DEVELOPMENT OF A STATE ESTIMATION ALGORITHM FOR THE ELECTRICAL DISTRIBUTION SYSTEM

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Degree of Master of Science in Electrical Engineering

Department of Electrical Engineering

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DECLARATION OF THE CANDIDATE & SUPERVISOR

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(Dr. P. S. N De Silva)

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(Dr. W. D. S. N. Rodrigo)

Signature of the supervisor: Date

(Dr. R. Samarasinghe)

Abstract

Over the past decade, the complexity of the electrical distribution network has been significantly increased. Power flow of the network has been changed from unidirectional to a dynamic scenario with the introduction of distributed energy generators, and the network complexity has been increased with the introduction of numerous power electronic devices and the diversification of loads. In order to ensure the reliability of this complex network, it is essential to provide accurate information and feedback to the control center governing it. If the system operator knows exactly where the system stands in terms of its stability and operation, he would be able to get the best decision in any situation. This has created a demand for more sophisticated tools and equipment which aids in network monitoring and analysis in present time. Real time modeling of the network plays a vital role in achieving this.

Further, implementation of a grid wide sensor network is one of the primary requirements of a smart grid. Extraction of the exact state of the network, to create a decision support system, is impairable from building a user friendly smart grid.

This project envisages a methodology, as to how a medium scale distribution company can make use of the imperfect data from their smart meters, distribution automation devices and boundary meters to derive an accurate, real time, network status map for distribution control center operation. In this project, a statistical criterion based on the weighted least square method of power system state estimation has been used to demonstrate a successful, consistence network voltage and current estimation system, which has been developed to be the core of a practical distribution control center operation software. The network topology is directly extracted from the Geographical Information System (GIS), enabling to grab the most updated picture of this rapidly evolving system.

Acknowledgement

I take this opportunity to record my profound gratitude to all those who contributed in successfully completing this research.

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Also I take this opportunity to express a deep sense of gratitude for the co-supervisors of this research, Dr. W. D. A. S. Rodrigo and Dr. R. Samarasinghe, for their continuous guidance and the encouragement, which helped me in completing this task through various stages.

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My sincere thanks go to my immediate supervisor Mr. S. D. C. Gunawardhana, System Development Manager of LECO, and to all my colleagues at Lanka Electricity Company Private Limited, who helped me in many ways during this period.

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Last but not least, I express my heartiest gratitude and love to my husband and my parents, who took a lot of burden and patient, and helped me in many ways to successfully complete this research.

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List of Abbreviations

Abbreviation	**Description**
PUCSL	Public Utilities Commission of Sri Lanka
LECO	Lanka Electricity Company Private Limited
CEB	Ceylon Electricity Board
LV	Low Voltage
MV	Medium Voltage
GIS	Geographic Information System
RMR	Remote Meter Readings
DG	Distributed Generator

CHAPTER 1

INTRODUCTION

1.1. Background

1.1.1. Revolution of the Conventional Distribution System

1900s is a century where many of the great inventions were introduced to the word, which were once even beyond imagination. The advancement of technology unveiled previously unknown dimensions of applications in almost all the sectors such as transportation, health care and communication. Despite the huge leaps that the other sectors went through during the century, no salient changes were made in the electrical distribution system until the recent past.

But, the situation has changed over the last decade, causing significant enhancements in the complexity of the electrical network. Introduction of distributed generators (DGs) has converted the conventional unidirectional power flow into a dynamic scenario and the power electronic devices which are often associated with these DGs and the protection schemes have changed the system response. Further to this, diversification of the loads, digitalization of the systems and the usage of communication technologies to enhance the efficiency and the reliability of the network has disrupted the traditional model of electricity distribution.

1.1.2. Sri Lankan Distribution Network

Sri Lankan distribution network is mostly an overhead operating network in the medium voltages of 33 kV and 11 kV, apart from the underground network in the highly urbanized areas in Colombo and Kandy districts. The low voltage network is an all overhead operating system, in the voltage level of 400 V/ 230 V.

As a regulator to the Sri Lankan energy sector, Public Utilities Commission of Sri Lanka (PUCSL), has issued five licenses for electricity distribution. Four of these licenses are issued to CEB, and LECO possesses the other. Further to this, PUCSL has provided guidelines and set regulations to the distribution utilities on maintaining the quality of supply and reducing distribution losses.

1.1.3. Lanka Electricity Company

Lanka Electricity Co. (Pvt.) Ltd. (LECO) is a private limited company, registered under the Companies Act No.17 of Sri Lanka for the purpose of electricity distribution. LECO network is established along the southern and western costal belt, which is a highly urbanized area with a high customer density.

