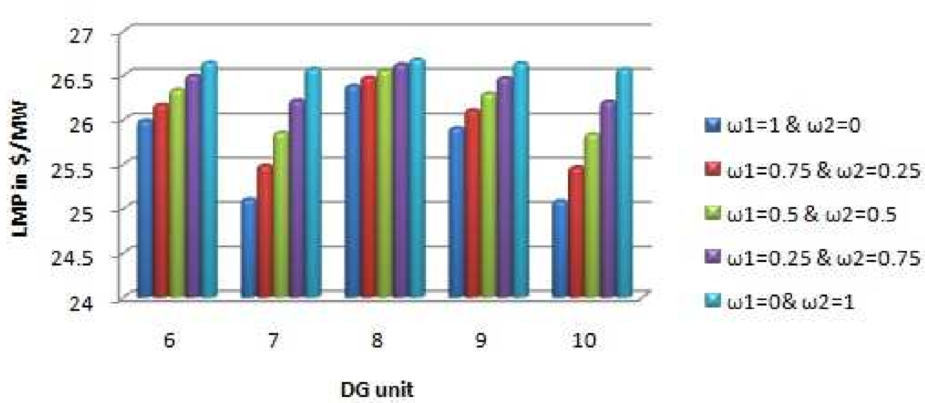


Figure 4.2: Variation in LMP values of Type2 DG units

- As iterations progress in the proposed algorithm, DISCO's extra benefit decreases and reaches zero.

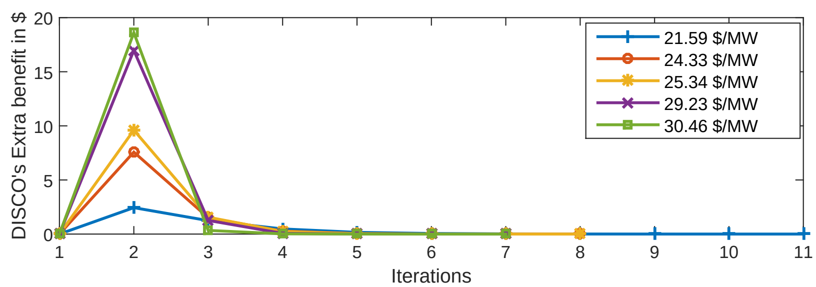


Figure 4.3: DISCO's Extra benefit variation

4.3.1.4 Variation in active power losses of distribution network during Iterative algorithm

Figure 4.4 shows variations in active power losses of distribution network as iterations progress in the proposed method at $\omega_1 = 0.5$ and $\omega_2 = 0.5$ for different market prices.

- As iterations progress, LMP and generation of DGs that have positive impact on loss reduction increases. This results in reduction of active power loss of network.

4.3.1.5 Variation in emissions of distribution network during Iterative algorithm

Variations in emissions from distribution network as iterations progress in the proposed method at $\omega_1 = 0.5$ and $\omega_2 = 0.5$ for different market prices are shown in Figure 4.5.

- As iterations progress, incentives and generation of low emission coefficient generators increase. This results in decrease in emissions.

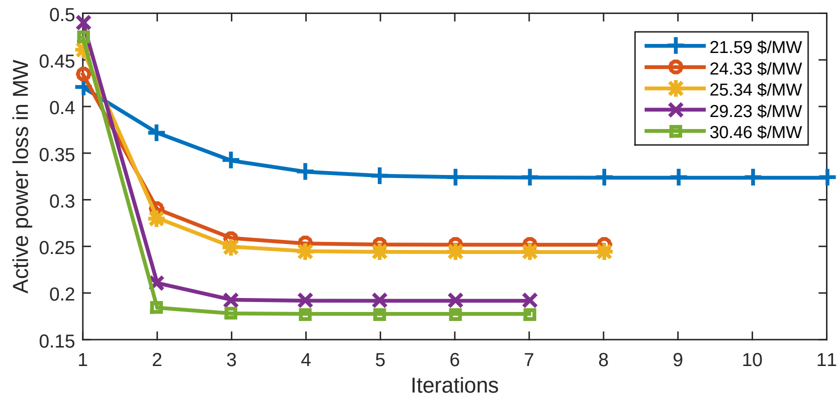


Figure 4.4: DISCO's active power loss variation

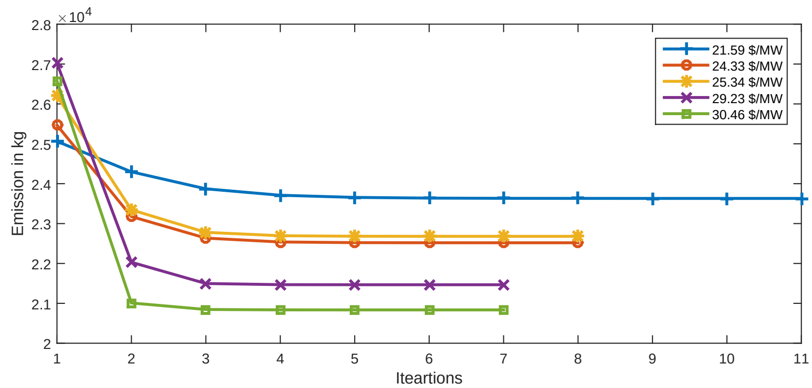


Figure 4.5: DISCO's emission variation

4.3.1.6 Comparisons in terms of emissions, active power losses and DISCO's extra benefit

The proposed method has been compared in terms of emissions, active power losses and DISCO's extra benefit with some published techniques on LMP computation like iterative nucleolus method [4], iterative shapley method [3], marginal loss method [93] and uniform price method [3, 4] in order to demonstrate the accuracy and validity.

Figure 4.6 and Figure 4.7 show emission and active power loss of the TPC distribution system at each hour of the day respectively based on proposed method and iterative nucleolus method [4] with forecasted load.

In case market price is less than 'b' coefficient value of all DG units, no DG unit can inject power into the network.

- In such a case the network operated as a passive network and total load was supplied only from substation.
- Due to this reason both methods operate the network with the same amount of green house

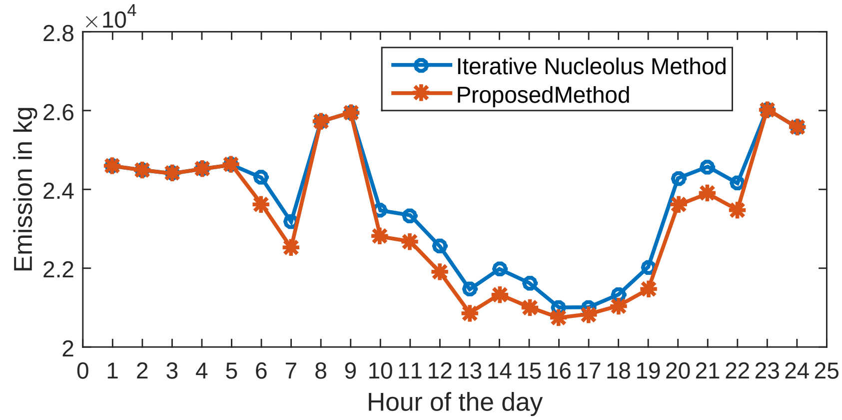


Figure 4.6: Comparison in terms of network emissions with iterative nucleolus method [4]

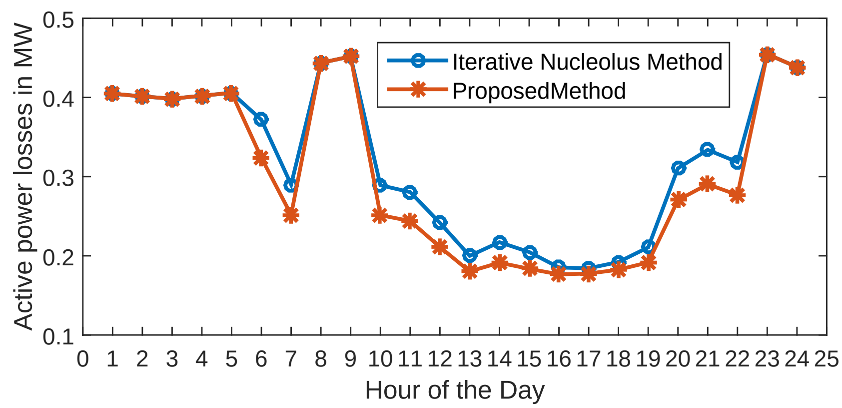


Figure 4.7: Comparison in terms of network active power losses with iterative nucleolus method [4]

gas emissions. The amount of emissions released from network depends on emission coefficients at substation bus.

- Similarly as no DG injects the power into the network, the network looks like base case network and both methods operate the network with the same amount of active power loss which is equal to base case active power losses.

The iterative nucleolus method proposed in [4] provides incentives to DG owners based on market price and contribution of DGs in reduction of active power losses and emissions. This type of computation leads to more incentive in each iteration but it also results in reaching quickly towards negative DISCO's extra benefit. To avoid this drawback,

- In the proposed method incentives were computed based on DISCO's financial savings due to loss and emission reduction, and contribution of DGs in reduced active power losses and emissions.

- This type of computation provides less incentive in each iteration, and more LMP at the time of convergence as this method reaches negative DISCO's extra benefit slowly.

In comparison to [4],as shown in Figure 4.6

- The proposed method provides more LMP to DG units that have positive impact on emission reduction.
- This leads to more generation from low emission coefficient generators.
- Due to this reason, at all hours of the day except where market price is less than 'b' coefficient of all DG units, the proposed method can operate the network with low emissions

In comparison to [4],as shown in Figure 4.7

- The proposed method provides more LMP to DG units that have positive impact on loss reduction. This leads to more generation from DG units having positive impact on loss reduction.
- The proposed method operates the network with less active power losses at all hours of the day except where market price is less than 'b' coefficient of all DG units

The proposed method has been compared with iterative shapley method [3] using forecast load at each hour of the day in terms of loss at ω_1=1 and ω_2=0. This combination of ω_1 and ω_2 has been used as iterative shapley method based on active power losses only. The results thus obtained have been presented in Figure 4.8.

In comparison to [3],as shown in Figure 4.8

- The proposed method operates the network with less active power losses by remunerating more to DG units based on their contribution in loss reduction.

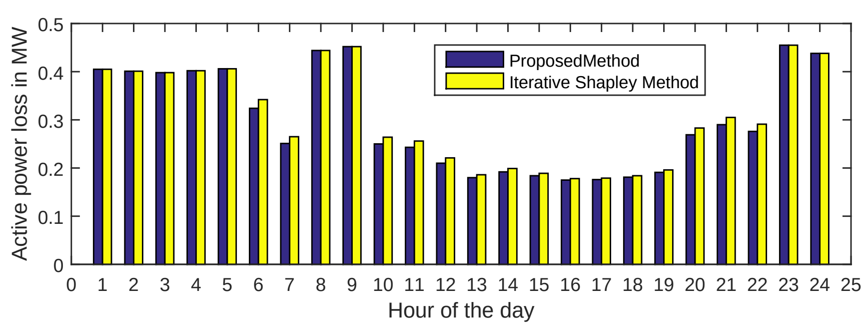


Figure 4.8: Comparison in terms of active power losses with iterative shapley method [3]

The proposed method's performance has been compared with iterative nucleolus method [4] and conventional methods like uniform price method [3, 4], and marginal loss method [93] in terms of active power losses and reduced loss amount at different market prices. Operating the network with less active power losses is DISCO's decision maker requirement as it releases the line capacity and improves voltage profile and maximum load that can be supplied by the system. All these methods have been implemented on TPC distribution system with load data as presented in [5]. However, while implementing the proposed method and iterative nucleolus method ω_1 and ω_2 values were considered as 0.5 and 0.5 respectively.

As per the results presented in Table 4.4, it has been observed that

- The proposed method drives the complete test system towards less active power losses and more reduced loss amount. This was due to more remuneration provided by the proposed method to DG owners in terms of LMP.

Table 4.4: Comparison of proposed method in terms of active power losses and reduced loss amount

	Reduced loss amount ($)				Active power loss (kW)			
Market Price λ^t($/MW)	Proposed method	Iterative nucleolus [4]	Marginal loss [93]	Uniform price [3, 4]	Proposed method	Iterative nucleolus	Marginal loss [93]	Uniform price [3, 4]
26	6.708	6.302	5.332	4.802	274.0	289.6	326.9	347.3
27	7.619	6.917	6.069	5.608	249.8	275.8	307.2	324.3
28	8.484	7.201	6.773	6.300	229.0	274.8	290.1	307.0
29	9.187	7.830	7.435	7.088	215.2	262.0	275.6	287.6
30	9.690	8.202	7.923	7.800	209.0	258.6	267.9	272.0
31	10.168	8.503	8.345	8.212	204.0	257.7	262.8	267.1

The proposed method has been validated with iterative nucleolus method [4] and conventional methods like uniform price method [3, 4] and marginal loss method [93] in terms of DISCO's extra benefit at ω_1=0.5 and ω_2=0.5. All these methods have been implemented on TPC distribution system with loads as shown in [5]. The DISCO's extra benefit values at different market prices are presented in Table 4.5. In a deregulated environment, to maintain fair competition among DG owners, non zero positive DISCO's extra benefit needs to be minimized.

As shown in Table 4.5

- The proposed method in reducing DISCO's extra benefit to zero.
- However the remaining three methods have non zero positive extra benefit.

Table 4.5: Comparison of proposed method in terms DISCO's extra benefit

	DISCO's Extra benefit ($)			
Market price λ^t($/MW)	Proposed method	Iterative nucleolus [4]	Marginal loss [93]	Uniform price [3,4]
20	0	0	0	0
22	0	1.1	4.35	6.3
24	0	0.73	6.94	13.6
26	0	1.9	9.14	20.8
28	0	0.46	10.72	27.7
30	0	1.4	11.65	34.6

4.3.2 Case Study - 2

The proposed method was implemented on PG & E 69 bus radial distribution system as shown in Figure C.1 in Appendix-C. Table 3.8 represents the location of 3 DG units of various types operating at 0.9 lagging power factor with 1 MW capacity. The cost coefficients of each type of DG are represented in Table 3.4. The proposed method has been simulated under MATLAB [121] environment on realistic price and load data drawn from [2] and presented in Figure 3.9. The PG & E 69bus radial distribution system data is captured from [7] and presented in Table C.1 in Appendix-C.

4.3.2.1 Impact of ω_1 and ω_2 on the DG unit's generation, Active power prices, Reactive Power Price, Active power losses and Emissions for PG & E 69 active distribution system

Table 4.6 and Table 4.7 present results obtained by the proposed PNT based iterative method at market price λ^t=19.29 $/MWh, λ^t=24.87 $/MWh and λ^t=28.24 $/MWh using different values of ω_1 and ω_2 for PG & E 69 active distribution system.

As shown in Table 4.6,

- When the market price is λ^t=24.87 $/MWh, active power losses of PG & E 69 active distribution system increases continuously as ω_2 increases. This is due to increasing the priority for emission reduction. For example DG2 with smaller emission coefficients compared to other DG units have increased their generation as ω_2 increases.
- Similarly emissions of PG & E 69 active distribution system increases as ω_1 increases. This is due to the encouragement of DISCO for DG units which have positive impact on

loss reduction like DG1.

- When the market price is 19.29 \$/MW, all DG units in PG & E 69 active distribution systems are off as the market price is less than 'b' coefficient in cost function of DG units. In such a case, active power losses and emissions are the same as base case.

- When ω_2=1 emissions released from PG & E 69 active distribution system are more than at ω_2=0.75. It is a contradictory case. It is due to both low emission coefficient DG units DG2 and DG3 are operating at maximum capacity and generation from DG1 decreases as ω_1=0. It leads to increase of power drawn from substation bus that has high emission coefficients.

Table 4.6: Impact of ω_1 and ω_2 on the DG unit's Generation (kW), Active power losses (kW) and Emissions (kg) for PG & E 69 active distribution system

Market Price	ω_1	ω_2	DG1	DG2	DG3	Loss (kW)	Emission (kg)
19.29 \$/MWh	1	0	0	0	0	0.1698	3412.9
	0.75	0.25	0	0	0	0.1698	3412.9
	0.5	0.5	0	0	0	0.1698	3412.9
	0.25	0.75	0	0	0	0.1698	3412.9
	0	1	0	0	0	0.1698	3412.9
24.87 \$/MWh	1	0	658.0	562.5	602.8	0.0566	2821.5
	0.75	0.25	631.6	607.2	628.3	0.0580	2799.1
	0.5	0.5	601.0	648.7	651.3	0.0599	2780.7
	0.25	0.75	566.1	687.2	672.0	0.0625	2766.4
	0	1	526.1	722.7	690.3	0.0658	2756.5
28.24 \$/MWh	1	0	939.0	881.3	935.3	0.0346	2538.2
	0.75	0.25	911.3	923.0	959.3	0.0362	2518.3
	0.5	0.5	880.6	962.8	981.9	0.0381	2500.9
	0.25	0.75	846.9	1000	1000	0.0402	2487.4
	0	1	812.3	1000	1000	0.0424	2499.0

As shown in Table 4.7,

- When the market price is 24.87 \$/MW, LMP value of type 2 unit i.e DG2 in PG & E distribution system increases with increase in the value of ω_2 because these units have more impact on emissions with low emission coefficients.

- Similarly LMP values of remaining DG units vary based on their contribution in active power loss and emission reduction.
- LMP of DG1 increases consistently with ω_1 that means it has much impact on active power losses of PG & E distribution system.
- When the market price is 19.29 $/MWh, all DG units are inactive as the market price is less than 'b' coefficient for all DG units and their LMP values are equal to market price.
- When the market price is 28.24 $/MWh, active power losses of PG & E distribution system decreases with increasing ω_1 value.
- Similarly emissions decreases as increasing the value of ω_2 except when ω_2=1. It is due to both low emission coefficient DG units DG2 and DG3 operating at maximum capacity with generation from DG1 decreasing as ω_1=0. It leads to increasing in power drawn from substation bus that has high emission coefficients. Due to this, emission released from PG & E 69 active distribution system at ω_2=1 is more in comparison with emissions at ω_2=0.75.

Table 4.8 shows the reactive power prices of each DG unit by implementing the proposed PNT based iterative method on PG & E 69 active distribution system with different weight parameter combinations when the market prices are 19.29 $/MWh, 24.87 $/MWh and 28.24 $/MWh respectively.

As shown in Table 4.8,

- When the market price is 19.29 $/MWh, all DG units are off as market price is less than 'b' coefficient of DG units. In such a case the reactive power price is equal to the market price of reactive power which is zero as mentioned in Algorithm 2.
- When the market price is 24.87 $/MWh and 28.24 $/MWh, the reactive power price of each DG unit is based on its contribution in active power loss reduction
- Reactive power price of each DG unit decreases with decrease in ω_1. When ω_1=0 reactive power price is equal to zero.

4.3.2.2 Impact of ω_1 and ω_2 on DG units LMP in PG & E 69 active distribution system

Figure 4.9 represents computed LMP values of each DG unit by implementing PNT based iterative algorithm on PG & E 69 active distribution system with weights ω_1=0 and ω_2=1.

Table 4.7: Impact of ω_1 and ω_2 on the DG unit's LMP ($/MWh), Active power losses (kW) and Emissions (kg) for PG & E 69 active distribution system

Market Price	ω_1	ω_2	DG1	DG2	DG3	Active power losses(kW)	Emissions (Kg)
19.29 $/MWh	1	0	19.29	19.29	19.29	0.1698	3412.9
	0.75	0.25	19.29	19.29	19.29	0.1698	3412.9
	0.5	0.5	19.29	19.29	19.29	0.1698	3412.9
	0.25	0.75	19.29	19.29	19.29	0.1698	3412.9
	0	1	19.29	19.29	19.29	0.1698	3412.9
24.87 $/MWh	1	0	28.63	25.96	26.03	0.0566	2821.5
	0.75	0.25	28.33	26.44	26.28	0.0580	2799.1
	0.5	0.5	27.97	26.88	26.51	0.0599	2780.7
	0.25	0.75	27.57	27.28	26.72	0.0625	2766.4
	0	1	27.10	27.66	26.90	0.0658	2756.5
28.24 $/MWh	1	0	31.89	29.34	29.35	0.0346	2538.2
	0.75	0.25	31.57	29.78	29.59	0.0362	2518.3
	0.5	0.5	31.21	30.21	29.82	0.0381	2500.9
	0.25	0.75	30.82	30.61	30.03	0.0402	2487.4
	0	1	30.42	30.95	30.22	0.0424	2499.0

Table 4.8: Impact of ω_1 and ω_2 on the DG unit's reactive power price ($/MVarh), Active power losses (kW) and Emissions (kg) for PG & E 69 bus active distribution system

Market Price	ω_1	ω_2	DG1	DG2	DG3	Loss (kW)	Emission (kg)
19.29 $/MWh	1	0	0	0	0	0.1698	3412.9
	0.75	0.25	0	0	0	0.1698	3412.9
	0.5	0.5	0	0	0	0.1698	3412.9
	0.25	0.75	0	0	0	0.1698	3412.9
	0	1	0	0	0	0.1698	3412.9
24.87 $/MWh	1	0	1.823	0.529	0.561	0.0566	2821.5
	0.75	0.25	1.388	0.395	0.419	0.0580	2799.1
	0.5	0.5	0.942	0.263	0.279	0.0599	2780.7
	0.25	0.75	0.481	0.131	0.139	0.0625	2766.4
	0	1	0.000	0.000	0.000	0.0658	2756.5
28.24 $/MWh	1	0	1.769	0.534	0.539	0.0346	2538.2
	0.75	0.25	1.344	0.397	0.401	0.0362	2518.3
	0.5	0.5	0.909	0.263	0.266	0.0381	2500.9
	0.25	0.75	0.462	0.131	0.132	0.0402	2487.4
	0	1	0.000	0.000	0.000	0.0424	2499.0

As shown in Figure 4.9,

- When the spot price of substation bus is 22.72 \$/MWh, 26.07 \$/MWh and 26.47 \$/MWh. Since more weight is provided by the decision maker to emission reduction, DG units which release low emissions would get more price for generation.
- DG 2 received more incentive compared to other DGs because it has low emission coefficients.

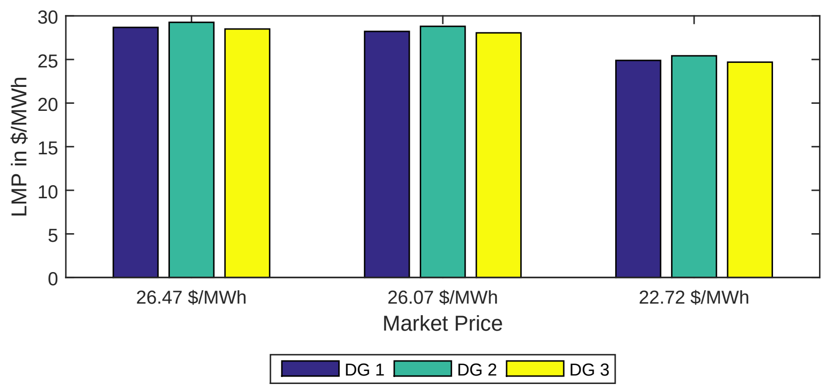


Figure 4.9: LMP values of each DG unit at ω_1=0 and ω_2=1 for PG & E 69 active distribution system

Figure 4.10 represents variation in LMP values of type2 (low emission coefficients) DG unit i.e DG2 with various ω_1 and ω_2 values when spot prices of substation bus are 26.47 \$/MW, 26.07 \$/MWh and 22.72 \$/MWh for PG & E 69 active distribution system.

- As DG2 is a type 2 DG unit, its LMP value increases with ω_2.

4.3.2.3 Variation in Extra benefit of DISCO for PG & E 69 active distribution system

Figure 4.11 shows variation in DISCO's extra benefit with proposed PNT based iterative algorithm at different market prices when ω_1=0.5 and ω_2=0.5 for PG & E 69 active distribution system.

As shown in Figure 4.11,

- The proposed iterative algorithm provides zero extra benefit at all market prices. This is happening as DISCO operator provides some financial incentives to DG unit from DISCO's extra benefit based on its contribution in active power loss and emission reduction.

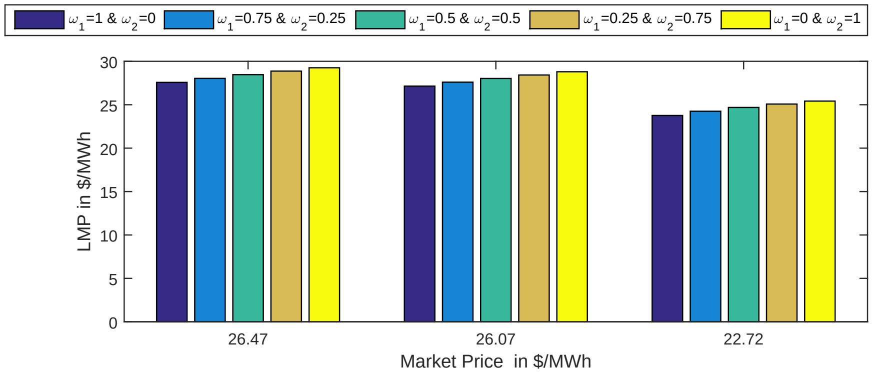


Figure 4.10: Variation in LMP values of Type2 DG units in PG & E 69 active distribution system

- As iterations progress in proposed algorithm, DISCO's extra benefit decreases and reaches zero.

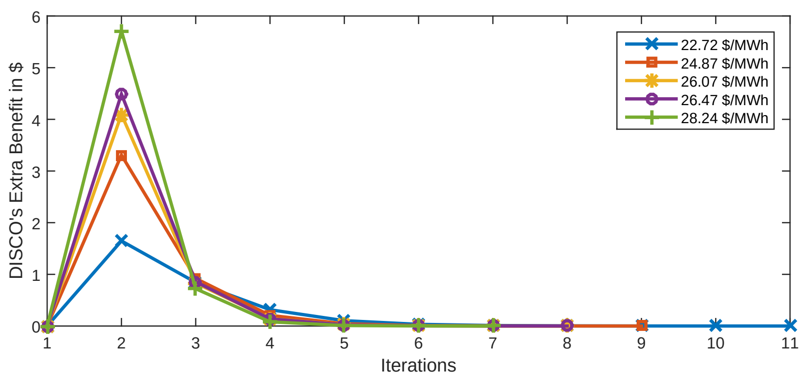


Figure 4.11: DISCO's Extra benefit variation for PG & E 69 active distribution system

4.3.2.4 Variation in active power losses of PG & E 69 active distribution system during Iterative algorithm

Figure 4.12 shows variations in active power losses of PG & E 69 active distribution system as iterations progress in the proposed method at $\omega_1 = 0.5$ and $\omega_2 = 0.5$ for different market prices. **As shown in Figure 4.12,**

- As iterations progress, LMP and generation of DGs that have positive impact on active power loss reduction will increase. This results in reduction of active power loss of network.

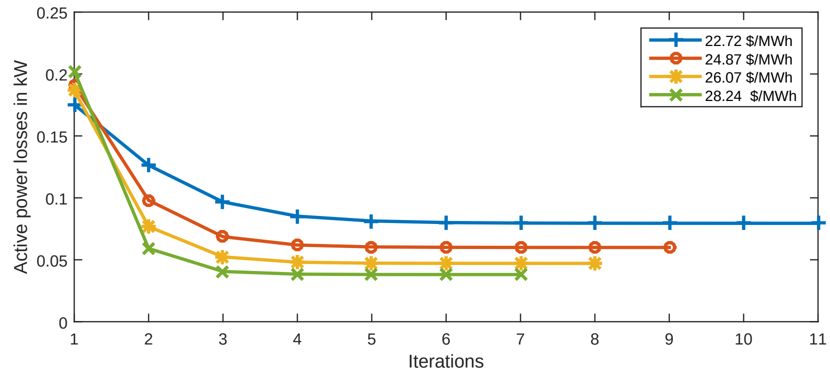


Figure 4.12: DISCO's active power loss variation for PG & E 69 active distribution system

4.3.2.5 Variation in emissions of of PG & E 69 active distribution system during Iterative algorithm

Variations in emissions from PG & E 69 active distribution system as iterations progress in the proposed method at $\omega_1 = 0.5$ and $\omega_2 = 0.5$ for different market prices are as shown in Figure 4.13.

As shown in Figure 4.13,

- As iterations progress, incentives and generation of low emission coefficient generators will increase. This results in decrease of emissions.

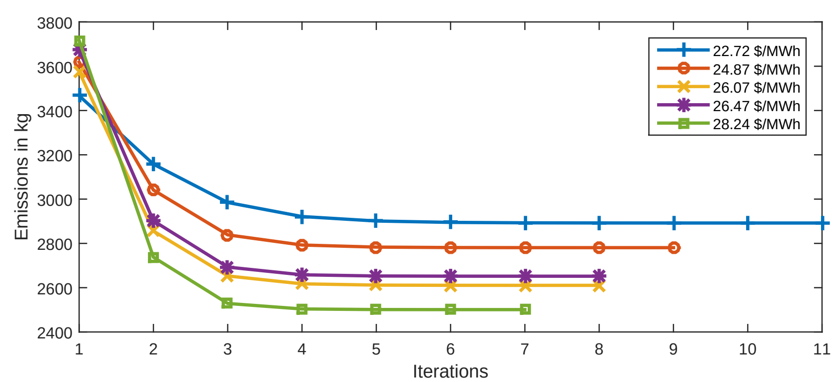


Figure 4.13: DISCO's emissions variation for PG & E 69 active distribution system

4.3.2.6 Comparisons In terms of emissions and active power losses for PG & E 69 active distribution system

The proposed method has been compared in terms of emissions and active power losses using iterative nucleolus method [4] for demonstrating the accuracy and validity of the proposed method. Figure 4.14 and Figure 4.15 shows active power losses and emissions of the PG & E 69 active distribution system at each hour of the day respectively based on proposed method and iterative nucleolus method [4].

