

Optimal Capacity and Location Assessment of Natural Gas Fired Distributed
Generation in Residential Areas

by

Krutak Kamdar

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Graduate Supervisory Committee:

George Karady, Chair
Raja Ayyanar
Keith Holbert

ARIZONA STATE UNIVERSITY

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ABSTRACT

With ever increasing use of natural gas to generate electricity, installed natural gas fired microturbines are found in residential areas to generate electricity locally. This research work discusses a generalized methodology for assessing optimal capacity and locations for installing natural gas fired microturbines in distribution residential network. The overall objective is to place microturbines to minimize the system power loss occurring in the electrical distribution network; in such a way that the electric feeder does not need any up-gradation. The IEEE 123 Node Test Feeder is selected as the test bed for validating the developed methodology. Three-phase unbalanced electric power flow is run in OpenDSS through COM server, and the gas distribution network is analyzed using GASWorkS. The continual sensitivity analysis methodology is developed to select multiple DG locations and annual simulation is run to minimize annual average losses.

The proposed placement of microturbines must be feasible in the gas distribution network and should not result into gas pipeline reinforcement. The corresponding gas distribution network is developed in GASWorkS software, and nodal pressures of the gas system are checked for various cases to investigate if the existing gas distribution network can accommodate the penetration of selected microturbines. The results indicate the optimal locations suitable to place microturbines and capacity that can be accommodated by the system, based on the consideration of overall minimum annual average losses as well as the guarantee of nodal pressure provided by the gas distribution network. The proposed method is generalized and can be used for any IEEE test feeder or an actual residential distribution network.

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TABLE OF CONTENTS

	Page
LIST OF TABLES	v
LIST OF FIGURES	vii
NOMENCLATURE	viii
CHAPTER	
1 INTRODUCTION	1
1.1 Overview	1
1.2 Research Motivation and Objectives	2
1.3 Thesis Organization	2
2 LITERATURE REVIEW	4
2.1 Natural Gas Distribution Network	4
2.2 Distributed Generation.....	7
2.3 Natural Gas Microturbine Technologies	11
2.4 Impacts of DG on the Transmission and Distribution System	14
2.5 Network DG Capacity Assessment	15
2.6 Conclusions	19
3 ELECTRICAL DISTRIBUTION MODELING	20
3.1 Test System and Analytical Tools	20
3.2 Power Loss in Distribution System with DG Placement	25
3.3 Voltage Profile with DG Placement	30
4 POWER LOSS MINIMIZATION BASED ON OPTIMUM DG PLANNING	33
4.1 Sensitivity Calculation	33

CHAPTER	Page
4.2 Continuous Sensitivity Analysis	37
4.3 Result and Analysis of Continuous Sensitivity Analysis	38
4.4 Annual Simulation Analysis	41
5 NATURAL GAS NETWORK MODELING	48
5.1 Natural Gas Distribution System	48
5.2 Natural Gas Network Design	50
5.3 Case Studies	56
6 CONCLUSIONS AND FUTURE WORK	63
6.1 Conclusions and Main Contributions	63
6.2 Future Work	64
REFERENCES	66
APPENDIX	
A OPENDSS SCRIPT	72
B MATLAB FILE FOR POWER LOSS VARIATION	80
C MATLAB FILE FOR VOLTAGE PROFILE	83
D MATLAB FILE FOR CONTINUOUS SENSITIVITY ANALYSIS	85
E MATLAB FILE FOR CALCULATING ANNUAL AVERAGE LOSSES	92

LIST OF TABLES

Table	Page
2.1 Gas and Electric Network Analogies	5
2.2 Summary of DG Technologies	9
2.3 Capstone Microturbine C65 Cost Parameters	11
4.1 Initial Sensitivity Values	35
4.2 Sensitivity Values after 300 kW DG Placement at Bus 95	36
4.3 Loss Comparison with High DG Penetration	42
4.4 Annual Average Losses with Optimal DG Placement	45

LIST OF FIGURES

Figure	Page
2.1 Pipeline Network Structure Diagram	4
2.2 Natural Gas Distribution Network in Gurgaon, India Geographical Area	6
2.3 Residential Microgrid Model	10
2.4 Specifications of Capstone Microturbines	12
2.5 Commercial Fuel Cell Running on Natural Gas at ASU East Campus	13
3.1 Chandler Residential Area	20
3.2 IEEE 123 Node Test Feeder	22
3.3 OpenDSS Architecture	23
3.4 OpenDSS Object Structure	24
3.5 Radial Line with One Generation and One Load	26
3.6 Power Loss Variations for Different DG Sizes at a Particular Node	28
3.7 Power Loss Variations for Different DG Sizes at Node 83	29
3.8 Power Loss Variations for Different DG Sizes at Node 76 and 64	29
3.9 Unbalanced Voltage Profile of IEEE 123 Node Test Feeder	31
3.10 Unbalanced Voltage Profile with 1500 kW and 4000 kW DG at Node 83 ...	32
4.1 Electric Load Flow Architecture	33
4.2 Initial Sensitivity Values at Node 83 with DG Size Variation	34
4.3 Algorithm for Continual Sensitivity Analysis	37
4.4 Variation of Power Loss with Optimal DG Placement	39
4.5 Unbalanced Voltage Profile with 48 DG Units	40
4.6 Annual Load Profile	41

Figure	Page
4.7 Loss Analysis with Optimal DG Placement	44
4.8 Modified Algorithm for Optimal DG Placement	46
4.9 Annual Simulation Analysis Results	47
5.1 Gas Transmission Pipeline System Map	49
5.2 IEEE 123 Node Gas Distribution Network	52
5.3 IEEE 123 Node Base Case Pressures	55
5.4 Combined Electric and Gas Load Flow Architecture	56
5.5 IEEE 123 Node Pressures with 48 Microturbines in Distribution Network ...	57
5.6 IEEE 123 Node Pressures with 38 Microturbines in Distribution Network ...	58
5.7 IEEE 123 Node Pressures with 31 Microturbines in Distribution Network ...	59
5.8 IEEE 123 Node Pressures with 24 Microturbines in Distribution Network ...	60
5.9 Nodal Gas Pressure for Microturbine Placement in Gas Network	61

NOMENCLATURE

ABC	Artificial bee colony
ACOPF	AC optimal power flow
AEP	American Electric Power
AI	Artificial Intelligence
ANSI	American National Standards Institute
CCHP	Combined cooling, heating and power
CERTS	Consortium of Electric Reliability Technology Solution
cfh	Cubic feet per hour
CHP	Combined heat and power
COM	Computer Object Model
DG	Distributed generation
DISCO	Distribution company
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
GA	Genetic algorithm
i	Iteration
I	Current flowing through the line
I_i	Current of the element
IEEE	Institute of Electrical and Electronics Engineers
LM	Load Multiplier
Mcfh	Thousand cubic feet per hour
MDPE	Medium density polyethylene
MG	Microgrid

n	Node in the distribution system
OpenDSS	Open Source Distribution System Simulator
P_G	Power generated
P_L	Real power loss in the system
PLR	Percentage Loss Reduction
PNNL	Pacific Northwest National Laboratory
psi	Pounds per square inch
pu	Per unit
R	Per phase resistance of the line
R_i	Resistance of the element
S_n^i	Sensitivity index
SOFC	Solid oxide fuel cell
SRP	Salt River Project
V_G	Magnitude of voltage at generation node
V_L	Magnitude of voltage at load node
X	Per phase reactance of the line
δ	Capacity of test DG in kW

CHAPTER 1

INTRODUCTION

1.1 Overview

A worldwide energy crisis and increased environmental concerns have been the driving force for the development and increased penetration of distributed generation (DG) into electric distribution systems. Many states in US have encouraged the development of smaller generation facilities that connects directly at the distribution level of the electricity system. Traditional centralized power plants are inefficient and environmentally unfriendly as they use fossil fuels for energy generation. With the continuing market deregulation, the DG penetration into the distribution systems has rapidly increased over the years. The concept of DG differs from the traditional centralized power plants, where the electricity is generated in large power plants and then transmitted to the customers through transmission and distribution lines. The central power plants are critical to global energy supply, but their flexibility to adjust to changing energy needs is limited.

The spare natural gas in the gas distribution pipelines flowing through the residential areas can be utilized to generate electricity locally by feeding natural gas into microturbines. These microturbines can be connected in parallel with the electric grid. These types of distributed generation systems have capacity to generate 25 to 500 kW of electricity, and are suitable for generating electricity at residential or small scale commercial level [1]. This project can be realized as a community microgrid where

several residential customers (200-1000) can purchase small natural gas microturbine units and place them at several locations in their residential area.

1.2 Research Motivation and Objectives

This study is interdependent on both electrical and gas distribution networks. The locations and capacity should be selected in such a way that the existing grid conditions and gas distribution flow parameters are maintained, and there is no need for electric distribution feeder up-gradation or gas pipeline reinforcement. To the knowledge of the author, the assessment of optimal locations and capacity of microturbines has not been done at a distributed level.

The objective of this study is to develop a generalized approach of placing multiple microturbine units in integrated electrical and natural gas distribution network. The electric distribution feeder has been modeled in a commercially available distribution system analysis software, OpenDSS, to suggest optimal locations on the distribution feeder where small natural gas microturbines can be placed in a way that system power losses are minimized. The gas distribution network is modeled in GASWorkS software and various cases are simulated to check the pressure drop in the gas network, and assess the cases which would not result in gas pipeline reinforcement.

1.3 Thesis Organization

The main contents of this thesis are partitioned into five chapters. The first chapter provides an introduction and presents research motivation and objectives of this study. Chapter two discusses relevant background and literature review. An overview of electric distribution system, natural gas network and distributed generation is given, and

present methodologies to assess distributed generation are discussed. In chapter three, the developed methodology of optimally allocating distributed generation in the electric distribution network is discussed. It is based on continual sensitivity analysis and the method is tested for IEEE 123 node test feeder for peak loss reduction. In chapter four, the algorithm is modified to include annual simulation technique for minimizing the annual average power losses in the distribution system. The result analysis and discussions for the solved model are presented. In chapter five, a gas distribution network has been designed in accordance with the selected electric distribution system. The base nodal gas consumption of the household is first calculated, and then microturbines are placed in the gas distribution network for various cases. The result analysis and discussion for the gas distribution network are presented, and the optimal case based on the gas pressure guarantee is selected. Chapter six concludes the thesis by describing important results, conclusions, contributions and future work. There are five appendices provided. Appendix A describes the corresponding OpenDSS file for developing the IEEE 123 node test feeder. Appendix B, C, D, and E describes the MATLAB algorithm developed for performing various tasks for this study.

CHAPTER 2

LITERATURE REVIEW

2.1 Natural Gas Distribution Network

Natural Gas network is quite similar to the electrical network, both systems being designed to carry energy from suppliers to customers. They can be divided into:

- Suppliers (gas fields)
- Transmission (high pressure network)
- Distribution (medium/low pressure network)
- Customers (gas customers)

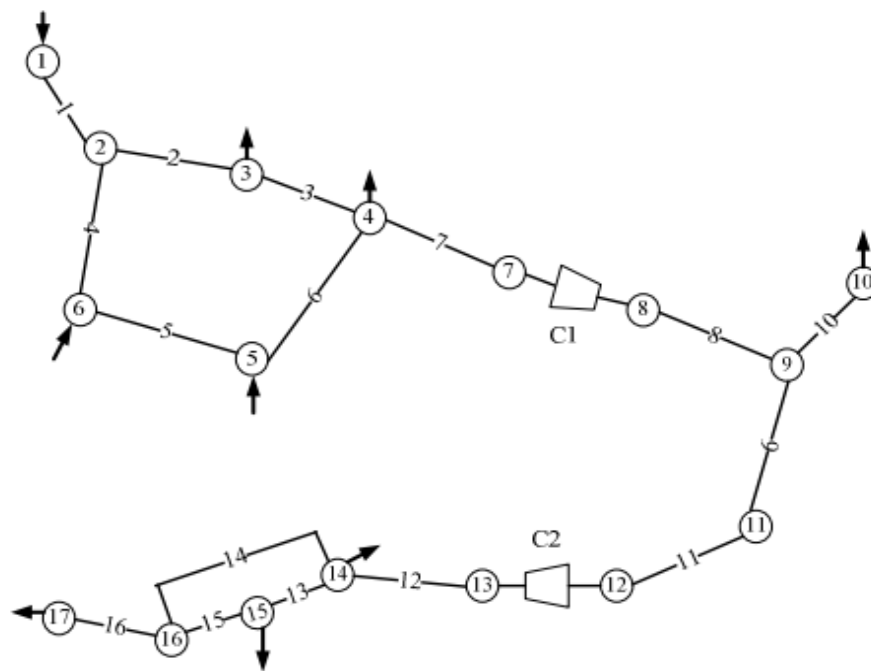


Figure 2.1 Pipeline network structure diagram [2]

Figure 2.1 shows gas pipeline network consisting of 17 nodes, 16 pipelines and 2 compressor stations [2]. In this network, nodes 1, 5 and 6 are supply nodes, and nodes 3,

4, 10, 14, 15 and 17 are gas loads. Two compressor stations C1 and C2 are present in the gas network to transport the natural gas smoothly and meet the gas pressure limits of customers. Gas systems can store energy in the gas pipelines which can be utilized during the peak load, while electrical energy storage is not very efficient. Line Packing is a special characteristic of natural gas pipelines, which is the ability to effectively store small quantities of natural gas for shorter durations, that can be used to manage the load fluctuations on the system. A 50 mile section of 42 inch transmission gas pipeline operating at 1000 psi contains about 200 million cubic feet of gas, which is sufficient to provide gas to 2000 households for a year for cooking purposes [3]. Line packing is done by storing natural gas when the demand is less, by increasing the operating pressure of pipe, which later can be used during periods of high demand.

Table 2.1 Gas and electric network analogies [4]

Aspect	Gas system	Electric system
Potential	Pressure (N/m^2)	Voltage (V)
Flux	Flow (m^3/s)	Current (A)
Power	Pressure*Flow (W)	Voltage*Current (W)
Power loss	Δ Pressure*Flow (W)	Δ Voltage*Current (W)
Resistance	Friction factor (k)	Impedance (Ω)

Table 2.1 gives an overview of the main terms considered when an integrated electric and gas system is developed. Figure 2.2 shows a natural gas distribution network in Gurgaon, India where existing and proposed gas distribution pipelines are shown.

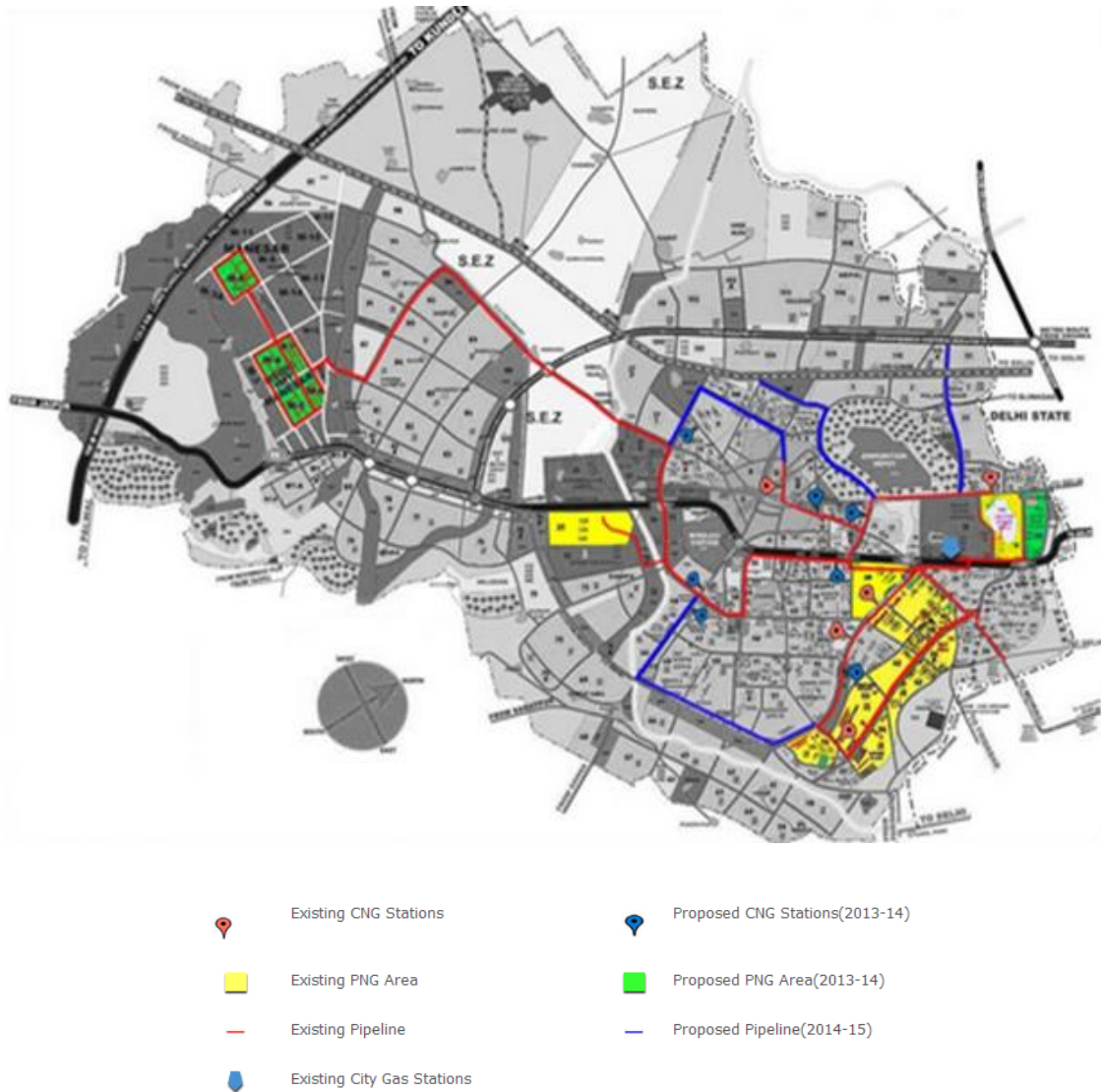


Figure 2.2 Natural gas distribution network in Gurgaon, India geographical area [5]

The U.S. natural gas pipeline network is highly integrated transmission and distribution network of gas wells, gathering lines, compressor stations, transmission and distribution lines, and storage facilities. The gas is carried from the gas fields to customers through an extensive network of gas pipelines. The transmission gas pipelines operate between 200 psi to 1500 psi, and its diameter can range from 20 inches to 42

inches [3]. Compressor stations are located every 50 to 60 miles to boost the pressure which is lost because of the friction of the natural gas moving through the steel pipe. Larger commercial, industrial and electric generation customers directly receive the natural gas from high pressure pipelines. Gate station reduces the pipeline pressure from transmission levels (200 psi to 1500 psi) to distribution levels (1/4 psi to 200 psi), and measures the gas flow rate. Natural gas then moves from gate stations to distribution pipelines of diameter in the range from 2 inches to 24 inches. Natural gas arrives to a household through a service line which is a small diameter plastic line ranging from an inch or less in diameter, and operating between 1/4 psi to 60 psi.

According to a recent report by Gas Technology Institute, the integration of natural gas with electricity into a highly reliable energy delivery network would provide an increased level of reliability [6]. According to U.S. Energy Information Administration (EIA), natural gas fired plants will account for 63% of capacity addition from 2012 to 2040 [7].

2.2 Distributed Generation

Electric power distribution is one of the major areas of an electric power infrastructure that transfers electricity from high voltage transmission system to the end users, and it consists of tap changing transformers, voltage regulators, protection devices, switches and reactive power compensation devices [8].

The term Distributed Generation (DG) refers to any electric power production technology that is closer to the point of use, and is integrated with the distribution systems. Distributed generators are connected to the low or medium voltage grid. The

Electric Power Research Institute (EPRI) defines distributed generation as generation from a few kilowatts up to 50 MW [9]. ANSI/IEEE standard 1001 states that "small dispersed generators are less than 5 MW and normally connected to the utility distribution system" [10]. In distributed electricity systems the micro generators are directly connected to households, factories, offices and to low voltage distribution grid. Electricity not consumed by the directly connected customers can be fed back into the distribution network. Electricity storage systems can be utilized to store the excess generated energy. Distribution generating systems are capable of operating on broad range of gas fuels, and offer clean, efficient, reliable and flexible on-site power alternative.

Interest in operating DG in parallel with utility distribution systems has been increasing rapidly because of its wide variety of advantages [11], [12]:

1. Backup power to improve the availability of electric power
2. Power loss reduction
3. Transmission congestion alleviation
4. Improved reliability
5. Energy efficiency
6. Improved power quality
7. Voltage profile improvement
8. Peak load shaving
9. Cogeneration, also known as Combined heat and power (CHP)
10. Selling power to the grid under net metering

A number of DG technologies have been promoted by different states through incentive programs. These include solar PV, fuel cells, wind turbines, microturbines and energy storage technologies. The main characteristics of DG technologies are summarized in Table 2.2 [13], [14] and [15]:

Table 2.2 Summary of DG technologies

	Fuel cells	PV generators	Microturbines
Size range	1 kW-2 MW	1 kW-1 MW	25 kW-1 MW
Installation cost (\$/kWh)	3000-4000	6000-10,000	700-1100
O & M costs (\$/kWh)	0.003-0.015	0.001-0.004	0.002-0.01
Efficiency	40-70%	10-20%	25-30%
Energy density (kW/m ²)	1-3	0.02	59

A microgrid (MG) is defined as an interconnected network of distributed energy systems (DG resources and loads) that can function irrespective of their connection with the grid [16]. Microgrid generation resources can include solar, wind, fuel cells or other energy sources. With the efficient integration of small scale distributed generation resources into low voltage system and its ability to supply local customer demand, the microgrid have a number of benefits [17]:

1. Encouraging public to involve in community investment of small scale generation
2. Reduction in marginal central power plants
3. Reduction in system losses
4. Development of green and sustainable electricity
5. Better network congestion management and improved security of supply

Many types of microgrids have been developed for small and large scale operations. American Electric Power (AEP) developed a microgrid test bed for the Consortium of Electric Reliability Technology Solution (CERTS). It has three 60 kW natural gas generators, and are connected to AEP distribution network [18]. A residential microgrid model is shown in Figure 2.3 where green square boxes represents household gas loads, and red square boxes are for natural gas microturbine gas loads. It is a part of Chandler residential area, and the model is developed in GASWorkS software.



Figure 2.3 Residential microgrid model

A microgrid was built at Illinois Institute of Technology (IIT) for improving the existing electric distribution system on the campus. The old electric distribution system at the campus experiences three or more power outages every year and annual losses of up

to \$500,000. The upgraded power system consists of onsite power generation, intelligent system controllers, demand response capability, and self sustaining electricity infrastructure [19]. A microgrid developed in Kythnos is a single phase standalone system consisting of PV modules of 10 kW, three battery inverters of 3.6 kW each, a 53 kWh battery bank and a 5 kVA diesel Genset [20]. This microgrid is operated in islanded mode, and used to research on centralized and decentralized control strategies in islanded mode.