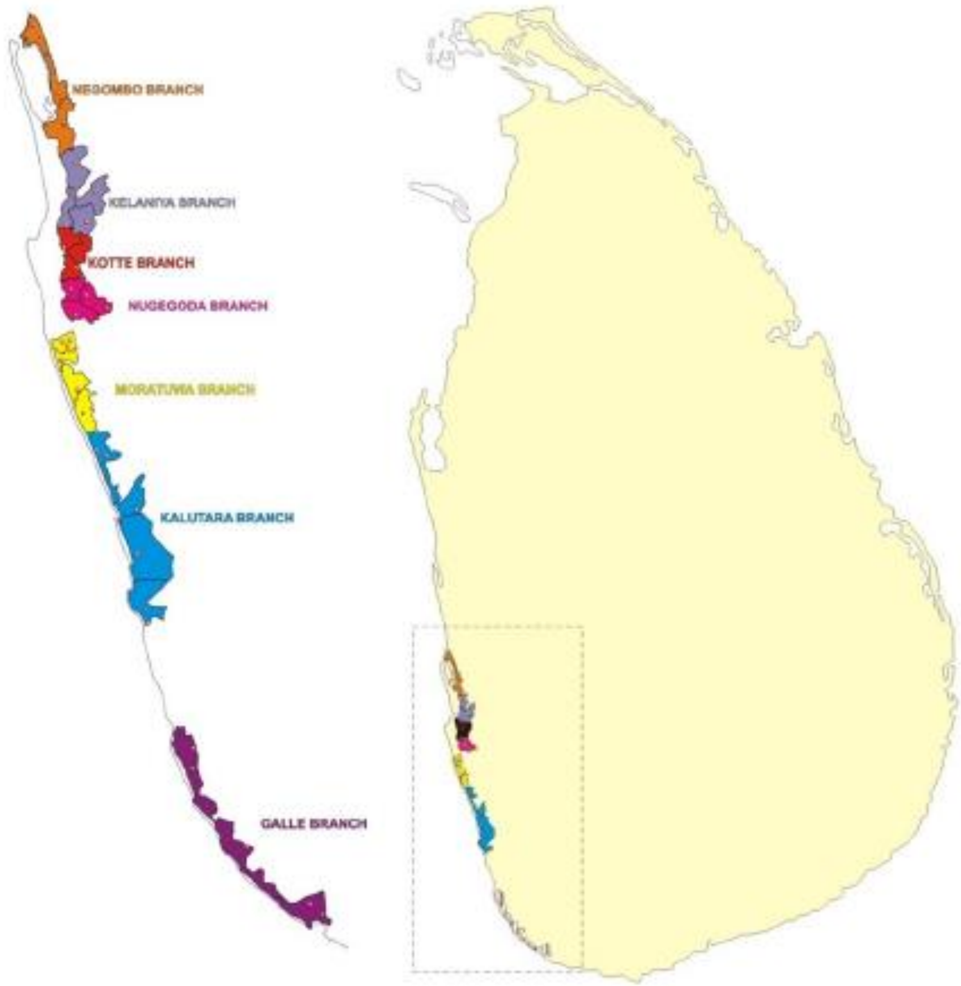

Figure 1.1: LECO Operational Area

The main function of LECO is purchasing electricity from the Sri Lankan transmission utility, Ceylon Electricity Board (CEB), and selling it to the customer base in the LECO operational area, which is around 545,000, as per the 2017 statistics. The network summary, as per 2017 is given in Table 1.1

Table 1.1: LECO Network Summary

LECO Network Summary	
Total Number of Customers	545,000
Total Number of Branches	7
Total Number of CSC	23
11kV line length	1,070 km
LV line length	3,500 km
11kV/400V substations - Total	4,097
11kV/400V Distribution Substations	2,371
11kV/400V Distribution Substations Capacity	374,528 kVA
Total Energy Sales in MWh (2017)	1,518,000 MWh
Total Solar Exports to the Network (2017)	13,724 MWh
Average Distribution Loss in the Network	4.0%

Foreseeing the requirement of this rapidly evolving distribution network, LECO is successfully adopting new technologies and concepts to enhance its' operational quality, being in line with the modernizing world. Even after 30 years of operation, LECO continues the service to the country and its development, with the sole operational objective of providing a quality electricity supply to the customers while reducing the distribution losses in the network.