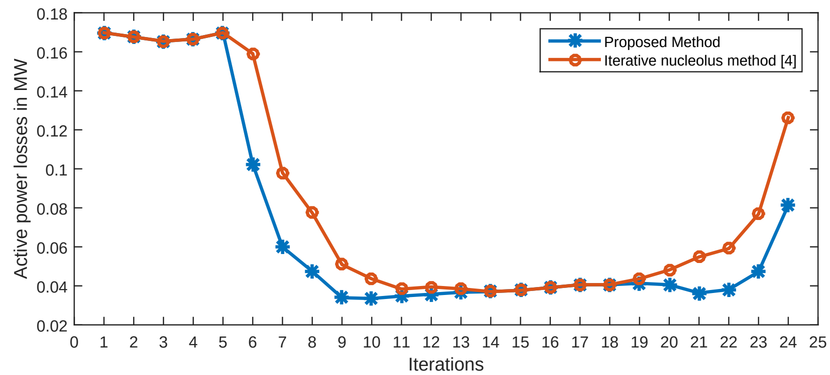


Figure 4.14: Comparison in terms of network active power losses with iterative nucleolus method [4] for PG & E 69 active distribution system

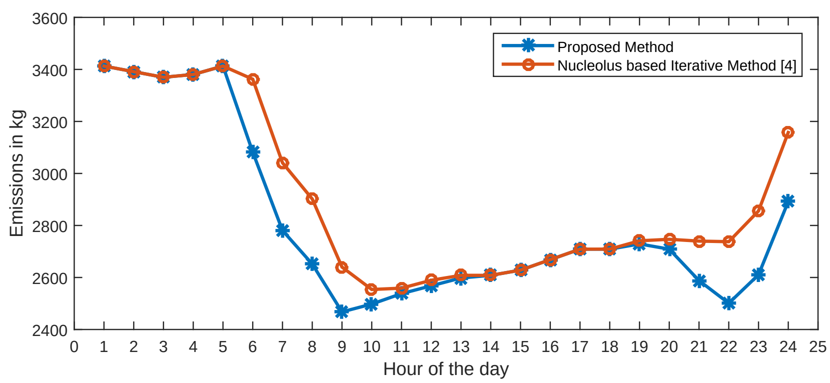


Figure 4.15: Comparison in terms of network emissions with iterative nucleolus method [4] for PG & E 69 active distribution system

As shown in Figure 4.14,

- Active power losses of PG & E 69 active distribution are same in both proposed method and nucleolus based iterative method [4] between 14^{th} and 17^{th} hours. This is because at these hours all DG units are operating at their maximum capacity for initial price (market price). So there is no need to provide extra price over market price. In this case all DG units are operating at uniform price, that is market price, in both methods.

- At 1^{st},2^{nd},3^{rd},4^{th} and 5^{th} hour no DG unit is able to generate the power as market price at these hours is less than 'b' coefficients of all DG units. In such a case, the network operated as a passive network and the total load was supplied only from substation.

- As no DG injects power in to the network, the network looks like base case network and both methods operate the network with same amount of active power losses which is equal to base case active power losses.
- At the remaining hours of the day, the proposed method operates the PG & E 69 active distribution system at less active power losses in comparison with nucleolus based iterative method.

As shown in Figure 4.15,

- At 1^{st},2^{nd},3^{rd},4^{th} and 5^{th} hour no DG unit is able to generate the power as market price at these hours is less than 'b' coefficients of all DG units. In such a case, the network operated as a passive network and the total load was supplied only from substation.
- As no DG injects power in to the network, the network looks like base case network and both methods operate the network with same amount of emissions which is equal to base case emissions.
- Emissions of PG & E 69 active distribution are the same in both proposed method and nucleolus based iterative method [4] between 14^{th} and 17^{th} hours as all DG's operating at their limit.
- At the remaining hours of the day, the proposed method operates the PG & E 69 active distribution system at low emissions in comparison with nucleolus based iterative method.

4.4 Summary

In this chapter, presented a proportional nucleolus theory based iterative method to compute LMP at DG buses is developed in such a way that active power losses and emissions have been reduced. In this method financial incentives have been provided to DG owners from reduced active power losses and reduced emissions cost from base case. DISCO's extra benefit at any iteration has been computed effectively based on LMP and active power generation of DG units at that iteration. As the system load is a probabilistic variable, two layers of ANN have been implemented to forecast load on the system for the next 24 hours. For the first time proportional nucleolus theory which is monotonic unlike nucleolus theory, has been used to compute LMPs at DG buses based on active power losses and emissions.

As the integration of DG units into the distribution network is expected to grow in future, the proposed PNT based iterative method can be helpful to DISCOs to maintain fair competition among private DG owners. DISCO can use this work to operate the network optimally in terms of active power losses and emissions. This work is also helpful to DISCO to estimate the state of network in terms of DG unit's generation with controllable DISCO's extra benefit in day ahead operation. The proposed method computes LMP for DG owners based on DISCO's decision maker priority among DISCO's extra benefit, loss reduction and emission reduction. The proposed method will not have any impact on customer prices. As all the countries are trying to reduce green house gas emissions, this work can help DISCOs to reduce emissions. This work can be further extended by considering technical objectives like Reliability improvement and Service quality.

Chapter 5

Computation of Locational Marginal Price at DG buses in active distribution system based on Reliability Improvement

Chapter 5

Computation of Locational Marginal Price at DG buses in active distribution system based on Reliability Improvement

5.1 Introduction

Distribution networks are prone to failure [124] and hence the supply from power generation plants to the distribution networks will be interrupted [125, 126]. Statistics emphasize the necessity of reassessment of available strategies to improve the electrical services by improving reliability of network [127].

Most of the active distribution systems (ADSs) have been operated in a radial structure as the operation is simple and coordinating the protecting devices can be easy. In order to improve reliability, loop systems concept has been introduced to support uninterrupted power flow to the load by including the inherent complexity of coordinating simple protection devices [128].

Some of the most significant methods [129–131] to improve reliability of the system are as follows:

- Adding protective devices
- Having fewer equipment failures to avoid contingency
- Improving the accuracy of available protection methods
- Re-closing and switching
- Network automation
- Fast fault prediction techniques
- Fast team to accelerate the repair process
- Reconfiguration

If any line outage occurs due to either failure or maintenance [132] then the network splits into two parts. Part-I corresponds to network connected to substation whereas part-II corresponds to network disconnected from substation. There is no encouragement to DG owners from DISCO for supplying the load in part-II of the network.

The problems related to ADS planning are non linear, non convex, non differentiable and constrained optimization problems with integer and continuous decision variables. Conventional optimization techniques have some flaws like curse of dimensionality and non differentiability [133]. In addition to these, conventional techniques usually suffer from the problem of convergence at local minimum instead of at global. Hence these methods are not recommended for solving problems that have a large number of local minimum points. Heuristic and evolutionary algorithms are powerful and effective for solving complex real time problems [134]. Genetic Algorithm (GA) simultaneously evaluates more number of points in search space and is most effective among existing evolutionary algorithms. The authors in [135] proposed a new swarm algorithm called Dragonfly Algorithm (DA) based on the swarming behavior of dragonfly for hunting and migration.

In this chapter, Hybrid Genetic Dragonfly Algorithm (HGDA) based optimal power flow (OPF) has been proposed to compute LMP at DG buses for reliability improvement. The dragonfly based hybrid optimization algorithm has high exploration capability due to proper modeling of dynamic swarming behavior of the dragonflies. Further, has good convergence capability due to proper modeling of static swarming behavior of the dragonflies

LMP values of DG units based on reliability depends on converged solution of optimization problem. In hybrid algorithm weights are tuned in such a way that the converged solution landed near global solution. Alignment and cohesion weights are tuned in such a way that during the exploration phase there is high alignment and low cohesion whereas during exploitation phase there is high cohesion and low alignment. Similarly separation, inertia and enemy factors gradually got reduced.

In the proposed method, the state of the part-II of the network can be observed by computing LMP at each DG bus. It is assumed that LMP at DG bus in part-I of the network are at market price.

The proposed method enables DISCO to plan for scheduling the load or the generation in part-II of the network. Load scheduling is being done if load is more than the available generation in part-II of network, else generation scheduling is initiated. The proposed method provides generation and LMP for each DG unit and the load that can be supplied at each bus in part-II of the network.

In the proposed method, the weighted sum of Expected Energy Not Supplied (EENS) for each type of bus in part-II of network has been considered as objective for load scheduling. However the weighted sum of objectives like DISCO's investment to purchase power from

DG owners, emission and loss in part-II of network has been considered as a single objective function for generation scheduling.

The original contributions of this chapter are as follows:

- Provided LMP computation for improving the reliability for the first time
- Hybridized GA and DA for improved results for the first time
- Enabled DISCO's Decision Maker to handle trade off among the customers
- Enabled DISCO's Decision Maker to handle trade off among objectives like DISCO's investment cost, emission and active power loss during generation scheduling
- Estimated the state of the network with single contingency
- Developed algorithms to locate the buses beyond each line and to renumber the buses in both parts of the network

5.2 Problem formulation

The main aim of optimal power flow is either to schedule the load if the total load is more than available generation or to schedule the generation if the available generation is more than load in part-II of network. It is assumed that LMP at DG buses in the part-I of the network will be at market price. The generation of each DG unit 'i' is computed as shown in equation (5.1) such that the DG owner will receive maximum profit at a given LMP. The bus which has more injection in part-II of the network is considered as slack bus. Slack bus position will not change during load scheduling. The position of slack bus may shuffle between DG buses in part-II of network during generation scheduling. If there exists only one DG unit whose generation is more than the local load then the DG unit bus is considered as a slack bus.

$$P^i_{gen} = \frac{LMP_i - b_i}{2a_i} \tag{5.1}$$

5.2.1 Load scheduling

The optimal power flow is trying to optimize an objective by controlling power flow within an electrical network without violating network power flow constraints or system and equipment operating limits [136]. Minimization of Expected Energy Not Supplied (EENS) is considered as an objective function for load scheduling. In order to improve the reliability of network, all loads have to be served with out interruption. The reliability of ADS has been evaluated in terms of several indices, such as System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI). These indices are more helpful in operational perspective rather than planning [137] and are not adequate to evaluate the reliability of industrial and commercial ADSs [138]. In this chapter EENS [139] has been considered as network reliability evaluation parameter. The objective and fitness functions are represented in equations (5.2) and (5.3) respectively.

$$
\begin{aligned}
min\ EENS_l &= \sum_{i=1}^{N_{type}^{part-II}} \omega_i * (TL_i - AL_i) * OT_l \\
min\ EENS_l^{norm} &= \sum_{i=1}^{N_{type}^{part-II}} \omega_i * \frac{(TL_i - AL_i) * OT_l}{TL_i * OT_l} \\
& i = 1 : Residential\ Loads \\
& i = 2 : Commercial\ Loads \\
& i = 3 : Industrial\ Loads
\end{aligned}
\tag{5.2}
$$

$$
max\ \ FitnessFunction = \frac{1}{1 + EENS_l^{norm}} \tag{5.3}
$$

Subject to the following equality and inequality constraints as in equation (5.4).

$$
\begin{aligned}
\sum_{i=1}^{N_{DG}^{part-II}} P_{gen}^i - \sum_{i=1}^{N_{type}^{part-II}} AL_i - Loss^{part-II} &\approx 0 \\
Voltage\ \ limits : V_b^{LL} \leq V_b &\leq V_b^{UL} \\
Thermal\ \ limits : S_l &\leq S_l^{max} \\
Load\ \ limits : AL_i^{LL} \leq AL_i &\leq AL_i^{UL}
\end{aligned}
\tag{5.4}
$$

AL_i^{UL} value depends on maximum capacity of DG units (P_{gen}^{max}) which are located on type i buses and TL_i. Assume bus 'b' is type 'i'. If the maximum capacity of DG unit (P_{gen}^{max}) is more than the load on the bus 'b' where it is located, then AL_i^{UL} and TL_i are updated using equation (5.5) else using equation (5.6) by setting AL_i^{LL} always to zero.

$$\begin{aligned} AL_i^{UL} &= TL_i - P_{Load}^b \\ TL_i &= TL_i - P_{Load}^b \end{aligned} \tag{5.5}$$

$$\begin{aligned} AL_i^{UL} &= TL_i - P_{gen}^{max} \\ TL_i &= TL_i - P_{gen}^{max} \end{aligned} \tag{5.6}$$

Let P_{Load}^{Act} be the vector which represents load on each bus of network containing 'n' number of buses as in equation (5.7). If the maximum capacity of DG unit (P_{gen}^{max}) is more than the load on bus 'i' where it is located then modify load on that bus 'i' using equation (5.8), else modify load on that bus 'i' using equation (5.9).

$$P_{Load}^{Act} = \{P_{Load}^1, P_{Load}^2, ..., P_{Load}^i, ..., P_{Load}^n\} \tag{5.7}$$

$$P_{Load}^{Mod} = \{P_{Load}^1, P_{Load}^2, ..., P_{Load}^i = 0, ..., P_{Load}^n\} \tag{5.8}$$

$$P_{Load}^{Mod} = \{P_{Load}^1, P_{Load}^2, ..., P_{Load}^i = P_{Load}^i - P_{gen}^{max}, ..., P_{Load}^n\} \tag{5.9}$$

The various type of loads considered in this chapter are *residential loads*, *commercial loads* and *industrial loads*. The length of variable string depends on a number of variables. If part-II of network contains all type of loads then $N_{type}^{Part-II}$=3 and variable string is as shown in equation (5.10). The initial value of each element in variable string is randomly generated. This randomly generated loads were allocated proportionally among buses in part-II of network using equations (5.11), (5.12), and (5.13).

$$\{P_{Load}^{Res}, P_{Load}^{Com}, P_{Load}^{Ind}\} \tag{5.10}$$

If bus 'i' is a residential load bus then

$$P_{Load}^{Alloc}(i) = \frac{P_{Load}^{Mod}(i)}{TL_1} P_{Load}^{Res} \tag{5.11}$$

If bus 'i' is a commercial load bus then

$$P_{Load}^{Alloc}(i) = \frac{P_{Load}^{Mod}(i)}{TL_2} P_{Load}^{Com} \tag{5.12}$$

If bus 'i' is a industrial load bus then

$$P_{Load}^{Alloc}(i) = \frac{P_{Load}^{Mod}(i)}{TL_3} P_{Load}^{Ind} \tag{5.13}$$

If the maximum capacity P_{gen}^{max} of DG unit is more than the load on bus 'i' where DG is located then P_{load}^{Alloc}(i) is modified using equation (5.14) else P_{load}^{Alloc}(i) is modified using equation (5.15).

$$P_{load}^{Alloc}(i) = P_{load}^{Alloc}(i) + P_{Load}^{i} \tag{5.14}$$

$$P_{load}^{Alloc}(i) = P_{load}^{Alloc}(i) + P_{gen}^{max} \tag{5.15}$$

LMP at each DG bus where DG unit i is located in part-II of network is computed using equation (5.16) so that the DG owner receives maximum profit to generate P_{gen}^{i}.

$$LMP_i = 2a_i P_{gen}^{i} + b_i \tag{5.16}$$

5.2.2 Generation Scheduling

Generation scheduling has been opted for if the total load is lower than available generation in part-II of network. The objective function and constraints which have been considered for generation scheduling are shown in equations (5.17) and (5.18) respectively.

$$min\ Obj = \omega_{inv} \frac{DISCO_{inv}^{part-II}}{DISCO_{max}^{inv}} + \omega_{emis} \frac{Emis^{part-II}}{Emis_{max}^{part-II}} + \omega_{los} \frac{Loss^{part-II}}{Loss_{max}^{part-II}} \tag{5.17}$$

$$\begin{aligned} Power\ balance: \sum_{i=1}^{N_{DG}^{part-II}} P_{gen}^{i} - P_{load}^{part-II} - Loss^{part-II} &\approx 0 \\ Generation\ limits: P_{gen}^{LL}(i) \le P_{gen}^{i} &\le P_{gen}^{UL}(i) \\ Voltage\ limits: V_b^{LL} \le V_b &\le V_b^{UL} \\ Thermal\ limits: S_l &\le S_l^{max} \end{aligned} \tag{5.18}$$

P_{gen}^{LL} of DG depends on load on the bus where it is located. Assume DG unit i is located at bus 'b' then $P_{gen}^{LL}(i)$ and $P_{gen}^{UL}(i)$ are determined from the limits represented in Table 5.1.

Table 5.1: Limits on DG generation

Condition	$P_{gen}^{LL}(i)$	$P_{gen}^{UL}(i)$
$P_{Load}^{b} \leq P_{gen}^{max}(i)$	P_{Load}^{b}	$P_{gen}^{max}(i)$
$P_{gen}^{max}(i) \leq P_{Load}^{b}$	$P_{gen}^{max}(i)$	$P_{gen}^{max}(i)$

$DISCO_{inv}^{part-II}$ and $DISCO_{max}^{inv}$ have been computed based on cost coefficients of DG units using equation (5.19). Similarly, emission from part-I and part-II of network have been computed using equations (5.20) and (5.21) respectively. However $Loss^{part-II}$ and $Loss_{max}^{part-II}$ are computed using backward and forward sweep load flow method [113] as shown in Figure F.1 in Appendix-F. This algorithm utilizes complete advantage of ladder structure of distribution network to achieve high speed, robust convergence and low memory requirements [114, 115]. In this load flow solution, a simultaneously controlled PQ modeled [116] DG has been used.

$$\begin{aligned} DISCO_{inv}^{part-II} &= \sum_{i=1}^{N_{DG}^{part-II}} (2 * a_i * P_{gen}^{i} + b_i) * P_{gen}^{i} \\ DISCO_{max}^{inv} &= \sum_{i=1}^{N_{DG}^{part-II}} (2 * a_i * P_{gen}^{max}(i) + b_i) * P_{gen}^{max}(i) \end{aligned} \tag{5.19}$$

$$\begin{aligned} Emis^{part-I} = \sum_{i=1}^{N_{DG}^{part-I}} ({SO_2}^{DG_i} + {CO_2}^{DG_i} + CO^{DG_i} + {NO_x}^{DG_i}) * P_{gen}^{i} + \\ ({SO_2}^{sub} + {CO_2}^{sub} + CO^{sub} + {NO_x}^{sub}) * (P_{load}^{part-I} + loss^{part-I} - \sum_{i=1}^{N_{DG}^{part-I}} P_{gen}^{i}) \end{aligned} \tag{5.20}$$

$$\begin{aligned} Emis^{part-II} &= \sum_{i=1}^{N_{DG}^{part-II}} ({SO_2}^{DG_i} + {CO_2}^{DG_i} + CO^{DG_i} + {NO_x}^{DG_i}) * P_{gen}^{i} \\ Emis_{max}^{part-II} &= \sum_{i=1}^{N_{DG}^{part-II}} ({SO_2}^{DG_i} + {CO_2}^{DG_i} + CO^{DG_i} + {NO_x}^{DG_i}) * P_{gen}^{max}(i) \end{aligned} \tag{5.21}$$

Distribution system load flow study is employed for getting the state of network. Proper numbering for each line and bus of the network is required for successfully implementing any load flow algorithm. If line outage has occurred in a radial distribution system (RDS) then there is no guarantee that all lines and buses have sequential numbering. Even if they have sequential numbering for a particular slack bus, the sequential number of buses and lines will be modified when the slack bus is shuffled between other buses. To avoid these difficulties the following algorithms have been developed.

- Identification of nodes beyond a particular bus
- ADS at single contingency
- Renumbering of buses in part-I of ADS
- Identification of slack bus and position of each bus from slack bus in part-II of ADS
- Renumbering of buses in part-II of ADS

All these algorithms have been implemented on IEEE 15 bus ADS for enabling clean understanding by considering the outage of the line between buses 2 and 3 in the Appendix-D of this thesis.

5.2.3 Genetic Algorithm and Dragonfly Algorithm

5.2.3.1 Genetic Algorithm

Genetic Algorithm (GA) was first introduced by John Holland and developed further by Goldberg [140]. In GA an array of all control variables is represented by chromosomes and the number of chromosomes generated depends on the population size. New generations have been evaluated from old generations using genetic operators like reproduction, cross over and mutation. Elitism operator has been used to keep better individuals of previous generation. The binary-coded Genetic Algorithm has Hamming cliff problems [141]. Sometimes it creates difficulty for coding of continuous variables and GA requires more computation time and memory. In order to overcome such difficulties, real coded genetic algorithm has been used in this chapter. The Step by step procedure for solving a problem using GA is shown in Algorithm 3. The values of GA parameters considered in this chapter are represented in Table 5.2.

5.2.3.2 Dragonfly Algorithm (DA)

Dragonfly Algorithm (DA) was developed by Seyedali Mirjalili [106] based on static (hunting) and dynamic (migration) behavior of Dragonflies. Dragonflies form sub-swarms and fly over different areas in a static swarm for hunting, which is the main objective of the exploration

Table 5.2: The values of GA parameters

Parameter	Value
Control Variable	AL_i i$\varepsilon\{1,2,3\}$ For load scheduling
	P^i_{gen} i$\varepsilon\{1,2,..,N^{part-II}_{DG}\}$ For generation scheduling
Population size	80
Cross over probability(P_c)	0.9
Mutation probability(P_m)	0.01
Elitism probability(P_m)	0.05
Maximum iterations	300

Algorithm 3 Real coded Genetic Algorithm

Inputs

1: Read number of variables (n)
2: Read population size (pop)
3: Read cross over probability (P_c)
4: Read mutation over probability (P_m)
5: Read elitism over probability (P_e)

Steps

1: Initialization ▷ Randomly generate a matrix of size popsize rows and n columns, all elements represented in floating values
2: Set iter=1
3: **while** $iter \leq itermax$ **do**
4: Evaluation ▷ Evaluate objective function for each chromosome
5: Elitism ▷ Selecte most fitted $P_e * pop$ chromosomes
6: Selection ▷ Roulette wheel selection [105]
7: Crossover ▷ Using probability distribution P(β) [105]
8: Mutation ▷ Polynomial Mutation [142]
9: Replace worst chromosomes of new generation with new chromosomes due to elitism
10: iter=iter+1
11: **end while**
12: Print optimal solution and corresponding objective values

Table 5.3: The values of DA parameters

Parameter	Value
Control Variable	AL_i i$\varepsilon\{1,2,3\}$ For load scheduling
	P^i_{gen} i$\varepsilon\{1,2,..,N^{part-II}_{DG}\}$ For generation scheduling
Population size	80
Weight (w)	0.9-0.4
Separation factor (s)	0.2-0
Alignment factor (a)	0.2-0
Cohesion factor (c)	0.2-0
Food factor (f)	0-2
Enemy factor (e)	0.1-0
Maximum iterations	300

phase. In dynamic stage swarm dragonflies form big swarms and fly in one direction for migration, which is favorable for exploitation phase. While swarming Dragonflies exhibit some characteristics like separation, alignment, cohesion, getting attracted towards food source and distracting the enemy for survival. Weights corresponding to the above characteristics (s,a,c,f,e) and inertia weight (w) are adaptively tuned for maintaining exploration and exploitation. The step by step procedure for solving a problem using DA is shown in Algorithm 4. The values of DA parameters considered in this chapter are represented in Table 5.3.

Algorithm 4 Dragonfly Algorithm

Inputs

1: Read number of variables (n)
2: Read population size (pop)
3: Read lower bound (lb) and upper bound (ub) for each variable
4: Read maximum step $\Delta x^{max} = \frac{ub-lb}{4}$

Steps

1: Initialization ▷ Randomly generate a position (X) matrix and step (ΔX) matrix between lb and ub
2: Set iter=1
3: **while** $iter \leq itermax$ **do**
4: Set $r = \Delta x^{max} + ((ub-lb) * \frac{iter}{itermax} * 2)$; ▷ Radius
5: Set w=0.9-iter*$\frac{0.9-0.4}{itermax}$; ▷ Inertia Weight
6: Set f=2*rand ▷ food factor
7: **if** iter < $\frac{itermax}{2}$ **then**
8: Set s=2*rand*(0.1-iter*$\frac{0.2}{itermax}$) ▷ Separation weight
9: Set a=2*rand*(0.1-iter*$\frac{0.2}{itermax}$) ▷ Alignment weight
10: Set c=2*rand*(0.1-iter*$\frac{0.2}{itermax}$) ▷ Cohesion weight

Algorithm 4 (Continued) Dragonfly Algorithm

Set e=(0.1-iter*$\frac{0.2}{itermax}$) ▷ enemy factor
else
set s=a=c=e=0
end if
Evaluation ▷ Evaluate objective function for each individual
Update food fitness, food position (X^+), enemy fitness and enemy position (X^-) among all individuals in X
Identify number of neighboring individuals (N_i) for each individual i ▷ If distance between X_i and X_j is less than 'r' then individuals i and j are neighbors
Compute separation (S_i), alignment (A_i) and cohesion (C_i) for each individual i using equations (5.31), (5.32), and (5.33) if neighbors exist else set all these values to zero

$$S_i = -\sum_{j=1}^{N_i}(X_i - X_j) \tag{5.22}$$

$$A_i = \frac{\sum_{j=1}^{N_i} \Delta X_j}{N_i} \tag{5.23}$$

$$C_i = \frac{\sum_{j=1}^{N_i} X_j}{N_i} - X_i \tag{5.24}$$

▷ j belongs to set of neighboring individuals of i
Compute distance (D_{fi}) between X_i and X^+ and distance (D_{ei}) between X_i and X^- for each individual 'i'
if all (D_{fi})$\leq$ r **then** ▷ Checking whether individual 'i' is neighbor for X^+ or not
Set $F_i = X^+ - X_i$
else
Set $F_i = 0$
end if
if all (D_{ei})$\leq$ r **then** ▷ Checking whether individual 'i' is neighbor for X^- or not
$E_i = X^- + X_i$
else
Set $E_i = 0$
end if
if any (D_{fi})$>$ r **then** ▷ Checking whether individual 'i' is neighbor for X^+ or not
if N_i >1 **then** ▷ Checking whether individual 'i' has neighbors or not
Set $\Delta X_i = w * \Delta X_i + rand * A(i) + rand * C(i) + rand * S(i)$ ▷ Updating step vector (ΔX_i) of individual i
Set X(i)=X(i)+ΔX_i ▷ Updating position vector (X_i) of individual i
else
X(i)=X(i)+Levy(d)*X(i); ▷ Updating position vector (X_i) of individual i

Algorithm 4 (Continued) Dragonfly Algorithm

Set ΔX_i=0 ▷ Updating step vector (ΔX_i) of individual i
end if
else
Set ΔX_i=(a*A(i)+c*C(i)+s*S(i)+f*F(i)+e*Enemy(i)) + w*ΔX_i ▷ Updating step vector (ΔX_i) of individual i
X(i)=X(i)+ΔX_i; ▷ Updating position vector (X_i) of individual i
end if
end while
Print optimal solution and corresponding objective values

5.2.4 Hybrid Genetic Dragonfly Algorithm (HGDA)

In order to achieve a global optimal solution by any population based algorithm, proper balancing is required between exploration and exploitation of the search space. Exploration related to global search in search space and exploitation related to local search in search space are based on current best solution. Too much diversification and intensification will result in increasing convergence time and increasing the possibility of the solution getting trapped into local optimum point [143].

Genetic Algorithm has a problem in finding the exact solution but it is good at moving towards global region and slow convergence. GA works based on evolution from generation to generation by not considering individuals in the same generation. Basic GA has no memory, which means previous knowledge of the problem stands destroyed once the population changes [144]. But this problem can be overcome by including elitism concept. This means that GA with elitism concept has memory which stores best individuals from previous population.

However, in contrast with GA, DA has fast convergence and its performance is increased as best individuals are available but it does not have internal memory. Due to absence of internal memory DA never maintains tracking on possible set of solutions which have the potential to converge to global optimum that may result in trapping the solution towards local optimum point [145].

To overcome the above drawbacks, a novel hybrid algorithm based on GA and DA has been proposed in this chapter to exploit the advantages of both GA and DA algorithms. This hybridization includes two additional features to DA like internal memory and improvised searching capability. The proposed hybrid genetic dragonfly algorithm acquires good local and global searching capability to avoid the problem of trapping the solution towards local optimum point. The step by step procedure for HGDA is shown in Algorithm 5.

Algorithm 5 Hybrid Genetic Dragonfly Algorithm (HGDA)

Inputs

1: Read number of variables (n)
2: Read population size (pop)
3: Read cross over probability (P_c)
4: Read mutation over probability (P_m)
5: Read elitism over probability (P_e)
6: Read lower bound (lb) and upper bound (ub) for each variable
7: Read maximum step Δx^{max}=$\frac{ub-lb}{4}$

Steps

1: Initialize X ▷ Randomly initialize population
2: Initialize ΔX ▷ Randomly initialize step vector of size $\frac{pop}{2}$ rows and n columns
3: Set iter=1
4: **while** $iter \leq itermax$ **do**
5:     Evaluation ▷ Evaluate objective function for each individual of X
6:     Sort population (X) based on objective function value and choose top half population (X_{half}) ▷ Sort either in ascending order for minimization problem or in descending order for maximization problem
7:     Implement elitism, selection, crossover and mutation X_{half} population and generate new population X_{GA} ▷ Implement steps 8 to 45 on X_{half} population and generate new population X_{DA} ▷ X=X_{half}
8:     Set $r = \Delta x^{max} + ((ub - lb) * \frac{iter}{itermax} * 2)$; ▷ Radius
9:     Set w=0.9-iter*$\frac{0.9-0.4}{itermax}$; ▷ Inertia Weight
10:     Set f=2*rand ▷ food factor
11:     **if** iter $<$ $\frac{itermax}{2}$ **then**
12:         Set s=2*rand*(0.1-iter*$\frac{0.2}{itermax}$) ▷ Separation weight
13:         Set a=2*rand*(0.1-iter*$\frac{0.2}{itermax}$) ▷ Alignment weight
14:         Set c=2*rand*(0.1-iter*$\frac{0.2}{itermax}$) ▷ Cohesion weight
15:         Set e=(0.1-iter*$\frac{0.2}{itermax}$) ▷ enemy factor
16:     **else**
17:         set s=a=c=e=0
18:     **end if**
19:     Evaluation ▷ Evaluate objective function for each individual
20:     Update food fitness, food position (X^+), enemy fitness and enemy position (X^-) among all individuals in X
21:     Identify number of neighboring individuals (N_i) for each individual i ▷ If distance between X_i and X_j is less than 'r' then individuals i and j are neighbors

Algorithm 5 (Continued) Hybrid Genetic Dragonfly Algorithm (HGDA)

Compute separation (S_i), alignment (A_i) and cohesion (C_i) for each individual i using equations (5.31), (5.32), and (5.33) if neighbors exist else set all these values to zero

$$S_i = -\sum_{j=1}^{N_i} (X_i - X_j) \tag{5.25}$$

$$A_i = \frac{\sum_{j=1}^{N_i} \Delta X_j}{N_i} \tag{5.26}$$

$$C_i = \frac{\sum_{j=1}^{N_i} X_j}{N_i} - X_i \tag{5.27}$$

▷ j belongs to set of neighboring individuals of i

Compute distance (D_{fi}) between X_i and X^+ and distance (D_{ei}) between X_i and X^- for each individual 'i'

    if all (D_{fi})≤ r **then** ▷ Checking whether individual 'i' is neighbor for X^+ or not
        Set $F_i = X^+ - X_i$
    else
        Set $F_i = 0$
    end if
    if all (D_{ei})≤ r **then** ▷ Checking whether individual 'i' is neighbor for X^- or not
        $E_i = X^- + X_i$
    else
        Set $E_i = 0$
    end if
    if any (D_{fi})> r **then** ▷ Checking whether individual 'i' is neighbor for X^+ or not
        if N_i >1 **then** ▷ Checking whether individual 'i' has neighbors or not
            Set $\Delta X_i = w * \Delta X_i + rand * A(i) + rand * C(i) + rand * S(i)$ ▷ Updating step vector (ΔX_i) of individual i
            Set X(i)=X(i)+ΔX_i ▷ Updating position vector (X_i) of individual i
        else
            X(i)=X(i)+Levy(d)*X(i); ▷ Updating position vector (X_i) of individual i
            Set ΔX_i=0 ▷ Updating step vector (ΔX_i) of individual i
        end if
    else
        Set ΔX_i=(a*A(i)+c*C(i)+s*S(i)+f*F(i)+e*Enemy(i)) + w*ΔX_i ▷ Updating step vector (ΔX_i) of individual i
        X(i)=X(i)+ΔX_i; ▷ Updating position vector (X_i) of individual i ▷ X_{DA}=X
    end if
    Form new population X consisting of pop individuals by vertically concatinating X_{GA} and X_{DA}
end while
Print optimal solution and corresponding objective values

5.2.5 Computation of LMP using Hybrid Genetic Dragonfly Algorithm based Optimal power flow (HGDA-OPF)

The Hybrid Genetic Dragonfly Algorithm based optimal power flow for computing LMP value for each DG unit for load scheduling is achieved by employing Algorithm 6 and for generation scheduling by employing Algorithm 7 respectively. The complete flowchart for computing LMP using HGDA-OPF is presented in Figure E.1 of Appendix-E.