2.3 Natural Gas Microturbine Technologies

Microturbines provided by Capstone Turbine Corporation are widely used by small scale industrial customers. Capstone microturbines are used in distributed power generation applications including secure power, cogeneration, resource recovery and hybrid electric vehicles. They provide 30 kW, 65 kW and 200 kW products. Capstone microturbines can be connected to the grid or they can operate as stand-alone, they can operate continuously or on-demand as per the requirement. These microturbines run on a variety of fuels: natural gas, flare gas, diesel, biogas, propane and kerosene [21].

Table 2.3 Capstone microturbine C65 cost parameters

Parameter	Capital Cost (\$)	Replacement Cost (\$)	O&M Cost (\$)	Lifetime (hours)
C65 microturbine	90,000	70,000	0.013	175,200

The cost data of Capstone microturbine C65 is shown in Table 2.3. All the data were achieved from relevant technical reference [22] and with the consultation of

distributors of Capstone microturbines. Specifications of Capstone microturbines are shown in Figure 2.4.

Model	Fuels	Power Output ⁽¹⁾	Electrical Efficiency	Exhaust Gas Flow		Exhaust Temperature		Net Heat Rate		Dimensions ⁽²⁾ (W x D x H)	
		kW	%	kg/s	lbm/s	C°	F°	MJ/kWh	btu/kWh	m	in
GASEOUS FUELS⁽³⁾											
C30 LP	NG	28	25	0.31	0.68	275	530	13.8	13,100	0.76 x 1.5 x 1.8	30 x 60 x 70
C30 HP	NG, P, LG, DG	30	26	0.31	0.68	275	530	13.8	13,100	0.76 x 1.5 x 1.8	30 x 60 x 70
C30 HZLC ⁽⁴⁾	NG	30	26	0.32	0.70	275	530	13.8	13,100	0.87 x 2.9 x 2.2	34 x 112 x 85
C65	NG, P	65	29	0.49	1.08	309	588	12.4	11,800	0.76 x 1.9 x 1.8	30 x 77 x 76
C65 ICHP	NG, P, LG, DG	65	29	0.49	1.08	309	588	12.4	11,800	0.76 x 2.2 x 2.4	30 x 87 x 93
C65 CARB	NG	65	28	0.51	1.13	311	592	12.9	12,200	0.76 x 2.2 x 2.6	30 x 87 x 103
C65 CARB	LG, DG	65	29	0.49	1.08	309	588	12.4	11,800	0.76 x 2.2 x 2.6	30 x 77 x 85
C65 HZLC ⁽⁴⁾	NG	65	29	0.50	1.09	325	617	12.9	12,200	0.87 x 3.2 x 2.3	35 x 128 x 90
C200 LP	NG	190	31	1.3	2.9	280	535	11.6	11,000	1.7 x 3.8 x 2.5	67 x 150 x 98
C200 HP	NG, P, LG, DG	200	33	1.3	2.9	280	535	10.9	10,300	1.7 x 3.8 x 2.5	67 x 150 x 98
C200 HZLC ⁽⁴⁾	NG	200	33	1.3	2.9	280	535	10.9	10,300	1.9 x 3.2 x 3.1	74 x 126 x 122
C600 LP	NG	570	31	4.0	8.8	280	535	11.6	11,000	2.4 x 9.1 x 2.9	96 x 360 x 114
C600 HP	NG, P, LG, DG	600	33	4.0	8.8	280	535	10.9	10,300	2.4 x 9.1 x 2.9	96 x 360 x 114
C800 LP	NG	760	31	5.3	11.7	280	535	11.6	11,000	2.4 x 9.1 x 2.9	96 x 360 x 114
C800 HP	NG, P, LG, DG	800	33	5.3	11.7	280	535	10.9	10,300	2.4 x 9.1 x 2.9	96 x 360 x 114
C1000 LP	NG	950	31	6.7	14.7	280	535	11.6	11,000	2.4 x 9.1 x 2.9	96 x 360 x 114
C1000 HP	NG, P, LG, DG	1000	33	6.7	14.7	280	535	10.9	10,300	2.4 x 9.1 x 2.9	96 x 360 x 114
LIQUID FUELS⁽⁵⁾											
C30	D, A, K	29	25	0.31	0.69	275	530	14.4	13,700	0.76 x 1.5 x 1.9	30 x 60 x 70
C65	D, A, K	65	29	0.49	1.08	309	588	12.4	11,800	0.76 x 1.9 x 1.8	30 x 77 x 76
C65 ICHP	D, A, K	65	29	0.49	1.08	309	588	12.4	11,800	0.76 x 2.2 x 2.4	30 x 87 x 93
C200	D	190	30	1.3	2.9	280	535	10.9	10,300	1.7 x 3.8 x 2.5	67 x 150 x 98

⁽¹⁾ Nominal full power performance at ISO conditions: 59° F, 14.696 psia, 60% RH
⁽²⁾ Height dimensions are to the roofline. Exhaust outlet can extend up to 7 inches above the roofline.
⁽³⁾ Models available to operate on these different fuels: NG – Natural Gas; P – Propane; LG – Landfill Gas; DG – Digester Gas
⁽⁴⁾ Hazardous Location units suitable for use in potentially explosive atmospheres (UL Class I, Division 2 or Atex Class I, Zone 2)
⁽⁵⁾ Models available to operate on these different fuels: D – Diesel; A – Aviation; K – Kerosene

Figure 2.4 Specifications of Capstone microturbines [22]

Micro Turbine Technology BV (MTT) has developed recuperated microturbines up to 30 kW of electric power for CHP (Combined Heat and Power) and other applications. They generally operate on natural gas for the domestic micro CHP application, though it can also operate on liquid fuels such as heating oil or diesel. Their most popular product in the market is 3 kW unit, which they claim can reduce the energy

bill by 20-25 % [23]. It meets the environmental standards with low noise and exhaust emissions.

As a part of SRP's renewable energy program a commercial-scale fuel cell power system utilizing natural gas has been implemented at ASU east campus. The fuel cell is a large-scale 250 kWac molten carbonate fuel cell system, fueled by natural gas [24]. Electric output from the fuel cell (480 Vac) is stepped-up to 12 kV and interconnected to the SRP electric grid. Natural gas is supplied at 15 psi and its annual energy output is 1,752 MWh.



Figure 2.5 Commercial fuel cell running on natural gas at ASU east campus [24]

DOE's Pacific Northwest National Laboratory (PNNL) developed a Solid Oxide Fuel Cell (SOFC) system that uses methane, the primary component of natural gas, as its fuel and achieves efficiency of 57 percent, significantly higher than the 30 to 50 percent efficiencies previously reported for other solid oxide fuel cell systems. The pilot system

generates about 2 kW of electricity, which can be scaled up to produce between 100 and 250 kW [25].

2.4 Impacts of DG on the Transmission and Distribution System

DG may have positive and negative impacts on the transmission and distribution system. The current penetration level of DG is low which have resulted in relatively lower impact of DG on the distribution and transmission system [26]. With the increase in DG penetration level, the expected impacts will increase. These impacts would first occur on the distribution system due to its direct connection with DG; however, with further increase in DG penetration level, transmission system will also have impacts. Many of the DG impacts are because the grid was not originally designed to accommodate generation on the distribution system. A report published by Rocky Mountain Institute and PG&E in March 2012 claims that "DG that is at the right place at the right time will create the greatest value, while additional electricity supply in the wrong place at the wrong time could result in added costs to the system."

As DG penetration level increases, there are more chances of reverse power flow, that is, generation flowing back to the distribution system. Reverse power flow can impact the coordination between DG installations and existing distribution feeder automated protection features. Also, some load tap changers that regulates voltage may not function correctly if electricity flows opposite to their original design [11].

2.4.1 Size and Location Dependent Impact of DG

The capacity and location of the DG unit can affect its impact on the distribution grid. A smaller DG unit generally has lower risk of having negative impacts and causing

grid instability through voltage and frequency fluctuations, faults, tripping protection schemes or back-feeding onto the transmission system. However, these impacts are also dependent on the distribution circuit. Some circuits may have necessary characteristics and capacity to easily accommodate a single large DG unit, while other circuit may not be able to handle a large DG unit [11].

Location of the DG unit along the radial distribution circuit, i.e., whether it is near the substation or far from substation, affects the size of DG unit. In general, a larger number of small DG units would have lesser negative impact on grid operations than a smaller number of large DG systems. Geographic locations of DG units affect grid operations. If large numbers of DG units are clustered then it can affect grid operations, as they resemble a single large DG unit.

2.5 Network DG Capacity Assessment

A number of publications have investigated the interaction between electricity and natural gas networks. Most of the existing publications deal with interaction between electricity and natural gas networks at a transmission level rather than the distribution level. In [27], the proposed model is formulated as a mixed-integer linear optimization problem where the investment and operation costs are minimized to determine the optimal location and technologies of new power generation. The case study of Brazilian integrated electricity and gas system is studied. Reference [28] focuses on integrated formulation of steady state analysis of electricity and gas systems considering the effect of temperature in the natural gas system operation, and distributed slack node technique in the electricity network. The Newton-Raphson formulation is used to demonstrate the

applicability of the proposed approach on Belgian gas network combined with the IEEE-14 test system.

The nexus between distributed generation, urban gas and water network infrastructure has been discussed in [29], [30] and [31]. An integrated dispatch model is discussed in [29] where optimal DG capacity is assessed for integrated electricity and water network in urban setting. Reference [32] analyzes the impacts of gas and water distribution networks on the optimal locations and capacity of distributed generation. A microgrid model is developed for residential community in Phoenix using Photovoltaic (PV) modules, microturbines and fuel cells as distributed energy resources. The model proposes using exhaust heat from the microturbines to provide daily hot water demand, and absorption chillers are connected to the microturbines to provide cooling, achieving combined cooling, heating and power (CCHP). Reference [33] discusses a methodology of planning complex energy service systems with multiple energy carriers. A methodology including economic, technical and environmental aspects is developed and is used for integrated planning of electricity, gas and heat.

Various mathematical optimization based studies in the literature assesses optimal DG location and capacity. In [34] and [35], the AC optimal power flow (ACOPF)-based techniques are used to analyze the optimal DG capacity, for which the DG locations in the network are fixed and maximum DG power injections are evaluated. Multi-objective optimization techniques are proposed for DG capacity assessment in [36] and [37]. Reference [38] discusses an optimization model to assess optimal DG locations and capacity based on the cost-benefit analysis approach. A heuristic method based on exact loss formula is proposed in [39]. The location and size of the first DG unit is search by

the algorithm, it is then fixed and all the possible solutions for second DG unit are checked. This type of heuristic method does not search the whole solution space, and the result might not be optimum. The 2/3 rule is often used for capacitor allocation in electric distribution network. Similar approach is used in [40] to analyze radial distribution system with uniformly distributed load for power loss minimization. However, this approach does not provide a proper solution when the load distribution type is varied, and it cannot be applied in meshed network.

DG has a wide variety of advantages, e.g. power loss reduction, voltage profile improvement, reliability and transmission congestion alleviation [41]. However, inappropriate planning may bring in negative impacts to the operation and reliability of distribution systems. It is essential to allocate distributed generation at proper location and with optimal capacity to maximize the economic benefits and overall system efficiency. Allocating DG with inappropriate planning may lead to higher power loss as compared to when no DG exists in the distribution network at all [42]. In [41], the power loss profile for the system with DG installation is discussed. An approach to perform repeated power flow on OpenDSS using MATLAB linked through COM server is developed. Results obtained from the developed method are compared with repeated load flow method, and they are fairly equal. Some analytical approaches for optimal DG sizing and allocation for radial and networked distribution system to minimize the system power loss are discussed in [43]. The proposed approaches are not iterative algorithms, like power flows, and there are no convergence problems involved. Although, results are obtained very quickly from this analysis, only overhead lines with uniformly distributed

reactance and resistance along the feeder is considered. However, in practical distribution network conductor size gradually decreases from substation to the load centre [44].

In [45], methodology of optimally allocating DG units in meshed electric power systems is discussed. The objective function consists of system loading margin and the profit of the distribution companies (DISCOs) over the planning period, and it is solved using genetic algorithm (GA). In [46], a multi-objective index-based approach to optimally allocate DG units in distribution system with non-unity power factor considering different load models is discussed. The proposed multi-objective function considers a wide range of technical issues and particle swarm optimization technique is used. In [47], an adaptive weight particle swarm intelligence optimization algorithm has been developed to determine optimum generation capacity of multiple DG units. The unbalanced three phase distribution load flow has been performed using OpenDSS tool and IEEE 123 node test feeder is used as test bed. In [48], an optimization approach based on artificial bee colony (ABC) algorithm is used to determine the optimal size, power factor and location of DG unit to minimize the total system power loss. These techniques give a single or multi (2-4) large DG units in the distribution network. However, the objective of the proposed research study is to allocate several (20-40) smaller DG units in the residential distribution network. Although these techniques based on artificial intelligence (AI) provides near optimum solution, they have slow convergence characteristic and are computationally very demanding [44].

Most of the research on DG allocation and sizing has been based on a balanced distribution system. However, the distribution network is unbalanced three-phase system and more analysis is needed based on this consideration. A methodology based on

sensitivity analysis has been proposed in [41] and [47]. Sensitivity value for each location is captured by analyzing the change in power loss when a small DG unit is placed at that location. The capacity of DG unit at the selected location is decided by increasing the size of DG until the total system power losses starts increasing. This approach results in a large DG unit at a single location. However, it might not be possible to install large microturbine units in residential areas.

2.6 Conclusions

To the knowledge of the author, the optimal locations and capacity of natural gas microturbines have not been assessed at a distributed level. Most of the existing publications investigating the interaction between electricity and natural gas networks deals at a transmission level. Various mathematical optimization based studies have been performed to assess optimal DG location and capacity, but they are computationally complex and yield single or multiple (2-3) optimal DG locations. A generalized approach needs to be developed to assess optimal placement of multiple natural gas microturbine units in residential distribution network.

CHAPTER 3

ELECTRICAL DISTRIBUTION MODELING

3.1 Test System and Analytical Tools

The electrical system selected has to be a distribution system such that energy and gas infrastructure can be developed based on it. Local utilities Salt River Project (SRP) and SouthWest Gas were consulted for residential area selection. SRP suggested residential area of Chandler consisting of 200 houses. The area is surrounded by Adams Ave on East, McQueen Road on West, Ocotillo Road on North and Brooks Farm Road on South, as shown in Figure 3.1 and Figure 3.2.

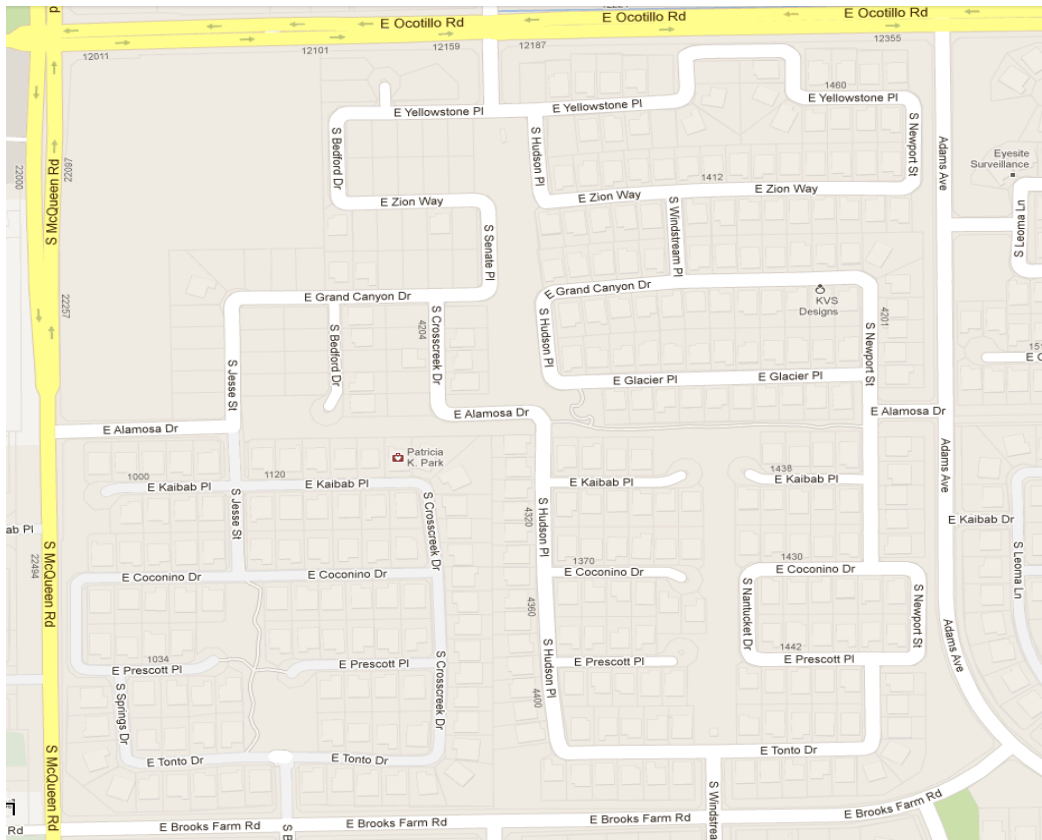


Figure 3.1 Chandler residential area

Chandler area was first selected as the study area and power flow models were developed in PowerWorld Simulator software. However, only feeders' data were provided with insufficient information by Salt River Project (SRP). Due to lack of accurate and complete data, the real test bed plan was abandoned.

Distribution working group of the IEEE PES Distribution System Analysis Subcommittee have released several unbalanced multi-phase test feeders [49]. These test feeders have unbalanced loads with various types of load models, different types of conductors including overhead and underground lines, and voltage control devices like voltage regulators. These distribution feeders are considered for research and planning purposes. The IEEE 123 node test feeder is selected as the electrical system for this study, as shown in Figure 3.3. This system has been already complicated enough as a distribution system feeder and enough electrical data are provided.

This test feeder is actually extracted from some real distribution system in US; therefore, it can be used for research purpose to represent the real system feeder. The system voltage level is 4.16 kV. The main feeder is overhead three-phase, most lateral feeders are single phase overhead, and some two-phase overhead feeders are also present. One substation transformer and distribution step-down transformer are connected with this feeder. Four step-type voltage regulators are included to improve voltage profile of the system, and four shunt capacitor banks are present for reactive power compensation. It has an unbalanced loading with all combinations of load types, including constant current, constant power and constant impedance. Three-phase switches are also present.

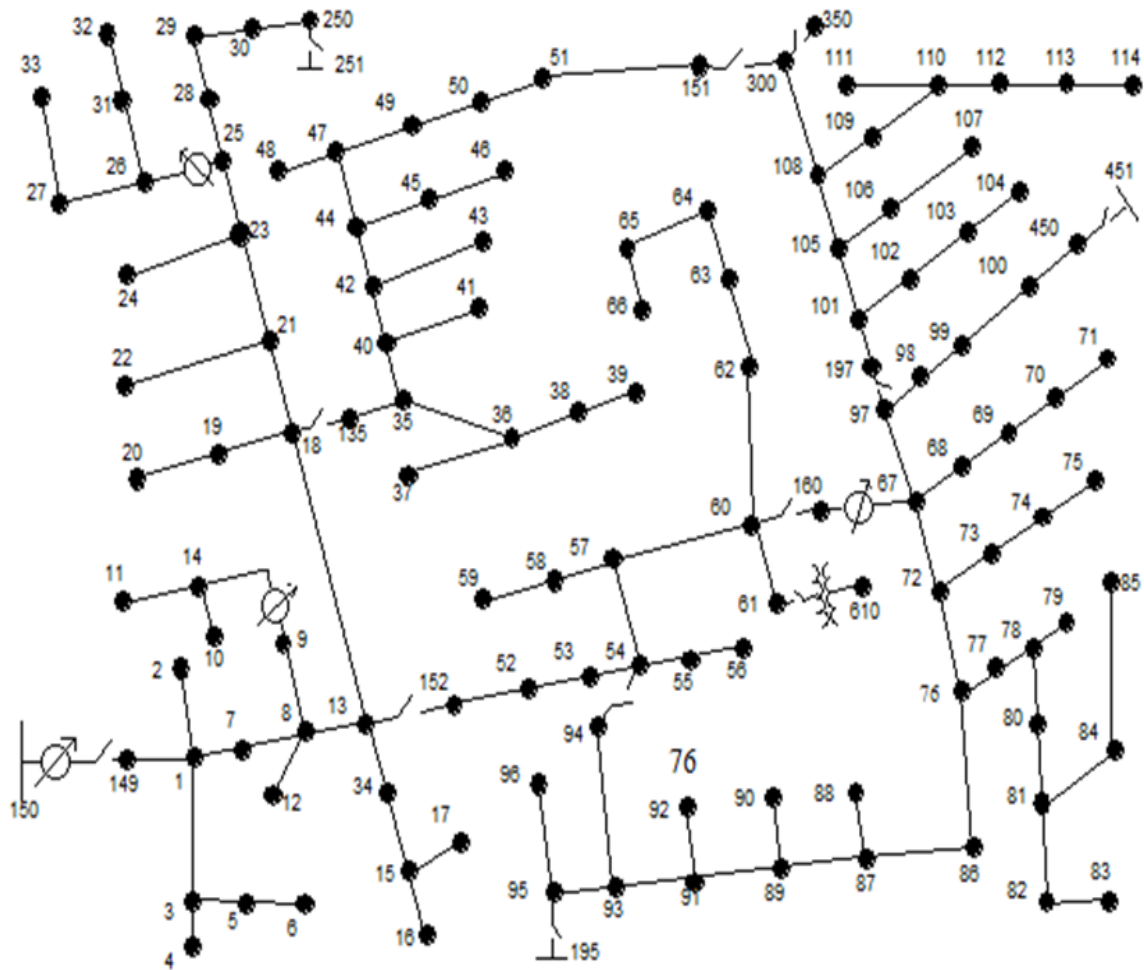


Figure 3.2 IEEE 123 node test feeder [49]

Electric Power Research Institute's (EPRI) open source software Distribution System Simulator (OpenDSS) is used to model unbalanced network components and loads. OpenDSS is a script-driven simulation engine that is normally configured as shown in Figure 3.4. The simulator can be interfaced to data sources and other programs. The engine has a Windows Computer Object Model (COM) interface through which its features can be accessed by other programs [50].