1.1.4. MV Network of LECO

LECO medium voltage network is a 11 kV, radially operating network, which has been constructed according to a ring type feeder design. This 11 kV feeders are routed mostly along road corridors and other such access routes. Three phase, four wire, low voltage system comprises of approximately 150-200 A rated feeder circuits with 15 A, 30 A and 60A service connections.

Transformers used by LECO are three phase, 11 kV/ 415 V, double wound, Dy11, hermetically sealed type with the capacities of 100 kVA, 160 kVA, 250 kVA, 400 kVA and 630 kVA. Only the transformers sized up to 250 kVA are used in LECO as distribution transformers.

Distribution network arrangement of LECO is maintained in the small transformer small feeder basis. This practice has increased the number of distribution transformers in the network and reduce the lengths of the feeders. As a result, this has reduced the number of service connections added to a single transformer or a single feeder and reduce the voltage drops and line losses in the network.

1.2. Problem Statement and Motivation

After several decades of consistency, the electricity distribution system is going through a huge transformation, as the technology and innovation disrupt the traditional models. This transformation is predicted to become revolutionary within the next decade, with the electrification of the large sectors such as transportation, decentralization of the generation and the introduction of various power electronic devices and communication systems to the electricity network.

When we consider the Sri Lankan context, Sri Lanka is one of the early lighted up countries with electricity during the British colonial period. Yet, the structure of the Sri Lankan distribution network has not faced significant changes since the early 50s, until recent past. The conventional Sri Lankan distribution network includes the typical items such as primary substations, medium voltage feeders, distribution transformers, low voltage feeders, protection and metering mechanisms etc. The power flow has been vertically downwards from the grid substation to the customer premises. Distribution utilities currently use historical data to forecast the current network state and the control actions mainly depends on those historical data, information received over the phone as well as the experience of the control center operator.

However, the things are now being changing with the rapid addition of distributed energy generators, digitalization of the grid with smart metering, smart sensors, automation and other digital network technologies and the surge in power consuming devices and their diversification. These new additions to the conventional distribution network and the resultant increment in the network complexity have created a demand for more sophisticated tools, which aids in planning, monitoring and controlling the distribution system. Therefore, now is the high time for the Sri Lankan distribution utilities to advert on restructuring the controlling and operational systems of their distribution network.

While focusing on this, it would be an initial necessity to have an updated, real time, accurate picture of the network, at the distribution control center, to facilitate the decision making process and to take effective control actions. The popular network monitoring systems include the conditions such as installing network monitoring devices with remote meter reading facility at all the significant points of the network, using metering units with a high accuracy class, adopting advance technologies and communication protocols for data transmission etc. But, all these solutions can be highly expensive for a distribution utility in a developing country. Therefore, as an alternative to increase the accuracy of the distribution monitoring system, this research proposes a methodology, which has been developed using the State Estimation techniques.

1.3. State Estimation

Effective management of distribution system requires sophisticated tools, which are capable of projecting the exact real time picture of the network on the control center screen. But the advanced real time simulators which has been developed to capture the current network state may not be suitable for all the systems, due to numerous economical and technical constraints. State estimation is an effective technique which can be used to reduce these concerns.

The objective of state estimation is producing the best possible estimate of the system state, utilizing whatever the information available, while recognizing that there can be errors in the meter readings and redundant measurements. It is capable of smoothing out small, random errors in meter readings, detecting and identifying gross measurement errors, filling in the measurements which have been failed due to communication failures, compensating the errors due to asynchronous data transmission and estimating the values in un-metered locations. 1

Further, state estimation is a key enabler for the smart grid applications on the distribution system. These include reactive power management, outage management, loss reduction, demand response, management of protection schemes, distributed energy generation dispatch, integration with transmission systems and more. 2

CHAPTER 2

PROJECT OVERVIEW

2.1. Research Study

This research envisages a methodology, as to how a medium scale distribution company can make use of the imperfect data from their smart meters, distribution automation devices and boundary meters to derive an accurate, real time, network status map for distribution control center operation.

The underlying concept of the project is a statistical criterion, based on the weighted least square method of power system state estimation. Forward-backward algorithm of power flow analysis, with the modifications to embed bad data identification and optimization capabilities, has been used to demonstrate a successful, consistence network voltage and current estimation system.

The state estimation algorithm requires mainly two types of inputs and thus has been linked with the two databases; Remote Meter Reading (RMR) database and the Geographical Information System (GIS) database. RMR database stores the data transmitted from smart meters, which are installed at the distribution transformers. Each reading updates in 15minutes intervals.

GIS database has the most updated picture of this rapidly evolving distribution network, with a geographical reference to the network assets. Therefore, the network topology is directly extracted from the GIS database, enabling the state estimation tool to use the exact network structure existing in the present time.