Algorithm 6 LMP computation using HGDA-OPF for load scheduling

Inputs

1: Read linedata of ADS
2: Read DG units size ($P_{gen}^{max}(i)$), power factor and location
3: Read outage line ($Line_{out}$)
4: Read cross over probability (P_c)
5: Read mutation over probability (P_m)
6: Read elitism over probability (P_e)
7: Read population size (pop)
8: Read maximum step Δx^{max}

Steps

1: Set P_{gen}^{i}=$P_{gen}^{max}(i)$ for i=1,2,..$N_{DG}^{part-II}$
2: Split the network data based on $Line_{out}$ and renumber buses using flowcharts in Figure D.2, Figure D.3, Figure D.4, Figure D.6, Figure D.7 and FigureD.8 presented in Appendix-D.
3: Set number of control variables ncv=$N_{type}^{part-II}$ ▷ Control variables are AL_i for iε1,2,3
4: Update AL_i^{UL} and TL_i using equation (5.5) or equation (5.6)
5: Update P_{Load}^{Mod} of part-II of network using equation (5.8) or equation (5.9).
6: Initialize X of size [pop,n] ▷ Randomly initialize AL_i for iε 1,2,3 between AL_i^{LL} and AL_i^{UL}
7: Initialize step vector ΔX of size [$\frac{pop}{2}$,n] ▷ Randomly initialize AL_i for iε 1,2,3 between AL_i^{LL} and AL_i^{UL}
8: Set iter=1
9: **while** $iter \leq itermax$ **do**
10: Update load data of part-II of network for each individual in X as shown in equations (5.11),(5.12),(5.13),(5.14), and (5.15).
11: Evaluation ▷ Evaluate objective function for each individual of X and Use step 10 of this Algorithm 6 as and when required.
12: Sort population (X) based on objective function value and choose top half population (X_{half}) ▷ Sort either in ascending order for minimization problem or in descending order for maximization problem

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Algorithm 6 (Continued) LMP computation using HGDA-OPF for load scheduling

13: Implement elitism, selection, crossover and mutation X_{half} population and generate new population X_{GA}
 ▷ Implement steps 14 to 53 on X_{half} population and generate new population X_{DA} ▷ X=X_{half}
14: Set $r = \Delta x^{max} + ((ub - lb) * \frac{iter}{itermax} * 2)$; ▷ Radius
15: Set w=0.9-iter*$\frac{0.9-0.4}{itermax}$; ▷ Inertia Weight
16: Set f=2*rand ▷ food factor
17: **if** iter $< \frac{itermax}{2}$ **then**
18: Set s=2*rand*(0.1-iter*$\frac{0.2}{itermax}$) ▷ Separation weight
19: Set a=2*rand*(0.1-iter*$\frac{0.2}{itermax}$) ▷ Alignment weight
20: Set c=2*rand*(0.1-iter*$\frac{0.2}{itermax}$) ▷ Cohesion weight
21: Set e=(0.1-iter*$\frac{0.2}{itermax}$) ▷ enemy factor
22: **else**
23: set s=a=c=e=0
24: **end if**
25: Evaluation ▷ Evaluate objective function for each individual
26: Update food fitness, food position (X^+), enemy fitness and enemy position (X^-) among all individuals in X
27: Identify number of neighboring individuals (N_i) for each individual i ▷ If distance between X_i and X_j is less than 'r' then individuals i and j are neighbors
28: Compute separation (S_i), alignment (A_i) and cohesion (C_i) for each individual i using equations (5.31), (5.32), and (5.33) if neighbors exist else set all these values to zero

$$S_i = -\sum_{j=1}^{N_i}(X_i - X_j) \tag{5.28}$$

$$A_i = \frac{\sum_{j=1}^{N_i} \Delta X_j}{N_i} \tag{5.29}$$

$$C_i = \frac{\sum_{j=1}^{N_i} X_j}{N_i} - X_i \tag{5.30}$$

▷ j belongs to set of neighboring individuals of i
29: Compute distance (D_{fi}) between X_i and X^+ and distance (D_{ei}) between X_i and X^- for each individual 'i'
30: **if** all (D_{fi})≤ r **then** ▷ Checking whether individual 'i' is neighbor for X^+ or not
31: Set $F_i = X^+ - X_i$
32: **else**
33: Set $F_i = 0$
34: **end if**
35: **if** all (D_{ei})≤ r **then** ▷ Checking whether individual 'i' is neighbor for X^- or not
36: $E_i = X^- + X_i$
37: **else**
38: Set $E_i = 0$
39: **end if**

Algorithm 6 (Continued) LMP computation using HGDA-OPF for load scheduling

40: **if** any $(D_{fi}) >$ r **then** ▷ Checking whether individual 'i' is neighbor for X^+ or not
41: **if** $N_i > 1$ **then** ▷ Checking whether individual 'i' has neighbors or not
42: Set $\Delta X_i = w * \Delta X_i + rand * A(i) + rand * C(i) + rand * S(i)$ ▷ Updating step vector (ΔX_i) of individual i
43: Set X(i)=X(i)+ΔX_i ▷ Updating position vector (X_i) of individual i
44: **else**
45: X(i)=X(i)+Levy(d)*X(i); ▷ Updating position vector (X_i) of individual i
46: Set ΔX_i=0 ▷ Updating step vector (ΔX_i) of individual i
47: **end if**
48: **else**
49: Set ΔX_i=(a*A(i)+c*C(i)+s*S(i)+f*F(i)+e*Enemy(i)) + w*ΔX_i ▷ Updating step vector (ΔX_i) of individual i
50: X(i)=X(i)+ΔX_i; ▷ Updating position vector (X_i) of individual i ▷ X_{DA}=X
51: **end if**
52: Form new population X consisting of pop individuals by vertically concatinating X_{GA} and X_{DA}
53: **end while**
54: Compute LMP value for each DG using equation (5.16)
55: Print optimal solution and corresponding objective values

Algorithm 7 LMP computation using HGDA-OPF for generation scheduling

Inputs

1: Read linedata of ADS
2: Read DG units size ($P_{gen}^{max}(i)$), power factor and location
3: Read outage line ($Line_{out}$)
4: Read cross over probability (P_c)
5: Read mutation over probability (P_m)
6: Read elitism over probability (P_e)
7: Read population size (pop)
8: Read maximum step Δx^{max}

Steps

1: Split the network data based on $Line_{out}$ and renumber buses using flowcharts in Figure D.2, Figure D.3 and Figure D.4
2: Set number of control variables ncv=$N_{DG}^{part-II}$ ▷ Control variables are P_{gen}^i for i ε 1,2,..,$N_{DG}^{part-II}$
3: Update $P_{gen}^{LL}(i)$ and $P_{gen}^{UL}(i)$ as shown in Table 5.2
4: Initialize X of size [pop,ncv] ▷ Randomly initialize P_{gen}^i for iε 1,2,..,$N_{DG}^{part-II}$ between $P_{gen}^{LL}(i)$ and $P_{gen}^{UL}(i)$
5: Initialize step vector ΔX of size [$\frac{pop}{2}$,ncv] ▷ Randomly initialize P_{gen}^i for iε 1,2,..,$N_{DG}^{part-II}$ between $P_{gen}^{LL}(i)$ and $P_{gen}^{UL}(i)$

Algorithm 7 (Continued) LMP computation using HGDA-OPF for generation scheduling

6: Set iter=1

7: **while** $iter \leq itermax$ **do**

8: Provide renumbering to each line and bus in part-II of network using flowcharts in Figure D.6,Figure D.7 and Figure D.8 for each individual in X (if required)

9: Evaluation ▷ Evaluate objective function shown in equation (5.17) based on constraints shown in equation (5.18) for each individual of X and use step 8 of this Algorithm 7 as and when required.

10: Sort population (X) based on objective function value and choose top half population (X_{half}) ▷ Sort either in ascending order for minimization problem or in descending order for maximization problem

11: Implement elitism, selection, crossover and mutation X_{half} population and generate new population X_{GA}

▷ Implement steps 12 to 49 of of dragonfly algorithm on X_{half} population and generate new population X_{DA} ▷ X=X_{half}

12: Set $r = \Delta x^{max} + ((ub - lb) * \frac{iter}{itermax} * 2)$; ▷ Radius

13: Set w=0.9-iter*$\frac{0.9-0.4}{itermax}$; ▷ Inertia Weight

14: Set f=2*rand ▷ food factor

15: **if** iter $< \frac{itermax}{2}$ **then**

16: Set s=2*rand*(0.1-iter*$\frac{0.2}{itermax}$) ▷ Separation weight

17: Set a=2*rand*(0.1-iter*$\frac{0.2}{itermax}$) ▷ Alignment weight

18: Set c=2*rand*(0.1-iter*$\frac{0.2}{itermax}$) ▷ Cohesion weight

19: Set e=(0.1-iter*$\frac{0.2}{itermax}$) ▷ enemy factor

20: **else**

21: set s=a=c=e=0

22: **end if**

23: Evaluation ▷ Evaluate objective function for each individual

24: Update food fitness, food position (X^+), enemy fitness and enemy position (X^-) among all individuals in X

25: Identify number of neighboring individuals (N_i) for each individual i ▷ If distance between X_i and X_j is less than 'r' then individuals i and j are neighbors

26: Compute separation (S_i), alignment (A_i) and cohesion (C_i) for each individual i using equations (5.31), (5.32), and (5.33) if neighbors exist else set all these values to zero

$$S_i = -\sum_{j=1}^{N_i}(X_i - X_j) \tag{5.31}$$

$$A_i = \frac{\sum_{j=1}^{N_i} \Delta X_j}{N_i} \tag{5.32}$$

$$C_i = \frac{\sum_{j=1}^{N_i} X_j}{N_i} - X_i \tag{5.33}$$

▷ j belongs to set of neighboring individuals of i

27: Compute distance (D_{fi}) between X_i and X^+ and distance (D_{ei}) between X_i and X^- for each individual 'i'

Algorithm 7 (Continued) LMP computation using HGDA-OPF for generation scheduling

if all (D_{fi})$\leq$ r **then** ▷ Checking whether individual 'i' is neighbor for X^+ or not
  Set $F_i = X^+ - X_i$
else
  Set $F_i = 0$
end if
if all (D_{ei})$\leq$ r **then** ▷ Checking whether individual 'i' is neighbor for X^- or not
  $E_i = X^- + X_i$
else
  Set $E_i = 0$
end if
if any (D_{fi})$>$ r **then** ▷ Checking whether individual 'i' is neighbor for X^+ or not
  if $N_i > 1$ **then** ▷ Checking whether individual 'i' has neighbors or not
    Set $\Delta X_i = w * \Delta X_i + rand * A(i) + rand * C(i) + rand * S(i)$ ▷ Updating step vector (ΔX_i) of individual i
    Set X(i)=X(i)+ΔX_i ▷ Updating position vector (X_i) of individual i
  else
    X(i)=X(i)+Levy(d)*X(i); ▷ Updating position vector (X_i) of individual i
    Set ΔX_i=0 ▷ Updating step vector (ΔX_i) of individual i
  end if
else
  Set ΔX_i=(a*A(i)+c*C(i)+s*S(i)+f*F(i)+e*Enemy(i)) + w*ΔX_i ▷ Updating step vector (ΔX_i) of individual i
  X(i)=X(i)+ΔX_i; ▷ Updating position vector (X_i) of individual i ▷ X_{DA}=X
end if
Form new population X consisting of pop individuals by vertically concatinating X_{GA} and X_{DA}
end while
Compute LMP value for each DG using equation (5.16)
Print optimal solution and corresponding objective values

5.3 Analytical Studies

5.3.1 Case study-1

The proposed HGDA based OPF has been implemented on 38 bus ADS as shown in Figure B.1 in Appendix-B to compute LMP values at DG buses in part-II of network under MATLAB [121] environment. The system data for 38 bus ADS was taken from [6] and presented in Table B.1 in Appendix-B. The location and type of each DG unit of capacity 50MW operating at 0.9 lagging power factor are shown in Table 5.4. The cost function coefficients of each type of DG unit are considered from [4]. The duration of each line l outage OT_l is assumed as one hour, and the market price for active power generation is assumed as 32.38 \$/MWh.

Table 5.4: Type and Location of DG units in 38 bus ADS

DG unit	Type	Location	Engine type
DG1	1	5	Combined cycle gas turbines
DG2	1	11	Combined cycle gas turbines
DG3	2	19	Gas internal combustion engines
DG4	3	23	Diesel internal combustion engines
DG5	3	27	Diesel internal combustion engines
DG6	2	29	Gas internal combustion engines

5.3.1.1 Load Scheduling

The line between buses 5 and 6 was considered as an outage line. As the total load is more than the available generation in part-II of network, LMP values of each DG unit in part-II of network are computed by scheduling the load. The Proposed HGDA based OPF has been implemented 10 times on part-II of 38 bus ADS. Out of 10 runs the best objective function (EENS) value is considered for estimating the state of part-II of ADS. The best, worst and average objective function values are shown in Table 5.5 for ω_1=0.333, ω_2=0.333 and ω_3=0.333.

Table 5.5: HGDA-OPF performance in terms of EENS (MWh)

Best	Average	Worst
56.4	56.6	57.1

Table 5.6 presents active power generation and LMP of each DG unit in 38 bus ADS for ω_1=0.333, ω_2=0.333 and ω_3=0.333.

As shown in Table 5.6,

- As the total generation in part-II of network is 150MW which is less than total load 205.5MW, all DG units in part-II of network can dispatch a maximum capacity of 50MW. The corresponding LMPs are 601 $/MWh, 520 $/MWh and 550 $/MWh.

- DG units in part-I of network do not have any contribution in reliability improvement and so no incentive has been provided over and above the market price of 32.38 $/MWh.

- DG units in part-I of network generate power such that DG owners get maximum profit for a given LMP.

Figure 5.1 shows the scheduled load at each bus in part-II of network using proposed HGDA based OPF method while considering equal priority among all type of loads.

Table 5.6: DG units generation (MW) and LMP ($/MWh) for 38 bus ADS

Unit	DG1	DG2	DG3	DG4	DG5	DG6
LMP	32.38	601	32.38	32.38	520	550
Generation	0.98	50	1.17	1.24	50	50

As shown inFigure 5.1,

- There is no load curtailment at buses 11, 27 and 29 as DG units which were installed at these buses supply total load.
- The total curtailed load on part-II of network is 56.4MW. As repair time is considered to be one hour, EENS value is 56.4MWh.

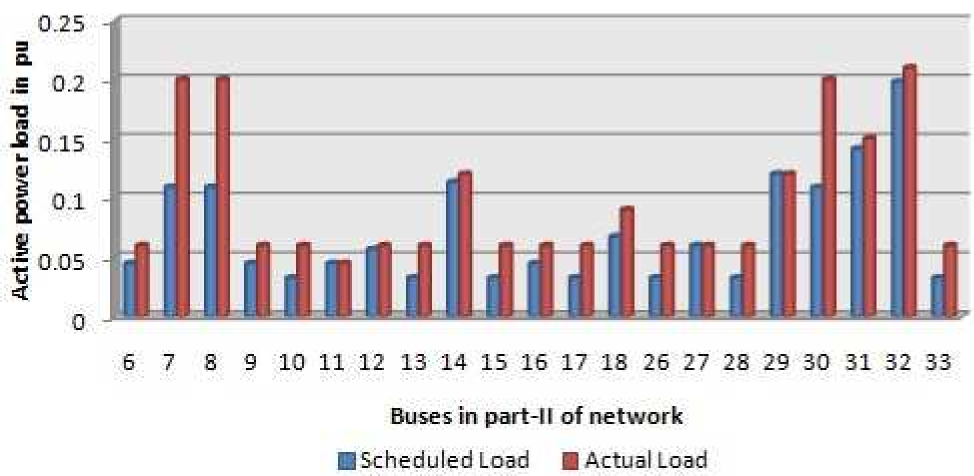


Figure 5.1: Scheduled load at each bus in part-II of 38 bus ADS after the line outage between buses 5 and 6

Figure 5.2 shows the actual voltage (V_{act}) at each bus in part-II of network at ω_1=0.333, ω_2=0.333 and ω_3=0.333.

As shown in Figure 5.2,

- All bus voltages are within maximum limit (V_{max}) 1.02 pu and minimum limit (V_{min}) 0.9 pu. It means that the proposed HGDA based OPF method will schedule the loads such that all voltages are within the limits.

The impact of weights corresponding to residential, commercial and industrial loads on EENS is as shown in Table 5.7.

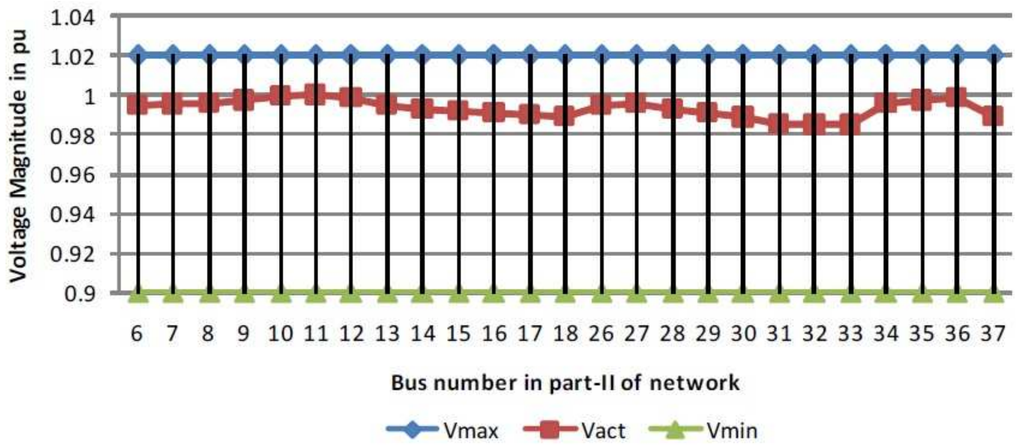


Figure 5.2: Voltage at each bus in part-II of 38 bus ADS after the line outage between buses 5 and 6

As shown in Table 5.7,

- As weight ω_1 corresponding to residential load increases, EENS value corresponding to residential load decreases.
- As ω_2 and ω_3 increase the EENS value corresponding to the commercial and industrial loads decreases respectively.
- The EENS value for overall system remains almost constant as the generation does not change. However, small changes in EENS value for the overall system are due to variations in loss.

Table 5.7: Impact of ω_1, ω_2 and ω_3 on EENS in 38 bus ADS

ω_1	ω_2	ω_3	$EENS_1(MWh)$	$EENS_2(MWh)$	$EENS_3(MWh)$	EENS(MWh)
0.6	0.3	0.1	10.3	30.8	15.5	56.6
0.3	0.6	0.1	17.4	14.4	25.2	57.0
0.1	0.6	0.3	26.6	26.5	3.5	56.6
0.1	0.3	0.6	24.7	31.7	0.00	56.5
0.6	0.1	0.3	0.00	50.8	5.6	56.4

5.3.1.2 Generation Scheduling

Consider the line between buses 6 and 26 as an outage line. The proposed HGDA based OPF computes LMP and generation of each DG unit in part-II of network using generation scheduling as the total load of 0.92 pu is lower than the generated power of 1.0 pu in part-II of network.

The computed values of LMP and the generation of each DG unit by the proposed method are presented in Table 5.8 after assigning same weights to all objectives. As there is no contribution from DG units in part-I of the network, no incentive has been provided over and above the market price.

Table 5.8: DG units generation (MW) and LMP ($/MWh) in 38 bus ADS

Unit	DG1	DG2	DG3	DG4	DG5	DG6
LMP	32.38	32.38	32.38	32.38	457.5	543.1
Generation	0.98	0.98	1.17	1.24	43.75	49.35

Generation of each DG unit in part-II of network has been scheduled using the proposed HGDA based OPF method so that voltage at each bus in part-II of network must be between V_{max} and V_{min}. Computed voltage (V_{act}) at each bus in part-II of network for equal weights among the objectives is shown in Figure 5.3.

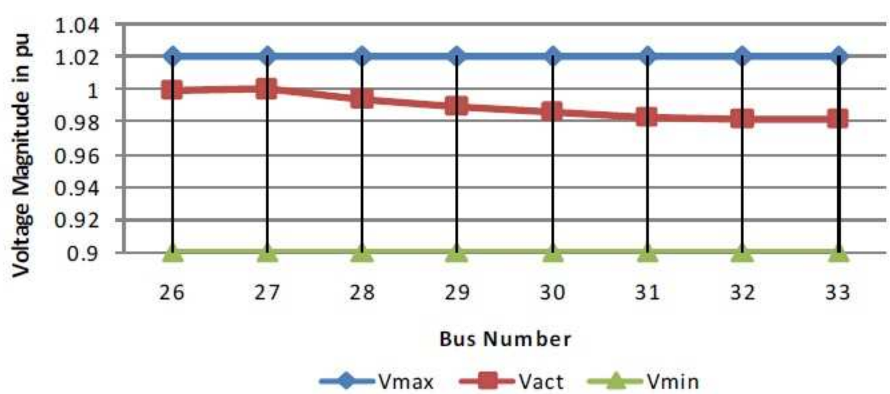


Figure 5.3: Voltage at each bus in part-II of 38 bus ADS after the line outage between buses 6 and 26

Table 5.9 shows the impact of ω_{inv}, ω_{emis} and ω_{los} values on DISCO's investment in purchasing power from DG owners, the emissions released from part-II of network and the losses in part-II of network respectively. DISCO's decision maker can increase ω_{inv} to supply total load by purchasing more power from low cost coefficient generator. Similarly DISCO's decision maker can supply a total load at less emission by increasing ω_{emis}. DISCO can reduce active power loss of network by increasing ω_{los}.

As shown in Table 5.9,

- As the value of ω_{inv} increases, DISCO's investment in purchasing power from DG owner decreases.

- As the value of ω_{emis} increases, DISCO gets power from low emission coefficient generators which leads to reduction in emissions.

- The weight combination of [0,0,1] has reduced emissions in comparison with the weight combinations of [0.6 0.3 0.1] and [0.3 0.3 0.3] despite the value of ω_{emis} being reduced to zero. It is due to the huge positive impact of DG6 on loss reduction.

- The weight combination of [0.6 0.3 0.3] has increased emissions in comparison with weights combination of [0.3 0.3 0.3] despite the value of ω_{emis} remaining the same. It is due to the influence of low cost and high emission generator DG5 over high cost and low emission generator DG6.

- Active power loss in part-II of network having a weight combination of [0.6 0.3 0.1] is more in comparison with weight combination of [0.3 0.6 0.1] despite the value of ω_{los} being the same in both cases. It is due to high positive impact of low emission coefficient generator (DG6) on active power loss reduction.

- Active power loss of network is low with a weight combination of [0.3 0.6 0.1] in comparison with a weight combination of [0.3 0.3 0.3] despite the weight corresponding to ω_{los} showing an increase. It is due to increasing priority for DG6 generation that has a huge positive impact on loss reduction.

Table 5.9: Impact of ω_{inv}, ω_{emis} and ω_{los} in 38 bus ADS

ω_{inv}	ω_{emis}	ω_{los}	$DISCO_{inv}^{part-II}(\$)$	$Emis^{part-II}(kg)$	$Loss^{part-II}(kW)$
0.6	0.3	0.1	46735	51019	1115.7
0.3	0.3	0.3	46824	50922	1106.7
0.3	0.6	0.1	46856	50890	1103.734
0	0	1	46857	50891	1103.73

Table 5.10 presents the impact of ω_{inv}, ω_{emis} and ω_{los} on active power generation and LMP values of DG units in part-II of network.

As shown in Table 5.10,

- As ω_{inv} increases, DISCO's decision maker is willing to get power from low fuel cost coefficient generator that leads to an increase in the generation and LMP value of DG5.

- The weight combination of [0,0,1] the generation and LMP of DG5 are more in comparison with the weight combination of [0.3 0.6 0.1] despite the value of ω_{inv} is increased. It is also due to contribution of DG5 in active power loss reduction.

- If ω_{emis} increases at lower ω_{los} values then generation and LMP value of DG6 (low emission coefficients generator) increase.
- If ω_{los}=1, high priority is given to loss reduction and generation and LMP value of DG6 are more even when ω_{emis}=0. It is due to the high impact of DG6 on loss reduction.
- The weight combination of [0 0 1] active power generation of DG6 is more than DG5. It is due to the positive impact of DG6 on active power loss reduction which is more than DG5.

Table 5.10: Impact of ω_{inv}, ω_{emis} and ω_{los} on generation and LMP in 38 bus ADS

			Generation (kW)		LMP ($/MWh)	
ω_{inv}	ω_{emis}	ω_{los}	DG5	DG6	DG5	DG6
0.6	0.3	0.1	44380	48740	463.777	536.618
0.3	0.3	0.3	43754	49352	457.541	543.136
0.3	0.6	0.1	43551.6	49551.6	455.516	545.247
0	0	1	43552.1	49552.1	455.521	545.252

State of part-I of network has been observed in terms of active power loss and voltage magnitude. No DG units in part-I of network have any impact on reliability improvement. DISCO does not provide any incentives over the market price to these units. Hence LMP value for each DG unit in part-I of network is equal to market price i.e 32.38 ($/MWh). DG units in part-I of network will dispatch generation such that the DG owner gets maximum profit at a given LMP. Voltage at each bus in part-I of network while considering line outage between 5 and 6 is shown in Figure 5.4 and the active power loss is 1.78MW. Similarly Figure 5.5 shows voltage at each bus in part-I of network while considering line outage between buses 6 and 26 and the active power loss in part-I of the network is 7.05MW. Shuffling of slack bus between buses 27 and 29 in part-II of network is as shown in Figure 5.6. This shuffling occurred due to change of bus which has maximum injection.

Table 5.11 presents LMP value of each DG unit in test system for different line outages and at equal weights among objectives.

As shown in Table 5.11,

- As there is no DG unit in part-II of network for outage of line 3 or 4, EENS value provided by the proposed method is equal to base case EENS value.
- As all DG units are located in part-I of network and there is no contribution from these units on reliability improvement, no incentive has been provided over the market price.

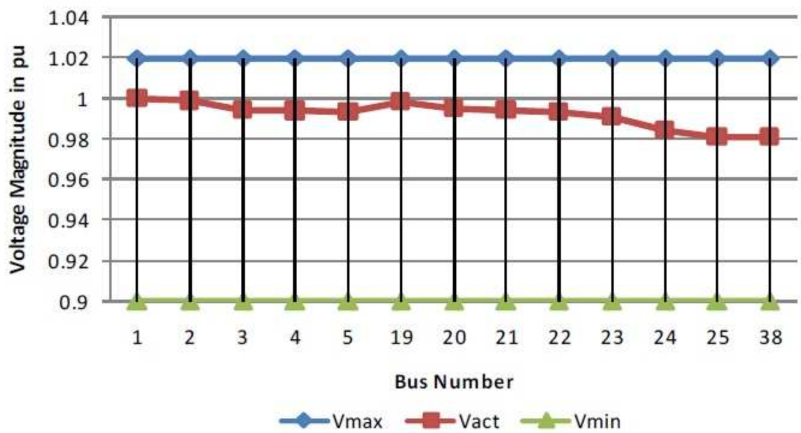


Figure 5.4: Voltage at each bus in part-I of 38 bus ADS after line outage between buses 5 and 6

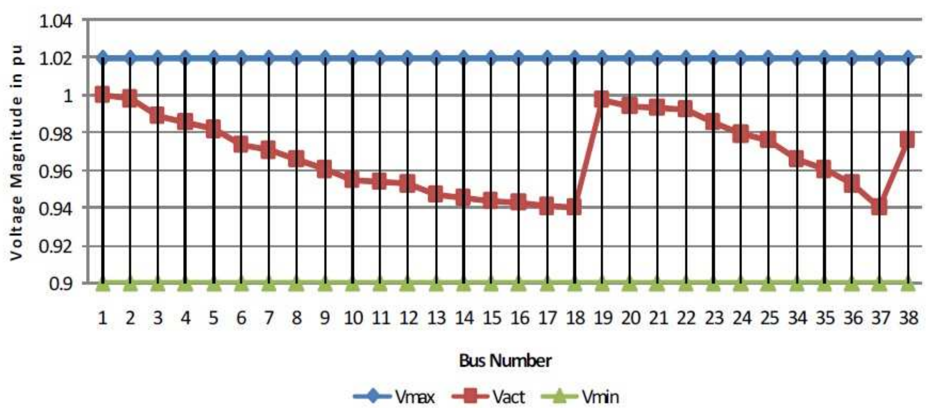


Figure 5.5: Voltage at each bus in part-I of 38 bus ADS after line outage between buses 6 and 26

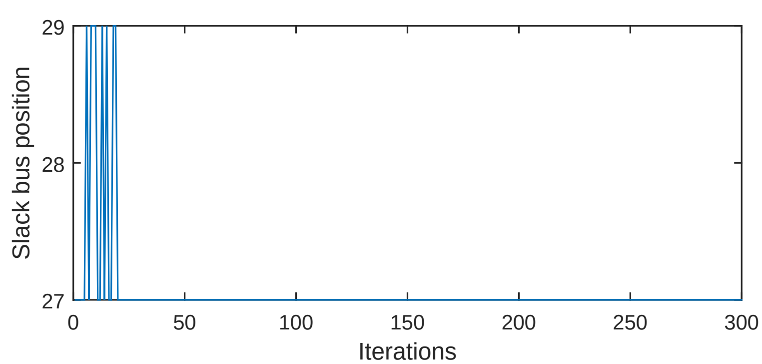


Figure 5.6: Shuffling of slack bus position in part-II of 38 bus ADS

Hence LMP value of each DG unit for outage of line 3 or 4 is equal to market price of 32.38 $/MWh.