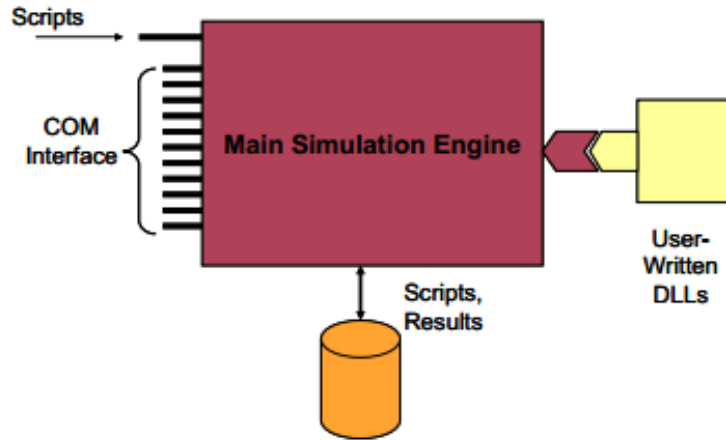


Figure 3.3 OpenDSS Architecture [51]

OpenDSS is a frequency domain tool which supports all rms steady-state analyses and some of its key features are discussed below [51]:

1. It can be interfaced externally with other software, such as Visual Basic, MATLAB, etc.
2. It is possible to model n-phase lines of any arbitrary configuration.
3. The 'dynamic' solution mode can be used for dynamics of power conversion elements.
4. It is an object-oriented program which gives flexibility in adding new models of components and controls without the need to be concerned about other program parts.
5. It can simulate different load types with different configurations and loadings, as well as many different load types on the same node.
6. It can perform sequential time simulations called 'quasi-static solutions.' This feature can be used to perform daily, yearly and duty cycle simulations.

Figure 3.4 shows the internal architecture of the OpenDSS software. A relatively small executive manages most of the interactions; it processes the main script commands and redirects the remainder of it to each class of object for further processing. The DSS Executive stored global variable and options; it has one Circuit object which has a Solution and five classes of general and circuit elements.

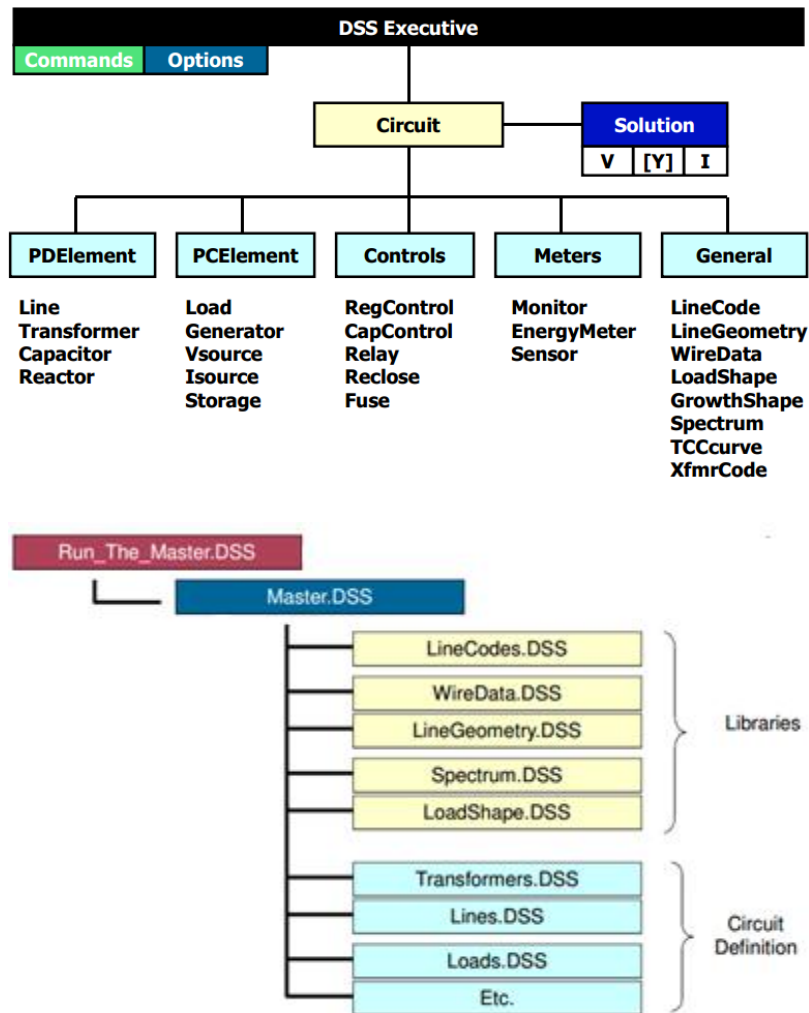


Figure 3.4 OpenDSS object structure [51]

3.2 Power Loss in Distribution System with DG Placement

Power losses occur throughout the transmission of electric energy from generating centers to the load centers due to transmission and distribution line resistances. A distribution system operates at a lower voltage level than a transmission system, and it has a higher resistance. This results in higher power losses in the distribution system than the transmission system. 70% of power losses occur in the distribution network, and only 30% of power losses occur in transmission network [52]. High distribution losses have detrimental impact on the system as it increases the energy demand which results in increase in cost of production. Due to increased load currents across the devices, additional compensation devices are required further increasing the costs. Hence, it is beneficial to keep distribution losses within a limit to maximize overall system efficiency and economic benefits.

Losses in a distribution network comprises of variable and fixed losses. Fixed losses are referred as iron losses and they mainly occur in the cores of transformers and motors, while variable losses are referred as copper losses and they occur in power delivery equipments, such as lines, cables and in transformer copper parts. The variable loss is the most significant part of the losses and it is proportional to the square of the current flowing through the line or device.

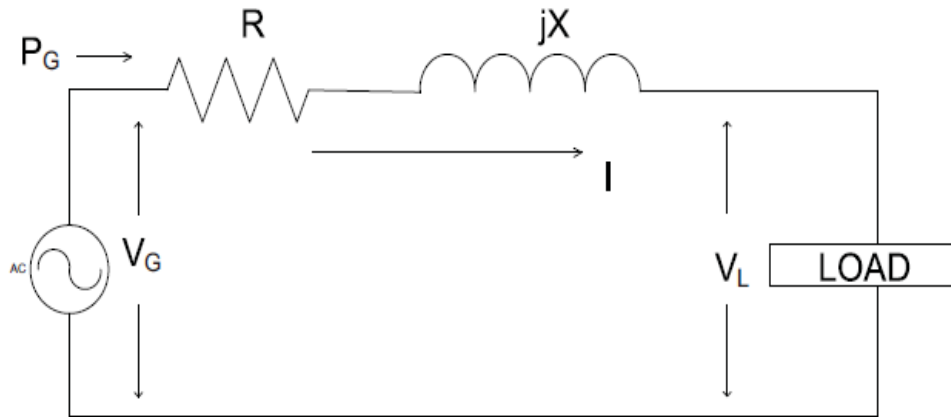


Figure 3.5 Radial line with one generation and one load [53]

Real power losses in any element are associated with the current flowing through it and its series resistance. Total real power loss in a distribution network consisting of 'n' branches is given by:

$$P_L = \sum_{i=1}^n I_i^2 R_i \quad (3.1)$$

where, P_L is the total real power loss in the system, I_i and R_i are the current and resistance of the associated element respectively. Current in any element can be obtained from the load flow study. Considering a simple three-phase balanced equivalent radial transmission line with generation as shown in Figure 3.5, the real power losses are:

$$P_L = 3I^2R \quad (3.2)$$

where, R is per phase resistance of the line, and I is current flowing through the line which can be obtained using:

$$I = \frac{P_G}{\sqrt{3}V_G \cos \theta_G} \quad (3.3)$$

where, P_G refers to the power generated, V_G is the magnitude of voltage at generation node, and $\cos \theta_G$ is the generator power factor. Using the expression for I , the power loss from (3.2) can be expressed as:

$$P_L = \frac{R(P_G)^2}{|V_G|^2(\cos \theta_G)^2} \quad (3.4)$$

Considering generator voltage and power factor to be constant, the losses can be written as:

$$P_L = kP_G^2 \quad (3.5)$$

where,

$$k = \frac{R}{|V_G|^2(\cos \theta_G)^2} \quad (3.6)$$

From (3.5), we can say that power losses in a system are an approximate quadratic function of generation, as discussed in [54]. Placing a DG unit in distribution network will affect the power loss profile of the system. Power loss curve when the generation unit is varied at a particular location is approximately a quadratic function. The total system losses decreases when the DG size (penetration level) is increased up till a point, this particular penetration level is called optimum DG size for that particular node. If the DG size is increased beyond the optimum size, the system loss increases. This variation of power loss with variations in DG size is shown in Figure 3.6 and it has been discussed in [44].

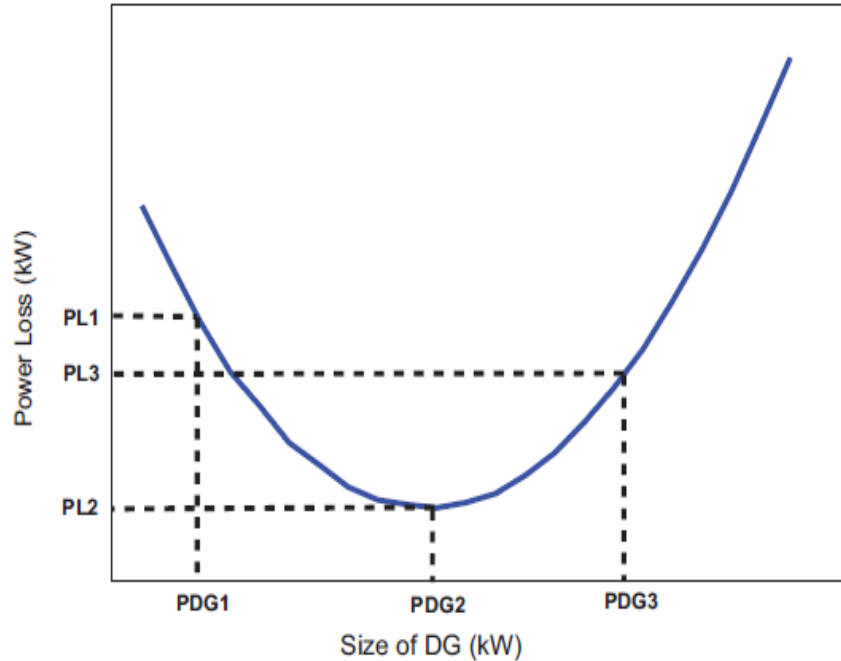


Figure 3.6 Power loss variations for different DG sizes at a particular node

The electrical distribution system is generally designed for unidirectional power flow from distribution substations to the end users. When a DG is placed in the distribution network, it is desirable that power be consumed within the distribution system, thereby avoiding reverse power flow and reducing the system losses. However, placing a DG unit of size greater than optimal capacity will result in reverse power flow towards the distribution substation. A DG is placed at node 83 in the IEEE 123 node test feeder and its size is varied, the OpenDSS file is given in Appendix A and developed MATLAB code is given in Appendix B. The variation in power loss is shown in Figure 3.7.

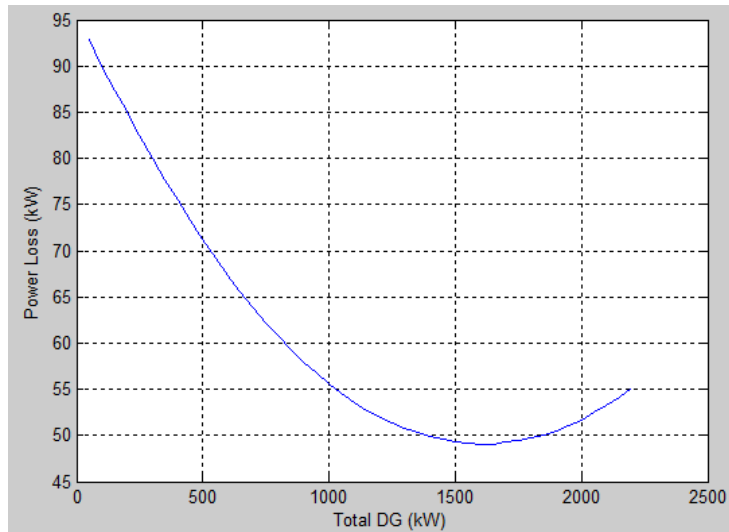


Figure 3.7 Power loss variations for different DG sizes at node 83

The power loss variation pattern is followed when DG size is varied at each location; however, the optimal DG size for each location varies. Power loss variation for different DG sizes at node 22 and node 33 is shown in Figure 3.8. The optimal DG size for node 76 is 2200 kW, and for node 64 is 1500 kW. This reflects that DG units have location impacts on power loss variation.

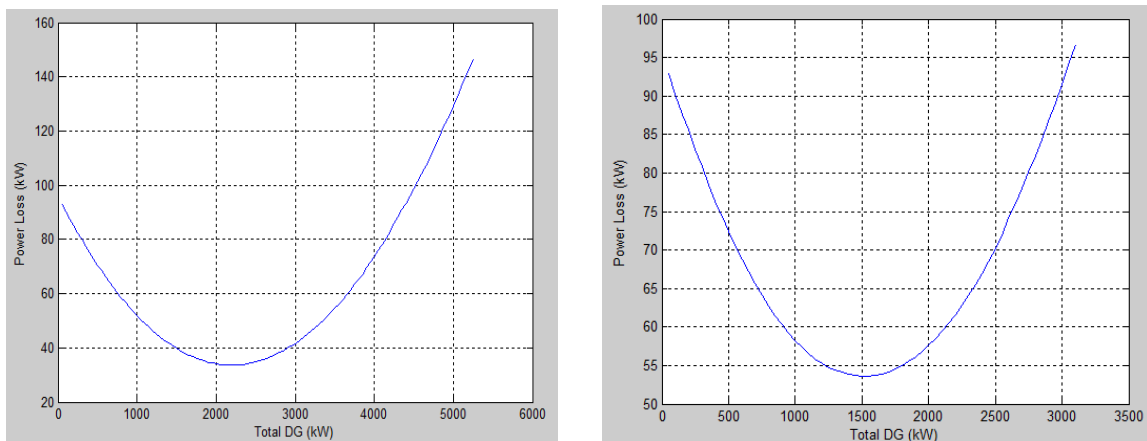


Figure 3.8 Power loss variations for different DG sizes at node 76 and 64

3.3 Voltage Profile with DG Placement

Power system stability comprises of frequency stability, angle stability and voltage stability. Voltage stability refers to the ability of a power system to maintain steady voltages at each of its buses when there is an uncontrollable or progressive voltage drop after a disturbance, increase in load or change in operating conditions [55]. Voltage instability can result in voltage collapse under which the voltage becomes uncontrollable after voltage instability [56]. Voltage collapse can occur due to inadequate reactive power support or a low voltage profile [57]. A DG is generally expected to improve the voltage profile; however, this depends on the penetration level, location and DG technology.

Distribution networks are modeled for power delivery and consumption as a passive network considering the drop in voltage that takes place in distribution network. The resistance of the distribution system conductors is very high which results in voltage drops along the distribution network from the distribution substation to the load centre. For equivalent radial transmission line shown in Figure 3.5, the voltage drop equation can be written as:

$$\Delta V = V_G - V_L = I(R + jX) \quad (3.7)$$

where, V_G and V_L are the magnitude of voltages at generation and load node respectively, I is current flowing through the line, R is per phase resistance of the line, and X is per phase reactance of the line. The impact of DG placement on the voltage profile is studied by placing DG at a particular node in the IEEE 123 node test feeder. The voltage profile of the system in the base case is shown in Figure 3.9, and the

MATLAB code is given in Appendix-C. The voltage regulators are included in the system as defined in the base system.

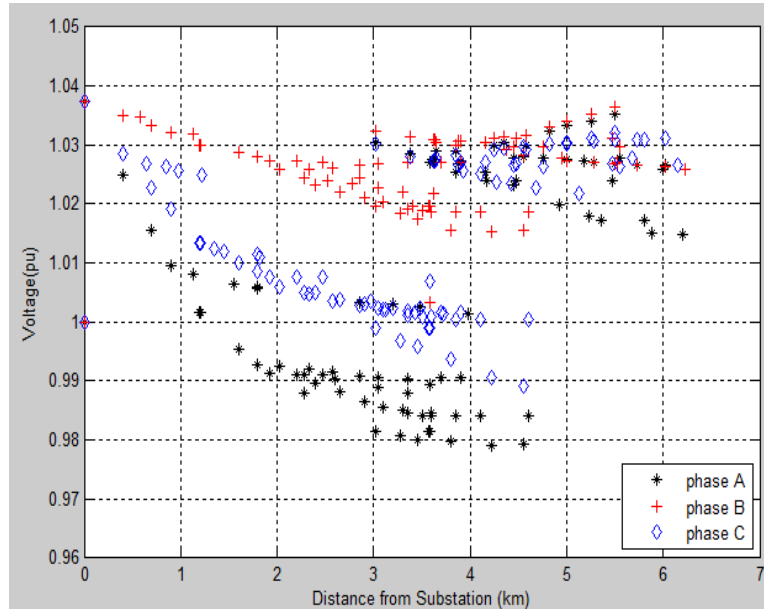


Figure 3.9 Unbalanced voltage profile of IEEE 123 node test feeder

The integration of DG into the system can create a voltage rise; this is particularly true if the DG penetration level is high at a particular node. 1500 kW and 4000 kW DG units are placed at node 83 in the test feeder and the corresponding voltage profile are shown in Figure 3.10. IEEE 1547 specifies the interconnection standards for distributed energy resources [58]. The voltage regulation should be within $\pm 5\%$. However, when a 4000 kW DG is placed at node 83 in the system, the voltage rises beyond five percent at some of the nodes. This analysis shows that voltage profile of the system depends on DG penetration level.

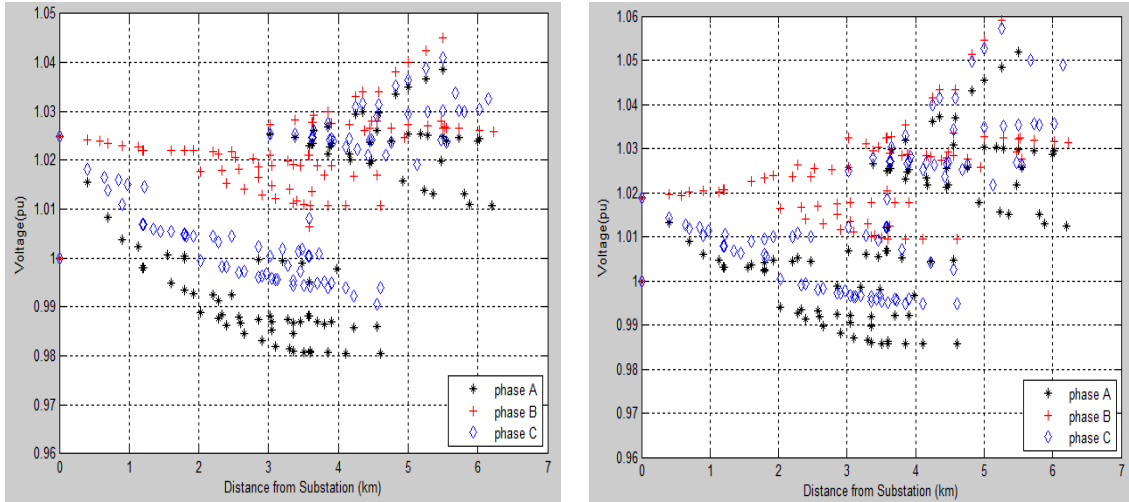


Figure 3.10 Unbalanced voltage profile with 1500 kW and 4000 kW DG at node 83

CHAPTER 4

POWER LOSS MINIMIZATION BASED ON OPTIMUM DG PLANNING

4.1 Sensitivity Calculation

From the previous discussions, it is clear that the location and capacity of DG units have an impact on system losses and voltage profile, which in turn affects economical benefits of integrating DG into the distribution networks. In this section, a heuristic method is proposed for loss reduction in a distribution system. The developed electric load flow architecture is shown in Figure 4.1. Custom scripts for allocating DGs in the IEEE 123 node test feeder are developed in MATLAB and it is interfaced with OpenDSS Simulator through COM Interface. The IEEE 123 node test feeder is developed in OpenDSS using the architecture explained in Figure 3.4, and multiple distributed load flows are run in it. Load flow results after each distributed load flow are exported to MATLAB where it is processed and stored to compare with the results of other load flows, which suggests optimal locations to place DG units to minimize the losses.

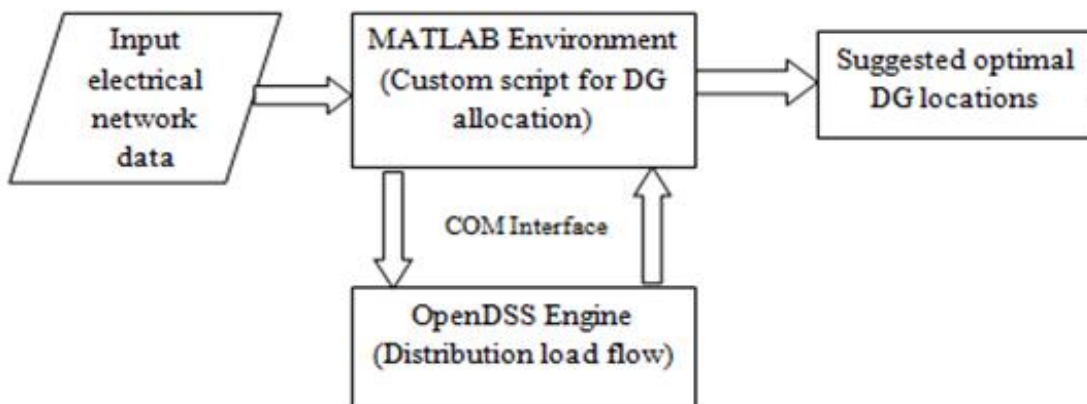


Figure 4.1 Electric load flow architecture

A methodology based on continual sensitivity analysis is proposed. The sensitivity index S_n^i is defined as:

$$S_n^i = \frac{(\text{System Loss})^{i-1} - (\text{System Loss with DG } \delta \text{ at node } n)^i}{\delta} \times 100 \quad (4.1)$$

where, n is the node in the distribution system for which the sensitivity is calculated, i is the iteration, and δ is the capacity of DG in kW. S_n^i reflects the sensitivity value of node n when $(i-1)$ previously selected DG units are in the distribution system, and another DG of δ kW is placed at node n .

The objective of the analysis is to find multiple locations in the distribution system where small size DG units can be placed to minimize the system losses. A DG is placed at node 83 in the IEEE 123 node test feeder and its size is varied to analyze its effect on the sensitivity values. The plot of sensitivity values is shown in Figure 4.2. Here, n is node 83, $\delta = 100$ kW and i is varied.