- For the outage of remaining lines such as 1, 6 and 14, the EENS value by the proposed method is low compared to base case. This is due to the presence of DG units in part-II of network and LMP values of these DG units are based contribution on EENS reduction and fuel cost coefficients.

- LMP of DG3 for outage of line 6 and, DG1, DG2, DG3 and DG4 for outage of line 14 is equal to the market price of 32.38 $/MWh as these units are located in part-I of network.

Table 5.11: LMP values for different line outages in 38 bus ADS

			LMP in $/MWh						HGDA	Basecase
Line	From	To	DG1	DG2	DG3	DG4	DG5	DG6	EENS(MWh)	EENS(MWh)
1	1	2	601**	601**	550**	520**	520**	550**	73.6	371.5
3	19	20	32.38*	32.38*	32.38*	32.38*	32.38*	32.38*	27	27
4	20	21	32.38*	32.38*	32.38*	32.38*	32.38*	32.38*	18	18
6	2	3	601**	601**	32.38*	520**	520**	550**	76.9	325.5
14	6	26	32.38*	32.38*	32.38*	32.38*	457.54**	543.14**	0	92

* DG in part-I ** DG in part-II

Table 5.12 presents active power generation of each DG unit for different line outages and at equal priorities among objectives.

As shown in Table 5.12,

- All DG units in part-I of network due to the outage of any line generate active power such that the owners will receive maximum profit at the market price of 32.38$/MWh.

- All DG units in part-II of the network due to outage of either line 1 or 6 dispatch maximum capacity as the total load in part-II of the network is more than generation.

- DG units in part-II of network due to outage of line 14 such as DG5 and DG6 generate 43.75MW and 49.35MW respectively based on DISCO's priority on DISCO's investment in purchasing power from DG owners, emission and loss of part-II network.

- The EENS value for each type of customers is the same as base case in case of no DG in part-II of network; otherwise the EENS value for each type of customers is lower than base case values as DG units supply load in part-II of network.

Table 5.13 presents DISCO's investment to purchase power from DG owners and grid, emission and active power loss in part-I and part-II of network for different line outages and

Table 5.12: DG units active power generation for different line outages in 38 bus ADS

Line	Generation in MW						HGDA			Base case		
	DG1	DG2	DG3	DG4	DG5	DG6	$EENS_1$ (MWh)	$EENS_2$ (MWh)	$EENS_3$ (MWh)	$EENS_1$ (MWh)	$EENS_2$ (MWh)	$EENS_3$ (MWh)
1	50	50	50	50	50	50	30.9	42.7	0	88	232.5	51
3	0.981	0.981	1.17	1.24	1.24	1.17	9	9	9	9	9	9
4	0.981	0.981	1.17	1.24	1.24	1.17	9	0	9	9	0	9
6	50	50	1.17	50	50	50	0.886	71.45	4.58	60	223.5	42
14	0.981	0.981	1.17	1.24	43.75	49.35	0	0	0	36	50	6

equal priorities among stated objectives. The values of $DISCO_{inv}^{part-I}$ and $Emis^{part-I}$ are obtained based on the amount of power purchased from grid and DG owners. However $DISCO_{inv}^{part-II}$ and $Emis^{part-II}$ are computed based on power purchased from DG owners only.

As shown in Table 5.13

- The values of DISCO's investment, emission and loss in part-I of network are zero as no load exists in part-I of network while considering line 1 as an outage line.
- DISCO's investment, emission and loss values are zero in part-II of the network for outage of line 3 or 4 as no DG exists in part-II of network.

Table 5.13: DISCO's investment, emission and active power loss for different line outages in 38 bus ADS

	Part-I of network			Part-II of network		
Line	$DISCO_{inv}^{part-I}$ (\$)	$Emis^{part-I}$ (kg)	$Loss^{part-I}$ (kW)	$DISCO_{inv}^{part-II}$ (\$)	$Emis^{part-II}$ (kg)	$Loss^{part-II}$ (kW)
1	0	0	0	167100	180396.2	2099.1
3	11154.97	332446.1	17348	0	0	0
4	11446.4	341197.8	17407	0	0	0
6	1489.58	44153.24	127.92	139600	156544.2	1410.8
14	9050.27	270249	7053.2	46824	50922	1106.7

Table 5.14 shows a comparison of the proposed method with GA, DA and uniform price method in terms of EENS value for outage of line between buses 5 and 6.

As shown in Table 5.14,

- The proposed method provides least EENS value in comparison with other methods.
- The proposed method effectively improves reliability of network by providing proper incentives to DG units in terms of LMP.

Table 5.14: Comparison of reliability in 38 bus ADS for line outage between bus 5 and bus 6

	EENS in kWh				
	HGDA	GA [105]	DA [106]	Uniform Price Method [3]	Base Case
EENS (kWh)	56399.7	56489.6	56421.3	202110	205500
Time (Sec)	317	240	150	–	–

Table 5.15 shows a comparison of the proposed method with GA, DA and uniform pricing method by considering line outage between buses 6 and 26.

As shown in Table 5.15,

- the proposed method, GA and DA provide better results compared to uniform pricing method in terms of EENS value.
- As all iterative methods have the same EENS value, the effectiveness of the proposed method has been compared with objective function value.
- The proposed method provides better objective function value compared to GA and DA.

Table 5.15: Comparison of objective function values and EENS in 38 bus ADS for line outage between buses 6 and 26

	HGDA	GA [105]	DA [106]	Uniform Price Method [3]	Base case
Objective Function Value	0.75369	0.75493	0.75432	0.00854	0
EENS (kWh)	0	0	0	89590	92000
Time (Sec)	148	118	99.6	—	—

Figure 5.7 presents the comparison between convergence characteristics of HGDA, DA and GA.

As shown in Figure 5.7,

- GA takes more number of iterations to converge, and gives minimum value of objective function at 300^{th} iteration. It can be inferred that there is no guarantee that this solution is close to global solution.
- DA converges at around 230^{th} iteration. It shows that DA is converging at fewer number of iterations compared to GA.
- As HGDA is hybridization of GA and DA, the number of iterations taken by HGDA to converge is between GA and DA.

- As HGDA has good local and global searching capability, it provides better solution close to global as compared to DA and GA.

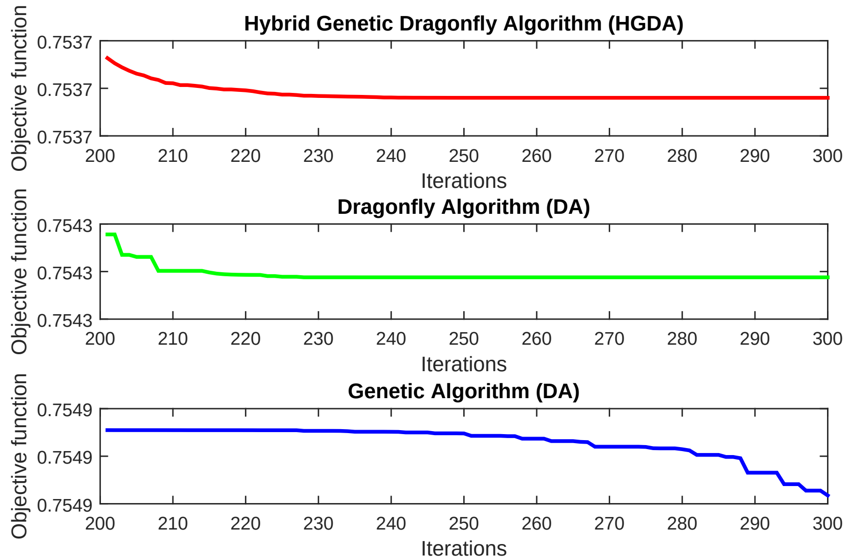


Figure 5.7: Convergence characteristics of HGDA, DA and GA in 38 bus ADS

5.3.2 Case study-2:

The proposed HGDA based OPF has been implemented on Pacific Gas and Electric Company (PG & E) 69 bus ADS shown in Figure C.1 in Appendix-C to verify the performance. The line data and bus data of PG&E 69 bus ADS as shown in Table C.1 in Appendix-C is drawn from [7]. It is assumed that all DG units have the capacity of 1MW at 0.9 lagging power factor. The location and type of each DG is shown in Table 5.16. In this study, the market price for active power generation is considered as 21.59 $/MWh.

Table 5.16: Type and Location of DG units in PG & E 69 bus ADS

DG unit	Type	Location	Engine type
DG1	1	61	Combined cycle gas turbines
DG2	2	53	Gas internal combustion engines
DG3	3	11	Diesel internal combustion engines

5.3.2.1 Load scheduling

The performance of the proposed method during load scheduling on PG & E 69 bus ADS has been observed by considering the line between buses 3 and 4 as an outage line. The results in terms of EENS, generation and LMP values are presented in Table 5.17.

As shown in Table 5.17,

- EENS value for each type of load is changed based on a combination of priorities (in terms of weights ω_1, ω_2 and ω_3) considered.
- EENS value of any type of load is reduced to zero by keeping priority 1 (high priority) for that type of load.
- A small change in overall EENS value at different weight combinations is unavoidable even though generation remains constant, and this is due to variation in active power losses in network.
- As the total load in part-II of network is more than available generation, all three DG units injecting power into the network up to maximum capacity of 1 MW and the corresponding LMP values are 32.6 \$/MWh, 30.6 \$/MWh and 30 \$/MWh respectively. These LMP values have been computed such that DG owners receive maximum profit for generating 1 MW active power.

Table 5.17: Impact of ω_1, ω_2 and ω_3 on EENS, DG units generation and LMP in PG&E 69 bus ADS

ω_1	ω_2	ω_3	EENSR	EENSC	EENSI	EENS	Generation in kW DG1	Generation in kW DG2	Generation in kW DG3	LMP in \$/MWh DG1	LMP in \$/MWh DG2	LMP in \$/MWh DG3
1	0	0	0	0.09	0.46	0.55	1000			32.6	30.6	30
0.6	0.3	0.1	0	0	0.55	0.55						
0.3	0.1	0.6	0	0.5	0.19	0.69						
0.1	0.3	0.6	0.56	0	0	0.56						
0	0	1	0.4	0.47	0	0.87						
0	1	0	0.02	0	0.53	0.55						

DG unit generation, LMP and EENS for different line outages are presented in Table 5.18 by considering equal priorities among objectives.

As shown in Table 5.18,

- While considering either line 1 or line 2 as an outage line, all DG units injecting power into the system up to a maximum capacity of 1000 kW have been considered. It is due to excess load over the available generation in part-II of network.

- LMP values for DG1, DG2 and DG3 that correspond to 1000 kW generation are 32.6 \$/MWh, 30.6 \$/MWh and 30 \$/MWh respectively.
- While considering line 8 as an outage line, DG2 and DG3 generations have been curtailed as available generation is more than load in part-II of network.
- While considering line 52 as an outage line, DG2 generation has been curtailed.
- These generation curtailments are based on priorities considered among DISCO's investment, emission and active power loss.
- DG1 is injecting up to a maximum capacity of 1000 kW as local load which is more than DG unit capacity.
- While considering line 52 as an outage line, DG3 is located in part-I of network and it does not have any contribution in reliability improvement. Hence there is no incentive given to DG3 over market price of 21.59 \$/MWh.
- For all tested outages the proposed method improves the reliability of network by decreasing the EENS value.

Table 5.18: DG units generation, LMP and EENS at different line outages in PG&E 69 bus ADS

Line	From	To	Generation in kW			LMP in \$/MWh			$EENS_l$	$EENS^l_{base}$
			DG1	DG2	DG3	DG1	DG2	DG3	(kWh)	(kWh)
1	1	2	1000**	1000**	1000**	32.6**	30.6**	30**	823.06	3802.29
2	2	3	1000**	1000**	1000**	32.6**	30.6**	30**	822.71	3802.29
8	8	9	1000**	884.3**	663.1**	32.6**	29.4**	26.6**	0	2514.65
52	9	53	1000**	737.8387**	159*	32.6**	27.82**	21.59*	0	1717.15

* DG in part-I of network ** DG in part-II of network

DISCO's investment to purchase power from grid and DG owners, emissions and active power losses for various outages by considering equal priorities among objectives are presented in Table 5.19.

As shown in Table 5.19,

- DISCO's investment to purchase power from grid, emissions and active power losses are zero while considering line 1 or line 2 as an outage line. This is due to absence of load in part-I of network.

Table 5.19: DISCO's investment, emission and active power loss at different outages in PG&E 69 bus ADS

	Part-I of network			Part-II of network		
Line	$DISCO_{inv}^{part-I}$ (\$)	$Emis^{part-I}$ (kg)	$Loss^{part-I}$ (kW)	$DISCO_{inv}^{part-II}$ (\$)	$Emis^{part-II}$ (kg)	$Loss^{part-II}$ (kW)
1	0	0	0	93.2	1803.96	21.27
2	0	0	0	93.2	1803.96	20.92
8	54.35	2447.9	2.718	76.2	1517.9	33.18
52	37.47	1632.7	18.46	53.13	1152.6	21.19

- DISCO's investment and emission in part-I of network are computed based on load at substation bus and DG units generation. However these parameters computed in part-II of network are based on DG units generation only.

5.3.2.2 Generation Scheduling

The performance of the proposed method during generation scheduling has been observed by considering the line between buses 4 and 5 as an outage line. Impact of weights ω_{inv}, ω_{emis} and ω_{los} on DG units generation, LMP, DISCO's investment to purchase power from DG owners, emission released from network and network active power losses have been presented in Table 5.20.

As shown in Table 5.20,

- As increasing the weight corresponds to emission reduction ω_{emis}, generation and LMP values of the low emission coefficient generator DG2 increases. This means that low emission coefficient generators receive more incentive from DISCO as and when DISCO increases priority to emission reduction is achieved by increasing ω_{emis}. This further results in reduction of network emission.

- The DG1 is placed at bus 61 where the total load is 1244 kW, more than the local DG unit (DG1) capacity. Hence DG1 injects power into the network up to its rated capacity. Hence generation of DG1 at each combination of weights is equal to 1000 kW and the corresponding LMP value is 32.60 \$/MWh.

DG3 is responsible for both loss reduction and DISCO's investment cost reduction due to its low cost coefficients. Hence DG3 generation and LMP, network active power loss and

Table 5.20: Impact of weights ω_{inv}, ω_{emis} and ω_{los} on DG units generation, LMP, DISCO's investment, emission and loss in PG & E 69 bus ADS

ω_{inv}	ω_{emis}	ω_{los}	Generation (kW)			LMP ($/MWh)			$DISCO_{inv}^{part-II}$	$Emis^{part-II}$	$Loss^{part-II}$
			DG1	DG2	DG3	DG1	DG2	DG3	($)	(kg)	(kW)
0	1	0	1000	1000	709.5	32.6	30.6	27.1	82.43	1622	33.29
0.6	0.3	0.1	1000	918.4	791	32.6	29.74	27.91	81.98	1634	33.11
0.3	0.1	0.6	1000	875.9	833.4	32.6	29.28	28.33	81.86	1641	33.06
0	0	1	1000	835.3	874.7	32.6	28.85	28.75	81.83	1647	33.04
1	0	0	1000	828	881.3	32.6	28.78	28.81	81.82	1648	33.04

DISCO's investment cost vary based on net weight that corresponds to both loss reduction and investment cost reduction. Net weight (ω_{net}) is equal to the sum of weights corresponding to active power loss reduction and DISCO's investment cost reduction. Table 5.21 presents impact of ω_{net} on DG3 generation, LMP, DISCO's investment and loss in PG & E 69 bus ADS.

As shown in Table 5.21,

- As DG3 generation and LMP values increase, the active power loss of network and DISCO's investment cost decrease with ω_{net}

Table 5.21: Impact of weights ω_{net} on DG3 generation, LMP, DISCO's investment and loss in PG & E 69 bus ADS

ω_{inv}	ω_{los}	ω_{net}	$DISCO_{inv}^{part-II}$ ($)	$Loss^{part-II}$ (kW)	Generation (kW)	LMP ($/MWh)
0	0	0	82.43	33.29	709.5	27.1
0.6	0.1	0.7	81.98	33.11	791	27.91
0.3	0.6	0.9	81.86	33.06	833.4	28.33
0	1	1	81.83	33.04	874.7	28.75
1	0	1	81.82	33.04	881.3	28.81

Table 5.22: Comparison of proposed HGDA based OPF method with other methods on PG&E 69 bus ADS

Scheduling	Parameters	Proposed Method	DA [106]	GA [105]	Uniform price method [3]	Base case
Generation	objective function	0.6450146	0.6450147	0.6451	0.18393	0
	EENS (kWh)	0	0	0	2316.95	2676.75
Load	objective function	0.0818	0.08991	0.11236	0.20232	0.999
	EENS (kWh)	550.5	550.8	551.2	3165.2	3525.15

The proposed method has been compared in terms of objective function value and EENS with some meta heuristic techniques existing in literature, like GA [105], DA [106] and conventional method to compute LMP in ADS such as uniform Price Method [3] in order to demonstrate accuracy and validity. Comparison of the proposed method with other methods has been presented in Table 5.22.

As shown in Table 5.22,
For generation scheduling,

- Uniform price method provides least objective function value but it has more EENS value which is not acceptable from a reliability point of view.
- The proposed method provides minimum objective function value compared to GA [105] and DA [106].
- The proposed method provides EENS value which is the same as GA [105] and DA [106] for generation scheduling as available generation is more than load in part-II of network.
- The objective function value in base case is zero as no generation is available in part-II of network.

For generation scheduling,

- the proposed method provides least EENS value and objective function value in comparison with GA [105], DA [106] and uniform Price Method [3].

5.4 Summary

In this chapter, a hybrid genetic dragonfly algorithm (HGDA) based optimal power flow (OPF) is presented to compute LMP at each DG bus for reliability improvement. The proposed method enables DISCO to improve system reliability by controlling the private DG owners using financial incentives in terms of LMP. This method has been developed based on the assumption that there is no control on DG units located in part-II of network under outage. So this method is developed to specify financial incentives to encourage private DG owners in part-II of network to operate in such a way that reliability is improved. This method can estimate LMP values at any hour of day and at any line outage. It has been formulated by incorporating voltage limits, line flow limits, generation and load limits. The results show that DG units which have an impact on reliability improvement receive better incentives than the market price. This method also provides information on emissions, losses and DISCO's investment to purchase power from grid and DG owners. This method can estimate state of part-I of network in terms of voltage magnitude and active power losses.

In this chapter, the hybridization of the GA and DA for improved results has been implemented for the first time. This process uses the advantages of both methods and provides better results in comparison with individual method. The computation of LMP at DG buses for improving the reliability of the system has been considered for the first time in this study.

As integration of DG units in distribution network is bound to increase in future, this work can contribute significantly to the problems related to planning and operation of ADS

Chapter 6

Computation of Probabilistic Locational Marginal Price at DG buses in active distribution system based on Active Power Loss Reduction

Chapter 6

Computation of Probabilistic Locational Marginal Price at DG buses in active distribution system based on Active Power Loss Reduction

6.1 Introduction

In practice, active power load and market price at each hour of the day is uncertain in nature. DISCO's Decision Maker (DM) provides LMPs to DG units which are less sensitive to uncertainty that exist in market and load. To fulfill this requirement of DM, LMP computation mechanism which can handle uncertainty in load and market price is required. In literature many uncertainty handling techniques are available as shown below.

- Monte Carlo Simulation (MCS)
- Analytical Methods
- Approximation Methods

Monte Carlo simulation (MCS) method [108] randomly generates a huge number of samples for uncertain input variables like load and market price. Later, these samples are used to solve the deterministic problem. This technique has been widely used in power system analysis to handle the uncertainty that exists in random input variables. The main shortcomings of MCS is the great number of simulations required to attain convergence. However, it uses deterministic routines to solve the problem in each simulation.

Analytical methods like multilinear model has been used for handling the non linearity existing in the network [146, 147]. Convolution techniques are used to obtain a mathematical description of the behavior of output random variables. The Fast Fourier Transform (FFT) is used for probabilistic load flow solution in [148]. The cumulant method is used to solve the probabilistic power flow in [148]. Later this cumulant method is combined with Gram–Charlier expansion for estimating the probability functions of output random variables [149]. Stochastic power flow has been developed in [150]. In this power flow study cumulant and Von Mises functions combined to handle discrete distributions. The fuzzy load flow presented in [151] and methods which combine analytical techniques and Monte Carlo simulation [152], [153] may be pointed out as well. From a computation point of view, all these analytical methods are more effective. However these methods require some mathematical assumptions in order to simplify the problem.

Approximate methods give an approximate description of the probabilistic properties of output random variables. Most popularly used approximation methods are First-Order Second-Moment Method (FOSMM) [154] and point estimate methods. Point Estimation Method (PEM) has some benefits over remaining uncertainty handling techniques like:

- PEM uses deterministic routines for solving probabilistic problem. However PEM takes very low computational time in comparison with MCS
- PEM overcomes the difficulties associated with the lack of perfect knowledge of the probability functions of random input variables
- The probability functions of random input variables are approximated using only the first few statistical moments of those variables like mean, variance, skewness, and kurtosis
- Smaller level of data information of input variables are sufficient

In this chapter, Probabilistic Locational Marginal Price (PLMP) has been computed at each DG bus based on DG unit's contribution on Active Power Loss Reduction (APLR). 2m+1 scheme of point estimation method (2m+1:PEM) has been used to handle uncertainty that exists in load and market price. PNT based iterative method which was developed in chapter 3 was used as deterministic routine. The effectiveness and robustness of the proposed probabilistic approach is observed by comparing with other probabilistic approaches like MCS and 2m scheme of Point Estimation Method (2m:PEM). The performance of the proposed deterministic routine has been studied by comparing it with other deterministic routines like shapley value based iterative method (SVIM) [3] and Marginal Loss method (MLM) [93]. The proposed probabilistic and deterministic approaches have been implemented on test systems like 84 bus TPC distribution system and PG & E 69 bus distribution system.

The original contribution of this chapter are as follows:

- LMP, RPP and zero DISCO's extra benefit have been computed using loss sensitivity factors in probabilistic framework
- The proportional nucleolus theory has been used for the first time for allocation of change in APL of network among DG units in probabilistic framework
- 2m+1 scheme of PEM has been used to capture uncertainty

DISCO can use the proposed method in the following ways:

- To maintain fair competition among private DG owners irrespective of uncertainty that exists in load and market price
- To operate the network optimally in terms of APL by handling uncertainties that exist in load and market price
- To estimate the state of network in current and next operating condition in terms of active power losses and DG units generation, which are less sensitive to uncertainties that exist in inputs.
- To encourage DG owner's participation for reducing the APL of distribution network by considering uncertainties that exist in load and market price

6.2 Problem Formulation

The main parts of the proposed method for probabilistic LMP computation are calculation of LMP at DG buses based on DG units contribution in active power loss reduction in deterministic approach and handling the uncertainties that exist in load and market price. PNT based iterative method was developed to compute LMP at DG buses in deterministic approach and Km+1 scheme of point estimation method was used to capture uncertainties in random inputs. PNT based iterative method, Km+1 scheme of point estimation method and combination of these two to compute probabilistic LMP were discussed in this section.

6.2.1 Point Estimation Methods

The main goal of any point estimation method is to compute the moments of a random output variable 'z' which is a function of random input variable i.e z=F($x1, x2, .., xm$). Rosenblueth developed first point estimation method in 1975 [155] for symmetric variables and later it was extended in 1981 [156] for asymmetric variables. Later, many methods were developed based on Rosenblueth's approach. The main differences among these methods are the type of random input variables and the number of evolutions performed.

The number of random input variables involved in realistic power system problems are huge. Hence, point estimation methods proposed in [155,156] and more accurate point estimate methods based on Rosenblueth's approach like [157–159] are not suitable for realistic power system problem as the number of evolutions could be even greater than in MCS. The number of simulations in point estimation method proposed by Harr in [160] and Km scheme of point estimation method proposed by Hong in [161] increases linearly with the number of random input variables. Km+1 scheme of point estimation method (Km+1 PEM) in [107] is to overcome the shortcomings of [161] by adding one more simulation.

6.2.2 Km+1 scheme of Point Estimation Method (Km+1 PEM)

Point estimate methods are developed based on the concentration of random input variables. Concentrations are nothing but statistical information provided by few central moments of problem input variables at K points. By using these points and the function which relates input and output variables, the information about the uncertainty associated with problem output random variables can be obtained.

The concentration of random input variable 'x' is defined as a combination of location of point 'k' ($\rho_{x,k}$) and weight ($\omega_{x,k}$) of that point on probability distribution function (PDF) of random input variable 'x'. The location $\rho_{x,k}$ is k^{th} value of random input variable 'x' at which function F is evaluated. $\omega_{x,k}$ is a weight that represents relative importance to evaluation at $\rho_{x,k}$ on the random output variable.

The function F has been evaluated at 'K' points of random input variable 'x' by considering its value $\rho_{x,k}$ and mean value of remaining random input variables ($\mu_{x1}, \mu_{x2}, .., \mu_{xm}$) in order to estimate the random output variable Z as shown in equation (6.1). The same procedure is repeated for all remaining variables. As per this procedure number of evaluations performed is equal to Km.

$$Z = F(\mu_{x1}, \mu_{x2}, ..\rho_{x,k}, .., \mu_{xm}) \tag{6.1}$$

The variant (or) scheme of Hong's point estimation method proposed in [107] is Km+1 PEM. In Km+1 scheme of point estimation method, one more evaluation has been considered by taking the mean of each random input variable as shown in equation (6.2).

$$Z = F(\mu_{x1}, \mu_{x2}, ..\mu_{x}, .., \mu_{xm}) \tag{6.2}$$

The detailed algorithm for Km+1 scheme of point estimation method (Km+1 PEM) is presented in Algorithm 8

Algorithm 8 Km+1 scheme of Point Estimation Method [107]

Inputs

1: Read number of random input variables (m) and number of points of each variable (K)

2: Read standard deviation (σ_{x1},σ_{x2},..,σ_{xm}) and mean ($\mu_{x1}, \mu_{x2}, .., \mu_{xm}$) of each input variable x = $(x1, x2, .., xm)$

Steps

1: Compute $\lambda_{x,j}$ of input 'x' as shown in equation (6.3)

$$\lambda_{x,j} = \frac{\int_{-\infty}^{\infty}(x-\mu_x)^j f(x)dx}{(\sigma_x)^j} \tag{6.3}$$

where j=1,2,..,2K-1 and f(x) is probability density function of input variable 'x'

2: Compute $\xi_{x,k}$ for each random input variable 'x' at each point 'k'. As per the Miller and Rice's procedure [162], the values of $\xi_{x,k}$ are roots of polynomial equation as shown in equation (6.4). Set the value of $\xi_{x,K}$=0.

$$\pi(\xi) = \xi_{x,k}^3 + C_2\xi_{x,k}^2 + C_1\xi_{x,k} + C_0 \tag{6.4}$$

Compute coefficients of polynomial equation (6.4) as below

$$\begin{bmatrix} \frac{1}{m} & 0 & 1 \\ 0 & 1 & \lambda_{x,3} \\ 1 & 0 & \lambda_{x,4} \end{bmatrix} \begin{bmatrix} C_0 \\ C_1 \\ C_2 \end{bmatrix} = - \begin{bmatrix} \lambda_{x,3} \\ \lambda_{x,4} \\ \lambda_{x,5} \end{bmatrix}$$

3: Compute $\omega_{x,k}$ for each k and x using equation (6.5).

$$\omega_{x,k} = \frac{1 + \frac{1}{m}\prod_{i=1\&i\neq k}^{K}\xi_{x,i}}{\prod_{i=1\&i\neq k}^{K}(\xi_{x,i} - \xi_{x,i})} \tag{6.5}$$

4: Compute location value $\rho_{x,k}$ for each input variable 'x' using equation (6.6).

$$\rho_{x,k} = \mu_x + \xi_{x,k}\sigma_x \tag{6.6}$$

5: Using Deterministic approach compute output variable values Z(x,k) using equation (6.7) and j^{th} raw moment of output $E(Z^j)$ using equation (6.8) at all K-1 points of each input variable.

$$Z(x,k) = F(\mu_{x1}, \mu_{x2}, .., \rho_{x,k}, ..\mu_{xm}) \tag{6.7}$$

$$E(Z^j) = \sum_{x\varepsilon(x1,x2,..,xm)} \sum_{k\varepsilon(1,2,..,K-1)} \omega_{x,k} * (Z(x,k))^j \tag{6.8}$$

▷ j=1,2

Algorithm 8 (Continued) Km+1 scheme of Point Estimation Method

6: Compute the output Z using deterministic approach and calculate moments of output variables using equation (6.9)

$$Z(x,K) = F(\mu_{x_1}, \mu_{x_2}, .., \mu_{x_n})$$
$$E(z^j) = E(z^j) + \sum_{x=1}^{m} \omega_{x,3} * (Z(x,K))^j \tag{6.9}$$

▷ j=1,2

7: Stop

6.2.3 Deterministic Approach

The PNT based iterative method developed in Chapter 3 for computing LMP for each DG unit in distribution system based on APLR is considered as deterministic approach. In deterministic approach, it is assumed that load and market price remain constant. The procedure for computing LMP, RPP, APL and DISCO's extra benefit using deterministic approach is presented in Figure 6.1.

6.2.4 Probabilistic Approach

In probabilistic approach both inputs load and market price were considered as random variables. PNT based iterative method and 2m+1:PEM were hybridized to compute LMP, RPP, APL, DISCO's extra benefit and also to capture uncertainty in load and market price simultaneously. The complete procedure for probabilistic approach is presented in Figure 6.2 and Figure 6.3.

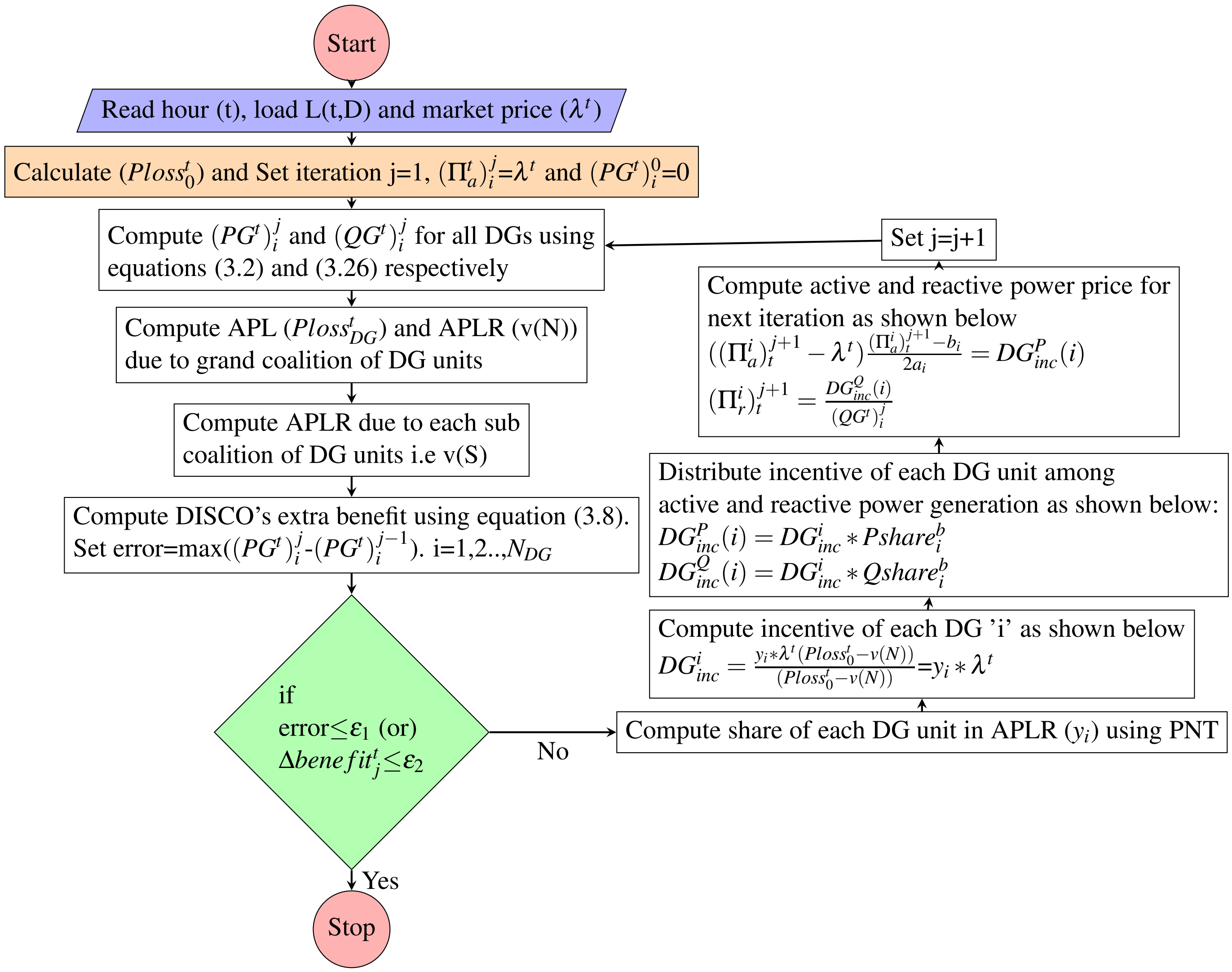


Figure 6.1: Deterministic approach for computation of LMP, RPP, APL and DISCO's extra benefit

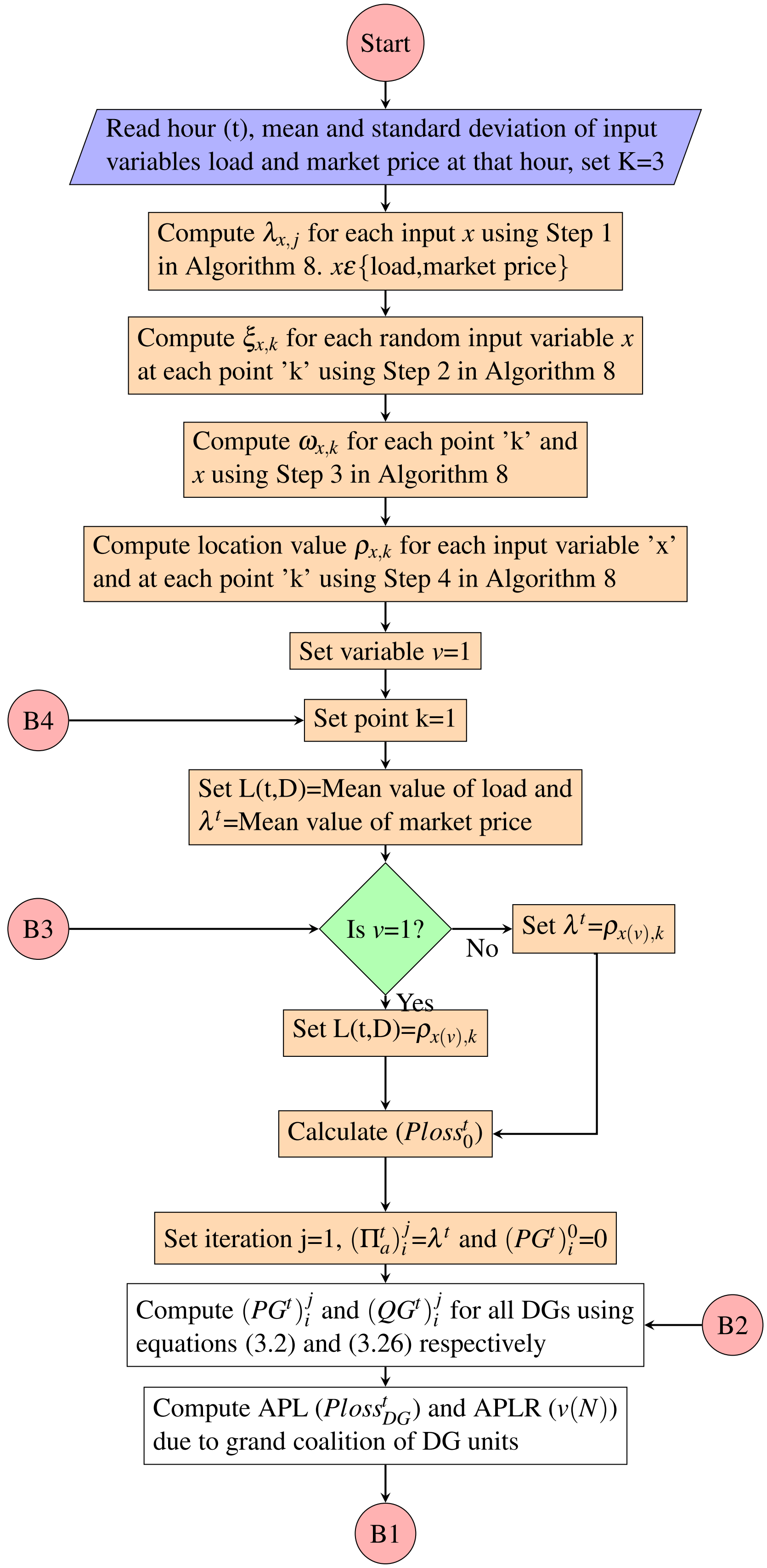


Figure 6.2: Probabilistic approach for computation of LMP, RPP, APL and DISCO's extra benefit

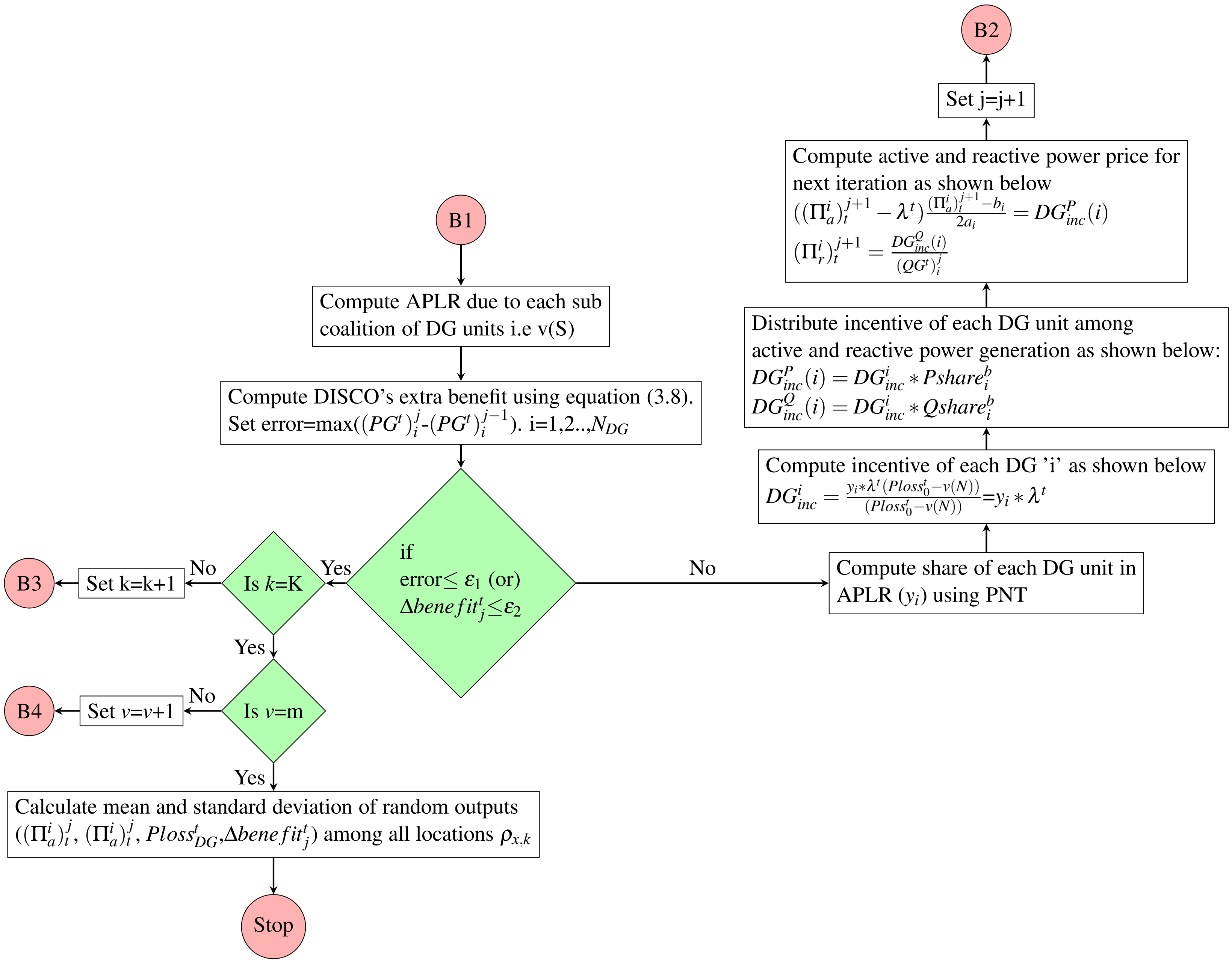


Figure 6.3: Probabilistic approach for computation of LMP, RPP, APL and DISCO's extra benefit cont.

6.3 Analytical Studies

6.3.1 Case Study - 1

The proposed method was implemented on 84 bus Taiwan Power Company (TPC) distribution system shown in Figure A.1 in Appendix-A. Line and bus data information of TPC distribution system has been drawn from [5] and presented in Table G.1 in Appendix-A. It is assumed that 15 DG units of different types with capacity of 1 MW having 0.9 lagging power factor is connected to TPC distribution system as represented in Table 3.4. Complete information about fuel cost coefficients of DG units are taken from [4]. Realistic average load and market price data at each hour of the day has been drawn from [2] and represented in Figure 6.4.

6.3.1.1 Deterministic Approach for 84 bus TPC active distribution system

Figure 6.5a represents LMP values of each DG unit using proposed deterministic approach.

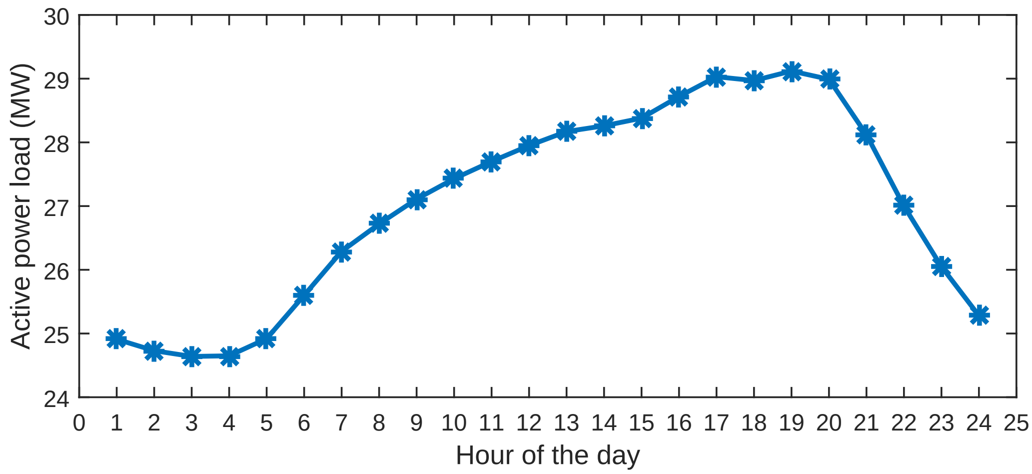
As shown in Figure 6.5a,

- When the market price is 19.29 \$/MWh, no incentive has been provided to DGs over market price. This is due to the inactive state of DG units. DG units are inactive since 'b' coefficients of all DG units are lower than market price.
- When market prices are 21.44 \$/MWh and 26.47 \$/MWh then DG owners receive incentives as LMP is based on DG contribution in APLR.
- DG11 has LMPs of 22.48 \$/MWh and 27.54 \$/MWh when the market prices are 21.44 \$/MWh and 26.47 \$/MWh respectively.
- DG11 receives more incentive as LMP over remaining DG units due to its huge contribution in APLR.
- In this way DISCO can maintain fair competition among DG owners by providing proper financial incentives using proposed method based on units performance in network operation.

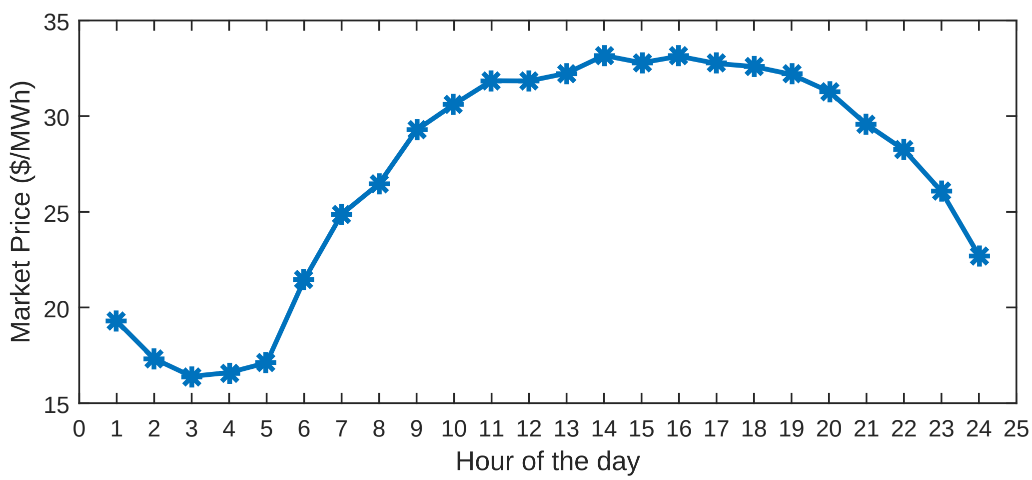
Figure 6.5b presents active power generation of each DG unit at different market prices.

As shown in Figure 6.5b,

- As the market price of 19.29 \$/MWh is less than 'b' coefficient of all DG units, no DG unit is able to generate power.



(a)



(b)

Figure 6.4: (a) Average load curve [2] (b) Average Market Price Curve [2]

- If the market prices are 21.44 \$/MWh and 26.47 \$/MWh then active power generation of DG units depends on LMP values of the DG units received from DISCO. DG units generate active power such that DG owners receive maximum profit at a given LMP.
- DG11 receives more incentives in terms of LMP due to its huge contribution in APLR. This unit will inject more active power into the network in comparison with the remaining DG units.

Figure 6.5c presents RPP of each DG unit at different market prices.

As shown in Figure 6.5b,

- As no DG unit is generating power at market price of 19.29 \$/MWh, RPP of each DG unit is equal to zero.
- The values of RPP of each DG unit at market price of 21.44 \$/MWh and 26.47 \$/MWh depends on the contribution of injected reactive power of that DG unit on APLR.
- As DG11 has more contribution in APLR, it receives more RPP in comparison with the remaining DG units.

Figure 6.6a presents the variation of DISCO's extra benefit with respect to iterations.

As shown in Figure 6.6a,

- The proposed method provides zero extra benefit at each market price which is essential to maintain fair competition among DG owners in deregulated environment.

Figure 6.6b presents variation of APL of network with respect to iterations.

As shown in Figure 6.6b,

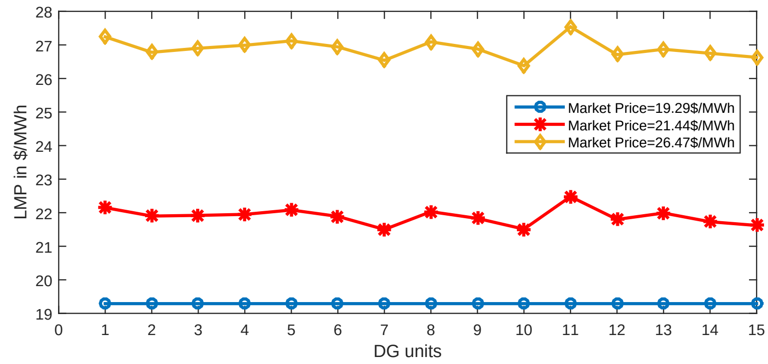
- As the iterations progress, the APL of network decreases. This was due to providing incentives to DG units which have more contribution in APLR.

6.3.1.2 Probabilistic Approach for 84 bus TPC active distribution system

Figure 6.7a shows probabilistic LMP (PLMP) of each DG unit based on its contribution in APLR.

As shown in Figure 6.7a,

- If the market price is 19.29 \$/MWh and is less than 'b' coefficients of all DG units, then no DG unit is able to generate power as there is no incentive provided over market price. Due to this both Deterministic LMP (DLMP) and PLMP values are same and equal to the market price of 19.29 \$/MWh.



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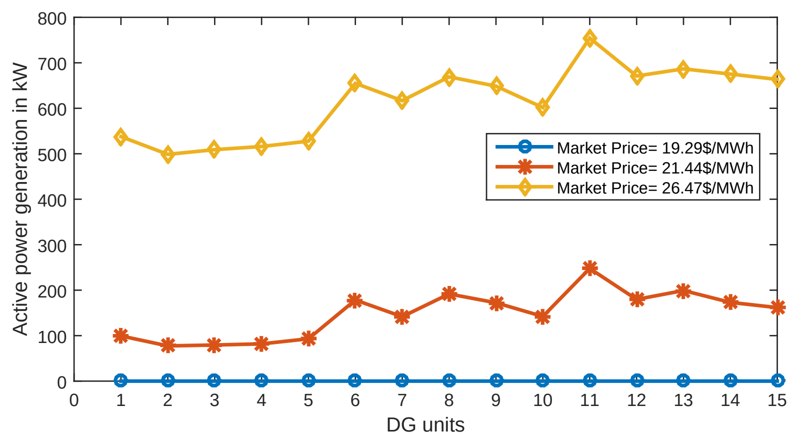

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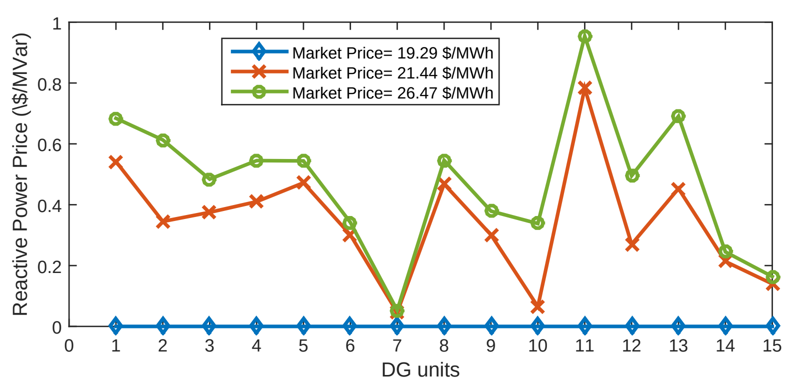

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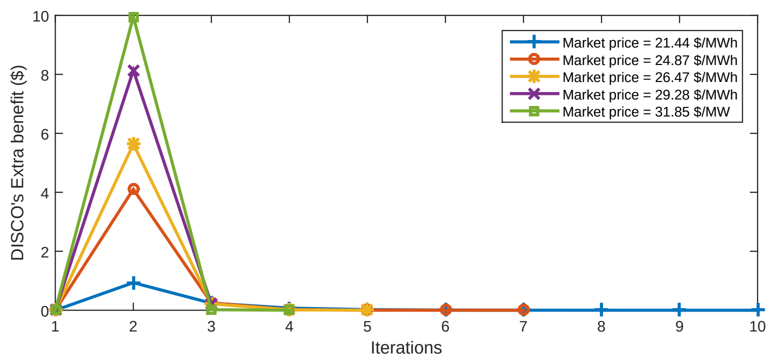
Figure 6.5: (a) Deterministic LMP (DLMP) of each DG unit at different market prices
(b) Deterministic Active Power Generation (DGEN) of each DG unit at different market prices
(c) Deterministic Reactive Power Price (DRPP) of each DG unit at different market prices



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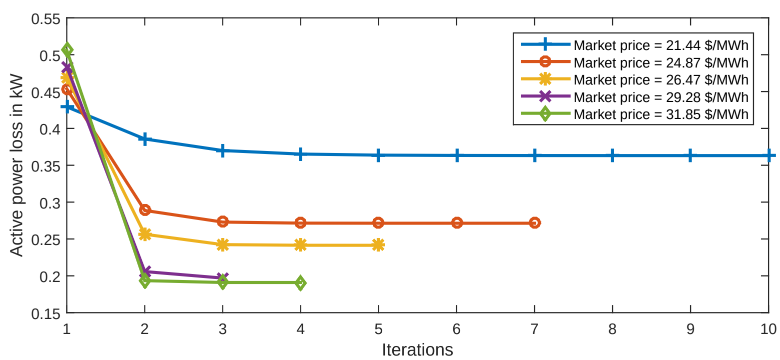


(b)

Figure 6.6: (a) Variation of DISCO's extra benefit with respect to iterations in deterministic approach
(b) Variation of APL of network with respect to iterations in deterministic approach

- At market price of 24.87 \$/MWh and 26.47 \$/MWh, DG units received incentives as PLMP. As DG11 has more impact on APLR, DG11 receives more incentive over market price.

Figure 6.7b shows the probabilistic active power generation (PGEN) of each DG unit.
As shown in Figure 6.7b,

- PGEN and active power generation with deterministic approach (DGEN) are equal to zero at market price 19.29 \$/MWh as market price is less than 'b' coefficients of all DG units.
- At market prices of 24.87 \$/MWh and 26.47 \$/MWh, the values of PGEN depend on how much incentive DG units have received in terms of PLMP. DG11 has more PGEN over remaining DG units as it receives more PLMP.

Figure 6.7c shows probabilistic reactive power price (PRPP) of each DG unit.
As shown in Figure 6.7c,

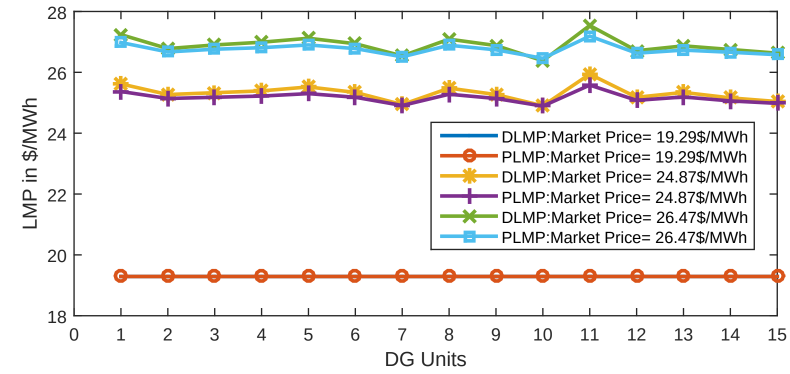
- As active power generation from DG units at market price of 19.29 \$/MWh is zero, PRPP value of each DG unit is equal to the reactive power price at substation bus which is equal to zero.
- At market prices of 24.87 \$/MWh and 26.47 \$/MWh, the PRPP value of each DG unit is based on that DG's reactive power contribution on APLR. As the reactive power of DG11 has more contribution on APLR it receives more PRPP over remaining DGs.

The variation in probabilistic values like PLMP, PGEN and PRPP over deterministic values like DLMP, DGEN and DRPP is mainly due to the capability of probabilistic approach in capturing the uncertainty present in the system.

6.3.1.3 Probabilistic Approach Vs Deterministic Approach for 84 bus TPC active distribution system

Table 6.1 represents the comparison between probabilistic and deterministic approaches in terms of APL.
As shown in Table 6.1,

- APL obtained in probabilistic approach is different in comparison with deterministic approach. This is due to the ability of probabilistic approach to capture the uncertainties that exist in random input variables like load and market price effectively.



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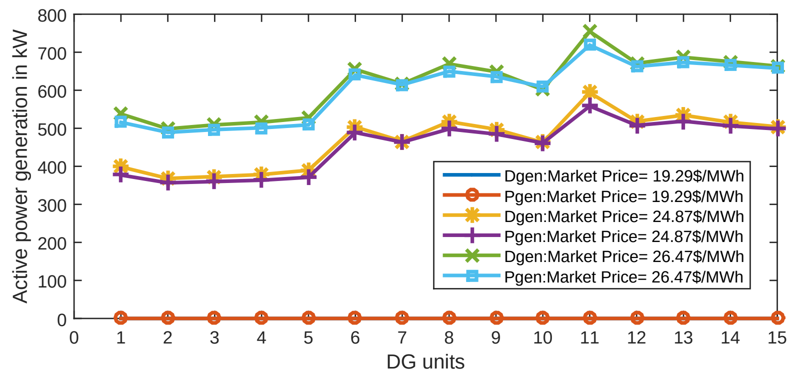

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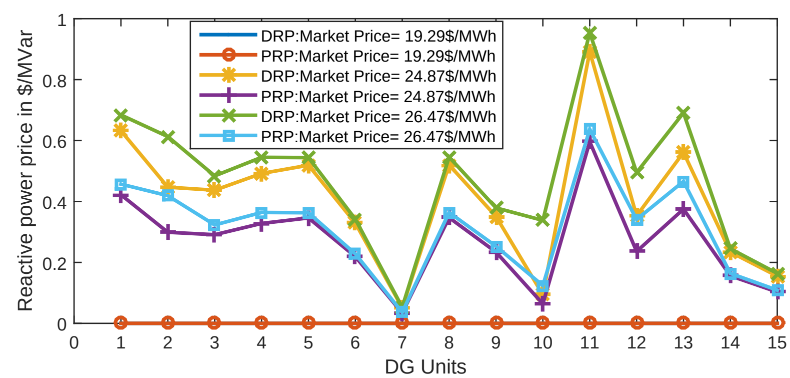


(c)

Figure 6.7: (a) PLMP and DLMP of each DG unit at different market prices for 84 bus TPC active distribution system
(b) PGEN and DGEN of each DG unit at different market prices for 84 bus TPC active distribution system
(c) PRPP and DRPP of each DG unit at different market prices for 84 bus TPC active distribution system

- This variation shows the necessity of probabilistic approach to handle the randomness in load and market price.
- Probabilistic and deterministic approaches provide zero extra benefit from DISCO at all market prices.

Table 6.1: Comparison of deterministic and probabilistic approaches in terms of APL and DISCO's extra benefit for 84 bus TPC active distribution system

Load (MW)	24.91		26.29		26.72	
Market Price	19.29 $/MWh		24.87 $/MWh		26.47 $/MWh	
	Deterministic	Probabilistic	Deterministic	Probabilistic	Deterministic	Probabilistic
loss (kW)	405.5	363.1	271.4	285.50	241.4	269.5
Base loss (kW)	405.5	407.2	453.70	455.8	469.3	471.5
Extra benefit ($/h)	0	0	0	0	0	0

6.3.1.4 Comparative Studies for 84 bus TPC active distribution system

Figure 6.8 shows the comparison of proposed deterministic method with existing methods like Marginal Loss Method (MLM) [93] and shapley value based iterative method (SVIM) [3] using load and price data at 8^{th} hour.

As shown in Figure 6.8,

- The proposed method enables the DISCO to operate the distribution network with less APL in comparison with both MLM and SVIM.
- The proposed method operates the network with 241.4 kW where as SVIM [3] and marginal loss [93] methods operate network with APL of 256.4 kW and 329.6 kW respectively.
- The base case APL is 469.3 kW.

The proposed method was compared with existing methods like MLM [93] and SVIM [3] in terms of APL at different market prices in probabilistic framework. Deterministic approaches MLM and SVIM have been implemented with 2m+1:PEM to capture uncertainty in load and market price.

- From Table 6.2 it has been observed that the proposed probabilistic method operates the network at lower APL in comparison with probabilistic MLM (PMLM) and probabilistic SVIM (PSVIM) at different market prices.

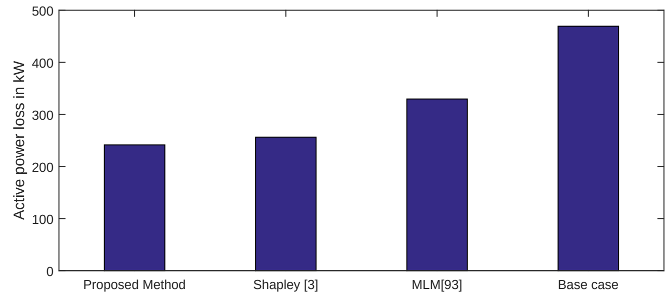


Figure 6.8: Comparison of deterministic approaches for LMP computation based on APL for 84 bus TPC active distribution system

Table 6.2: Comparison in terms of APL between proposed method and existing methods in probabilistic framework for 84 bus TPC active distribution system

Active Power Losses in kW			
Load (MW)	26.29	26.72	27.11
Market Price ($/MWh)	24.87	26.47	29.28
Proposed Method	285.5	269.5	244.6
PSVIM	296.5	279.1	249.3
PMLM	306.4	294.7	277.5
Base	453.7	469.3	598.9

The proposed probabilistic approach has been compared with other probabilistic approaches like MCS and 2m schemes of point estimation method. Table 6.3 presents comparisons among MCS, 2m:PEM and 2m+1:PEM in terms of mean and standard deviation of APL. **As shown in Table 6.3,**

- Monte Carlo Simulation (MCS) method is more accurate and so the results of this method was taken as the bench mark. However MCS take more computational time and requires more data to process. The accuracy of MCS depends on the number of sample (Data) points considered.