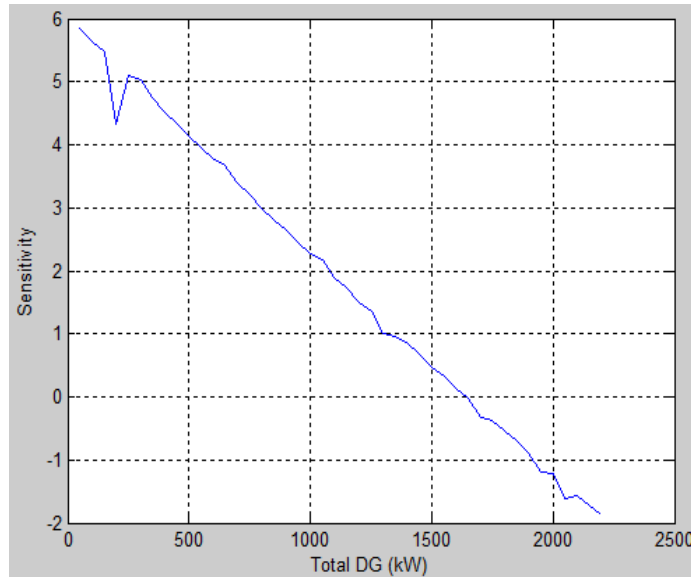


Figure 4.2 Initial sensitivity values at node 83 with DG size variation

It is a continuously decreasing graph, and it reflects that with each subsequent DG addition at the same location the loss reduction keeps on decreasing, that is, added benefit decreases. A positive sensitivity index indicates that there are some positive impacts of DG allocation on the network power loss profile. Negative values of sensitivity reflect that the system losses have start increasing as compared to the previous iteration, which is not desirable when planning for DG placement. There might be several locations with initial sensitivity values near each other. But, when a certain DG is placed at a location, and sensitivity values are again calculated, they will be different than initial values. Table 4.1 shows top ten buses with maximum initial sensitivity values for IEEE 123 node test feeder, where sensitivity of each node is calculated by (4.1).

Table 4.1 Initial sensitivity values

Rank	Bus number	Sensitivity
1.)	95	6.0169
2.)	93	6.0118
3.)	91	6.0017
4.)	89	5.9854
5.)	87	5.9579
6.)	66	5.953
7.)	83	5.9179
8.)	82	5.9165
9.)	81	5.9082
10.)	65	5.906

Bus 95 has maximum initial sensitivity of 6.0169. A 300 kW DG is placed at bus 95, and the sensitivity values are again calculated. Table 4.2 shows top ten buses with maximum sensitivity values after the placement of 300 kW DG at bus 95.

Table 4.2 Sensitivity values after 300 kW DG placement at bus 95

Rank	Bus number	Sensitivity
1.)	66	5.3565
2.)	65	5.3094
3.)	83	5.1505
4.)	82	5.1492
5.)	81	5.1409
6.)	80	5.1279
7.)	64	5.1161
8.)	79	5.084
9.)	78	5.08
10.)	77	5.067

From the above results, it is evident that there are several nodes with initial sensitivity values near 6. A 300 kW DG is put at the node 95 which had the highest sensitivity value, and the sensitivity values are again calculated. As expected, the new sensitivity values are lower than the initial sensitivity values, and the buses having the maximum sensitivity values are different than the buses which had highest initial sensitivity values.

4.2 Continuous Sensitivity Analysis

A methodology based on continual sensitivity analysis is developed and its algorithm is shown in Figure 4.3. The three phase unbalanced load flow is done in OpenDSS Simulator, and the algorithm is developed in MATLAB. OpenDSS is connected to MATLAB through COM server to accept parameters from MATLAB, and then transfer back the results. The relevant code is given in Appendix D.

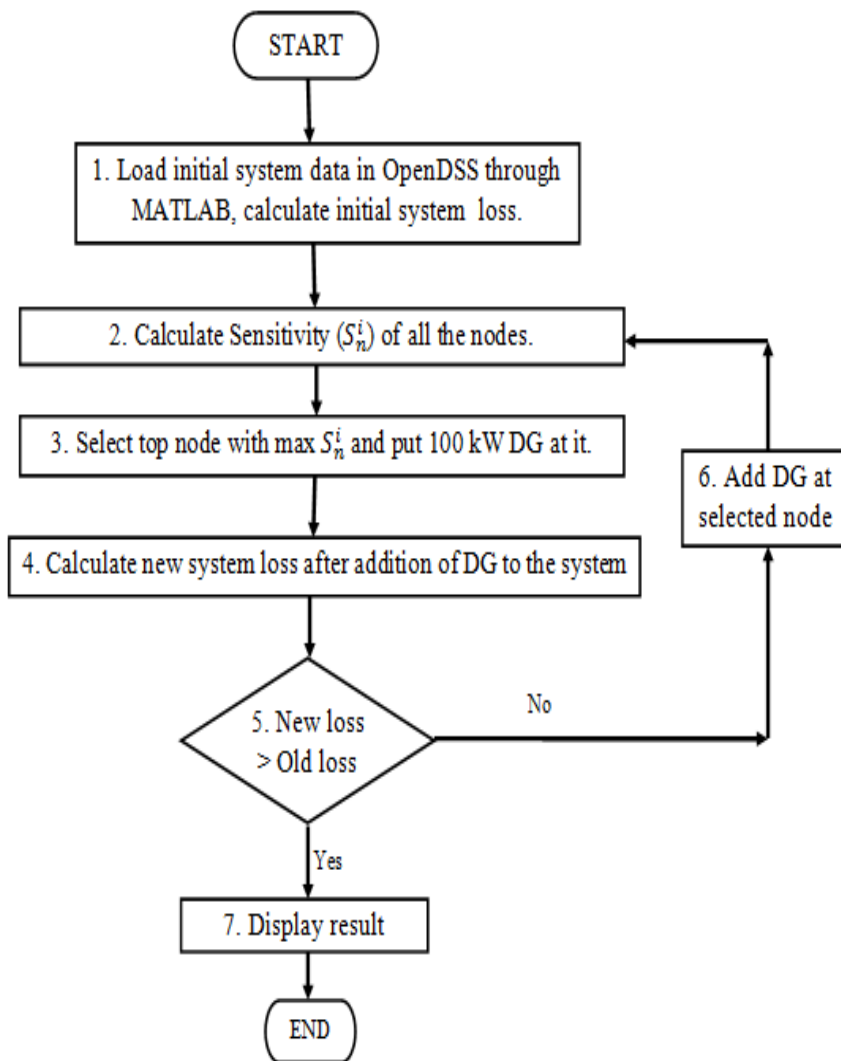


Figure 4.3 Algorithm for continual sensitivity analysis

Step 1: Base case power flow is run in OpenDSS to calculate initial system losses. This value is exported to MATLAB and saved for further comparison.

Step 2: A small DG of δ kW is put at each node in the distribution network and its effect is analyzed by calculating change in system losses. Sensitivity value for each node is calculated by formula given in (4.1) and it reflects the change in losses when an additional δ kW DG is placed in the distribution system.

Step 3: The location with maximum sensitivity as suggested by step 2 is selected for a 100 kW DG placement. For this study, size of a single DG unit is selected as 100 kW because of most of the natural gas microturbines in the market are available in unit size of 100 kW.

Step 4, 5 and 6: The new system loss with an additional 100 kW DG placed at the selected location is calculated. If the system loss of the current iteration is less than the system loss of the previous iteration, the selected DG is placed in the system, and step 2 to step 5 are repeated.

Step 7: With the selected DG in the system, the sensitivity values are again calculated for the next iteration at each location up till a point where system losses starts increasing. When the losses start increasing no further DG is added in the system, and the result is displayed.

4.3 Results and Analysis of Continual Sensitivity Analysis

When the developed continual sensitivity analysis is simulated, placing 48 DGs of 100 kW each is suggested for system loss minimization. Three DGs are suggested at node 76, two DGs at node 48, and following 43 locations are suggested a single DG: node 10,

101, 104, 105, 108, 11, 111, 113, 114, 16, 19, 2, 20, 25, 27, 29, 33, 35, 36, 4, 42, 46, 47, 49, 5, 50, 53, 6, 62, 64, 65, 66, 67, 71, 72, 75, 80, 82, 86, 89, 9, 93 and 99.

When a total of 4.8 MW DG is installed in the distribution network, the system losses are reduced to 12.4 kW. Initial system losses are 95.7 kW, which results in Percentage Loss Reduction (*PLR*) of 87%, where *PLR* is given by:

$$PLR = \frac{\text{System losses with suggested DG placement} - \text{Initial system losses}}{\text{Initial system losses}} \times 100 \% \quad (4.2)$$

However, it is realized that the loss reduction for each iteration keeps on decreasing. That is, when first 10 DGs (iteration 1- iteration 10) are placed in the distribution system, the losses are reduced from 95.7 kW to 50 kW, resulting in loss reduction of 45.7 kW. Variation of power loss with optimal DG placement is shown in Figure 4.4.

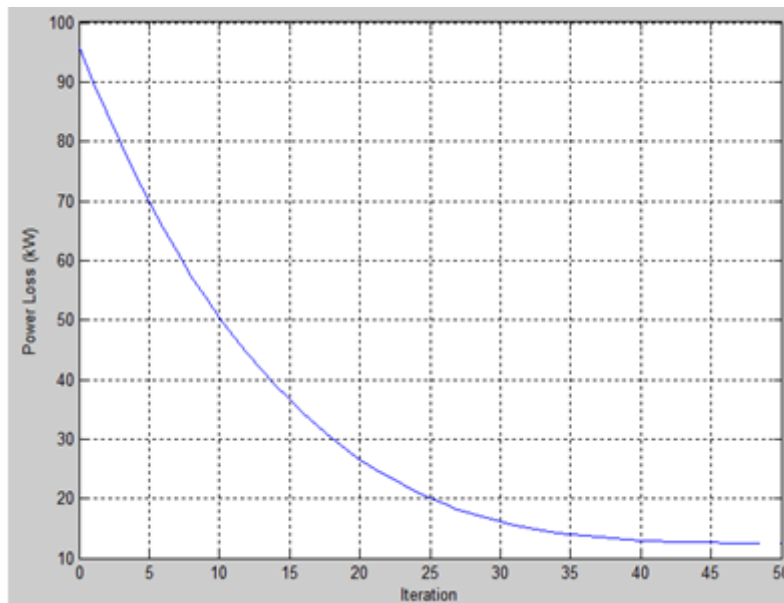


Figure 4.4 Variation of power loss with optimal DG placement

Placing next 10 DGs (iteration 10 - iteration 20) reduces the system losses to 26 kW, resulting in loss reduction of 19.7 kW, which is significantly lower than 45.7 kW. If 40 DGs are placed in the system rather than 48 DGs, the system losses are reduced to 12.9 kW and *PLR* of 86.5% is achieved. If 35 DGs are placed, the system losses are reduced to 13.9 kW and *PLR* of 85.5% is achieved.

A constraint of five percent over-voltage is included in the developed algorithm. If at any iteration of DG allocation, the voltage rises beyond 1.05 pu then no further DG placement is done. The voltage at each node is ensured to be within limits at each iteration. All the voltage regulators are assumed to be on, as per the base case. Three phase unbalanced voltages when 48 DGs are placed in the distribution system is shown in Figure 4.5.

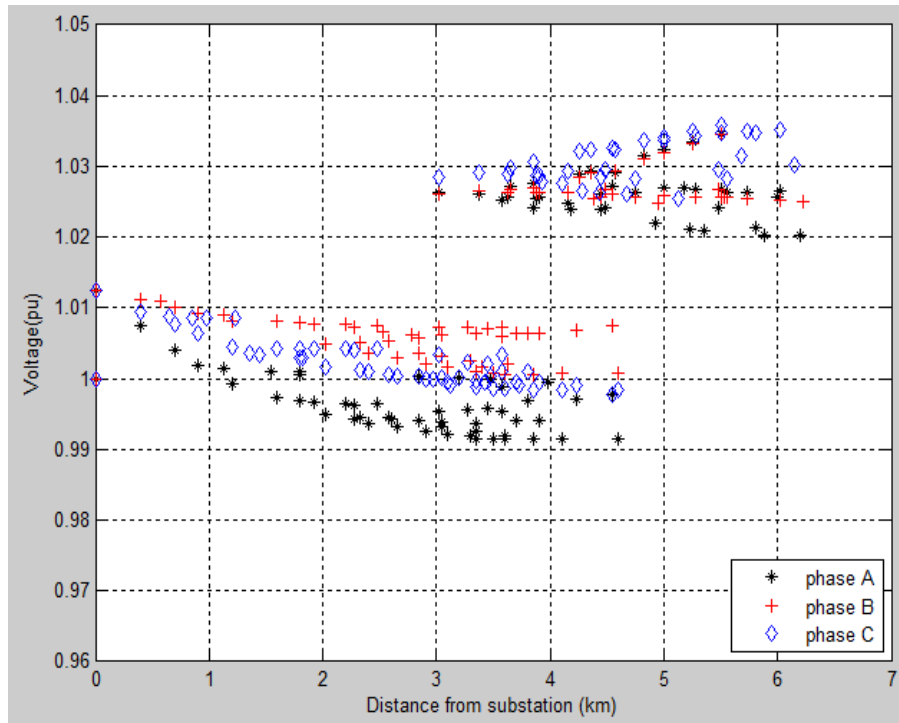


Figure 4.5 Unbalanced voltage profile with 48 DG units

It is observed that a high penetration of distributed generation is possible without violating the steady-state voltage stability limit. As these test system come with voltage control devices (voltage regulators) and compensation devices (shunt capacitor banks), voltages are maintained throughout the distribution network.

4.4 Annual Simulation Analysis

The continual sensitivity analysis methodology is developed and applied to peak load condition, but there are several light load days in a year. Figure 4.6 shows an annual load curve provided by EPRI along with OpenDSS. The load multiplier (LM) value for some days can be as low as 0.4.

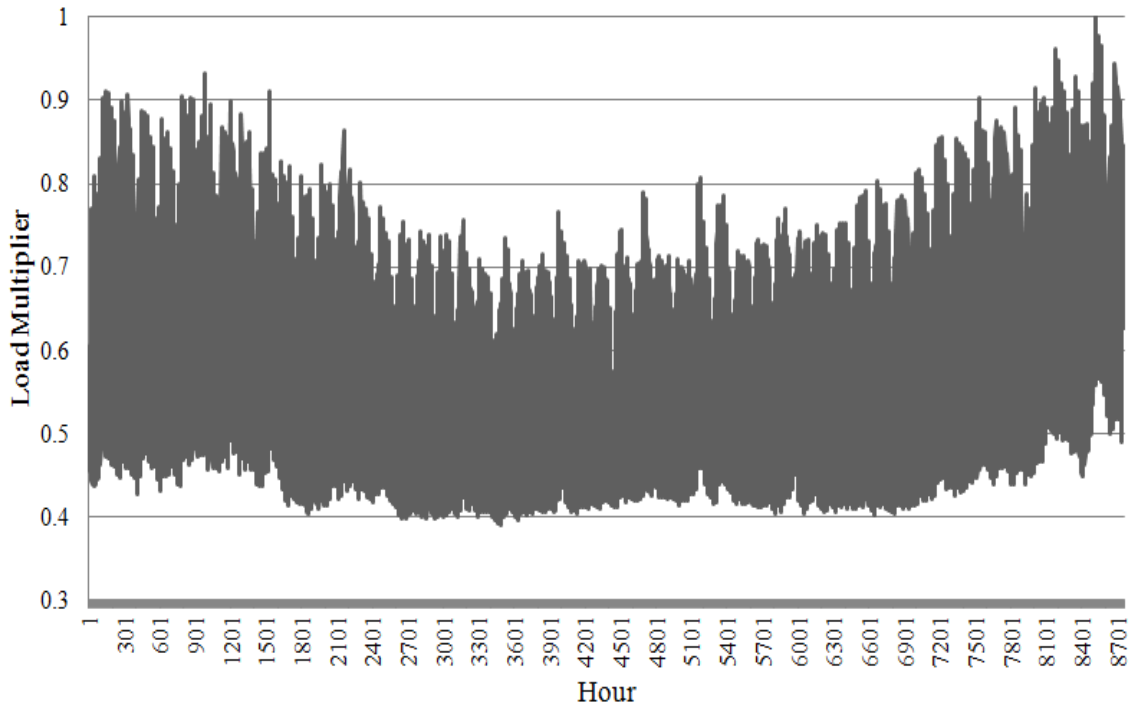


Figure 4.6 Annual load profile

Peak load losses are not necessarily indicative of annual losses occurring in the distribution network. If DG penetration is too high on a light load day then instead of losses minimizing, the system losses with DG placement might be higher than the base case losses. The optimally selected locations and capacity of DG on the basis of peak load condition might be inappropriate planning for a light load day. The 48 DGs suggested by the continual sensitivity analysis methodology are placed in the distribution network and the system losses are calculated for peak, moderate, light and very light load conditions. The results are showed in Table 4.1. It is evident that with high DG penetration level, the system losses will be higher than the base case losses for very light load conditions. Here, system losses doubles when high DG is penetrated in the distribution network on a very light load day (LM = 0.4).

Table 4.3 Loss comparison with high DG penetration

Load Condition	Base Load	Base Loss	Loss with 48 DG	Change in Loss
Peak Load (1)	3.49 MW	95.7 kW	12.4 kW	+ 87 %
Moderate Load (0.8)	2.8 MW	61 kW	12.1 kW	+ 80.2 %
Light Load (0.6)	2.1 MW	35.1 kW	20.2 kW	+ 42.4 %
Very Light Load (0.5)	1.75 MW	25.3 kW	27.2 kW	- 7.5 %
Very Light Load (0.4)	1.4 MW	18 kW	36.7 kW	- 103.9%

Some natural gas microturbines can be turned off on a light load day to reduce the DG penetration level. Since the initial investment of natural gas microturbines is high, this option is not considered in this study. If some microturbines are not used for a part of the year, it will result into increased payback time of the project.

The continual sensitivity analysis is applied for $LM = 0.8, 0.6$ and 0.5 , and the results are compared with those obtained when it was applied for $LM = 1$.

Placing 38 DGs of 100 kW each are suggested for system loss minimization when continual sensitivity analysis is done for $LM = 0.8$. Two DGs are suggested at node 48, 49, 76 and 9, and following 30 locations are suggested a single DG: node 105, 108, 11, 112, 113, 150, 16, 19, 20, 26, 29, 33, 35, 36, 4, 42, 53, 6, 63, 65, 66, 67, 71, 72, 75, 78, 81, 87, 93 and 99.

31 DGs of 100 kW each are suggested for system loss minimization when continual sensitivity analysis is done for $LM = 0.6$. A single DG is suggested at node 101, 108, 11, 110, 113, 150, 16, 20, 26, 28, 33, 36, 4, 42, 47, 48, 49, 57, 6, 64, 65, 71, 72, 75, 76, 81, 86, 9, 90, 91 and 98.

Placing 24 DGs of 100 kW each are suggested for system loss minimization when continual sensitivity analysis is done for $LM = 0.5$. Two DGs are suggested at node 76 and following 22 locations are suggested a single DG: node 1, 108, 11, 113, 150, 20, 28, 33, 35, 47, 48, 49, 6, 63, 65, 67, 71, 75, 81, 9, 91 and 98.

48, 38, 31 and 24 DGs are placed in the distribution network at the locations suggested, and the losses are compared with the base case losses for LM varying from 0.35 to 1. The results are showed in Figure 4.7, and the relevant MATLAB code is given in Appendix-F.

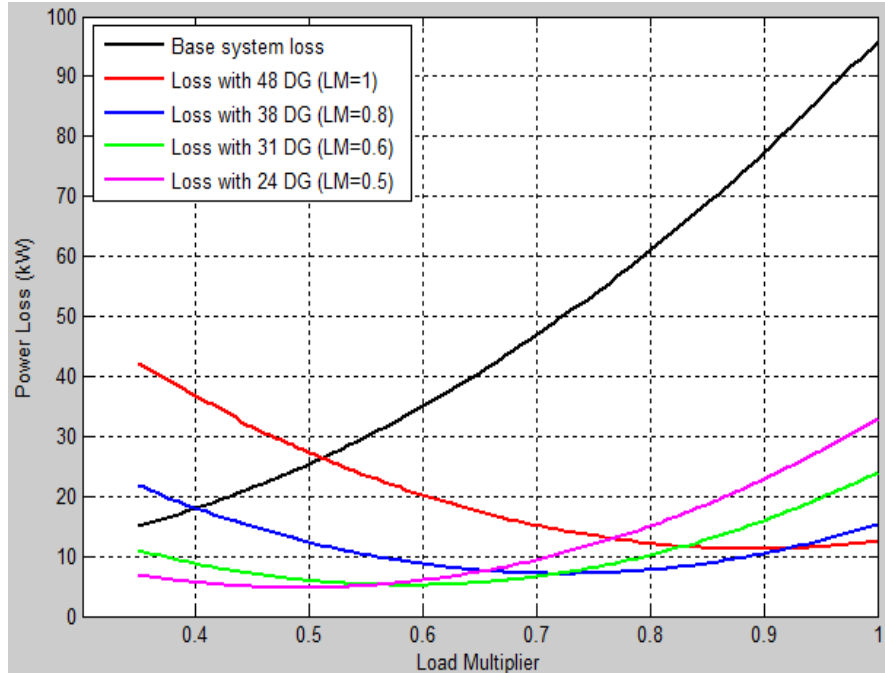


Figure 4.7 Loss analysis with optimal DG placement

The base peak load losses when there is no DG in the system are 95.7 kW, which can be minimized to 12.4 kW by placing 48 DG, that is, planning DG for LM = 1. However, during a light load day (LM = 0.4 - 0.5), the system losses are higher than the base case losses. If DG is planned for LM = 0.5, though the losses are minimum during a light load day, the losses are not minimized during a high load day.

It is realized that instead of minimizing the peak load losses, annual average losses should be minimized and an optimal value of LM should be determined for which the annual average losses are minimum when DGs are allocated as suggested by that LM planning. Loadshape provided by EPRI along with OpenDSS as shown in Figure 4.6 is used to run annual simulation. The annual simulation is run for 5 cases: base case, and placing 48 DG, 38 DG, 31 DG and 24 DG in the distribution network. The DGs are

placed at the locations suggested by the continual sensitivity analysis methodology and the load flow is performed to calculate the annual average losses occurring in the system.

The results are shown in the Table 4.4.

Table 4.4 Annual average losses with optimal DG placement

Case	Total Loss (kWh)	Annual Average Loss (kW)	PLR (%)
Base Case	332,550	37.96	0
48 DG ($LM=1$)	183,600	20.96	44.8 %
38 DG ($LM=0.8$)	97,278	9.88	73.4 %
31 DG ($LM=0.6$)	59,050	6.74	82.2 %
24 DG ($LM=0.5$)	68,504	7.82	79.4 %

High penetration of DG in the distribution system minimizes the losses during peak load condition, and low penetration of DG minimizes the losses during low load condition. But, either of the DG planning will not be able to minimize the annual average losses. It is important to determine an optimal LM for which when DG planning is done, it gives the minimum annual average losses. A methodology combining continual sensitivity and an annual simulation analysis is developed. Continual sensitivity is done for $LM = 0.35$ to 1. For each iteration different DG capacity and locations are suggested which are placed in the distribution network and then the annual simulation is run to calculate the annual average losses in the system after optimal DG placement. A time-series simulation is performed to determine the annual average power losses. During this process, a sequential 8760-hour simulation is performed with 1 hour interval for different proposed DG placement in the distribution network. The modified algorithm is shown in Figure 4.8.

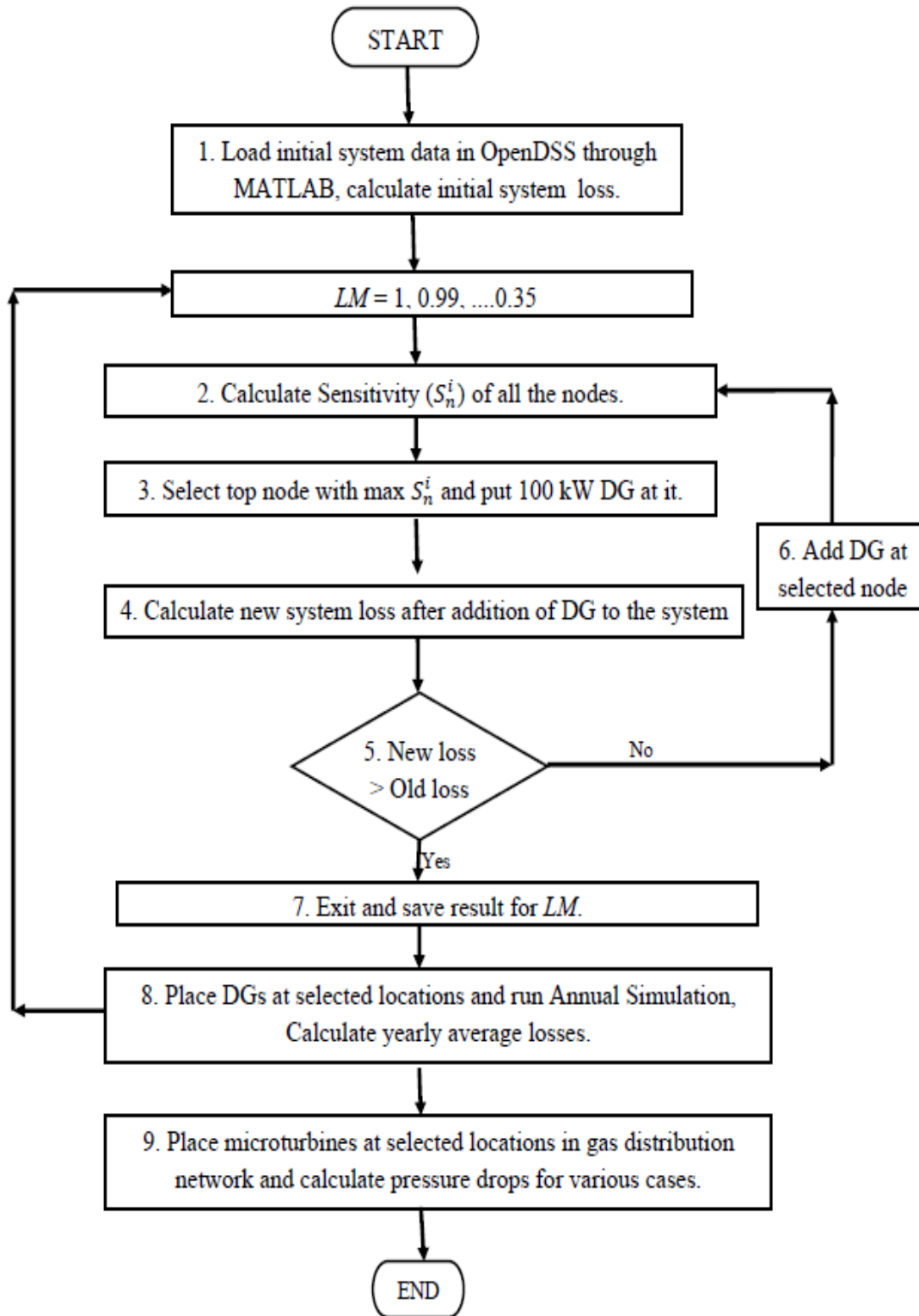


Figure 4.8 Modified algorithm for optimal DG placement

Variation in minimized average losses for different load multipliers are plotted and shown in Figure 4.9.

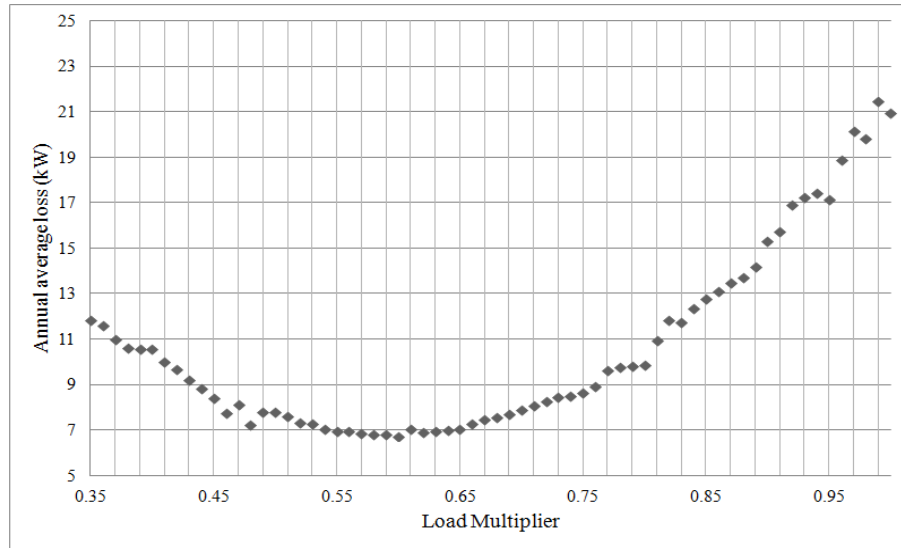


Figure 4.9 Annual simulation analysis results

The results demonstrate that if DG planning is done on the basis of peak load, the losses are minimized for peak load but annual average losses are not minimum. Here annual average losses for peak load planning are 21 kW which are the maximum if compared with annual average losses for DG planning for other load multipliers. For this study, if DG planning is done for $LM = 0.6$, the minimum annual average losses are obtained. Maximum Percentage Loss Reduction (PLR) of 82.2% is obtained and annual average losses are minimized to 6.7 kW when 31 DGs are placed in the distribution network as suggested by planning done based on 0.6 LM. There is a significant reduction in annual average loss when DGs are planned on the bases of annual simulation analysis.

CHAPTER 5

NATURAL GAS NETWORK MODELING

5.1 Natural Gas Distribution System

In most major cities of United States, natural gas is used as a clean fuel choice for cooking and heating. In countries like United States, Russia, Brazil and Europe, the natural gas electricity generation have rapidly increased in the last decade due to increase in number of combined cycle natural gas thermal power plants, which directly integrates electric power and natural gas [59]. Electric power generation using natural gas has several advantages, e.g. economic competitiveness, low environmental impact, and rich in natural storage, and thus it is a preferable source of electricity generation as compared to other fossil fuels such as coal and oil.

Transmission pipelines transport natural gas from compressor stations and storage facilities to regulators which reduces the gas pressure before feeding it into distribution network. Transmission gas pipelines generally operate at a higher pressure (more than 60 psig) and are larger (more than 24 inches) than distribution pipelines. This constrains the gas capacity that can be transported and stored in the gas distribution system. There is a close interconnection between gas supply in gas distribution network and natural gas microturbine placement in the electric distribution network. Gas consumption by microturbines affects the gas flows and reduces the pressures in the gas distribution network. It is necessary to integrate electric and gas distribution network to assess the possible placements of natural gas microturbines.

Gas transmission pipeline system map of PG&E's area around Mountain View, CA is showed in Figure 5.1. Any transmission lines operating at or above 60 psig is

included in this map, which means the additional distribution pipelines are not shown in this map. A properly maintained pipe can operate safely for 100 years or more, although age of the gas pipeline is a relevant factor while reviewing the status of pipeline and planning for pipeline reinforcement. The pressure is controlled in the pipeline system by pressure regulating stations and over-pressure protection devices, these systems operate to ensure that pressure is within the safety limits [60].

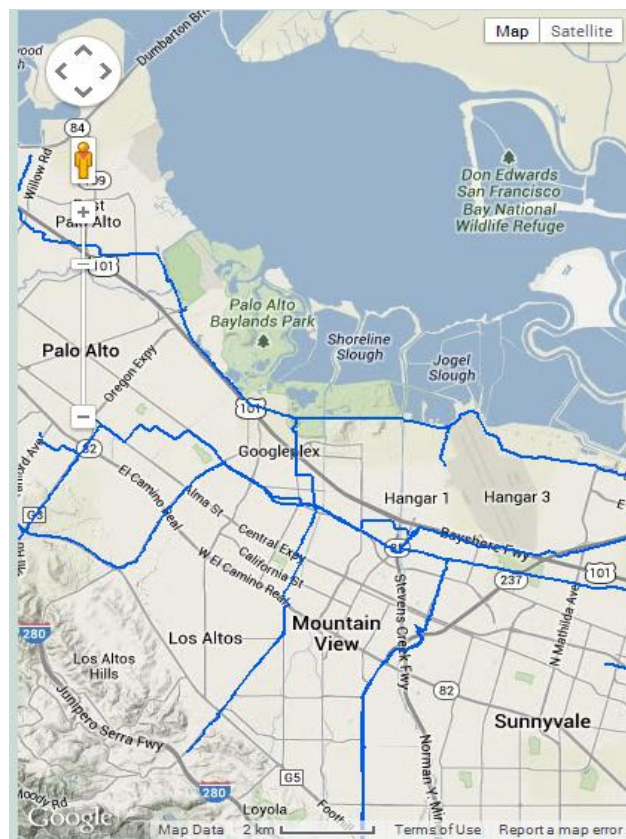


Figure 5.1 Gas transmission pipeline system map [61]

Local natural gas utility, SouthWest gas was consulted for detailed information on gas distribution network and typical values in Arizona residential gas distribution

networks. Sub transmission gas network carries natural gas at 300 psi and compressor stations are placed at every few miles to compress the gas down to 60 psi. The residential gas demand for cooking and heating varies during the year, and it can be approximated to 35 cfh (cubic feet per hour) for winter and 10 cfh for summer for a typical Arizona household. Winter gas demand is higher than summer since heating is required.

For this study, the worst case scenario is analyzed and hence the maximum pressure, that is, 35 cfh is considered for each residential load in the gas distribution network. Actual pressure requirement of residential load varies, and it can be as low as 1/4 psi. However, utilities regularly monitor the pressure in gas pipelines, and if they sense that gas pressure has been below a set pressure level for a long duration, they start planning for pipeline reinforcement. The pressures are not measured at every house and street on a real time basis. Utilities work on a historic data, and predict pressure in the next week and next month. If they see pressure to be dropping below the pressure constraint, then some measures needs to be taken.

The pressure constraint can be utility and area dependent. Some utilities have a strict pressure constraint, as well as, some areas might need stricter constraint due to older pipelines. As a rule of thumb, the tail-end pressure (lowest pressure in the system) is not allowed to get less than about half of the supply pressure under peak conditions. Here, supply node pressures are considered to be at 60 psi. Hence, while placing natural gas microturbine DGs in the distribution network, the pressure at each node should be maintained above 30 psi.

5.2 Natural Gas Network Design

The software used to model the natural gas distribution network is GASWorkS 9.0. The GASWorkS 9.0 is a windows based steady-state network modeling tool which can be used to design and analyze transmission, distribution, gathering and plant piping systems containing natural gas or other compressible fluids [62].

The nodes modeled in the gas distribution network exceeded the nodes which can be modeled in a demo version of the software. Upon the request of the author, the distributor of this software agreed to offer four month free academic version of GASWorkS 9.0 with no limit on the node number, the duration of which was subsequently extended upon request and constant support was provided in modeling the IEEE 123 gas distribution network as close as possible to a typical US residential area. However, GASWorkS 9.0 does not have any way to interact with MATLAB or any other third party application through COM server, and they are currently considering such options for a future release.

It is assumed that at all the nodes in IEEE 123 node test feeder where an electric load is present, the natural gas load is also there. Each node in the gas distribution network corresponds to the same node in the electric distribution network, which represents a cluster of houses. The base natural gas consumption by these loads is calculated by approximating households at each node and then multiplying by hourly winter natural gas consumption of individual household. Each household is assumed to have a peak electric load of 4 kW, which approximates total electric load of 3.49 kW of IEEE 123 node test feeder as 872 households. Each household is given a gas load of 35 cfh as per the winter data, which approximates total gas load of the distribution network to be 30,537.5 cfh or 30.53 Mcfh (thousand cubic feet per hour). The gas loads for

households are based on representative diversified values for central Arizona. The developed IEEE 123 node gas distribution network is shown in Figure 5.2.

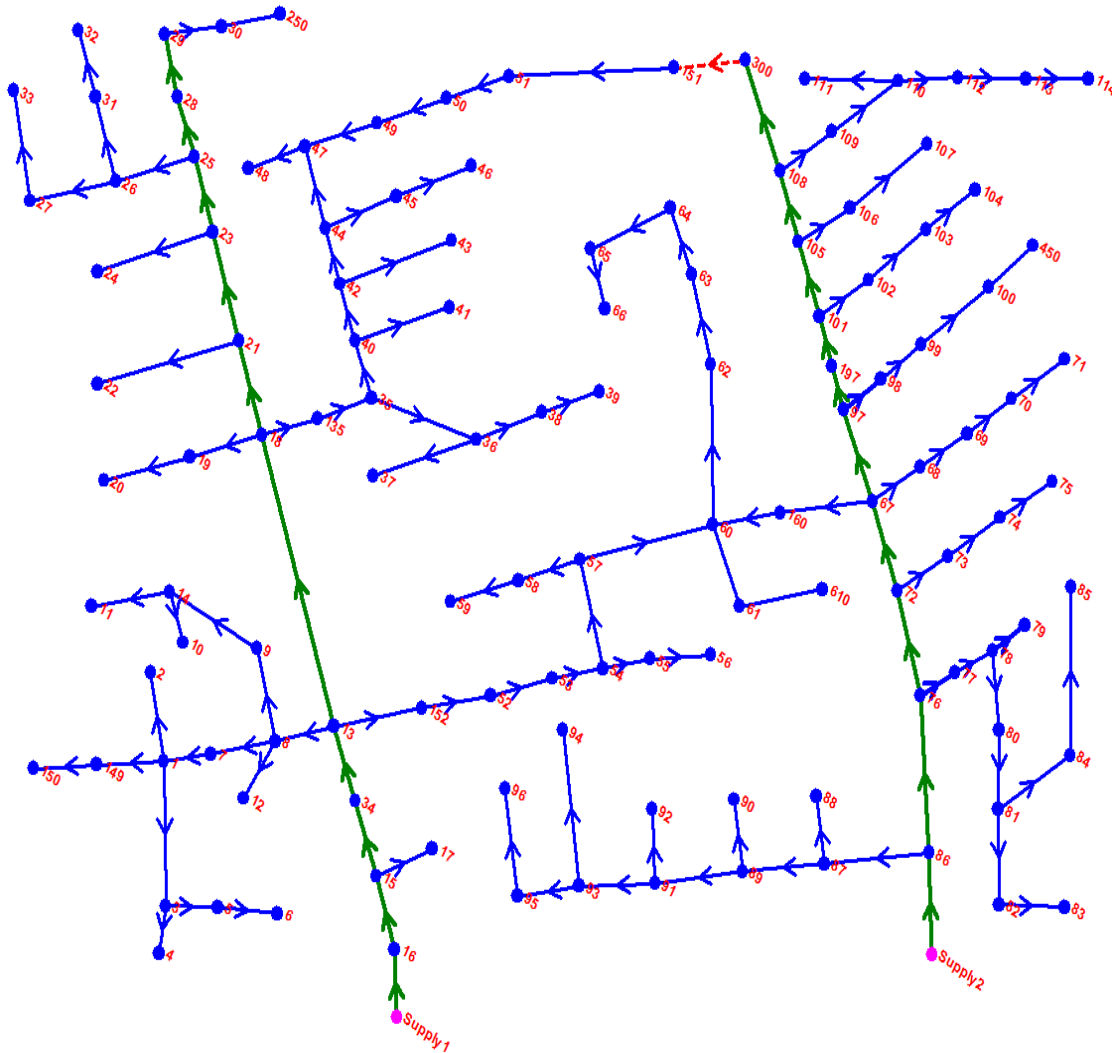


Figure 5.2 IEEE 123 node gas distribution network

As natural gas flows through the gas distribution network, pressure and energy are lost due to heat transfer and heat [4]. Gas load flow assesses the pressure values at all the consumption nodes and flow rates for all pipelines in the network. Known input data are

pressure values at supply nodes, load requirement in the system, and the connectivity matrix. Either an iterative process can be used to solve the set of non-linear equations or software can be used to run the simulation and give results.

There are many possible combinations of pipe diameter, material, valves, regulators, etc., making the gas distribution system design a complicated design. Smaller size service lines which are less than one inch in diameter are not modeled in this distribution network, they connect and provide gas to each individual household. Besides gas distribution pipelines, a gas distribution network also comprises of valves and regulators. Valves are not modeled in this distribution network as they are used only to switch on or off the gas supply in a specific area, not modeling them in the network does not have any effect on gas pressure drops in the network. The regulators are used to reduce the output gas pressure and they are also not modeled in this distribution network.

Medium-density polyethylene (MDPE) plastic pipes are selected for all pipelines as they are anticorrosive, and they are generally used in the residential underground gas distribution network. Gas pipeline diameter can vary from half inch to eight inches in distribution network. Typically, three inch (3P) diameter pipe is used in residential distribution network to carry gas at high pressures from the compressors, and two inch (2P) diameter pipe is used to connect individual households. Generally, 40 ft half inch MDPE service lines are tapped from the main line to connect to individual household. For this study, all the pipes are assumed to be of 2P size to represent an actual residential network.

The electric network is used as the background figure to determine coordinates of the nodes in the gas distribution network. To improve the reliability of gas supply, node

300 and node 151 are connected to make the original radial gas distribution network as looped network, which is generally the case for a typical residential gas distribution network. The node 16 and node 86 are designated as the supply nodes of natural gas. Supply pressure is fixed at 60 psi and the load as unknown. The load at these two nodes is determined by running the simulation of gas distribution network. At a supply node, the pressure is set as known and the load as unknown, and at all the other nodes the pressure is set as unknown and load as known.

The elevation of all the pipelines and nodes in the network are assumed to be at the same level, and the ambient temperature is set at 70° F. The gas flows from nodes at higher pressure to nodes at lower pressures, and gas pressure drops when flowing along the pipelines due to gravity and friction. Nodes with gas loads that are farther from the supply nodes, generally have lower gas pressures. The gas pressure in the distribution network can be less than 10 psi, and it might need to be increased by the natural gas booster placed along with gas microturbine DGs to ensure normal operation.

There are many pipe flow equations that are used to calculate the pressure drops and gas flow in the distribution network. Each equation has its own characteristic and applications, and appropriate equation has to be determined for a specific application. For this study, the IGT-Improved Equation [63] is selected and used in this application of medium pressure distribution for residential gas distribution network. This equation is applicable to all distribution networks operating between pressure of 1 to 500 psi for two inch and larger diameter pipelines, and it yields moderate results [64]. The base case gas flow is simulated and the pressure result at each node is shown in Figure 5.3.

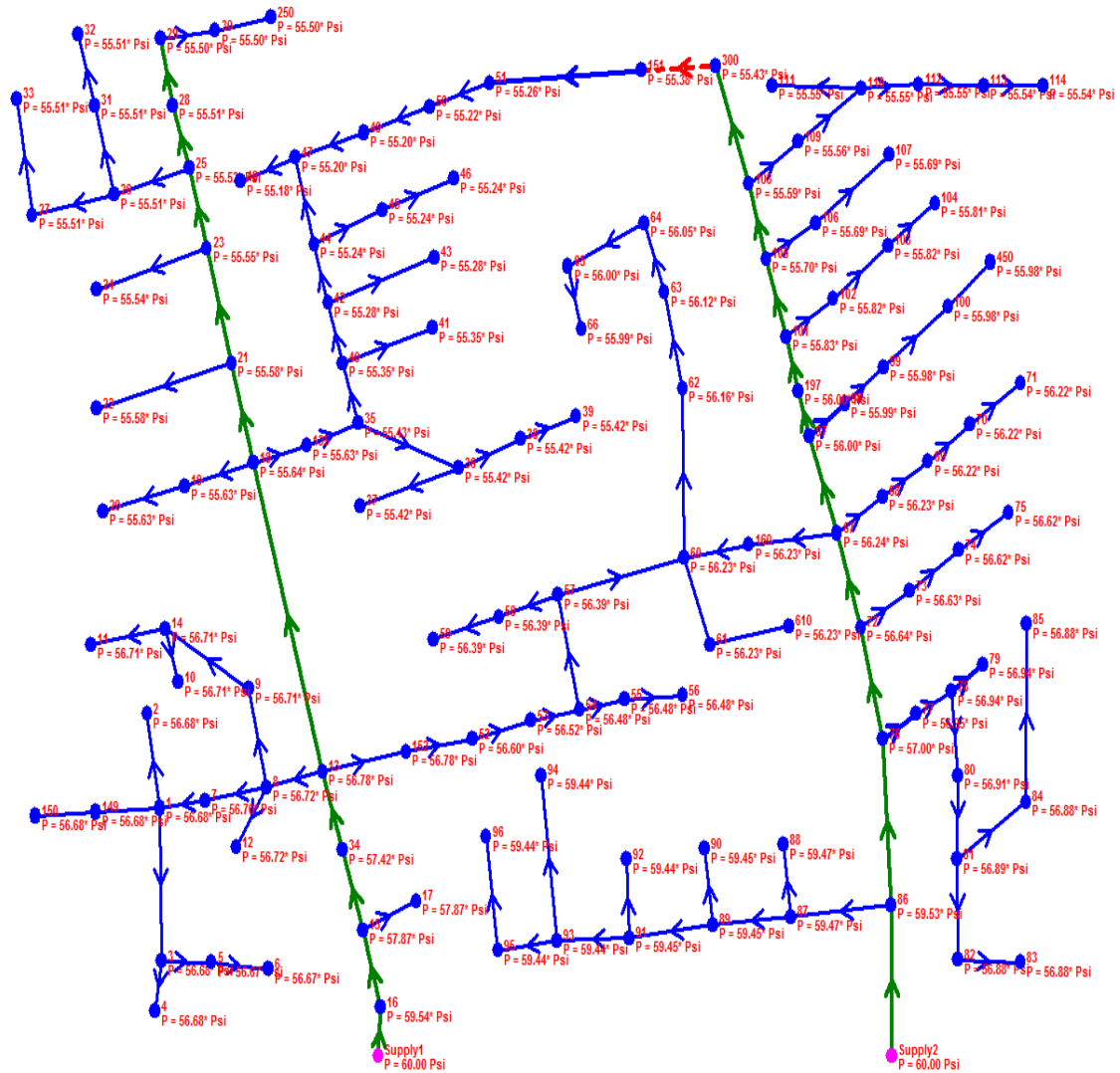


Figure 5.3 IEEE 123 node base case pressures

The nodes which are farther from the supply nodes have lower gas pressures as compared to nodes which are near to the supply nodes. Node 29 and surrounding nodes have 55.5 psi, which resembles a real residential distribution gas network as maximum pressure drop in it can be 5 psi to 10 psi for a similar network.