- Unlike MCS, PEM takes very low computational time, and fewer data samples to capture uncertainty in random input variables.

- 2m+1:PEM achieves almost the same accuracy as MCS in terms of Mean and Standard Deviation of APL for fewer number of simulations.

- 2m+1:PEM is more accurate than 2m:PEM as the former considers skewness of the input random variable.

- The main drawback of 2m:PEM is that locations are directly varying with the number of random input variables.

Table 6.3: Comparison in terms of APL obtained from proposed method with different probabilistic frameworks for 84 bus TPC active distribution system

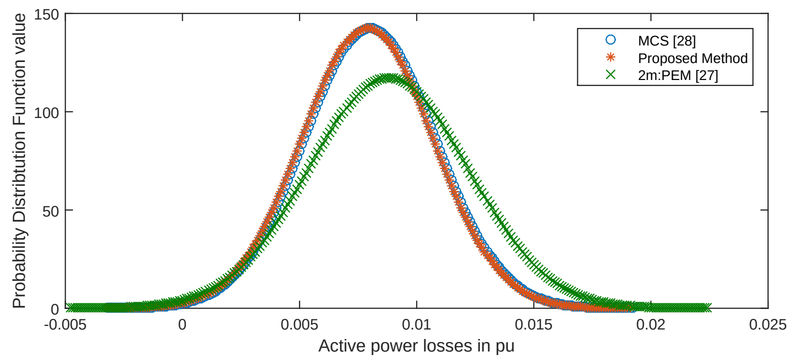
Active Power Losses (pu)									
Market Price	2m:PEM [107]			MCS [108]			2m+1:PEM [107]		
$/MWh	Mean	Std	Avg.Time	Mean	Std	Avg.Time	Mean	Std	Avg.Time
32.24	0.0081	0.0028	68.03sec	0.0075	0.0017	66029.4sec	0.0074	0.0022	784.28sec
32.75	0.0088	0.0034		0.0080	0.0028		0.0079	0.0028	
32.79	0.0083	0.0031		0.0078	0.0020		0.0075	0.0025	
Samples	4			1200			5		

To verify the accuracy of the proposed method, Probability Distribution Function (PDF) curves and Cumulative Distribution Function (CDF) curves of APL obtained from PEMs are compared with MCS using load and market price at 17^{th} hour as shown in Figure 6.9a and Figure 6.9b.

- PDF curve and CDF curve of APL obtained from 2m+1:PEM is matching very closely with that of MCS than 2m:PEM.
- This means that 2m+1:PEM parallels to MCS performance with lower time and fewer sample data.
- PDF curve of APL obtained from 2m:PEM is located a little distance from MCS but not too far, but in case the number of random inputs increases, the deviation will increase.

The sensitivity of the proposed probabilistic approach is verified with respect to standard deviation of input variables as presented in Figure 6.9c. Sensitivity study has been implemented based on load and price data at 11^{th} hour. Standard deviation of both load and market price is varying from 0.75 to 2 times of actual standard deviation in steps of 0.25. The proposed method was simulated at different standard deviations and the cumulative density function (CDF) of APL was obtained. The output of the sensitivity analysis is the cumulative density function of APL.

- It has been observed from Figure 6.9c that changing the standard deviation of the random parameters has very little effect on the estimated value of APL.



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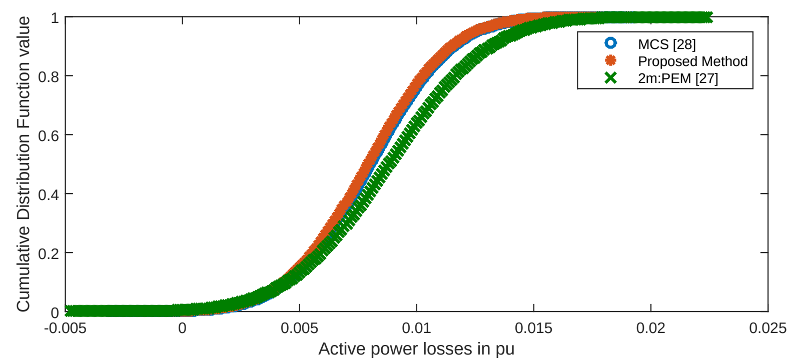

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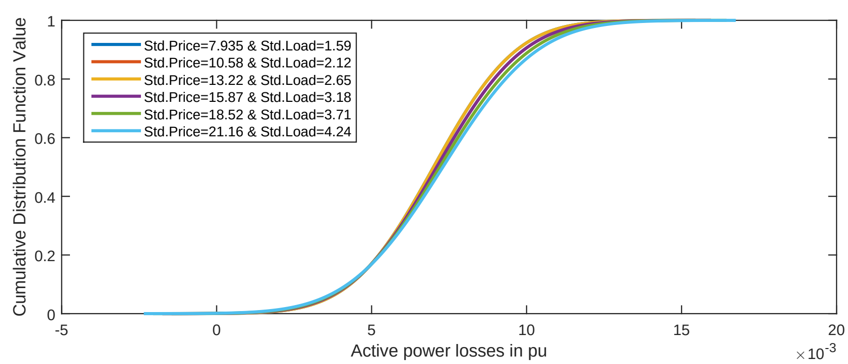


(c)

Figure 6.9: (a) PDF curve of APL for different probabilistic approaches for 84 bus TPC active distribution system
(b) CDF curve of APL for different probabilistic approaches for 84 bus TPC active distribution system
(c) CDF curve of APL at different standard deviation values of load and market price for 84 bus TPC active distribution system

6.3.2 Case Study - 2

The proposed method for probabilistic LMP computation at DG buses was implemented on PG & E 69 bus radial distribution system as shown in Figure A.1 in Appendix-C. Table 3.8 represents the location of 3 DG units of various types operating at 0.9 lagging power factor with 1 MW capacity. The cost coefficients of each type of DG are represented in Table 3.4. The proposed method has been simulated under MATLAB [121] environment on realistic price and load data drawn from [2] and presented in Figure 3.9. The PG & E 69 bus radial distribution system data captured from [7] and presented in Table C.1 in Appendix-C.

6.3.2.1 Probabilistic Approach for PG & E 69 bus active distribution system

Figure 6.10a shows probabilistic LMP (PLMP) of each DG unit in PG & E 69 bus active distribution system based on its contribution in APLR.

- If the market price is 19.29 \$/MWh and is lower than 'b' coefficients of all DG units, then no DG unit is able to generate the power as there is no incentive provided over market price. Due to this, both Deterministic LMP (DLMP) and PLMP values are the same and equal to market price of 19.29 \$/MWh.
- At market prices of 21.44 \$/MWh, 24.87 \$/MWh, 26.07 \$/MWh, 26.47 \$/MWh and 28.24 \$/MWh, DG units received incentives as PLMP. As DG1 has more impact on APLR, it receives more incentive over market price.

Figure 6.10b shows probabilistic active power generation (PGEN) of each DG unit.

- If the market price is less than 'b' coefficients of all DG units, then both PGEN and active power generation with deterministic approach (DGEN) are equal to zero.
- At market prices of 21.44 \$/MWh, 24.87 \$/MWh, 26.07 \$/MWh, 26.47 \$/MWh and 28.24 \$/MWh, the values of PGEN depend on how much incentive DG units received in terms of PLMP and fuel cost coefficients.

Figure 6.10c shows probabilistic reactive power price (PRPP) of each DG unit.

- If the market price is less than 'b' coefficients of all DG units, then both PRPP and reactive power price with deterministic approach (DRPP) are the same as reactive power price at substation bus which is equal to zero.

- At market prices 21.44 \$/MWh, 24.87 \$/MWh, 26.07 \$/MWh, 26.47 \$/MWh and 28.24 \$/MWh, PRPP value of each DG unit is based on that DG's reactive power contribution on APLR.

The variation in probabilistic values like PLMP, PGEN and PRPP over deterministic values like DLMP, DGEN and DRPP is mainly due to the capability of probabilistic approach in capturing the uncertainty present in the system.

6.3.2.2 Probabilistic Approach Vs Deterministic Approach for PG & E 69 bus active distribution system

Table 6.4 represents the comparison between probabilistic and deterministic approaches in terms of APL for PG & E 69 bus active distribution system.

- APL obtained in probabilistic approach is different in comparison with deterministic approach. This is due to the ability of the probabilistic approach to capture the uncertainties that exist in random input variables like load and market price effectively.

- This variation shows the necessity of probabilistic approach to handle the randomness in load and market price. However both probabilistic and deterministic approaches provide zero DISCO's extra benefit at all market prices.

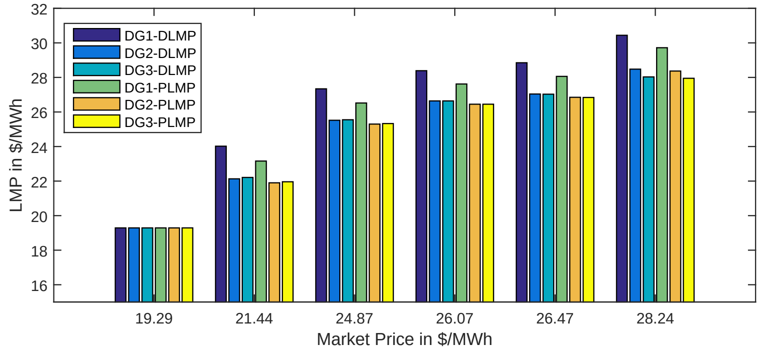
Table 6.4: Comparison of deterministic and probabilistic approaches in terms of APL and DISCO's extra benefit for PG & E 69 bus active distribution system

Load (MW)	3.34		3.53		3.58	
Market Price	19.29 \$/MWh		24.87 \$/MWh		26.47 \$/MWh	
	Deterministic	Probabilistic	Deterministic	Probabilistic	Deterministic	Probabilistic
loss (kW)	169.8	146.3	69.4	83.5	54.8	75.0
Base loss (kW)	169.8	169.8	191.4	192.4	197.3	198.4
Extra benefit (\$/h)	0	0	0	0	0	0

6.3.2.3 Comparative Studies for PG & E 69 bus active distribution system

Figure 6.11 shows the comparison of the proposed deterministic method with existing methods like Marginal Loss Method (MLM) [93] and shapley value based iterative method (SVIM) [3] using load and price data at 8^{th} hour.

- The proposed method enables DISCO to operate the distribution network with low APL in comparison with both MLM and SVIM.



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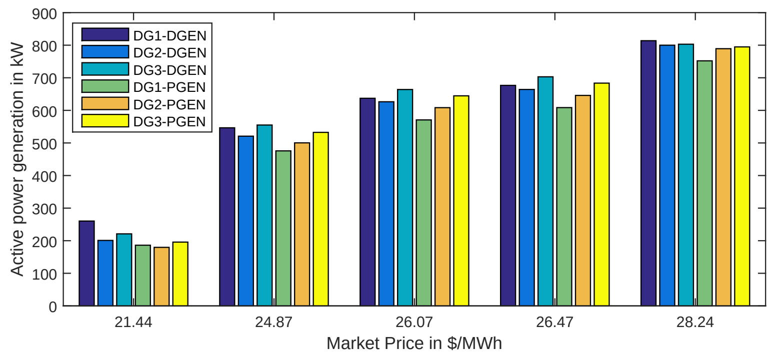

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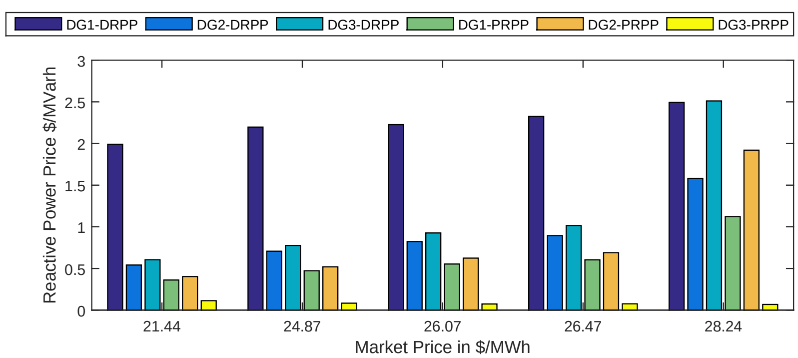

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Figure 6.10: (a) PLMP and DLMP of each DG unit at different market prices for PG & E 69 bus active distribution system
(b) PGEN and DGEN of each DG unit at different market prices for PG & E 69 bus active distribution system
(c) PRPP and DRPP of each DG unit at different market prices for PG & E 69 bus active distribution system

- The proposed method operates the network with 0.075 MW whereas SVIM [3] and marginal loss [93] methods operates network with APL of 0.0774 MW and 0.0995 MW respectively. However, the base case APL is 0.197 MW.

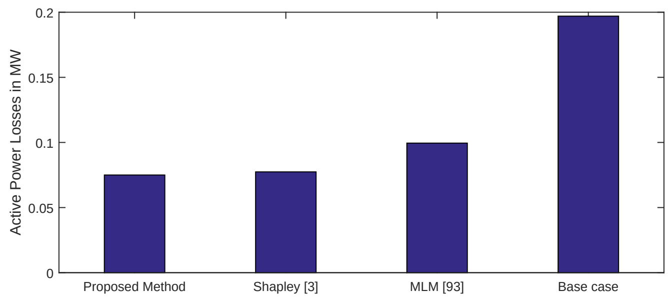

Figure 6.11: Comparison of deterministic approaches for LMP computation based on APL for PG & E 69 bus active distribution system

The proposed method has compared with existing methods like MLM [93] and SVIM [3] in terms of APL at different market prices in a probabilistic framework. Deterministic approaches MLM and SVIM have been implemented with 2m+1:PEM to capture uncertainty in load and market price. From the Table 6.5 it has been observed that

- The proposed probabilistic method operates the network at less APL in comparison with probabilistic MLM (PMLM) and probabilistic SVIM (PSVIM) at different market prices.

Table 6.5: Comparison in terms of APL between proposed method and existing methods in probabilistic framework for PG & E 69 bus active distribution system

Active Power Losses in MW			
Load (MW)	3.43	3.53	3.58
Market Price ($/MWh)	21.44	24.87	26.47
Proposed Method	0.113	0.0835	0.075
PSVIM	0.141	0.1028	0.0904
PMLM	0.116	0.0898	0.0776
Base	0.181	0.191	0.197

The proposed probabilistic approach has been compared with other probabilistic approaches like MCS and 2m schemes of point estimation method. Figure 6.12 presents comparisons among MCS, 2m:PEM and 2m+1:PEM in terms of mean of APL.

- Monte Carlo Simulation (MCS) method is more accurate and thus the results of this method were considered as bench mark. However MCS take more computational time and requires more data to process. Accuracy of MCS depends on the number of sample (Data) points considered.

- Unlike MCS, PEM takes very low computational time, and few data samples to capture uncertainty in random input variables.
- 2m+1:PEM achieve almost the same accuracy as MCS has in terms of mean of APL at less number of simulations.
- 2m+1:PEM is more accurate than 2m:PEM as former one consider skewness of the input random variable.
- The main drawback of 2m:PEM is that the locations directly vary with the number of random input variables.
- MCS takes 2116.8 sec computation time for 1200 samples whereas 2m:PEM and proposed method with 2m+1:PEM takes 3.633 sec and 5.067 sec respectively.

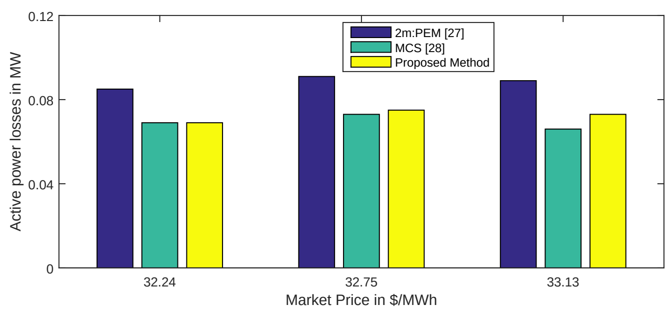

Figure 6.12: Comparison of probabilistic approaches for LMP computation based on APL for PG & E 69 bus active distribution system

The sensitivity of proposed probabilistic approach is verified with respect to standard deviation of input variables. Sensitivity study has been implemented based on load and price data at 11^{th} hour. Standard deviation of both load and market price is varying from 0.75 to 2 times of actual standard deviation in steps of 0.25. The proposed method was simulated at all different standard deviations and cumulative density function (CDF) and probability density function (PDF) curves of APL were drawn. The sensitivity analysis of proposed probabilistic approach is observed in terms of CDF and PDF values of APL.

- It has been observed from Figure 6.13 and Figure 6.14 that changing the standard deviation of the random parameters has very little effect on the estimated value of APL.

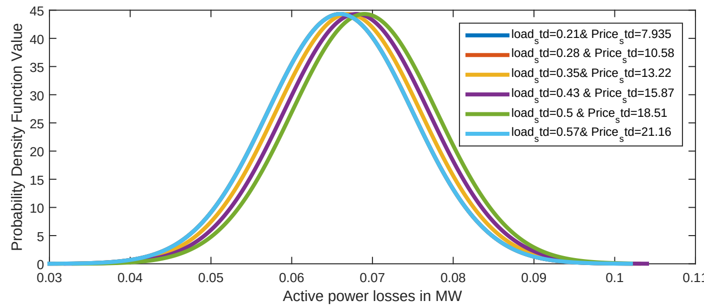

Figure 6.13: Sensitivity of proposed method in terms of PDF values for PG & E 69 bus active distribution system

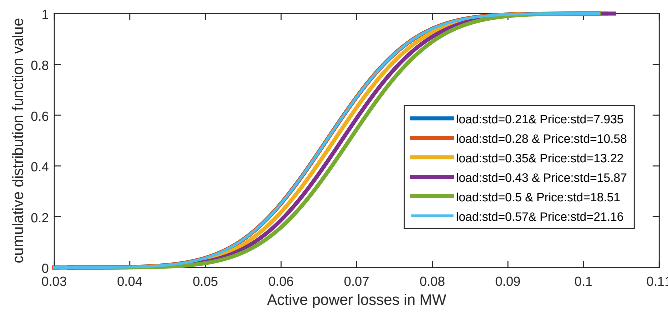

Figure 6.14: Sensitivity of proposed method in terms of CDF values for PG & E 69 bus active distribution system

6.4 Summary

The proposed iterative algorithm with Deterministic and Probabilistic approach was implemented on 84 bus TPC distribution system and PG & E 69 bus distribution system. Both Deterministic and Probabilistic approaches are performing well over MLM and SVIM in terms of APL. The proposed method with probabilistic frame work 2m+1:PEM performs with almost similar accuracy of MCS but with less computational time. The proposed method with 2m+1:PEM scheme performs well over 2m:PEM scheme by taking only one additional deterministic evaluation.

As the proposed method was developed based on uncertainties in load and market price, this method can be helpful to DISCO to provide financial incentives which are less sensitive to uncertainty that exist in market price and load. RPP of each DG unit was computed based on actual contribution of that DG's reactive power on APL of network using sensitivity factors. Financial incentives to DGs have been allocated from financial savings of DISCO due to APLR. PNT has been used for the first time for computation of LMP at DG buses due to it's superiority over other cooperative game theory concepts.

Chapter 7

Conclusions

Chapter 7

Conclusions

7.1 General

As the penetration of DG units in to the distribution system is increasing rapidly, controlling private DG owners and operating the distribution network optimally with the help of DG units is a challenging issue for DISCOs. Providing financial incentives in terms of locational marginal price (LMP) to DG owners based on DGs contribution in optimal operation is one of the solutions to overcome the above stated issues. So efficient and robust LMP computation algorithms are to be developed.

In this thesis, some LMP computation algorithms have been developed for properly controlling the private DG owners and for optimal operation of active distribution system in terms of active power losses, emissions and reliability. As market price and load are uncertain in nature, new probabilistic approach has been developed to compute LMP at DG buses based on active power loss reduction by considering uncertain input variables. These algorithms have been developed using game theory, meta heuristic techniques and point estimation methods.

Proportional nucleolus theory (PNT) based iterative method has been discussed to compute LMP at DG buses based on active power loss reduction. Subsequently, proportional nucleolus theory (PNT) based iterative method has been discussed to compute LMP at DG buses based on active power loss reduction and emission reduction. These algorithms were tested on practical 84 bus Taiwan Power Company (TPC) distribution system and PG & E 69 bus radial distribution system. Further, hybrid genetic dragonfly algorithm based optimal power flow method has been discussed to compute LMP at DG buses based on reliability improvement. This proposed method is tested on 38 bus radial distribution system and PG & E 69 bus radial distribution system. Subsequently, probabilistic iterative method has been discussed to compute LMP at DG buses based on active power loss reduction by considering uncertainties that exist in random inputs like load and market price. The proposed probabilistic approach is tested on practical 84 bus Taiwan Power Company (TPC) distribution system and PG & E 69 bus radial distribution system.

7.1.1 Summary of Important findings

The following conclusions have been arrived at from the current research

In this thesis, an efficient computation tool has been developed to compute LMP in active distribution network such that active power losses are reduced. The important findings and highlights from this study are as follows:

- Proportional nucleolus based cooperative game theory has been used for allocation of change in active power losses among DG units due to its superiority over remaining co-operative game theory concepts like core, shapley value and nucleolus.
- Fairness of the proportional nucleolus theory in this allocation problem was verified using individual rationality, coalition rationality and collective rationality.
- The proposed method provides financial incentives in terms of LMP to DG owners from reduced loss cost based DGs contribution in active power loss reduction.
- This type of computation provides less incremental price in each iteration but at convergence stage, DG owners get more profit.
- The proposed method provides guaranteed zero merchandising surplus (or) zero DISCO's extra benefit due to active power loss reduction, which is essential in deregulated environment.
- Loss sensitivity factors were developed to measure the actual impact of active and reactive generation at a particular bus on change in active power losses.
- It has been observed that the proposed method operates the network with less active power losses in comparison with shapley value based iterative method.
- Proposed method provides more DG profit in comparison with shapley value based iterative method.

In this thesis, an efficient computation tool has been developed to compute LMP in active distribution network so that active power losses and emissions have been reduced. The important findings and highlights from this study are as follows:

- Fair allocation of change in active power losses and emissions among DG units has been done using proportional nucleolus theory.

- Fairness of the allocation was verified using individual rationality, coalition rationality and collective rationality.
- The proposed method provides financial incentives in terms of LMP to DG owners from reduced loss cost and reduced emission penalty.
- This type of computation provides less incremental price in each iteration but at convergence stage DG owners will get more profit.
- The proposed method provides guaranteed zero merchandising surplus (or) zero DISCO's extra benefit due to reduced active power losses and emissions, which is essential in a deregulated environment.
- It has been observed that the proposed method operates the network with low active power losses and emissions in comparison with other existing LMP computation mechanisms.
- Proposed method provides more DG profit in comparison with other existing mechanisms.

In this thesis, Hybrid genetic dragonfly algorithm (HGDA) based optimal power flow (OPF) to compute LMP at each DG bus for reliability improvement was discussed. The important findings and highlights from this study are as follows:

- This method enables the DISCO to improve system reliability by controlling the private DG owners using financial incentives in terms of LMP.
- This method was developed based on consideration that there is no control on DG units located in part-II of network under outage.
- The proposed method encourages private DG owners in part-II of network to operate in such a way that reliability was improved.
- This method can estimate state of the network in terms of LMP, reactive power price (RPP), DG unit's generation, active power losses and emissions at any hour of the day and for any line outage.
- HGDA based OPF has been formulated by incorporating voltage limits, line flow limits, generation and load limits.
- The simulation results shows that the DG units which have an impact on reliability improvement receive better incentives than the market price.

- This method also provides information on emission, loss and DISCO's investment to purchase power from grid and DG owners.
- This method can estimate state of part-I of network in terms of voltage magnitude and active power loss.
- The hybridization of GA and DA for improved results has been implemented for the first time.
- This process uses the advantages of both methods and provides better results in comparison with individual method.
- The computation of LMP at DG buses for improving the reliability of the system has been considered for the first time.

In this thesis, probabilistic iterative approach was developed and implemented on practical test systems. The important findings and highlights from this study are as follows:

- Both Deterministic and Probabilistic approaches were performing well over marginal loss method and shapley value based iterative method in terms of active power losses.
- The proposed method with probabilistic frame work 2m+1 scheme of point estimation method performs with almost similar accuracy as Monte Carlo Simulation but with lower computational time.
- The proposed method with 2m+1 scheme of point estimation method scheme performs well over 2m scheme of point estimation method by taking only one additional deterministic evaluation.
- As the proposed method was developed based on uncertainties in load and market price, this method can be helpful to DISCO to provide financial incentives to DG owners which are less sensitive to uncertainty that exist in market price and load.
- RPP of each DG units was computed based on actual contribution of that DG's reactive power on active power losses of network using sensitivity factors.
- Financial incentives to DGs have been allocated from financial savings of DISCO due to active power loss reduction.
- Proportional nucleolus theory which is one of the cooperative game theory solution concepts has been used for the first time for computing of LMP at DG buses due to its superiority over other cooperative game theory concepts like core, shapley and nucleolus.

7.2 Suggestions For Future Research

As an extension to the current research work, there is scope for exploring further for a prospective researcher:

- √ If DG units in distribution system increase, then game theory takes more computation time. So the proposed LMP computation mechanism with game theory can be extended by considering sensitivity factors instead of game theory.
- √ Due to growing environmental and cost concerns, renewable energies and their integration into the electric power distribution system in present scenario have attracted attention. So the proposed LMP computation mechanism can be extended by considering renewable energy sources. If renewable DGs wants to include in this study, researchers can use same proposed methods. However some additional work is required that is estimation of maximum possible generation for each renewable DG at each hour due to uncertainties that exist in irradiation, wind etc.
- √ LMP computation mechanism can be extended by considering the change in reactive power losses.
- √ LMP computation mechanism can be extended by considering the service quality of DG units.
- √ The proposed LMP computation mechanism can be extended as a multi objective optimization problem by considering minimization of active power losses, emissions and expected energy not supplied (EENS) as an objectives
- √ The complete study on locational marginal price computation in distribution system was implemented on radial distribution system as most of the distribution networks are in radial structure. However the same proposed algorithms can also be implementable on meshed distribution systems. The implementation of proposed algorithms on meshed distribution networks has been considered as a future work for researchers.

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Appendix

Appendix A

84 bus TPC Radial Distribution System

The single line diagram of 84 bus TPC RDS as shown in FigureA.1 is drawn from [5] and line data and bus data is represented in Table G.1.

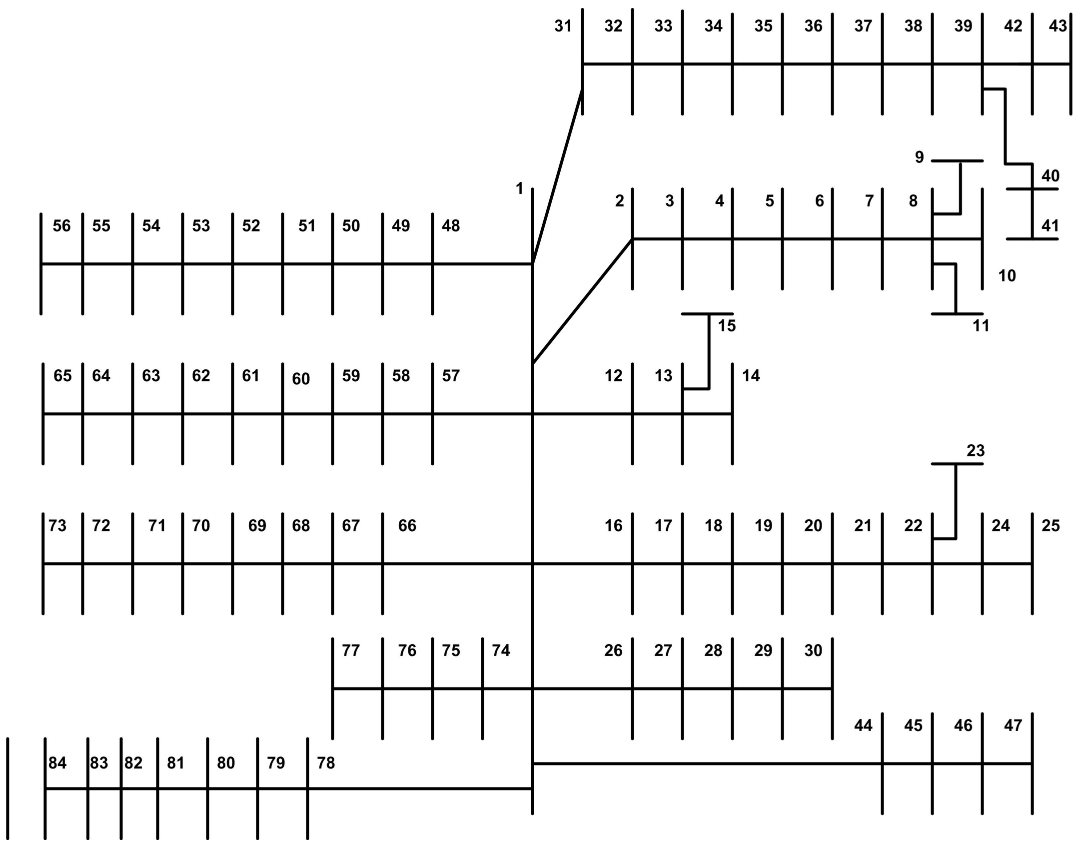

Figure A.1: Single line diagram of TPC 84 bus RDS [5]

Table A.1: 84 bus Taiwan Power Company Distribution System Data [5]

Line	From	To	R (Ω)	X(Ω)	P (kW)	Q (kVar)	Line	From	To	R (Ω)	X(Ω)	P (kW)	Q (kVar)
1	1	2	0.1944	0.6624	0	0	44	44	45	0.0393	0.0807	30	20
2	2	3	0.2096	0.4304	100	50	45	45	46	0.131	0.269	800	700
3	3	4	0.2358	0.4842	300	200	46	46	47	0.2358	0.4842	200	150
4	4	5	0.0917	0.1883	350	250	47	1	48	0.234	0.828	0	0
5	5	6	0.2096	0.4304	220	100	48	48	49	0.0655	0.1345	0	0
6	6	7	0.0393	0.0807	1100	800	49	49	50	0.0655	0.1345	0	0
7	7	8	0.0405	0.138	400	320	50	50	51	0.0393	0.0807	200	160
8	8	9	0.1048	0.2152	300	200	51	51	52	0.0786	0.1614	800	600
9	8	10	0.2358	0.4842	300	230	52	52	53	0.0393	0.0807	500	300
10	8	11	0.1048	0.2152	300	260	53	53	54	0.0786	0.1614	500	350
11	1	12	0.0786	0.1614	0	0	54	54	55	0.0524	0.1076	500	300
12	12	13	0.3406	0.6944	1200	800	55	55	56	0.131	0.269	200	80
13	13	14	0.0262	0.0538	800	600	56	1	57	0.2268	0.7728	0	0
14	13	15	0.0786	0.1614	700	500	57	57	58	0.5371	1.1029	30	20
15	1	16	0.1134	0.3864	0	0	58	58	59	0.0524	0.1076	600	420
16	16	17	0.0524	0.1076	300	150	59	59	60	0.0405	0.138	0	0
17	17	18	0.0524	0.1076	500	350	60	60	61	0.0393	0.0807	20	10
18	18	19	0.1572	0.3228	700	400	61	61	62	0.0262	0.0538	20	10
19	19	20	0.0393	0.0807	1200	1000	62	62	63	0.1048	0.2152	200	130
20	20	21	0.1703	0.3497	300	300	63	63	64	0.2358	0.4842	300	240
21	21	22	0.2358	0.4842	400	350	64	64	65	0.0243	0.0828	300	200
22	22	23	0.1572	0.3228	50	20	65	1	66	0.0486	0.1656	0	0
23	22	24	0.1965	0.4035	50	20	66	66	67	0.1703	0.3497	50	30
24	24	25	0.131	0.269	50	10	67	67	68	0.1215	0.414	0	0
25	1	26	0.0567	0.1932	50	30	68	68	69	0.2187	0.7452	400	360
26	26	27	0.1048	0.2152	100	60	69	69	70	0.0486	0.1656	0	0
27	27	28	0.2489	0.5111	100	70	70	70	71	0.0729	0.2484	0	0
28	28	29	0.0486	0.1656	1800	1300	71	71	72	0.0567	0.1932	2000	1500
29	29	30	0.131	0.269	200	120	72	72	73	0.0262	0.0528	200	150
30	1	31	0.1965	0.396	0	0	73	1	74	0.324	1.104	0	0
31	31	32	0.131	0.269	1800	1600	74	74	75	0.0324	0.1104	0	0
32	32	33	0.131	0.269	200	150	75	75	76	0.0567	0.1932	1200	950
33	33	34	0.0262	0.0538	200	100	76	76	77	0.0486	0.1656	300	180
34	34	35	0.1703	0.3497	800	600	77	1	78	0.2511	0.8556	0	0
35	35	36	0.0524	0.1076	100	60	78	78	79	0.1296	0.4416	400	360
36	36	37	0.4978	1.0222	100	60	79	79	80	0.0486	0.1656	2000	1300
37	37	38	0.0393	0.0807	20	10	80	80	81	0.131	0.264	200	140
38	38	39	0.0393	0.0807	20	10	81	81	82	0.131	0.264	500	360
39	39	40	0.0786	0.1614	20	10	82	82	83	0.0917	0.1883	100	30
40	40	41	0.2096	0.4304	20	10	83	83	84	0.3144	0.6456	400	360
41	39	42	0.1965	0.4305	200	160	Active Power load = 28.3 MW						
42	42	43	0.2096	0.4304	50	30	Recative power load: 20.7 Mvar						
43	1	44	0.0486	0.1656	0	0	Base case active power losses: 531.9kW						

Appendix B

38 bus Radial Distribution System

The single line diagram of 38 bus RDS as shown in FigureB.1 is drawn from [6] and line data and bus data is represented in Table B.1.

Table B.1: 38 bus RDS data [6]

Line	From	To	P (pu)	Q (pu)	R (pu)	X (pu)	S_l (pu)	Load	Line	From	To	P (pu)	Q (pu)	R (pu)	X (pu)	S_l (pu)	Load
1	1	2	0.1	0.06	0.000574	0.000293	4.6	1	21	32	33	0.06	0.04	0.002123	0.003301	0.1	2
2	2	19	0.09	0.04	0.001021	0.000974	0.5	1	22	6	7	0.2	0.1	0.001166	0.003853	1.5	2
3	19	20	0.09	0.04	0.009366	0.00844	0.5	2	23	7	8	0.2	0.1	0.00443	0.001464	1.05	2
4	20	21	0.09	0.04	0.00255	0.002979	0.21	3	24	8	34	0	0	0.012453	0.012453	0.5	0
5	21	22	0.09	0.04	0.004414	0.005836	0.11	1	25	8	9	0.06	0.02	0.006413	0.004608	1.05	3
6	2	3	0.09	0.04	0.00307	0.001564	4.1	3	26	9	35	0	0	0.012453	0.012453	0.5	0
7	3	23	0.09	0.05	0.002809	0.00192	1.05	2	27	9	10	0.06	0.02	0.006501	0.004608	1.05	2
8	23	24	0.42	0.2	0.005592	0.004415	1.05	2	28	10	11	0.045	0.03	0.001224	0.000405	1.05	2
9	24	25	0.42	0.2	0.005579	0.004366	0.5	2	29	11	12	0.06	0.035	0.002331	0.000771	1.05	1
10	25	38	0	0	0.003113	0.003113	0.1	0	30	12	36	0	0	0.012453	0.012453	0.5	0
11	3	4	0.12	0.08	0.002279	0.001161	2.9	2	31	12	13	0.06	0.035	0.009141	0.007192	0.5	2
12	4	5	0.06	0.03	0.002373	0.001209	2.9	1	32	13	14	0.12	0.08	0.003372	0.004439	0.45	1
13	5	6	0.06	0.02	0.0051	0.004402	2.9	3	33	14	15	0.06	0.01	0.00368	0.003275	0.3	2
14	6	26	0.06	0.025	0.001264	0.000644	1.5	2	34	15	16	0.06	0.02	0.004647	0.003394	0.25	3
15	26	27	0.06	0.025	0.00177	0.000901	1.5	3	35	16	17	0.06	0.02	0.008026	0.010716	0.25	2
16	27	28	0.06	0.02	0.006594	0.005814	1.5	2	36	17	18	0.09	0.04	0.004558	0.003574	0.1	3
17	28	29	0.12	0.07	0.005007	0.004362	1.5	2	37	18	37	0	0	0.003113	0.003113	0.5	0
18	29	30	0.2	0.6	0.00316	0.00161	1.5	2									
19	30	31	0.15	0.07	0.006067	0.005996	0.5	1									
20	31	32	0.21	0.1	0.001933	0.002253	0.5	1									

Type=1: Residential Load & Type 2: Commercial Load
Type=3: Industrial Load & Type 0: No Load

Base MVA=100 Base kV=23 Total Active Power load= 371.5MW Total Reactive Power load= 230MVar

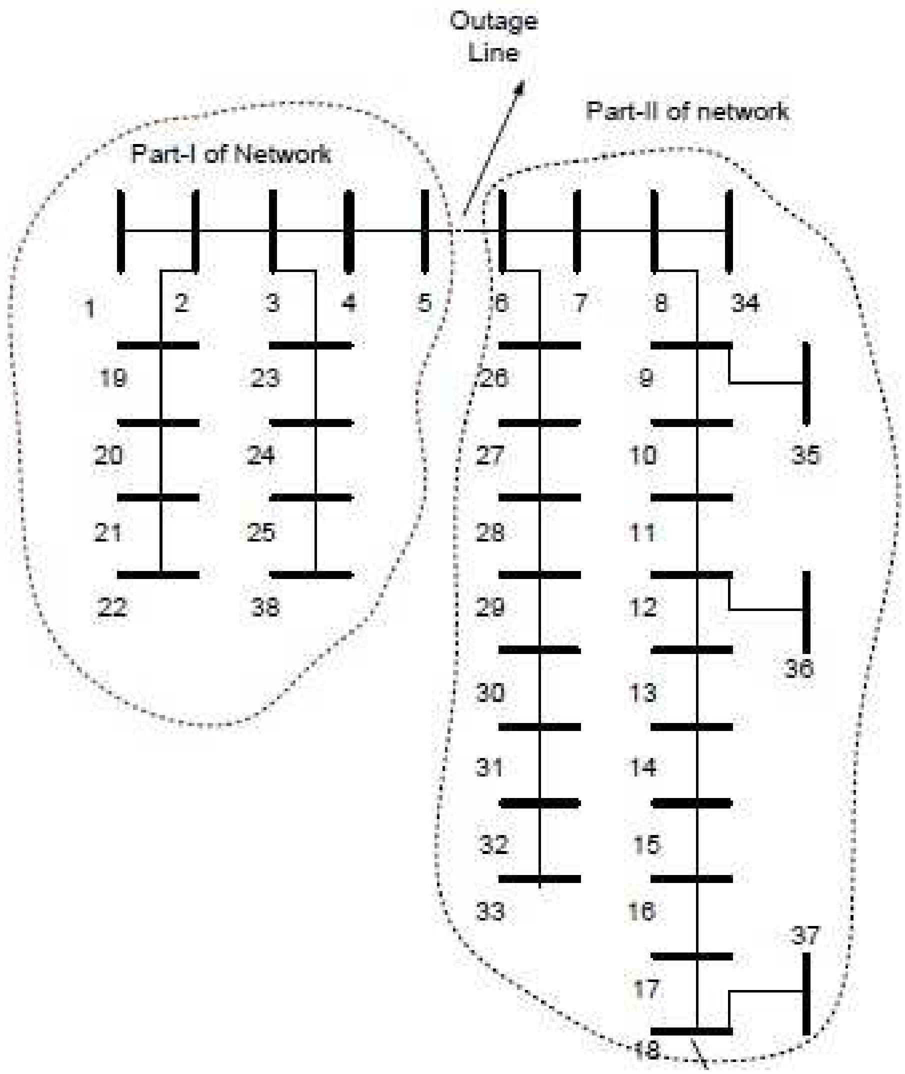

Figure B.1: Single line diagram of 38 bus RDS [6]

Appendix C

PG & E 69 bus Radial Distribution System

The single line diagram of PG & E 69 bus RDS as shown in FigureC.1 is drawn from [7] and line data and bus data is represented in Table C.1.

Table C.1: PG&E 69 bus RDS data [7]

Line	From	To	P (kW)	Q (kVar)	R (Ohms)	X (Ohms)	S_l (KVA)	Type	Line	From	To	P (kW)	Q (kVar)	R (Ohms)	X (Ohms)	S_l (KVA)	Type
1	1	2	0	0	0.0005	0.0012	5858.279	0	35	3	36	26	18.55	0.0044	0.0108	271.4951	1
2	2	3	0	0	0.0005	0.0012	5858.084	0	36	36	37	26	18.55	0.0640	0.1565	233.1679	1
3	3	4	0	0	0.0015	0.0036	5451.529	0	37	37	38	0	0	0.1053	0.1230	194.8057	0
4	4	5	0	0	0.0251	0.0294	4194.268	0	38	38	39	24	17	0.0304	0.0355	194.7749	1
5	5	6	2.6	2.2	0.3660	0.1864	4190.853	1	39	39	40	24	17	0.0018	0.0021	159.477	1
6	6	7	40.4	30	0.3811	0.1941	4149.53	1	40	40	41	1.2	1	0.7283	0.8509	124.1901	1
7	7	8	75	54	0.0922	0.0470	4050.542	1	41	41	42	0	0	0.3100	0.3623	122.2385	0
8	8	9	30	22	0.0493	0.0251	3866.126	1	42	42	43	6	4.3	0.0410	0.0478	122.2027	1
9	9	10	28	19	0.8190	0.2707	1131.275	1	43	43	44	0	0	0.0092	0.0116	113.3439	0
10	10	11	145	104	0.1872	0.0619	1084.966	2	44	44	45	39.22	26.3	0.1089	0.1373	113.3429	1
11	11	12	145	104	0.7114	0.2351	816.855	2	45	45	46	39.22	26.3	0.0009	0.0012	56.66589	1
12	12	13	8	5	1.0300	0.3400	518.1711	1	46	4	47	0	0	0.0034	0.0084	1256.972	0
13	13	14	8	5.5	1.0440	0.3450	505.3151	1	47	47	48	79	56.4	0.0851	0.2083	1256.909	1
14	14	15	0	0	1.0580	0.3496	492.1793	0	48	48	49	384.7	274.5	0.2898	0.7091	1138.865	3
15	15	16	45.5	30	0.1966	0.0650	490.7164	1	49	49	50	384.7	274.5	0.0822	0.2011	567.3941	3
16	16	17	60	35	0.3744	0.1238	425.1911	1	50	8	51	40.5	28.3	0.0928	0.0473	64.59976	1
17	17	18	60	35	0.0047	0.0016	341.7906	1	51	51	52	3.6	2.7	0.3319	0.1114	5.392596	1
18	18	19	0	0	0.3276	0.1083	258.8745	0	52	9	53	4.35	3.5	0.1740	0.0886	2685.854	1
19	19	20	1	0.6	0.2106	0.0690	258.7494	1	53	53	54	26.4	19	0.2030	0.1034	2671.587	1
20	20	21	114	81	0.3416	0.1129	257.2771	2	54	54	55	24.4	17.2	0.2842	0.1447	2623.822	1
21	21	22	5	3.5	0.0140	0.0046	89.72512	1	55	55	56	0	0	0.2813	0.1433	2576.099	0
22	22	23	0	0	0.1591	0.0526	82.41798	0	56	56	57	0	0	1.5900	0.5337	2564.558	0
23	23	24	28	20	0.3463	0.1145	82.4118	1	57	57	58	0	0	0.7837	0.2630	2505.189	0
24	24	25	0	0	0.7488	0.2475	41.20428	0	58	58	59	100	72	0.3042	0.1006	2475.973	2
25	25	26	14	10	0.3089	0.1021	41.19702	1	59	59	60	0	0	0.3861	0.1172	2317.734	0
26	26	27	14	10	0.1732	0.0572	20.59721	1	60	60	61	1244	888	0.5075	0.2585	2305.252	3
27	3	28	26	18.6	0.0044	0.0108	134.8741	1	61	61	62	32	23	0.0974	0.0496	466.4746	1
28	28	29	26	18.6	0.0640	0.1565	96.51161	1	62	62	63	0	0	0.1450	0.0738	419.3933	0
29	29	30	0	0	0.3978	0.1315	58.1433	0	63	63	64	227	162	0.7105	0.3619	419.2166	3
30	30	31	0	0	0.0702	0.0232	58.13626	0	64	64	65	59	42	1.0410	0.5302	86.28402	1
31	31	32	0	0	0.3510	0.1160	58.13501	0	65	11	66	18	13	0.2012	0.0611	53.20166	1
32	32	33	14	10	0.8390	0.2816	58.1288	1	66	66	67	18	13	0.0047	0.0014	26.59929	1
33	33	34	19.5	14	1.7080	0.5646	37.4686	1	67	12	68	28	20	0.7394	0.2444	82.45926	1
34	34	35	6	4	1.4740	0.4873	8.653876	1	68	68	69	28	20	0.0047	0.0016	41.21563	1

Base MVA=10 Base kV=12.66 Total Active Power load= 3802.3kW Total Reactive Power load= 2694.1kVar

Type=0: No Load & Type=1: Residential Load & Type 2: Commercial Load & Type=3: Industrial Load

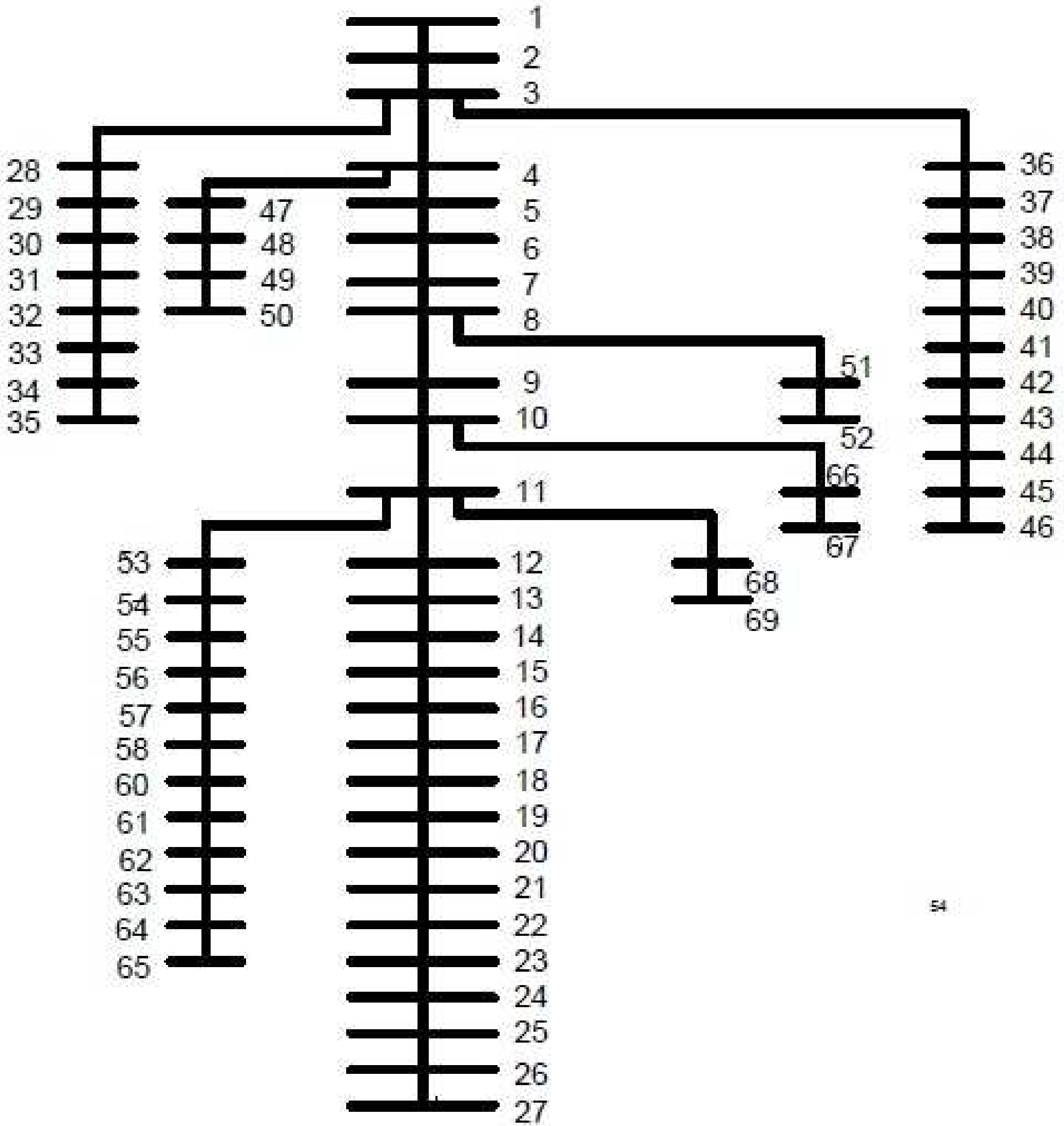

Figure C.1: Single line diagram of PG&E 69 bus RDS [7]

Appendix D

Prerequisite Algorithms

The single line diagram of IEEE 15 bus ADS is as shown in FigureD.1 and the line data and bus data are represented in Table D.1.

Table D.1: IEEE 15 bus Radial Distribution System data [8]

Line	From	To	P (pu)	Q (pu)	R (pu)	X (pu)
1	1	2	0.2205	0.2249	0.002237	0.002188
2	2	3	0.35	0.357	0.001934	0.001892
3	3	4	0.7	0.7141	0.00139	0.00136
4	4	5	0.2205	0.2249	0.002518	0.001699
5	2	9	0.35	0.357	0.003328	0.002244
6	9	10	0.2205	0.2249	0.002788	0.00188
7	2	6	0.7	0.7141	0.004227	0.002851
8	6	7	0.7	0.7141	0.001799	0.001213
9	6	8	0.35	0.357	0.002068	0.001395
10	3	11	0.7	0.7141	0.002968	0.002002
11	11	12	0.35	0.357	0.004047	0.00273
12	12	13	0.2205	0.2249	0.003328	0.002244
13	4	14	0.35	0.357	0.003687	0.002487
14	4	15	0.7	0.7141	0.001979	0.001335
Base KVA=200 Power factor of load =0.7 Base kV=11						
Active power load = 1.2264MW Reactive power load = 1.2510MVar						

D.1 Identification of nodes beyond a particular bus

The process of identifying nodes connected beyond a particular bus is presented in the flowchart as shown in Figure D.2. The proposed algorithm can be helpful to distribution network decision maker to get information about nodes which are disconnected from substation bus due to outage. This method can also be helpful to implement some of the load flow methods in ADS where information of nodes connected beyond a particular node is required as in [8, 163].

The flowchart as shown in Figure D.2 has been developed in such a way that 'cnode' vector stores information of buses connected beyond each bus. The vectors 'bntagf(i)' and

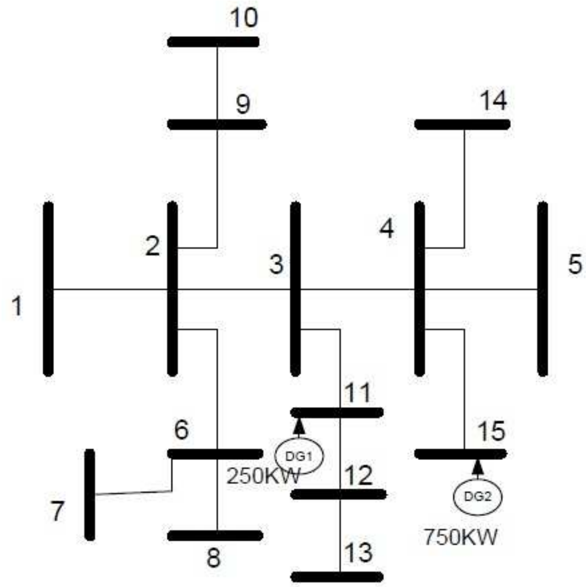

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Figure D.1: IEEE 15 Bus ADS [8]

'bntagto(i)' stores starting and ending locations in 'cnode' vector, where buses beyond bus 'i' are stored. The vectors 'cnode', 'bntagf' and 'bntagto' have been developed by extracting information of sending end and receiving end nodes of each line in ADS. The values of bntagf and bntagto for each bus in IEEE 15 bus ADS are presented in Table D.2 and cnode information is presented in Table D.3.

Table D.2: bntagf and bntagto matrices of IEEE 15 bus ADS

bus	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
bntagf	44	30	22	18	17	14	13	12	10	9	6	4	3	2	1
bntagto	58	43	29	21	17	16	13	12	11	9	8	5	3	2	1

Table D.3: Information of cnode vector of IEEE 15 bus ADS

<table>
<tr><td>bus</td><td>15</td><td>14</td><td>13</td><td colspan="2">12</td><td colspan="3">11</td><td>10</td><td colspan="2">9</td><td>8</td><td>7</td><td colspan="2">6</td></tr>
<tr><td>cnode</td><td>15</td><td>14</td><td>13</td><td>12</td><td>13</td><td>11</td><td>12</td><td>13</td><td>10</td><td>9</td><td>10</td><td>8</td><td>7</td><td>6</td><td>7</td></tr>
<tr><td>bus</td><td>6</td><td>5</td><td colspan="4">4</td><td colspan="8">3</td><td>2</td></tr>
<tr><td>cnode</td><td>8</td><td>5</td><td>4</td><td>5</td><td>14</td><td>15</td><td>3</td><td>4</td><td>5</td><td>14</td><td>15</td><td>11</td><td>12</td><td>13</td><td>2</td></tr>
<tr><td>bus</td><td colspan="13">2</td><td colspan="2">1</td></tr>
<tr><td>cnode</td><td>3</td><td>4</td><td>5</td><td>14</td><td>15</td><td>11</td><td>12</td><td>13</td><td>9</td><td>10</td><td>6</td><td>7</td><td>8</td><td>1</td><td>2</td></tr>
<tr><td>bus</td><td colspan="13">1</td><td colspan="2"></td></tr>
<tr><td>cnode</td><td>3</td><td>4</td><td>5</td><td>14</td><td>15</td><td>11</td><td>12</td><td>13</td><td>9</td><td>10</td><td>6</td><td>7</td><td>8</td><td colspan="2"></td></tr>
</table>

D.2 IEEE 15 bus ADS at single contingency

The flowchart as shown in Figure D.3 provides line and bus data of each part of network when a single line outage has taken place. OPF requires line data of part-II of network in order to compute scheduled load and generation. Line data information in part-I and part-II of the network are stored in LD_{sub} and LD_{ws} matrices respectively.

Line data information of part-I (LD_{sub}) and part-II (LD_{ws}) of IEEE 15 bus ADS by considering the line outage between buses 2 and 3 are shown in Table D.4 and Table D.5 respectively.

Table D.4: Line and Bus data of part-I of IEEE 15 bus ADS before renumbering after the line outage between buses 2 and 3 (LD_{sub})

Line	From	To	P(pu)	Q(pu)	R(pu)	X(pu)
1	1	2	0.2205	0.2249	0.0022	0.0022
5	2	9	0.3500	0.3570	0.0033	0.0022
7	2	6	0.7000	0.7141	0.0042	0.0029
8	6	7	0.7000	0.7141	0.0018	0.0012
9	6	8	0.3500	0.3570	0.0021	0.0014
6	9	10	0.2205	0.2249	0.0028	0.0019

Table D.5: Line and Bus data of part-II of IEEE 15 bus ADS before renumbering after the line outage between buses 2 and 3 (LD_{ws})

Line	From	To	P(pu)	Q(pu)	R(pu)	X(pu)
10	3	11	-0.5500	0.1087	0.0030	0.0020
14	4	15	-3.0500	-1.1021	0.0020	0.0013
4	4	5	0.2205	0.2249	0.0025	0.0017
12	12	13	0.2205	0.2249	0.0033	0.0022
13	4	14	0.3500	0.3570	0.0037	0.0025
11	11	12	0.3500	0.3570	0.0040	0.0027
3	3	4	0.7000	0.7141	0.0014	0.0014

D.3 Renumbering of buses in part-I of IEEE 15 bus ADS

Bus numbers which were stored in LD_{sub} from Figure D.3 may not be in sequence as some of buses were moved to LD_{ws}. In order to run any distribution load flow successfully on any part of network, it requires proper numbering of each line and bus. The process of renumbering of all buses in part-I of network is depicted in the flowchart as shown in Figure D.5. Part-I of IEEE 15 bus ADS after renumbering is as shown in Table D.6.

Table D.6: Renumbered line and Bus data of part-I of IEEE 15 bus ADS after line outage between buses 2 and 3 LD_{rec}

Line	From	To	P(pu)	Q(pu)	R(pu)	X(pu)
1	1	2	0.2205	0.2249	0.0022	0.0022
2	2	6	0.3500	0.3570	0.0033	0.0022
3	2	3	0.7000	0.7141	0.0042	0.0029
4	3	4	0.7000	0.7141	0.0018	0.0012
5	3	5	0.3500	0.3570	0.0021	0.0014
6	6	7	0.2205	0.2249	0.0028	0.0019

D.4 Identification of slack bus and position of each bus from slack bus in part-II of IEEE 15 bus ADS

A new algorithm has been developed to identify slack bus and position of remaining buses from slack bus. In this method the bus which has highest power injection has been considered as slack bus. This method also provides information about position of remaining buses from slack bus and this information is stored in $Node_{pos}$. The flowchart as shown in Figure D.6 has employed the following logic:

- Identify the bus which has maximum injection and consider it as slack bus and keep that bus as first element in vector $Node_{pos}$
- Identify the position of each bus from slack bus in part-II of network and update $Node_{pos}$

Information about slack bus and position of remaining buses from slack bus in part-II of IEEE 15 bus ADS are shown in Table D.7. Index represents location of bus in $Node_{pos}$.

Table D.7: $Node_{pos}$ matrix

Index	1(Slack bus)	2	3	4	5	6	7	8
$Node_{pos}$	15	4	3	5	14	11	12	13

D.5 Renumbering of buses in part-II of IEEE 15 bus ADS

In order to run any distribution load flow successfully on part-II of network, proper numbering of each line and bus is required.The flowchart as shown in Figure D.8 is employed for renumbering the line and buses in part-II of network.

The basic logic used for renumbering the buses and lines in part-II of network is as follows:

- Identify sending end and receiving end buses of each line of part-II of network (LD_{ws}^{ren}).

- If any of these two buses exist in $Node_{pos}$, then replace that bus number in LD_{ws}^{ren} with index of that bus in $Node_{pos}$ matrix.