5.3 Case Studies

The various cases of microturbine placement in the gas distribution network are simulated. Combined electric and gas load flow architecture is shown in Figure 5.3. Natural gas microturbines are placed at locations suggested by running DG allocation scripts and electric load flow, and gas load flow is run. The nodal DG gas consumption is calculated using the power/fuel conversion equation, and it is updated in MS Excel spreadsheets. The total nodal gas consumption is then calculated by adding DG gas consumption to the existing base gas load of the households. The total nodal gas consumption data is exported as a routine to the developed IEEE 123 gas distribution network in GASWorkS.

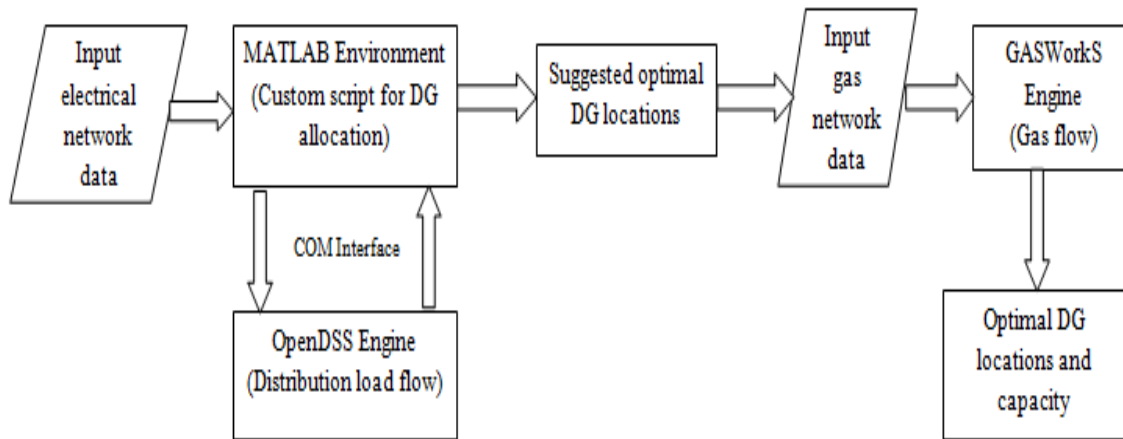


Figure 5.4 Combined electric and gas load flow architecture

The simulations are run for four cases: 48, 38, 31 and 24 natural gas microturbine placement in the gas distribution network at suggested locations discussed in section 4.4.

The nodal gas pressures for the four cases are showed in Figure 5.5, Figure 5.6, Figure 5.7 and Figure 5.8.

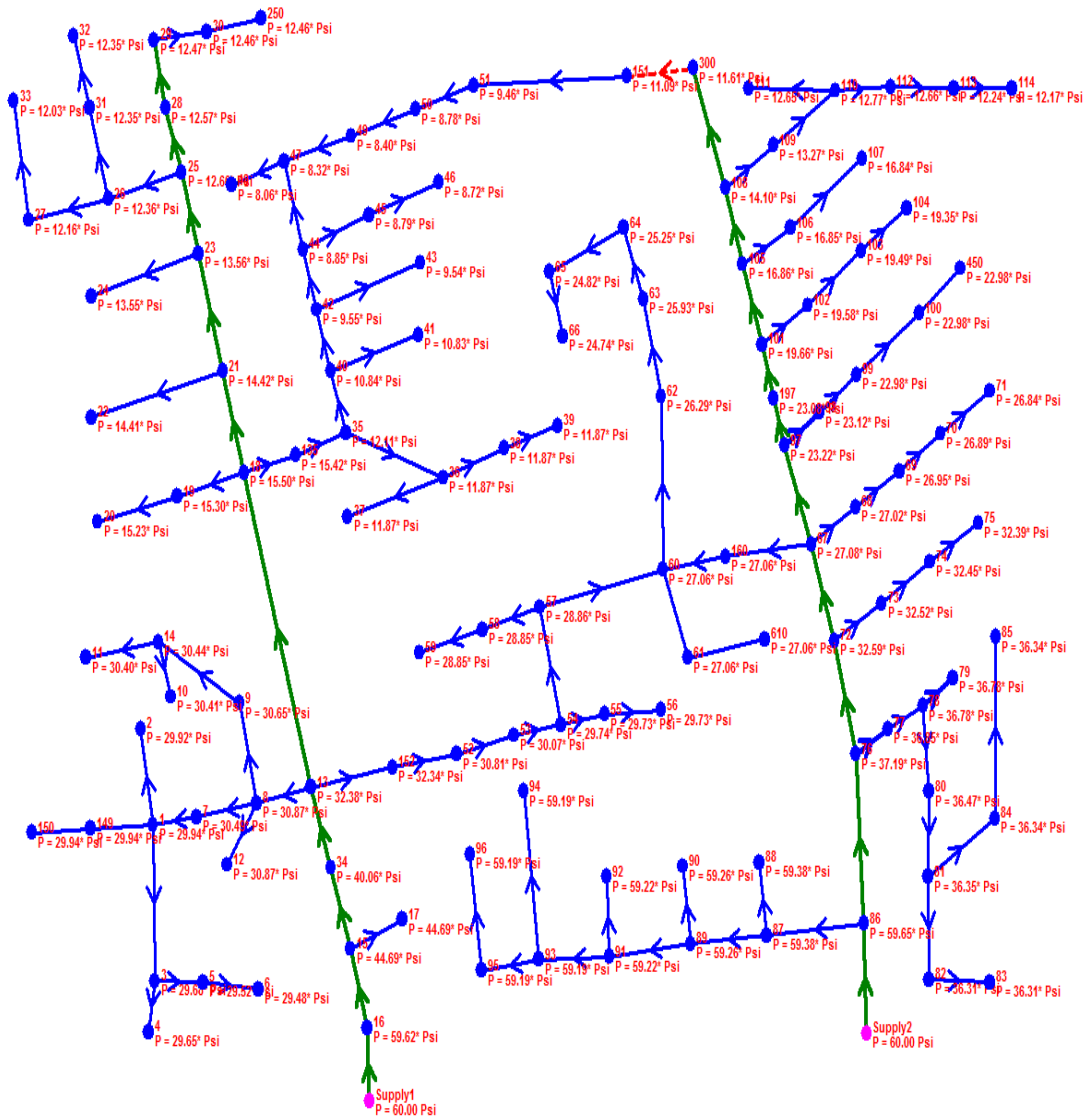


Figure 5.5 IEEE 123 node pressures with 48 microturbines in distribution network

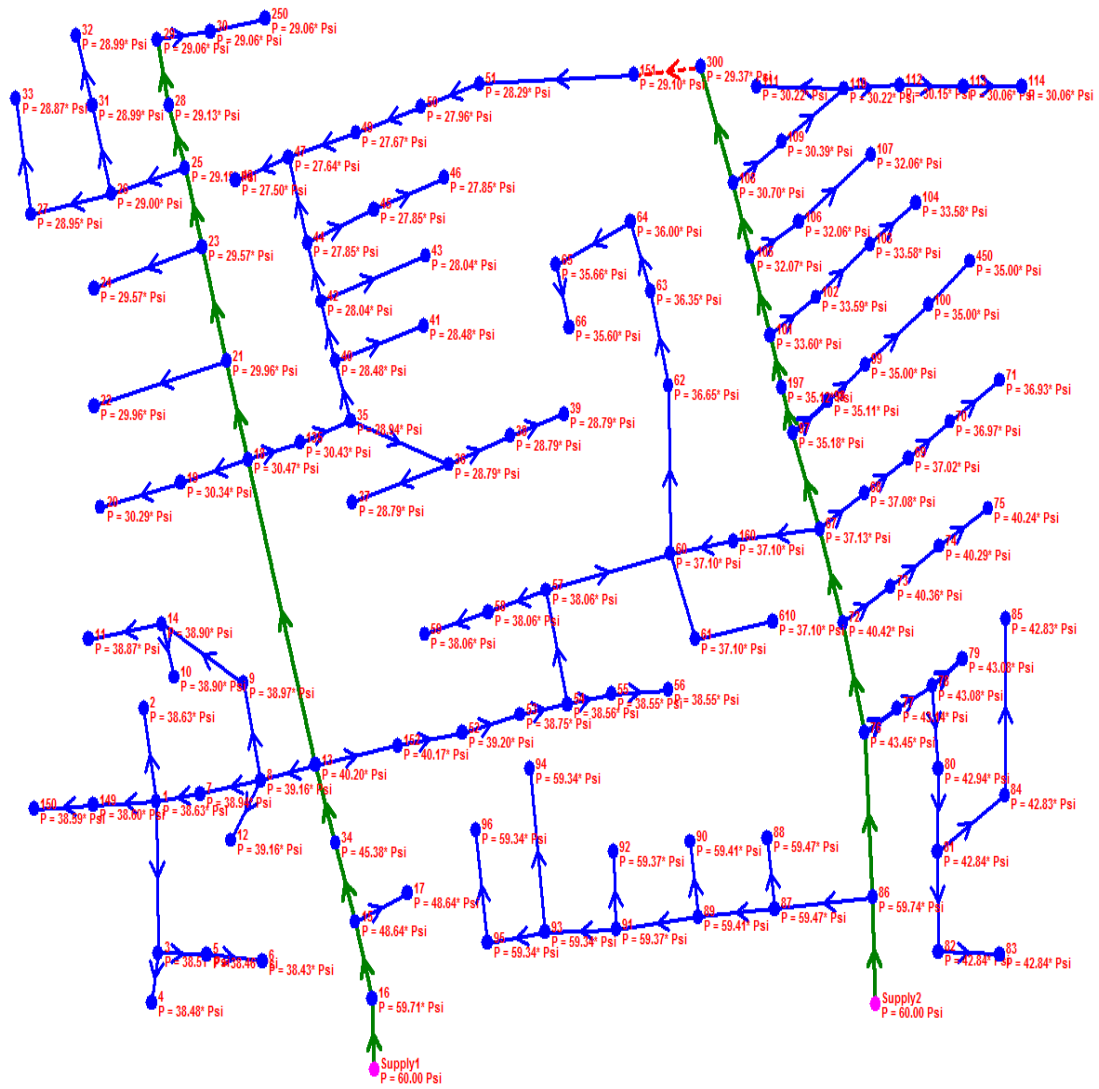


Figure 5.6 IEEE 123 node pressures with 38 microturbines in distribution network

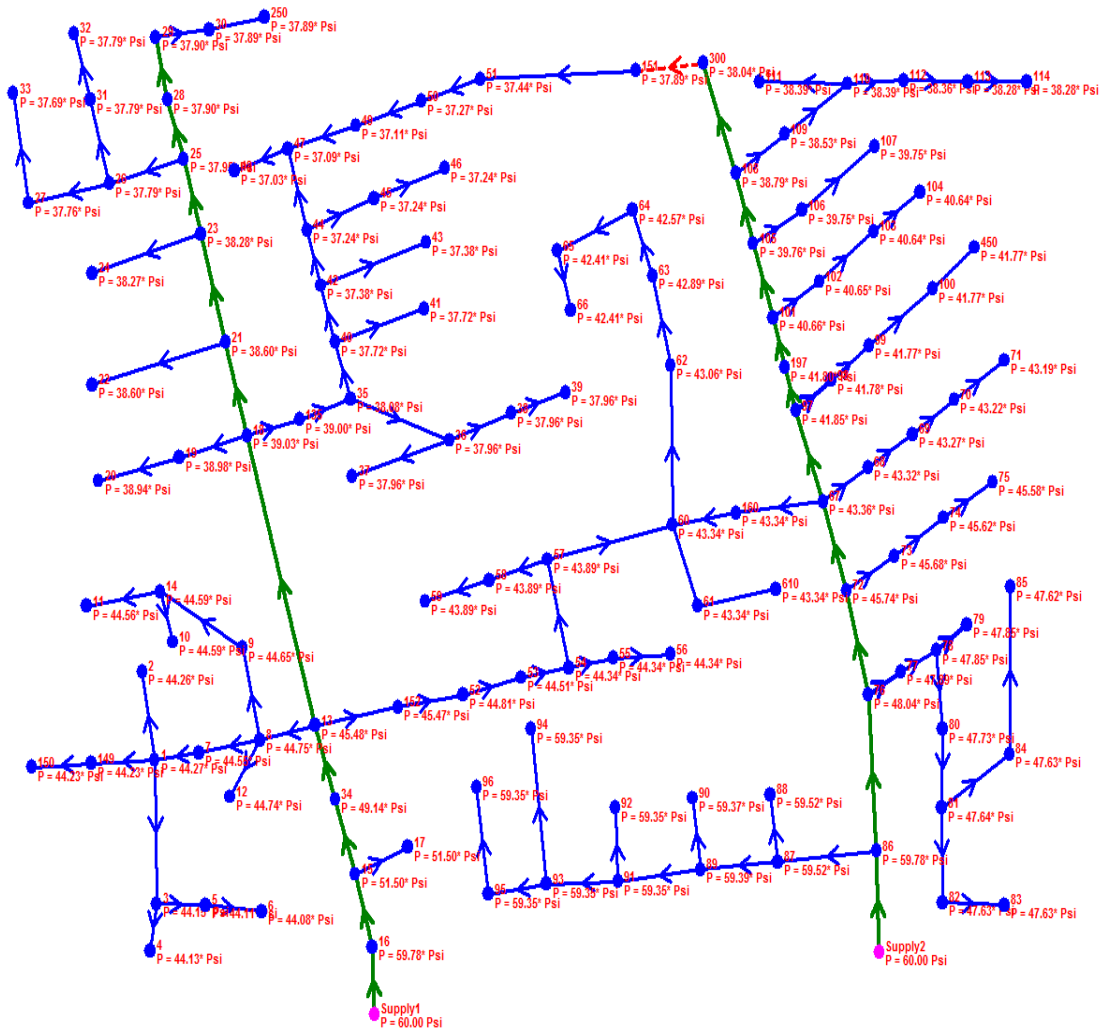


Figure 5.7 IEEE 123 node pressures with 31 microturbines in distribution network

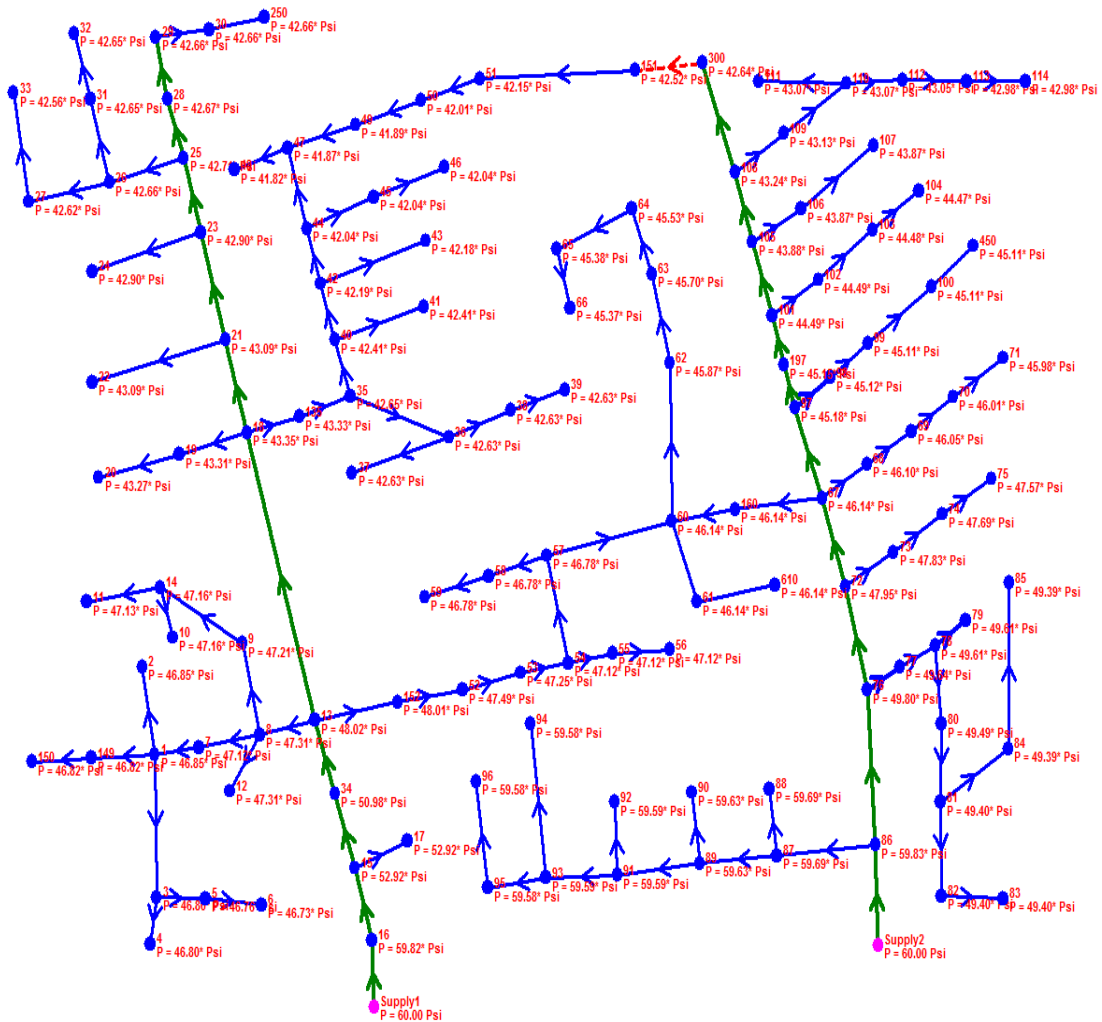


Figure 5.8 IEEE 123 node pressures with 24 microturbines in distribution network

The results are summarized in Figure 5.9. For all the four cases left top-most nodes are at the lowest pressures. This is because these nodes are farther from the supply pressures, and top right-most network is lopped after connecting node 151 and node 300, unlike top left-most network.

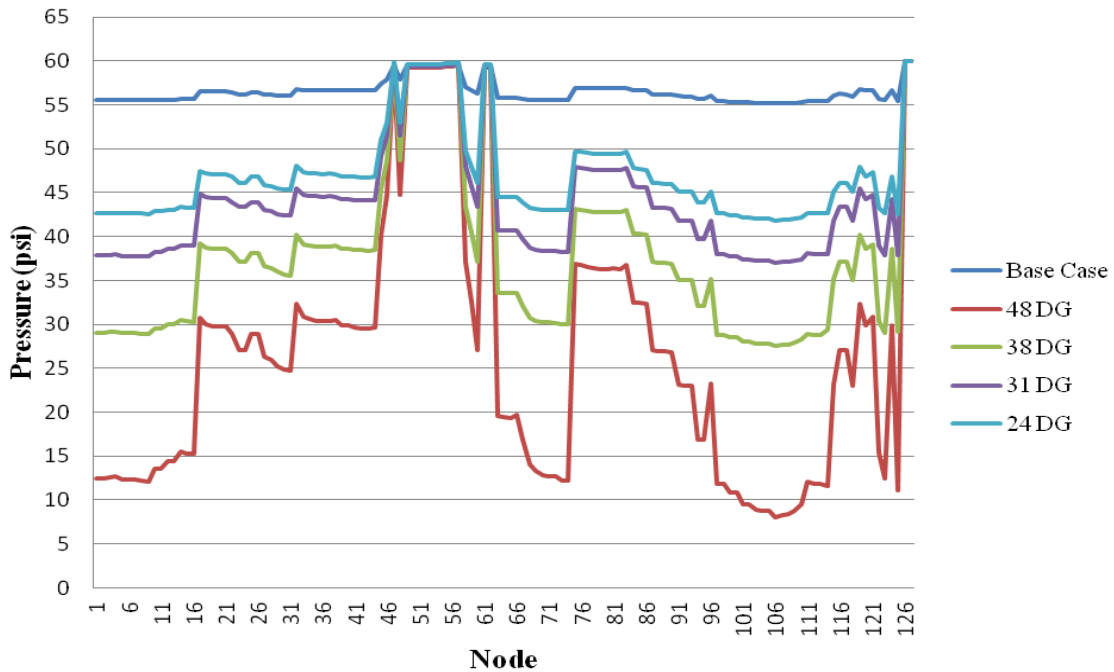


Figure 5.9 Nodal gas pressure for microturbine placement in gas network

High spike in the nodal gas pressure curve corresponds to high nodal gas pressure and less nodal gas consumption at that node, such as nodes around 51 and 125. Conversely, the pressure sag indicates the nodes where more gas is consumed compared to other nodes.

The total gas consumption is higher when 48 microturbines are placed in the network compared to when 24 microturbines are in the network. The nodal pressure drops to as low as 8 psi at few nodes when 48 microturbine DGs are placed in the distribution network. The results indicate that placing 48 microturbines is not possible due to high pressure drops, and the gas distribution network will need pipeline reinforcement. Placing 24 and 31 microturbines in the distribution network is possible as

the pressure at each node remains above half the initial supply pressure, that is, 30 psi.

Placing 38 microturbines might also be possible with certain relaxation in the standards.

CHAPTER 6

CONCLUSIONS AND FUTURE WORK

6.1 Conclusions and Main Contributions

The developed integrated methodology offers a generalized means of determining optimal natural gas microturbine capacity and locations in residential distribution networks. The overall objective of the integrated system is to place microturbines to minimize the system power loss occurring in the electrical distributed system; in such a way that the electric feeder does not need any up-gradation. The proposed placement of microturbines must be feasible in the gas distribution network and should not result into gas pipeline reinforcement. The proposed method is generalized and can be used for any IEEE test feeder or an actual residential distribution network.