Table D.8: Renumbered line and bus data of part-II of IEEE 15 bus ADS after the line outage between buses 2 and 3 (LD_{ws}^{ren})

Line	From	To	P(pu)	Q(pu)	R(pu)	X(pu)
1	1	2	0.7000	0.7141	0.0020	0.0013
2	2	4	0.2205	0.2249	0.0025	0.0017
3	2	5	0.3500	0.3570	0.0037	0.0025
4	2	3	0.7000	0.7141	0.0014	0.0014
5	3	6	-0.5500	0.1087	0.0030	0.0020
6	6	7	0.3500	0.3570	0.0040	0.0027
7	7	8	0.2205	0.2249	0.0033	0.0022

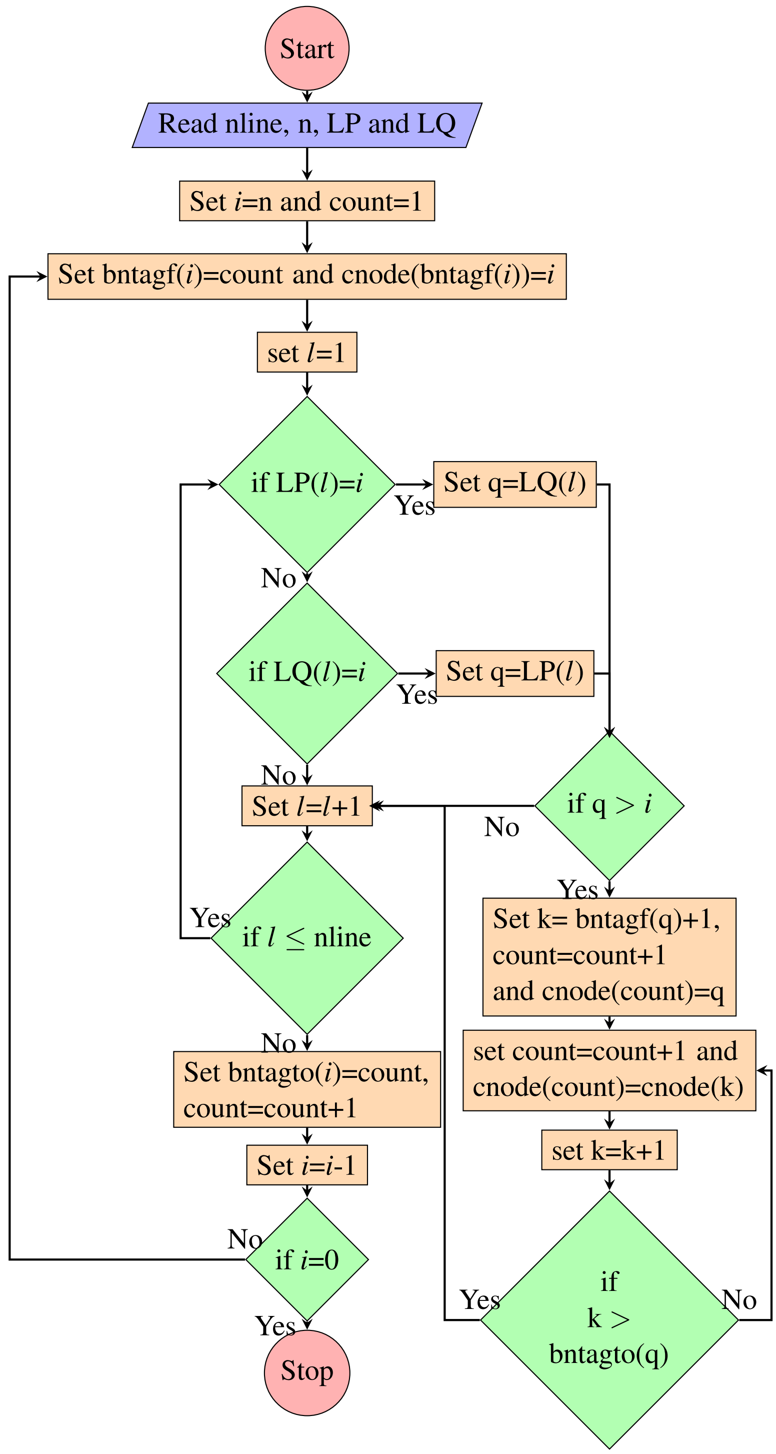

Figure D.2: Flowchart to identify nodes beyond a particular bus

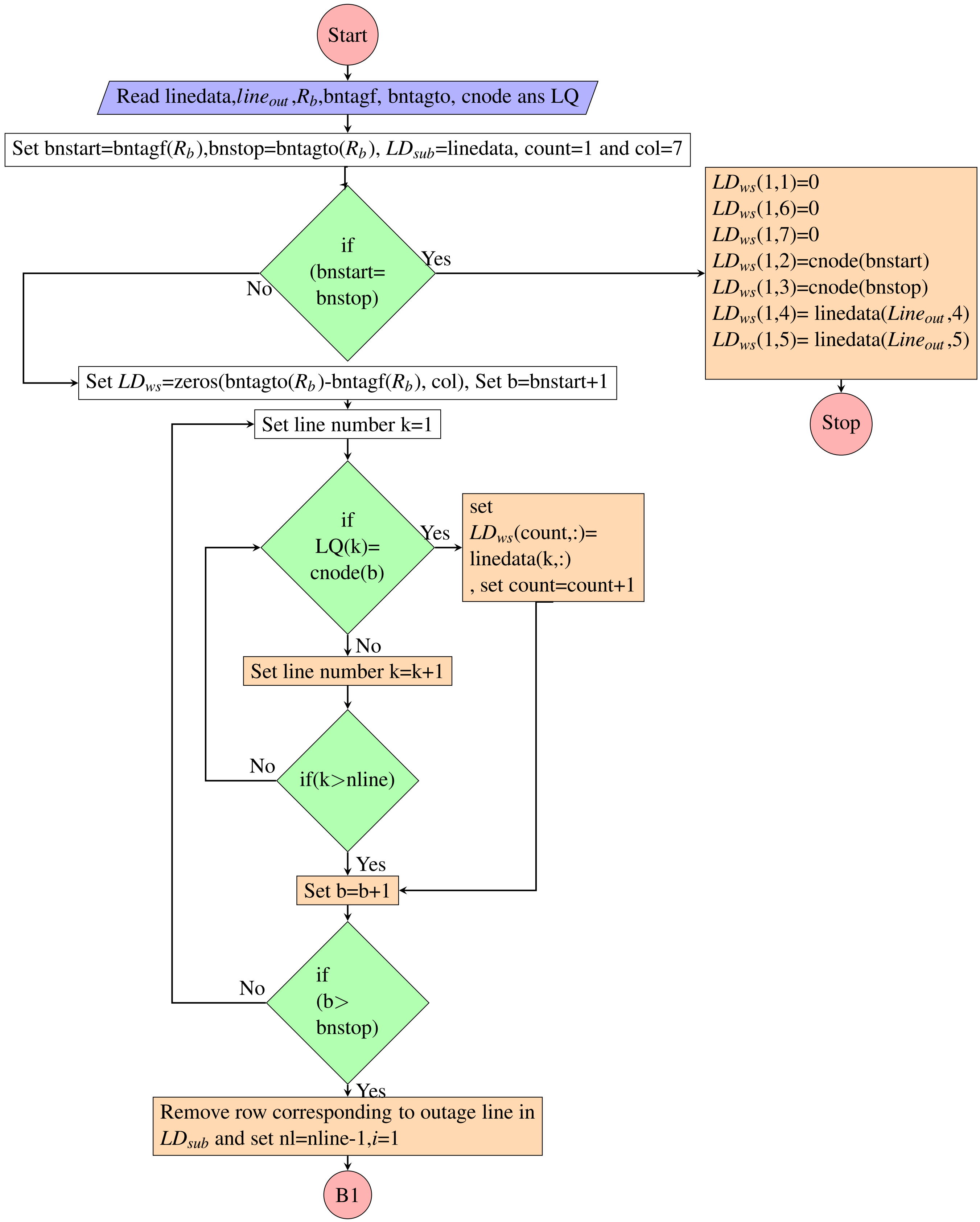

Figure D.3: Flowchart for line data selection of network at single contingency

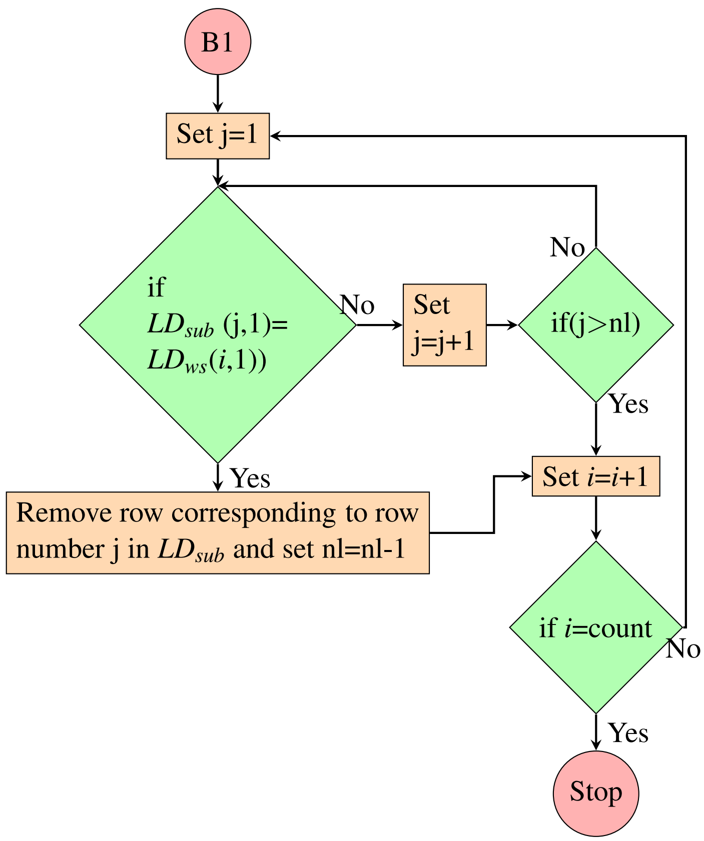

Figure D.4: Flowchart for line data selection of network at single contingency cont.

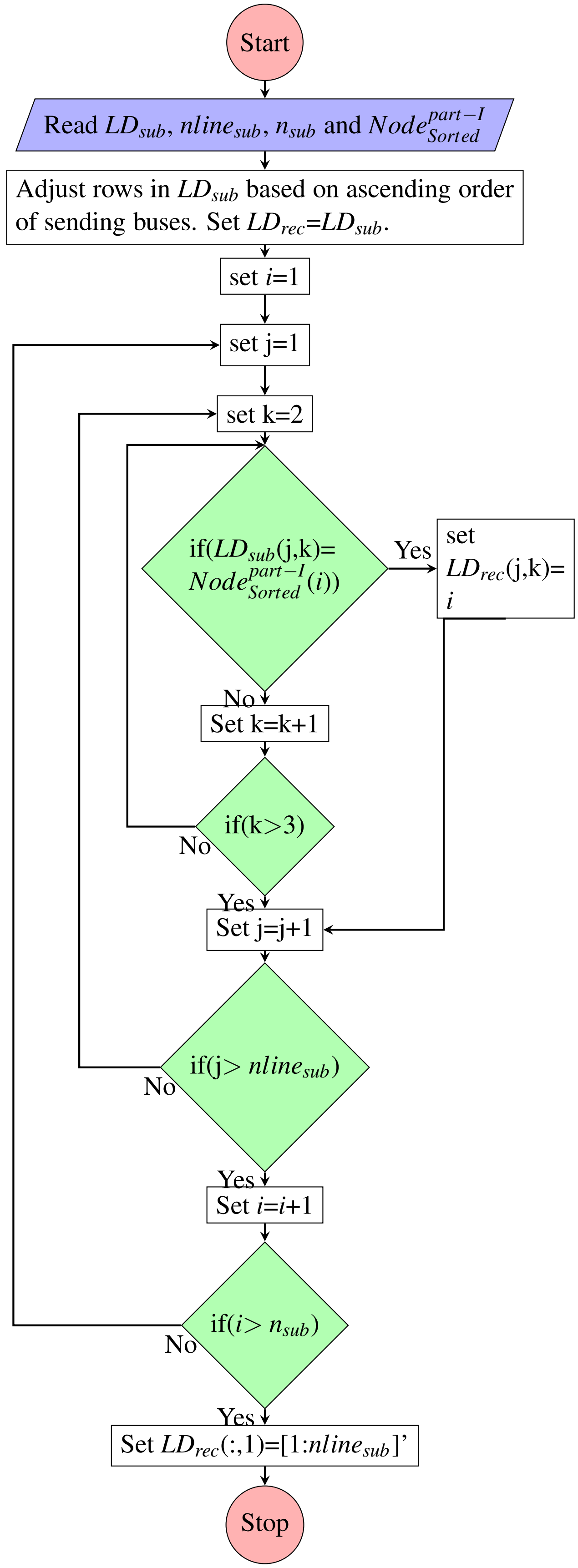

Figure D.5: Flowchart for Renumbering buses in part-I of network

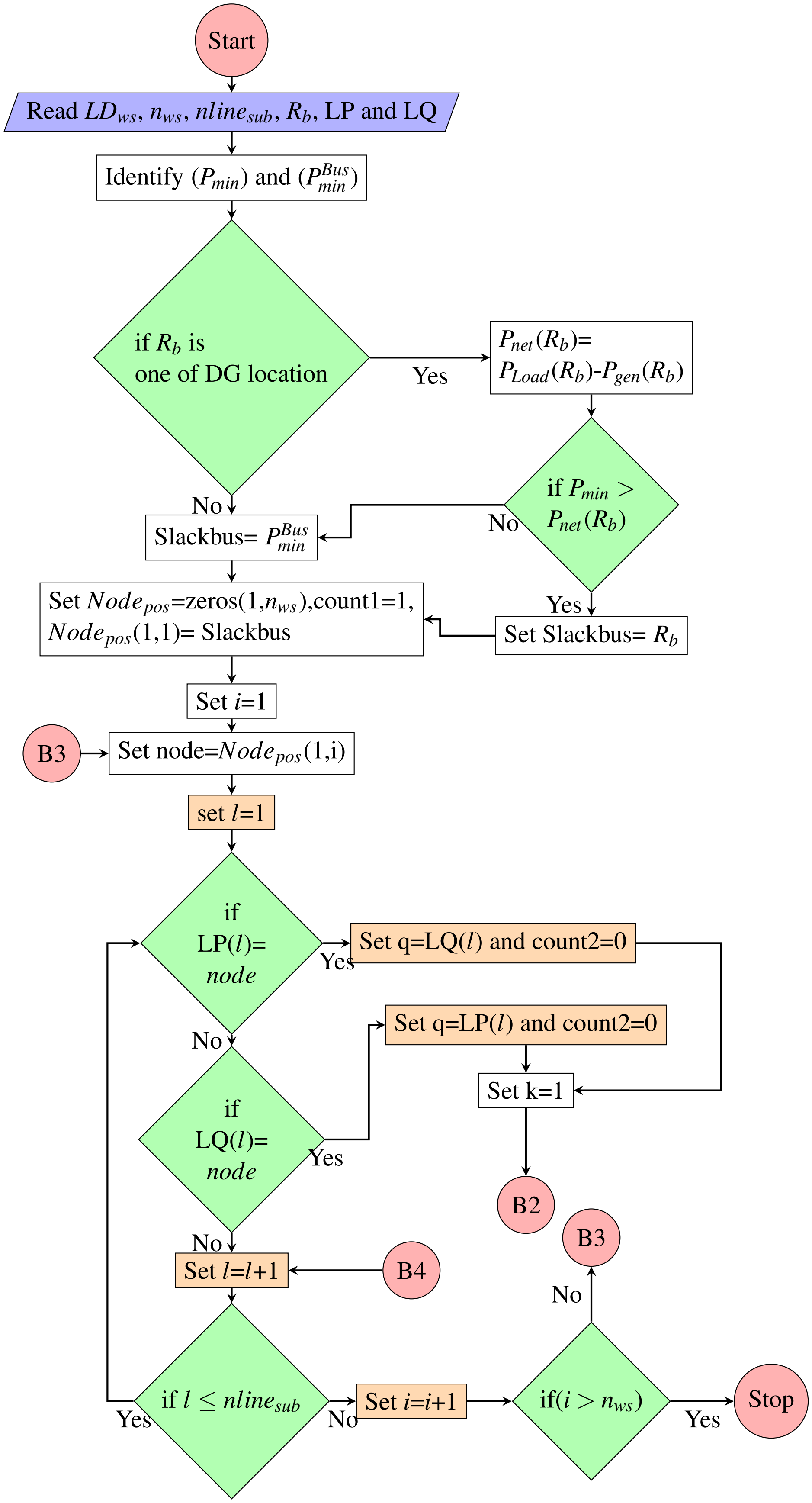

Figure D.6: Flowchart for Slack bus and position of each bus from slack bus in part-II of network

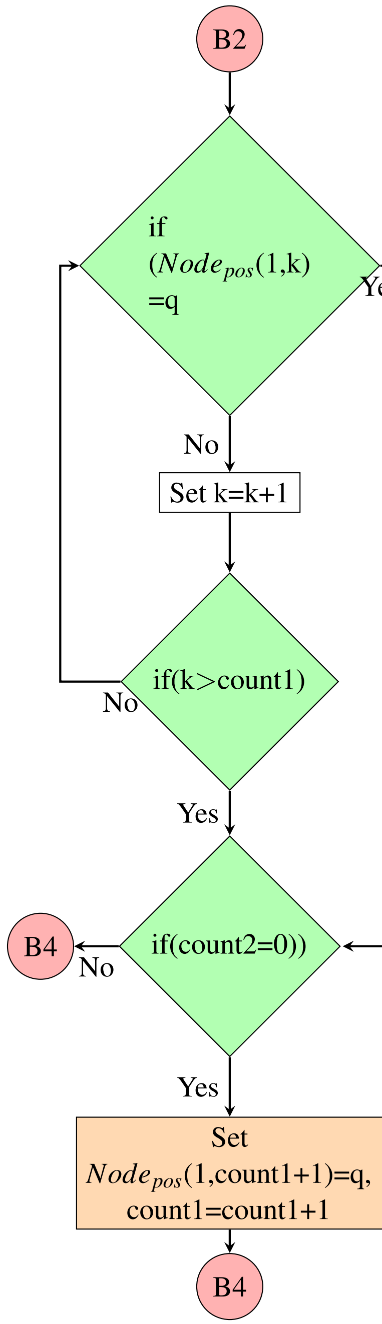

Figure D.7: Flowchart for Slack bus and position of each bus from slack bus in part-II of network cont.

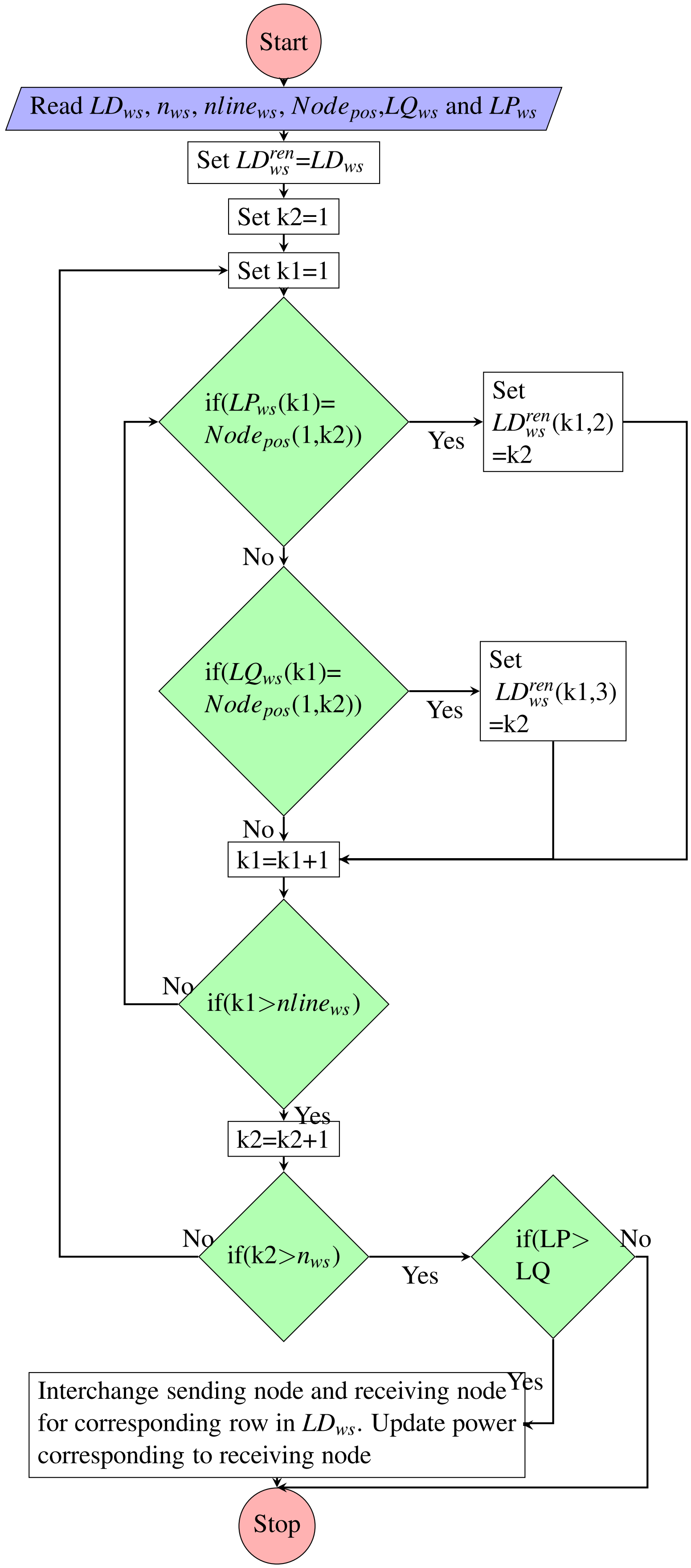

Figure D.8: Flowchart for Renumbering of buses in part-II of network

Appendix E

Flowchart for computing LMP using HGDA - OPF

Flowchart of the proposed HGDA-OPF method to compute LMP value of each DG unit in part-II of network based on reliability improvement and also to observe the state of the network connected to substation is presented in Figure E.1.

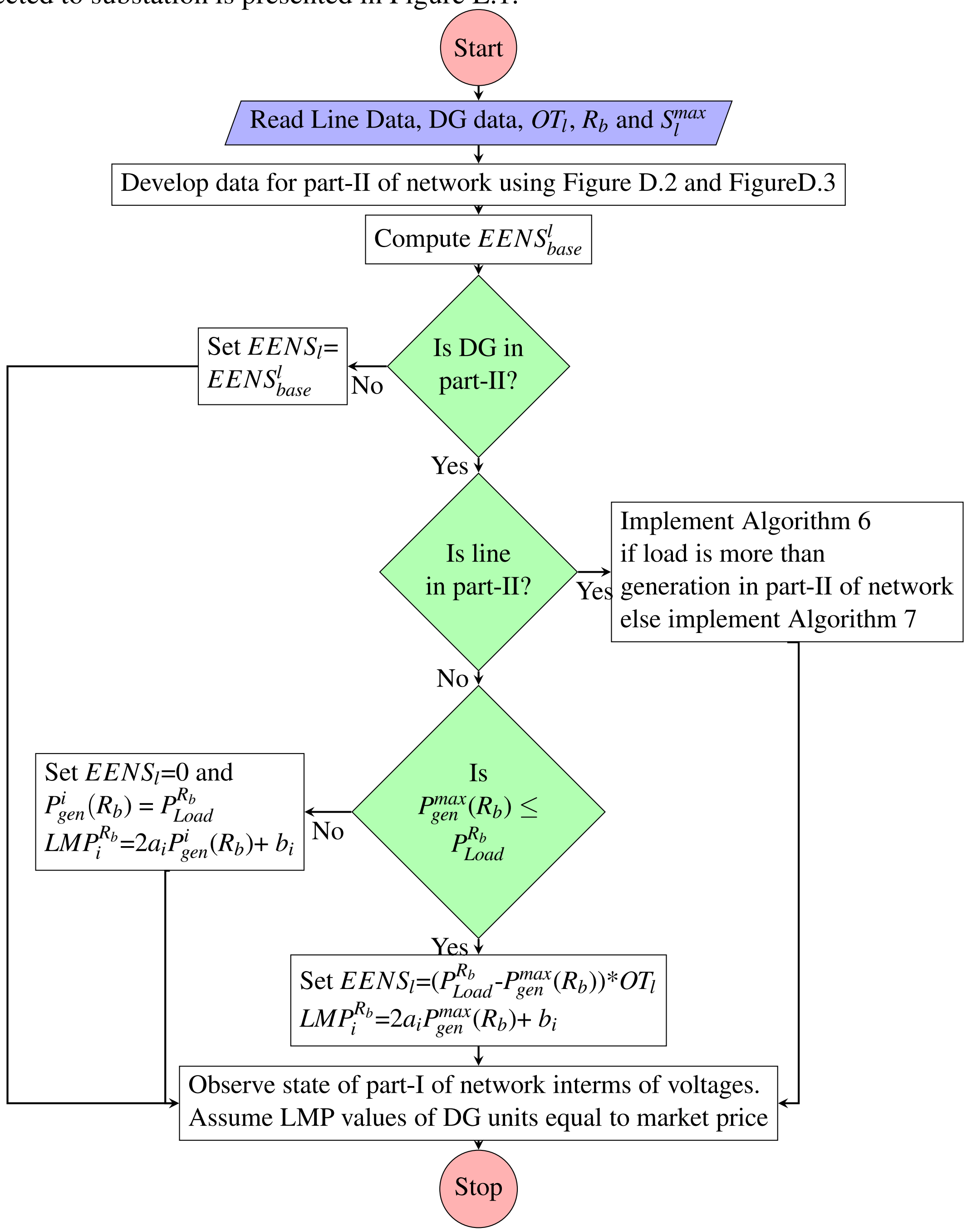

Figure E.1: Flowchart for computation of LMP at DG buses

Appendix F

Backward Forward Sweep load-flow analysis of radial distribution systems

In this thesis backward forward sweep load-flow method [113] has been used to compute voltages at each bus, active and reactive power losses of radial distribution system. This load-flow method utilizes complete advantage of ladder structure of distribution network, to achieve high speed, robust convergence and low memory requirements [114, 115].

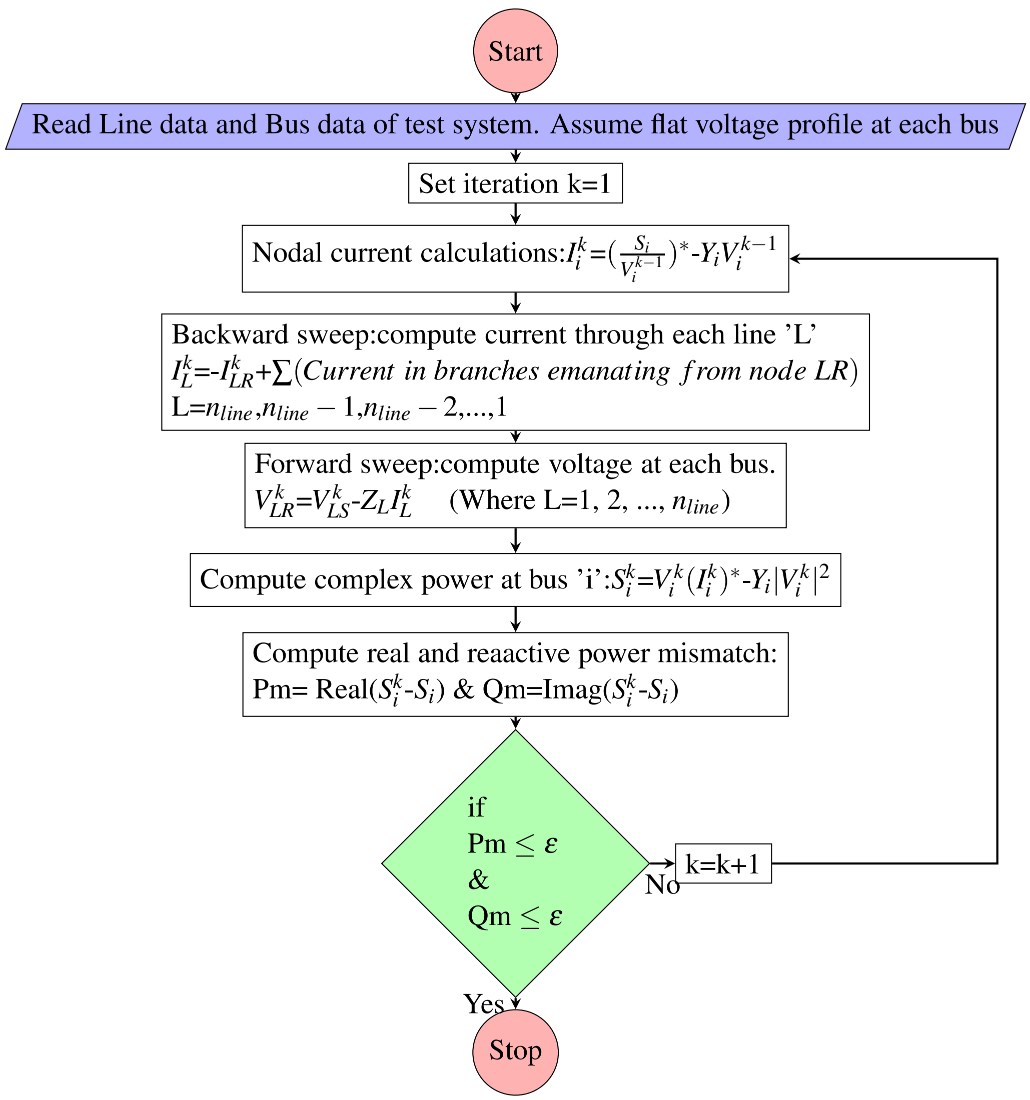

Figure F.1: Flowchart for backward forward sweep load-flow method

Appendix G

Weight factors and Their Impact on LMP

Table G.1: Weight factors and Their Impact on LMP

Weight Factor	Description	Impact on LMP
ω_{inv}	Weight corresponds to DISCO's investment in part-II of network	If this value is high, then DISCO wants to invest less amount to purchase power from DG units. Increase in ω_{inv} value leads to the increase in LMP values of DG units which have low fuel cost coefficient values.
ω_{emis}	Weight corresponds to emissions released in part-II of network	If this value is high, then DISCO gives more priority to operate the part-II of network with less emissions. Increasing in ω_{emis} value leads to the increase in LMP values of DG units which have low emission coefficient values in part-II of network.
ω_{los}	Weight corresponds to active power losses in part-II of network	If this value is high, then DISCO gives more priority to operate the part-II of network with less active power losses. Increasing in ω_{los} value leads to the increase in LMP values of DG units which have positive impact on active power loss reduction in part-II of network
ω_1	Weight corresponds to active power losses in distribution system	If this value is high, then DISCO gives more priority to operate the distribution network with less active power losses. Increasing in ω_1 value leads to the increase in LMP values of DG units which have positive impact on active power loss reduction in the network
ω_2	Weight corresponds to emissions released in distribution system	If this value is high, then DISCO gives more priority to operate the distribution network with less emissions. Increasing in ω_2 value leads to the increase in LMP values of DG units which have low emission coefficient values in the distribution network.
ω_i	Weight corresponds to priority for type 'i' loads	If this value is high, then DISCO gives more priority to type 'i' loads and amount of power interruption to these loads is less. All these factors have been used in load scheduling by assuming that all DG units are operating at their limit. LMP value of each DG unit is based on its size and it is independent of this parameter

Publications

Refereed International Journal Publications:

[1] Veeramsetty, V., Venkaiah, C., & Kumar, D. V. (2018). Hybrid genetic dragonfly algorithm based optimal power flow for computing LMP at DG buses for reliability improvement. Energy Systems, 9(3), 709-757.

[2] Veeramsetty, V., Chintham, V., & Vinod Kumar, D. M. (2018). Proportional nucleolus game theory–based locational marginal price computation for loss and emission reduction in a radial distribution system. International Transactions on Electrical Energy Systems, 28(8).

[3] Veeramsetty, V., Chintham, V., & Vinod Kumar, D. M. (2018). LMP computation at DG buses in radial distribution system. International Journal of Energy Sector Management, 12(3), 364-385

Journals Communicated:

[1] Veeramsetty Venkataramana, Chintham Venkaiah, and DM Vinod Kumar. ”Locational Marginal Price Computation in Distribution System using Self Adaptive Levy Flight based JAYA Algorithm and Game Theory ” **Utilities Policy : Elsevier - SCIE - (Under Review)**.

[2] Veeramsetty Venkataramana, Chintham Venkaiah, and DM Vinod Kumar. ”Probabilistic Locational Marginal Price Computation in active distribution system Based on Active Power Loss Reduction.” **IET Generation, Transmission & Distribution: IET - SCI - (Under Review)**.

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