There are several advantages of placing DG in distribution network. For this study, power loss minimization is selected as a key objective for determining optimal locations and capacity of DGs, and voltage stability is maintained throughout the analysis. IEEE 123 node test feeder is selected as the test bed for validation of the developed methodology. A global optimization algorithm for placing DGs in the distribution system have been developed in MATLAB and is dynamically linked to OpenDSS through COM server for running unbalanced multi-phase optimal power flow. A method based on sensitivity analysis is used to decrease the solution space and problem complexity, and optimal placement of DGs is determined for peak load loss reduction. A placement of 48 DGs is suggested and it reduces the system losses by 87 percent.

There are low load days also present in a given year, and it is realized that high penetration of DGs in a distributed network will result into increased system losses

during a low load day. Therefore, the optimally selected DG units based on a high load day are not applicable and economic for the real operation given a light load day. A method based on annual simulation is combined with sensitivity analysis to suggest optimal load multiplier for which DG placement should be planned. Placing 31 DGs of 100 kW based on 0.6 load multiplier planning results in 82.2% annual average loss reduction.

The gas distribution network model corresponding to IEEE 123 node test feeder is developed using GASWorkS software to assess whether the existing gas distribution network could support the large penetration of microturbines at suggested locations. Four cases are simulated in GASWorkS software by adding the microturbine gas loads to the existing household gas loads in the gas distribution network. The gas flow simulation results suggest that installation of large number of microturbines will need pipeline reinforcement due to constraint of nodal gas supply pressure.

For this study, an installation of 31 microturbine DG units results in the optimal scenario based on the consideration of overall minimum annual average losses as well as the guarantee of nodal pressure provided by the gas distribution network. The results based on this research work resulted in a research paper [65].

5.2 Future Work

The conducted study mainly focuses on assessing the optimal placement of microturbines by taking out few feasible solutions from the electric distribution network, and then checking feasibility of individual cases in the gas distribution network. In future, both electric distribution network and gas distribution system can be linked through API

server and a co-simulation platform can be developed. Such approach will make the entire process automatic and give an optimal result.

The mathematical model of the gas distribution network will be developed and integrated with the available mathematical model of electrical system. The integrated model is difficult to solve by available commercial solvers due to mathematical complexity and large size of the problem.

For this study, it is assumed that microturbines only provide real power, since majority of the microturbine units available in United States do not provide reactive power support. In future, reactive power support option will be considered and optimal power factor to operate the microturbines will be determined. For this study, the size of a microturbine unit is fixed at 100 kW since most of the available technologies provide 100 kW units. This size can be varied and an optimal size of a DG unit will be determined.

IEEE 123 node test feeder is selected as a test bad to conduct this study. A real residential distribution feeder in Chandler was initially selected, but due to lack of complete and accurate data, the real test bed plan was abandoned. In future, the developed method will be tested on a real residential distribution system.

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APPENDIX A
OPENDSS SCRIPT

Compile (IEEE123Master.dss)

```
RegControl.creg1a.maxtapchange=1 Delay=15 !Allow only one tap change
per solution. This one moves first
RegControl.creg2a.maxtapchange=1 Delay=30
RegControl.creg3a.maxtapchange=1 Delay=30
RegControl.creg4a.maxtapchange=1 Delay=30
RegControl.creg3c.maxtapchange=1 Delay=30
RegControl.creg4b.maxtapchange=1 Delay=30
RegControl.creg4c.maxtapchange=1 Delay=30
Set MaxControlIter=700
Set normvmaxpu=1.07
New EnergyMeter.Feeder Line.L115 1
```

OPENDSS MASTER SCRIPT

```
! Annotated Master file for the IEEE 123-bus test case.
!
! This file is meant to be invoked from the Compile command in the
"Run_IEEE123Bus.DSS" file.
!
Clear

New object=circuit.ieee123
~ basekv=4.16 Bus1=150 pu=1.00 R1=0 X1=0.0001 R0=0 X0=0.0001

new transformer.reg1a phases=3 windings=2 buses=[150 150r] conns=[wye
wye] kvs=[4.16 4.16] kvas=[5000 5000] XHL=.001 %LoadLoss=0.00001
ppm=0.0
new regcontrol.creg1a transformer=reg1a winding=2 vreg=120 band=2
ptratio=20 ctprim=700 R=3 X=7.5

! REDIRECT INPUT STREAM TO FILE CONTAINING DEFINITIONS OF LINECODES
! This file defines the line impedances in a similar manner to the
description in the test case.

Redirect IEEELinecodes.DSS

New Line.L115 Bus1=149 Bus2=1 LineCode=1
Length=0.4
New Line.L1 Phases=1 Bus1=1.2 Bus2=2.2 LineCode=10
Length=0.175
New Line.L2 Phases=1 Bus1=1.3 Bus2=3.3 LineCode=11
Length=0.25
New Line.L3 Phases=3 Bus1=1.1.2.3 Bus2=7.1.2.3 LineCode=1
Length=0.3
New Line.L4 Phases=1 Bus1=3.3 Bus2=4.3 LineCode=11
Length=0.2
New Line.L5 Phases=1 Bus1=3.3 Bus2=5.3 LineCode=11
Length=0.325
New Line.L6 Phases=1 Bus1=5.3 Bus2=6.3 LineCode=11
Length=0.25
New Line.L7 Phases=3 Bus1=7.1.2.3 Bus2=8.1.2.3 LineCode=1
Length=0.2
```

New Line.L8	Phases=1	Bus1=8.2	Bus2=12.2	LineCode=10
Length=0.225				
New Line.L9	Phases=1	Bus1=8.1	Bus2=9.1	LineCode=9
Length=0.225				
New Line.L10	Phases=3	Bus1=8.1.2.3	Bus2=13.1.2.3	LineCode=1
Length=0.3				
New Line.L11	Phases=1	Bus1=9r.1	Bus2=14.1	LineCode=9
Length=0.425				
New Line.L12	Phases=1	Bus1=13.3	Bus2=34.3	LineCode=11
Length=0.15				
New Line.L13	Phases=3	Bus1=13.1.2.3	Bus2=18.1.2.3	LineCode=2
Length=0.825				
New Line.L14	Phases=1	Bus1=14.1	Bus2=11.1	LineCode=9
Length=0.25				
New Line.L15	Phases=1	Bus1=14.1	Bus2=10.1	LineCode=9
Length=0.25				
New Line.L16	Phases=1	Bus1=15.3	Bus2=16.3	LineCode=11
Length=0.375				
New Line.L17	Phases=1	Bus1=15.3	Bus2=17.3	LineCode=11
Length=0.35				
New Line.L18	Phases=1	Bus1=18.1	Bus2=19.1	LineCode=9
Length=0.25				
New Line.L19	Phases=3	Bus1=18.1.2.3	Bus2=21.1.2.3	LineCode=2
Length=0.3				
New Line.L20	Phases=1	Bus1=19.1	Bus2=20.1	LineCode=9
Length=0.325				
New Line.L21	Phases=1	Bus1=21.2	Bus2=22.2	LineCode=10
Length=0.525				
New Line.L22	Phases=3	Bus1=21.1.2.3	Bus2=23.1.2.3	LineCode=2
Length=0.25				
New Line.L23	Phases=1	Bus1=23.3	Bus2=24.3	LineCode=11
Length=0.55				
New Line.L24	Phases=3	Bus1=23.1.2.3	Bus2=25.1.2.3	LineCode=2
Length=0.275				
New Line.L25	Phases=2	Bus1=25r.1.3	Bus2=26.1.3	LineCode=7
Length=0.35				
New Line.L26	Phases=3	Bus1=25.1.2.3	Bus2=28.1.2.3	LineCode=2
Length=0.2				
New Line.L27	Phases=2	Bus1=26.1.3	Bus2=27.1.3	LineCode=7
Length=0.275				
New Line.L28	Phases=1	Bus1=26.3	Bus2=31.3	LineCode=11
Length=0.225				
New Line.L29	Phases=1	Bus1=27.1	Bus2=33.1	LineCode=9
Length=0.5				
New Line.L30	Phases=3	Bus1=28.1.2.3	Bus2=29.1.2.3	LineCode=2
Length=0.3				
New Line.L31	Phases=3	Bus1=29.1.2.3	Bus2=30.1.2.3	LineCode=2
Length=0.35				
New Line.L32	Phases=3	Bus1=30.1.2.3	Bus2=250.1.2.3	LineCode=2
Length=0.2				
New Line.L33	Phases=1	Bus1=31.3	Bus2=32.3	LineCode=11
Length=0.3				
New Line.L34	Phases=1	Bus1=34.3	Bus2=15.3	LineCode=11
Length=0.1				

New Line.L35	Phases=2	Bus1=35.1.2	Bus2=36.1.2	LineCode=8
Length=0.65				
New Line.L36	Phases=3	Bus1=35.1.2.3	Bus2=40.1.2.3	LineCode=1
Length=0.25				
New Line.L37	Phases=1	Bus1=36.1	Bus2=37.1	LineCode=9
Length=0.3				
New Line.L38	Phases=1	Bus1=36.2	Bus2=38.2	LineCode=10
Length=0.25				
New Line.L39	Phases=1	Bus1=38.2	Bus2=39.2	LineCode=10
Length=0.325				
New Line.L40	Phases=1	Bus1=40.3	Bus2=41.3	LineCode=11
Length=0.325				
New Line.L41	Phases=3	Bus1=40.1.2.3	Bus2=42.1.2.3	LineCode=1
Length=0.25				
New Line.L42	Phases=1	Bus1=42.2	Bus2=43.2	LineCode=10
Length=0.5				
New Line.L43	Phases=3	Bus1=42.1.2.3	Bus2=44.1.2.3	LineCode=1
Length=0.2				
New Line.L44	Phases=1	Bus1=44.1	Bus2=45.1	LineCode=9
Length=0.2				
New Line.L45	Phases=3	Bus1=44.1.2.3	Bus2=47.1.2.3	LineCode=1
Length=0.25				
New Line.L46	Phases=1	Bus1=45.1	Bus2=46.1	LineCode=9
Length=0.3				
New Line.L47	Phases=3	Bus1=47.1.2.3	Bus2=48.1.2.3	LineCode=4
Length=0.15				
New Line.L48	Phases=3	Bus1=47.1.2.3	Bus2=49.1.2.3	LineCode=4
Length=0.25				
New Line.L49	Phases=3	Bus1=49.1.2.3	Bus2=50.1.2.3	LineCode=4
Length=0.25				
New Line.L50	Phases=3	Bus1=50.1.2.3	Bus2=51.1.2.3	LineCode=4
Length=0.25				
New Line.L51	Phases=3	Bus1=51.1.2.3	Bus2=151.1.2.3	LineCode=4
Length=0.5				
New Line.L52	Phases=3	Bus1=52.1.2.3	Bus2=53.1.2.3	LineCode=1
Length=0.2				
New Line.L53	Phases=3	Bus1=53.1.2.3	Bus2=54.1.2.3	LineCode=1
Length=0.125				
New Line.L54	Phases=3	Bus1=54.1.2.3	Bus2=55.1.2.3	LineCode=1
Length=0.275				
New Line.L55	Phases=3	Bus1=54.1.2.3	Bus2=57.1.2.3	LineCode=3
Length=0.35				
New Line.L56	Phases=3	Bus1=55.1.2.3	Bus2=56.1.2.3	LineCode=1
Length=0.275				
New Line.L57	Phases=1	Bus1=57.2	Bus2=58.2	LineCode=10
Length=0.25				
New Line.L58	Phases=3	Bus1=57.1.2.3	Bus2=60.1.2.3	LineCode=3
Length=0.75				
New Line.L59	Phases=1	Bus1=58.2	Bus2=59.2	LineCode=10
Length=0.25				
New Line.L60	Phases=3	Bus1=60.1.2.3	Bus2=61.1.2.3	LineCode=5
Length=0.55				
New Line.L61	Phases=3	Bus1=60.1.2.3	Bus2=62.1.2.3	LineCode=12
Length=0.25				

New Line.L62 Phases=3 Bus1=62.1.2.3 Bus2=63.1.2.3 LineCode=12
 Length=0.175
 New Line.L63 Phases=3 Bus1=63.1.2.3 Bus2=64.1.2.3 LineCode=12
 Length=0.35
 New Line.L64 Phases=3 Bus1=64.1.2.3 Bus2=65.1.2.3 LineCode=12
 Length=0.425
 New Line.L65 Phases=3 Bus1=65.1.2.3 Bus2=66.1.2.3 LineCode=12
 Length=0.325
 New Line.L66 Phases=1 Bus1=67.1 Bus2=68.1 LineCode=9
 Length=0.2
 New Line.L67 Phases=3 Bus1=67.1.2.3 Bus2=72.1.2.3 LineCode=3
 Length=0.275
 New Line.L68 Phases=3 Bus1=67.1.2.3 Bus2=97.1.2.3 LineCode=3
 Length=0.25
 New Line.L69 Phases=1 Bus1=68.1 Bus2=69.1 LineCode=9
 Length=0.275
 New Line.L70 Phases=1 Bus1=69.1 Bus2=70.1 LineCode=9
 Length=0.325
 New Line.L71 Phases=1 Bus1=70.1 Bus2=71.1 LineCode=9
 Length=0.275
 New Line.L72 Phases=1 Bus1=72.3 Bus2=73.3 LineCode=11
 Length=0.275
 New Line.L73 Phases=3 Bus1=72.1.2.3 Bus2=76.1.2.3 LineCode=3
 Length=0.2
 New Line.L74 Phases=1 Bus1=73.3 Bus2=74.3 LineCode=11
 Length=0.35
 New Line.L75 Phases=1 Bus1=74.3 Bus2=75.3 LineCode=11
 Length=0.4
 New Line.L76 Phases=3 Bus1=76.1.2.3 Bus2=77.1.2.3 LineCode=6
 Length=0.4
 New Line.L77 Phases=3 Bus1=76.1.2.3 Bus2=86.1.2.3 LineCode=3
 Length=0.7
 New Line.L78 Phases=3 Bus1=77.1.2.3 Bus2=78.1.2.3 LineCode=6
 Length=0.1
 New Line.L79 Phases=3 Bus1=78.1.2.3 Bus2=79.1.2.3 LineCode=6
 Length=0.225
 New Line.L80 Phases=3 Bus1=78.1.2.3 Bus2=80.1.2.3 LineCode=6
 Length=0.475
 New Line.L81 Phases=3 Bus1=80.1.2.3 Bus2=81.1.2.3 LineCode=6
 Length=0.175
 New Line.L82 Phases=3 Bus1=81.1.2.3 Bus2=82.1.2.3 LineCode=6
 Length=0.25
 New Line.L83 Phases=1 Bus1=81.3 Bus2=84.3 LineCode=11
 Length=0.675
 New Line.L84 Phases=3 Bus1=82.1.2.3 Bus2=83.1.2.3 LineCode=6
 Length=0.25
 New Line.L85 Phases=1 Bus1=84.3 Bus2=85.3 LineCode=11
 Length=0.475
 New Line.L86 Phases=3 Bus1=86.1.2.3 Bus2=87.1.2.3 LineCode=6
 Length=0.45
 New Line.L87 Phases=1 Bus1=87.1 Bus2=88.1 LineCode=9
 Length=0.175
 New Line.L88 Phases=3 Bus1=87.1.2.3 Bus2=89.1.2.3 LineCode=6
 Length=0.275

New Line.L89	Phases=1	Bus1=89.2	Bus2=90.2	LineCode=10
Length=0.25				
New Line.L90	Phases=3	Bus1=89.1.2.3	Bus2=91.1.2.3	LineCode=6
Length=0.225				
New Line.L91	Phases=1	Bus1=91.3	Bus2=92.3	LineCode=11
Length=0.3				
New Line.L92	Phases=3	Bus1=91.1.2.3	Bus2=93.1.2.3	LineCode=6
Length=0.225				
New Line.L93	Phases=1	Bus1=93.1	Bus2=94.1	LineCode=9
Length=0.275				
New Line.L94	Phases=3	Bus1=93.1.2.3	Bus2=95.1.2.3	LineCode=6
Length=0.3				
New Line.L95	Phases=1	Bus1=95.2	Bus2=96.2	LineCode=10
Length=0.2				
New Line.L96	Phases=3	Bus1=97.1.2.3	Bus2=98.1.2.3	LineCode=3
Length=0.275				
New Line.L97	Phases=3	Bus1=98.1.2.3	Bus2=99.1.2.3	LineCode=3
Length=0.55				
New Line.L98	Phases=3	Bus1=99.1.2.3	Bus2=100.1.2.3	LineCode=3
Length=0.3				
New Line.L99	Phases=3	Bus1=100.1.2.3	Bus2=450.1.2.3	LineCode=3
Length=0.8				
New Line.L118	Phases=3	Bus1=197.1.2.3	Bus2=101.1.2.3	LineCode=3
Length=0.25				
New Line.L100	Phases=1	Bus1=101.3	Bus2=102.3	LineCode=11
Length=0.225				
New Line.L101	Phases=3	Bus1=101.1.2.3	Bus2=105.1.2.3	LineCode=3
Length=0.275				
New Line.L102	Phases=1	Bus1=102.3	Bus2=103.3	LineCode=11
Length=0.325				
New Line.L103	Phases=1	Bus1=103.3	Bus2=104.3	LineCode=11
Length=0.7				
New Line.L104	Phases=1	Bus1=105.2	Bus2=106.2	LineCode=10
Length=0.225				
New Line.L105	Phases=3	Bus1=105.1.2.3	Bus2=108.1.2.3	LineCode=3
Length=0.325				
New Line.L106	Phases=1	Bus1=106.2	Bus2=107.2	LineCode=10
Length=0.575				
New Line.L107	Phases=1	Bus1=108.1	Bus2=109.1	LineCode=9
Length=0.45				
New Line.L108	Phases=3	Bus1=108.1.2.3	Bus2=300.1.2.3	LineCode=3
Length=1				
New Line.L109	Phases=1	Bus1=109.1	Bus2=110.1	LineCode=9
Length=0.3				
New Line.L110	Phases=1	Bus1=110.1	Bus2=111.1	LineCode=9
Length=0.575				
New Line.L111	Phases=1	Bus1=110.1	Bus2=112.1	LineCode=9
Length=0.125				
New Line.L112	Phases=1	Bus1=112.1	Bus2=113.1	LineCode=9
Length=0.525				
New Line.L113	Phases=1	Bus1=113.1	Bus2=114.1	LineCode=9
Length=0.325				
New Line.L114	Phases=3	Bus1=135.1.2.3	Bus2=35.1.2.3	LineCode=4
Length=0.375				

```
New Line.L116 Phases=3 Bus1=152.1.2.3 Bus2=52.1.2.3 LineCode=1
Length=0.4
New Line.L117 Phases=3 Bus1=160r.1.2.3 Bus2=67.1.2.3 LineCode=6
Length=0.35
```

```
! NORMALLY CLOSED SWITCHES ARE DEFINED AS SHORT LINES
! Could also be defined by setting the Switch=Yes property
```

```
New Line.Sw1   phases=3 Bus1=150r Bus2=149   r1=1e-3 r0=1e-3
x1=0.000 x0=0.000 c1=0.000 c0=0.000 Length=0.001
New Line.Sw2   phases=3 Bus1=13   Bus2=152   r1=1e-3 r0=1e-3
x1=0.000 x0=0.000 c1=0.000 c0=0.000 Length=0.001
New Line.Sw3   phases=3 Bus1=18   Bus2=135   r1=1e-3 r0=1e-3
x1=0.000 x0=0.000 c1=0.000 c0=0.000 Length=0.001
New Line.Sw4   phases=3 Bus1=60   Bus2=160   r1=1e-3 r0=1e-3
x1=0.000 x0=0.000 c1=0.000 c0=0.000 Length=0.001
New Line.Sw5   phases=3 Bus1=97   Bus2=197   r1=1e-3 r0=1e-3
x1=0.000 x0=0.000 c1=0.000 c0=0.000 Length=0.001
New Line.Sw6   phases=3 Bus1=61   Bus2=61s   r1=1e-3 r0=1e-3
x1=0.000 x0=0.000 c1=0.000 c0=0.000 Length=0.001
```

```
! NORMALLY OPEN SWITCHES; DEFINED AS SHORT LINE TO OPEN BUS SO WE CAN
SEE OPEN POINT VOLTAGES.
! COULD ALSO BE DEFINED AS DISABLED OR THE TERMINCAL COULD BE OPENED
AFTER BEING DEFINED
```

```
New Line.Sw7   phases=3 Bus1=151   Bus2=300_OPEN r1=1e-3 r0=1e-3
x1=0.000 x0=0.000 c1=0.000 c0=0.000 Length=0.001
New Line.Sw8   phases=1 Bus1=54.1   Bus2=94_OPEN.1 r1=1e-3 r0=1e-3
x1=0.000 x0=0.000 c1=0.000 c0=0.000 Length=0.001
```

```
! LOAD TRANSFORMER AT 61s/610
! This is a 150 kVA Delta-Delta stepdown from 4160V to 480V.
```

```
New Transformer.XFM1 Phases=3 Windings=2 Xhl=2.72
~ wdg=1 bus=61s      conn=Delta kv=4.16   kva=150   %r=0.635
~ wdg=2 bus=610     conn=Delta kv=0.48   kva=150   %r=0.635
```

```
! CAPACITORS
! Capacitors are 2-terminal devices. The 2nd terminal (Bus2=...)
defaults to all phases
! connected to ground (Node 0). Thus, it need not be specified if a Y-
connected or L-N connected
! capacitor is desired
```

```
New Capacitor.C83      Bus1=83      Phases=3      kVAR=600      kV=4.16
New Capacitor.C88a    Bus1=88.1    Phases=1      kVAR=50       kV=2.402
New Capacitor.C90b    Bus1=90.2    Phases=1      kVAR=50       kV=2.402
New Capacitor.C92c    Bus1=92.3    Phases=1      kVAR=50       kV=2.402
```

```
!REGULATORS - REDIRECT TO DEFINITIONS FILE
! This file contains definitions for the remainder of regulators on the
feeder:
```



```
Redirect IEEE123Regulators.DSS
```

```
! SPOT LOADS -- REDIRECT INPUT STREAM TO LOAD DEFINITIONS FILE
```

```
Redirect IEEE123Loads.DSS
```

```
Set VoltageBases = [4.16, 0.48] ! ARRAY OF VOLTAGES IN KV
```

```
CalcVoltageBases ! PERFORMS ZERO LOAD POWER FLOW TO ESTIMATE VOLTAGE  
BASES
```

APPENDIX B

MATLAB FILE FOR POWER LOSS VARIATION

```

clc
GenkW=0; E=50;
MaxVoltage=1; OldLoss=95.7743;
i=1;

while i<1000 && MaxVoltage<1.05
GenkW = GenkW + E;

[DSSStartOK, DSSObj, DSSText] = DSSStartup;
if DSSStartOK
DSSText.command='Compile (C:\Program
Files\OpenDSS\IEEETestCases\123Bus\IEEE123firstscript.dss)';
% Set up the interface variables
DSSCircuit=DSSObj.ActiveCircuit;
DSSSolution=DSSCircuit.Solution;

% Now let's add a generator at bus 83
DSSText.Command = 'New Generator.GL Bus1=83 kv=4.16 kW=0 PF=1 ';
DSSText.Command = ['Generator.GL.kW =' num2str(GenkW)];

% Solve executes the solution for the present solution mode, which is
"snapshot" and establishes the bus list.
DSSSolution.Solve;

% Now load in the bus coordinates so we can execute a circuit plot if
we want to
DSSText.Command='Buscoords Buscoords.dat ! load in bus coordinates';

% Get bus voltage magnitudes in pu and distances from energy meter and
plot in a scatter plot
V1 = DSSCircuit.AllNodeVmagPUByPhase(1);
Dist1 = DSSCircuit.AllNodeDistancesByPhase(1);
V2 = DSSCircuit.AllNodeVmagPUByPhase(2);
Dist2 = DSSCircuit.AllNodeDistancesByPhase(2);
V3 = DSSCircuit.AllNodeVmagPUByPhase(3);
Dist3 = DSSCircuit.AllNodeDistancesByPhase(3);

% Getting max voltage
MaxV1 = max(V1);
MaxV2 = max(V2);
MaxV3 = max(V3);
MaxVol = [MaxV1, MaxV2, MaxV3];
MaxVoltage = max (MaxVol);

GenkWdisplay(i)=GenkW;
MaxVotagedisplay(i)=MaxVoltage;
Loss = DSSCircuit.Losses;
Realpart = Loss(1);
RealLossesinkW(i)=Realpart/1000;
NewLoss = Realpart/1000;

if NewLoss>150
break
end

```

```
plot(GenkWdisplay, RealLossesinkW);
grid on; xlabel('Total DG (kW)', 'FontSize', 10); ylabel('Power Loss
(kW)', 'FontSize', 10);

i=i+1;

else
a='DSS Did Not Start'
disp(a)
end
end
```

APPENDIX C

MATLAB FILE FOR VOLTAGE PROFILE

```

[DSSStartOK, DSSObj, DSSText] = DSSStartup;
if DSSStartOK
DSSText.command='Compile (C:\Program
Files\OpenDSS\IEEETestCases\123Bus\IEEE123firstscript.dss)';
% Set up the interface variables
DSSCircuit=DSSObj.ActiveCircuit;
DSSSolution=DSSCircuit.Solution;

% Adding a generator at bus 83
DSSText.Command = 'New Generator.GL Bus1=83 kv=4.16 kW=1500 PF=1 ';

DSSSolution.Solve;
% Now load in the bus coordinates so we can execute a circuit plot
DSSText.Command='Buscoords Buscoords.dat ! load in bus coordinates';

% Get bus voltage magnitudes in pu and distances from energy meter and
plot in a scatter plot
% Get Voltage and Distances Array
V1 = DSSCircuit.AllNodeVmagPUByPhase(1);
Dist1 = DSSCircuit.AllNodeDistancesByPhase(1);
V2 = DSSCircuit.AllNodeVmagPUByPhase(2);
Dist2 = DSSCircuit.AllNodeDistancesByPhase(2);
V3 = DSSCircuit.AllNodeVmagPUByPhase(3);
Dist3 = DSSCircuit.AllNodeDistancesByPhase(3);

% Getting max voltage
MaxV1 = max(V1);
MaxV2 = max(V2);
MaxV3 = max(V3);
MaxVol = [MaxV1, MaxV2, MaxV3];
MaxVoltage = max (MaxVol);

% Make Plot
plot(Dist1, V1, 'k*'); % black *
hold on;
plot(Dist2, V2, 'r+'); % red +
plot(Dist3, V3, 'bd'); % diamond Marker
legend('phase A', 'phase B', 'phase C', 'Location', 'SouthEast');
ylim([0.96 1.07]);
ylabel('Voltage (pu)');
xlabel('Distance from Substation (km)');
hold off

else
a='DSS Did Not Start'
disp(a)
end

```

APPENDIX D

MATLAB FILE FOR CONTINUAL SENSITIVITY ANALYSIS

```

clc
f=0;
E=100;          % DG step size for checking sensitivity
DGincrease=100; % putting DG of 100 kW after each iteration
LossDifference = 1; k=1;

%Initializing the BusDGLossS matrix
[DSSStartOK, DSSObj, DSSText] = DSSStartup;
if DSSStartOK
DSSText.command='Compile (C:\Program
Files\OpenDSS\IEEETestCases\123Bus\IEEE123firstscript.dss)';
% Set up the interface variables
DSSCircuit=DSSObj.ActiveCircuit;
DSSSolution=DSSCircuit.Solution;
DSSSolution.Solve;
Loss = DSSCircuit.Losses;
InitialLoss = Loss(1)/1000
OldLoss=InitialLoss;
BusSet = DSSCircuit.AllBusNames;
else
a='DSS Did Not Start'
disp(a)
end
NumBuses = length(BusSet)

%Iniializing DG at each bus to be zero
for i=1:NumBuses
BusDGLossS(i,1)=BusSet(i); % Bus no
BusDGLossS(i,2)={0};      % Initial DG
BusDGLossS(i,3)={InitialLoss}; % Initial total system loss
BusDGLossS(i,4)={0};      % Initial Sensitivity
end

for i=1:NumBuses
for j=1:4
BusDGLossS1(i,j)=BusDGLossS(i,j);
end
end

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%while (LossDifference>0) && (MaxVoltage<1.05) %No. of
iteration

for j=1:NumBuses
[DSSStartOK, DSSObj, DSSText] = DSSStartup;
if DSSStartOK
DSSText.command='Compile (C:\Program
Files\OpenDSS\IEEETestCases\123Bus\IEEE123firstscript.dss)';
% Set up the interface variables
DSSCircuit=DSSObj.ActiveCircuit;
DSSSolution=DSSCircuit.Solution;

%Retrieving old DGs
for q=1:NumBuses

```



```

CurrentDG = BusDGLossS{q,2};
if CurrentDG~=0
NewDGLevel = BusDGLossS{q,2};
busname=strcat(num2str(BusDGLossS{q,1}));
NewGen=strcat('New Generator.Gen',busname,' bus1=',busname,' kv=4.16','
kw=',num2str(NewDGLevel),' PF=1');
DSSText.command=NewGen;
else
end
end

% Adding a generator E at j bus
busname=BusDGLossS{j,1};
NewGen=strcat('New Generator.TestGen bus1=',busname,' kv=4.16','
kw=',num2str(E),' PF=1');
DSSText.command=NewGen;
DSSSolution.Solve;
%Calculating losses for j bus
Loss = DSSCircuit.Losses;
Realpart = Loss(1);
OldLoss = BusDGLossS{j,3}; % Extracting current/old loss from
matrix
BusDGLossS{j,3}=Realpart/1000; % Replacing Loss columnn by new loss
NewLoss = Realpart/1000;

% Sensitivity calculation for j bus
S = ((OldLoss - NewLoss)*100)/E;
BusDGLossS{j,4} = S; % Feeding 4th column with sensitivity values
else
a='DSS Did Not Start'
disp(a)
end
end

%Selecting top 5 buses on the basis of sensitivity
NewMatrix = sortrows(BusDGLossS,4)

% Making last row as first row, and reversing the matrix
n=1;
for m=NumBuses:-1:1
BusDGLossS(n,1)=NewMatrix(m,1);
BusDGLossS(n,2)=NewMatrix(m,2);
BusDGLossS(n,3)=NewMatrix(m,3);
BusDGLossS(n,4)=NewMatrix(m,4);
n=n+1;
end
BusDGLossS

disp(' ')
disp(' ')
str=['Iteration ' num2str(k)];
disp(str)
disp('5 buses with highest sensitivities are:')
counter=0;

```

```

for h=1:5
counter=counter+1;
Str= [num2str(counter) '.) The Sensitivity for bus '
num2str(BusDGLossS{h,1}) ' is = ' num2str(BusDGLossS{h,4})];
disp(Str)
end

% Adding DG in the matrix to top 5 buses with max sensitivity
for p=1%:5
BusDGLossS{p,2}= BusDGLossS{p,2} + DGincrease;
end

% Adding k DG to OpenDSS, and Calculating new system losses after
addition of kx100 kW DG
[DSSStartOK, DSSObj, DSSText] = DSSStartup;
if DSSStartOK
DSSText.command='Compile (C:\Program
Files\OpenDSS\IEEEETestCases\123Bus\IEEE123firstscript.dss)';
% Set up the interface variables
DSSCircuit=DSSObj.ActiveCircuit;
DSSSolution=DSSCircuit.Solution;

%Retrieving old DGs as well as putting 5 more DGs
for q=1:NumBuses
CurrentDG = BusDGLossS{q,2};
if CurrentDG~=0
NewDGLevel = BusDGLossS{q,2};
busname=strcat(num2str(BusDGLossS{q,1}));
NewGen=strcat('New Generator.Gen',busname,' bus1=',busname,' kv=4.16','
kw=',num2str(NewDGLevel),' PF=1');
DSSText.command=NewGen;
else
end
end
DSSSolution.Solve;

%Calculating losses for the new system
Loss = DSSCircuit.Losses;
Realpart = Loss(1);
LossReplace = Realpart/1000 ;
else
a='DSS Did Not Start'
disp(a)
end

% Replacing loss column
for p=1:NumBuses
BusDGLossS{p,3}= LossReplace;
end
LossMatrix(k)=LossReplace;
disp(' ')
str11=['Modified matrix after Iteration ' num2str(k)];
disp(str11)
BusDGLossS

```

```

LossDifference=OldLoss-LossMatrix(k);
OldLoss=LossMatrix(k);
k=k+1;

V1 = DSSCircuit.AllNodeVmagPUByPhase(1);
V2 = DSSCircuit.AllNodeVmagPUByPhase(2);
V3 = DSSCircuit.AllNodeVmagPUByPhase(3);
MaxV1 = max(V1);
MaxV2 = max(V2);
MaxV3 = max(V3);
MaxVol = [MaxV1, MaxV2, MaxV3];
MaxVoltage = max (MaxVol);

if LossDifference>0
for i=1:NumBuses
for j=1:4
BusDGLossS1(i,j)=BusDGLossS(i,j)
end
end
else
end

end

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%%%%%%%%%
%Sort by bus number
BusDGLossS1 = sortrows(BusDGLossS1,1)
disp(' ')
disp(' ')
str3=['Initial system loss without any DG is = ' num2str(InitialLoss) '
kW'];
disp(str3)
Loss(1)=InitialLoss;
Iteration(1)=0;
for a=1:k-1
Iteration(a+1)=a;
Loss(a+1) =LossMatrix(a);
n=a*5;
strr=['System loss after iteration ' num2str(a) ' when ' num2str(n) '
DG have been put is = ' num2str(LossMatrix(a)) ' kW'];
disp(strr)
end

% plot(Iteration, Loss);
% ylabel('Power Loss (kW)');
% xlabel('Iteration');
disp(' ')
disp(' ')
counter=0;
for a=1:NumBuses % Made 6 in place of 1
DG=BusDGLossS1{a,2};
if DG~=0
counter=counter+1;

```

```

str2=[num2str(counter) '.) Total DG at bus ' num2str(BusDGLossS1{a,1})
' is = ' num2str(BusDGLossS1{a,2})];
disp(str2)
else
end
end

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%%%%%%%%
[DSSStartOK, DSSObj, DSSText] = DSSStartup;
if DSSStartOK
DSSText.command='Compile (C:\Program
Files\OpenDSS\IEEETestCases\123Bus\IEEE123firstscript.dss)';
% Set up the interface variables
DSSCircuit=DSSObj.ActiveCircuit;
DSSSolution=DSSCircuit.Solution;

for q=1:NumBuses
CurrentDG = BusDGLossS1{q,2}; % Have 5 extra DGs ???
if CurrentDG~=0
NewDGLevel = BusDGLossS1{q,2}; % +... ??
busname=strcat(num2str(BusDGLossS1{q,1}));
NewGen=strcat('New Generator.Gen',busname, ' bus1=',busname, ' kv=4.16', '
kw=', num2str(NewDGLevel), ' PF=1');
DSSText.command=NewGen;
else
end
end

DSSSolution.Solve;
% Now load in the bus coordinates so we can execute a circuit plot
DSSText.Command='Buscoords Buscoords.dat ! load in bus coordinates';

% Get bus voltage magnitudes in pu and distances from energy meter and
plot in a scatter plot
% Get Voltage and Distances Array
V1 = DSSCircuit.AllNodeVmagPUByPhase(1);
Dist1 = DSSCircuit.AllNodeDistancesByPhase(1);
V2 = DSSCircuit.AllNodeVmagPUByPhase(2);
Dist2 = DSSCircuit.AllNodeDistancesByPhase(2);
V3 = DSSCircuit.AllNodeVmagPUByPhase(3);
Dist3 = DSSCircuit.AllNodeDistancesByPhase(3);
% Getting max voltage
MaxV1 = max(V1);
MaxV2 = max(V2);
MaxV3 = max(V3);
MaxVol = [MaxV1, MaxV2, MaxV3];
MaxVoltage = max(MaxVol);
if MaxVoltage==MaxV1
str=['Phase A has max voltage of ' num2str(MaxV1) ' pu'];
disp(str)
elseif MaxVoltage==MaxV2
str=['Phase B has max voltage of ' num2str(MaxV2) ' pu'];
disp(str)
else

```

```

str=['Phase C has max voltage of ' num2str(MaxV3) ' pu'];
disp(str)
end

% Make Plot
plot(Dist1, V1, 'k*'); % black *
hold on;
plot(Dist2, V2, 'r+'); % red +
plot(Dist3, V3, 'bd'); % diamond Marker
legend('phase A', 'phase B', 'phase C', 'Location', 'SouthEast'); %put the
legend
ylim([0.96 1.05]);
ylabel('Voltage(pu)');
xlabel('Distance from substation (km)');
hold off
else
a='DSS Did Not Start'
disp(a)
end

```

APPENDIX E

MATLAB FILE FOR CALCULATING ANNUAL AVERAGE LOSSES

```

clc
set(0,'defaultlinelength',1.5)
c=0;
for m=1:-0.005:0.35
c=c+1;
LM(c) = m;
DSSStartOK, DSSObj, DSSText] = DSSStartup;
if DSSStartOK
DSSText.command='Compile (C:\Program
Files\OpenDSS\IEEETestCases\123Bus\IEEE123firstscript.dss)';
% Set up the interface variables
DSSCircuit=DSSObj.ActiveCircuit;
DSSSolution=DSSCircuit.Solution;
DSSSolution.LoadMult = m; %Mult(m);
DSSSolution.Solve;
%Calculating losses for j bus
Loss = DSSCircuit.Losses;
Realpart = Loss(1)/1000;
LossMatrix(c) = Realpart;
str = ['System losses for LoadMult = ' num2str(m) ' are '
num2str(Realpart) ' kW.'];
disp(str)
else
a='DSS Did Not Start'
disp(a)
end
end

BusSet = [10 101 104 105 108 11 111 113 114 16 19 2 20 25 27 29 33 35
36 4 42 46 47 48 49 5 50 53 6 62 64 65 66 67 71 72 75 76 80 82 86 89 9
93 99]; % NEW 48 DG, LM=1, E=100kW
NumBuses = length(BusSet);
cc=0;
for m=1:-0.005:0.35
cc=cc+1;
LMDG1(cc) = m;
[DSSStartOK, DSSObj, DSSText] = DSSStartup;
if DSSStartOK
DSSText.command='Compile (C:\Program
Files\OpenDSS\IEEETestCases\123Bus\IEEE123firstscript.dss)';
% Set up the interface variables
DSSCircuit=DSSObj.ActiveCircuit;
DSSSolution=DSSCircuit.Solution;

%Retrieving old DGs as well as putting 5 more DGs
for q=1:NumBuses
NewDGLevel = 100;
busname=strcat(num2str(BusSet(q)));
NewGen=strcat('New Generator.Gen',busname,' bus1=',busname,' kv=4.16','
kw=',num2str(NewDGLevel),' PF=1');
DSSText.command=NewGen;
end

NewGen=strcat('New Generator.Gena bus1=48 kv=4.16 kw=100 PF=1');
DSSText.command=NewGen;

```

```

NewGen=strcat('New Generator.Genb bus1=76 kv=4.16 kw=200 PF=1');
DSSText.command=NewGen;

DSSSolution.LoadMult = m; %Mult(m);
DSSSolution.Solve;
%Calculating losses for j bus
Loss = DSSCircuit.Losses;
Realpart = Loss(1)/1000;
LossMatrixDG1(cc) = Realpart;
str = ['System losses for LoadMult = ' num2str(m) ' are '
num2str(Realpart) ' kW.'];
disp(str)
else
a='DSS Did Not Start'
disp(a)
end
end

BusSet = [105, 108, 11, 112, 113, 150, 16, 19, 20, 26, 29, 33, 35, 36,
4, 42, 48, 49, 53, 6, 63, 65, 66, 67, 71, 72, 75, 76, 78, 81, 87, 9,
93, 99]; %NEW 38 DG, LM=0.8, E=100kW
NumBuses = length(BusSet);
a=0;
for m=1:-0.005:0.35
a=a+1;
LMDG8(a) = m;
[DSSStartOK, DSSObj, DSSText] = DSSStartup;
if DSSStartOK
DSSText.command='Compile (C:\Program
Files\OpenDSS\IEEETestCases\123Bus\IEEE123firstscript.dss)';
% Set up the interface variables
DSSCircuit=DSSObj.ActiveCircuit;
DSSSolution=DSSCircuit.Solution;

%Retrieving old DGs as well as putting 5 more DGs
for q=1:NumBuses
NewDGLevel = 100;
busname=strcat(num2str(BusSet(q)));
NewGen=strcat('New Generator.Gen',busname,' bus1=',busname,' kv=4.16','
kw=',num2str(NewDGLevel),' PF=1');
DSSText.command=NewGen;
end

NewGen=strcat('New Generator.Gena bus1=48 kv=4.16 kw=100 PF=1');
DSSText.command=NewGen;
NewGen=strcat('New Generator.Genb bus1=49 kv=4.16 kw=100 PF=1');
DSSText.command=NewGen;
NewGen=strcat('New Generator.Genc bus1=76 kv=4.16 kw=100 PF=1');
DSSText.command=NewGen;
NewGen=strcat('New Generator.Gend bus1=9 kv=4.16 kw=100 PF=1');
DSSText.command=NewGen;

DSSSolution.LoadMult = m; %Mult(m);
DSSSolution.Solve;

```



```

%Calculating losses for j bus
Loss = DSSCircuit.Losses;
Realpart = Loss(1)/1000;
LossMatrixDG8(a) = Realpart;
str = ['System losses for LoadMult = ' num2str(m) ' are '
num2str(Realpart) ' kW.'];
disp(str)
else
k='DSS Did Not Start'
disp(k)
end
end

BusSet = [101 108 11 110 113 150 16 20 26 28 33 36 4 42 47 48 49 57 6
64 65 71 72 75 76 81 86 9 90 91 98]; % NEW 31 DG, LM=0.6, E=100kW
NumBuses = length(BusSet);
cc=0;
for m=1:-0.005:0.35
cc=cc+1;
LMDG6(cc) = m;
[DSSStartOK, DSSObj, DSSText] = DSSStartup;
if DSSStartOK
DSSText.command='Compile (C:\Program
Files\OpenDSS\IEEETestCases\123Bus\IEEE123firstscript.dss)';
% Set up the interface variables
DSSCircuit=DSSObj.ActiveCircuit;
DSSSolution=DSSCircuit.Solution;

%Retrieving old DGs as well as putting 5 more DGs
for q=1:NumBuses
NewDGLevel = 100;
busname=strcat(num2str(BusSet(q)));
NewGen=strcat('New Generator.Gen',busname, ' bus1=',busname, ' kv=4.16', '
kw=',num2str(NewDGLevel), ' PF=1');
DSSText.command=NewGen;
end

DSSSolution.LoadMult = m; %Mult(m);
DSSSolution.Solve;
%Calculating losses for j bus
Loss = DSSCircuit.Losses;
Realpart = Loss(1)/1000;
LossMatrixDG6(cc) = Realpart;
str = ['System losses for LoadMult = ' num2str(m) ' are '
num2str(Realpart) ' kW.'];
disp(str)
else
a='DSS Did Not Start'
disp(a)
end
end

```

```

BusSet = [1 108 11 113 150 20 28 33 35 47 48 49 6 63 65 67 71 75 76 81
9 91 98]; %NEW 24 DG, LM=0.5, E=100kW
NumBuses = length(BusSet);
cc=0;
for m=1:-0.005:0.35
cc=cc+1;
LMDG5(cc) = m;
[DSSStartOK, DSSObj, DSSText] = DSSStartup;
if DSSStartOK
DSSText.command='Compile (C:\Program
Files\OpenDSS\IEEETestCases\123Bus\IEEE123firstscript.dss)';
% Set up the interface variables
DSSCircuit=DSSObj.ActiveCircuit;
DSSSolution=DSSCircuit.Solution;

%Retrieving old DGs as well as putting 5 more DGs
for q=1:NumBuses
NewDGLevel = 100;
busname=strcat(num2str(BusSet(q)));
NewGen=strcat('New Generator.Gen',busname, ' bus1=',busname, ' kv=4.16', '
kw=', num2str(NewDGLevel), ' PF=1');
DSSText.command=NewGen;
end
NewGen=strcat('New Generator.Gena bus1=76 kv=4.16 kw=100 PF=1');
DSSText.command=NewGen;
DSSSolution.LoadMult = m; %Mult(m);
DSSSolution.Solve;
%Calculating losses for j bus
Loss = DSSCircuit.Losses;
Realpart = Loss(1)/1000;
LossMatrixDG5(cc) = Realpart;
str = ['System losses for LoadMult = ' num2str(m) ' are '
num2str(Realpart) ' kW.'];
disp(str)
else
a='DSS Did Not Start'
disp(a)
end
end

plot(LM, LossMatrix, 'k'); % black
hold on;
plot(LMDG1, LossMatrixDG1, 'r'); % red
hold on;
plot(LMDG8, LossMatrixDG8, 'b'); % blue
hold on;
plot(LMDG6, LossMatrixDG6, 'g'); % green
hold on;
plot(LMDG5, LossMatrixDG5, 'm'); % magenta
legend('Base system loss', 'Loss with 48 DG (LM=1)', 'Loss with 38 DG
(LM=0.8)', 'Loss with 31 DG (LM=0.6)', 'Loss with 24 DG
(LM=0.5)', 'Location', 'SouthEast'); %put the legend
xlabel('Load Multiplier');
ylabel('Power Loss (kW)');
hold off

```