The 11 kV distribution system of Lanka Electricity Company (Pvt.) Ltd was selected as the case study and the developed tool was tested with the Ethulkotte - Kalubowila feeder. In order to verify the results, current profile obtained at the feeder starting point and the voltage profile obtained at a specific node from the state estimation program, were compared with the manual measurements taken for the same.

The methodology, data analysis, results and conclusion on the proposed method has been presented in the report.

2.2. Objectives of the Study

The objectives of the study are listed below.

a. To develop a state estimation algorithm for the real time monitoring of the electrical distribution system.
b. To validate the proposed methodology with a case study.

2.3. Methodology

Methodology is listed as below.

a. Studying the network and the existing network monitoring method. Hence, identifying the available resources and limitations for implementing a real time network monitoring system.
b. Determining a suitable technique for developing a real time network monitoring system using state estimation.
c. Developing the state estimation algorithm.
d. Developing a tool to extract the network topology from the GIS database, into the state estimation tool.
e. Linking the remote meter reading database to the state estimation tool. Identifying a suitable technique to estimate the load curves at the load ends, where remote meter reading facility is not available.
f. Verification and analysis of the results through a case study.

CHAPTER 3

MODELING AND DEVELOPMENT

3.1. Overview

As shown in Figure 3.2: Geographical Location of the Test Feeder , the real time network monitoring tool is based on a state estimation technique, which takes two real time inputs; one from the remote meter reading database and the other one from the GIS network database. A tool has been developed to convert the graphical network in the GIS database into the tabular format and extract the required parameters for running the state estimation algorithm. This chapter provides extensive information on each step.

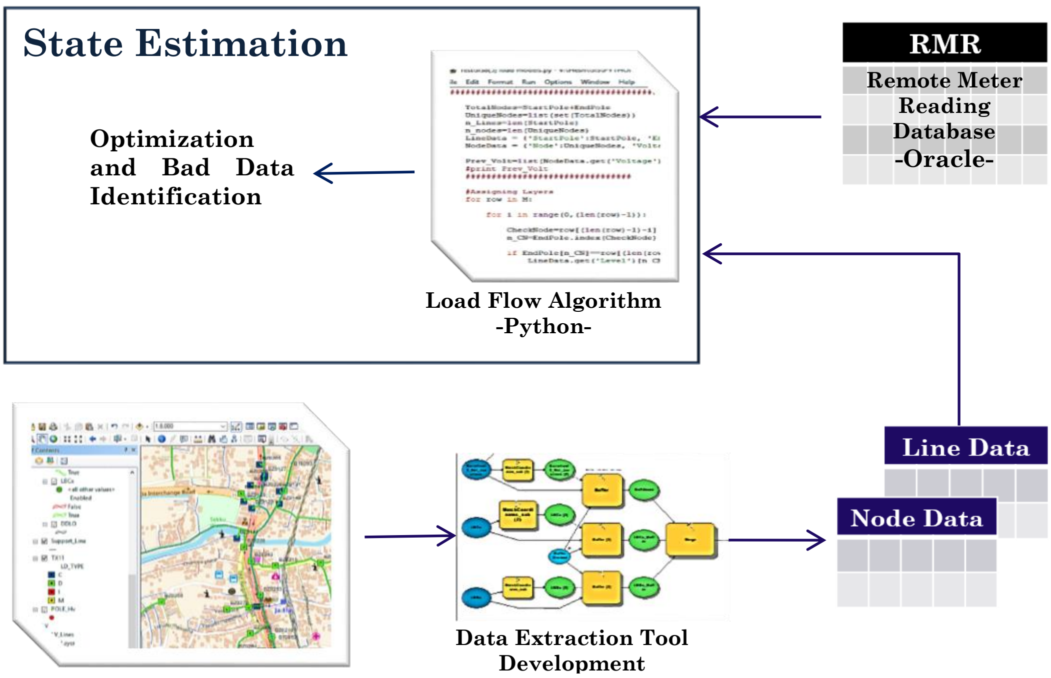

Figure 3.1: Tool Development Methodology

3.2. Test Feeder

This research study required a real time simulation of a medium voltage feeder for the testing and validation purposes of the developed tools. Out of the many feeders available, Ethulkotte – Kalubowila 11 kV feeder of the LECO network was selected for this purpose considering the following facts.

a. Diversified network architecture with extended branches.

b. Availability of remote meter reading facility at most of the distribution transformers.

c. Availability of around 42 transformers of different categories with a total capacity over 8 MVA.

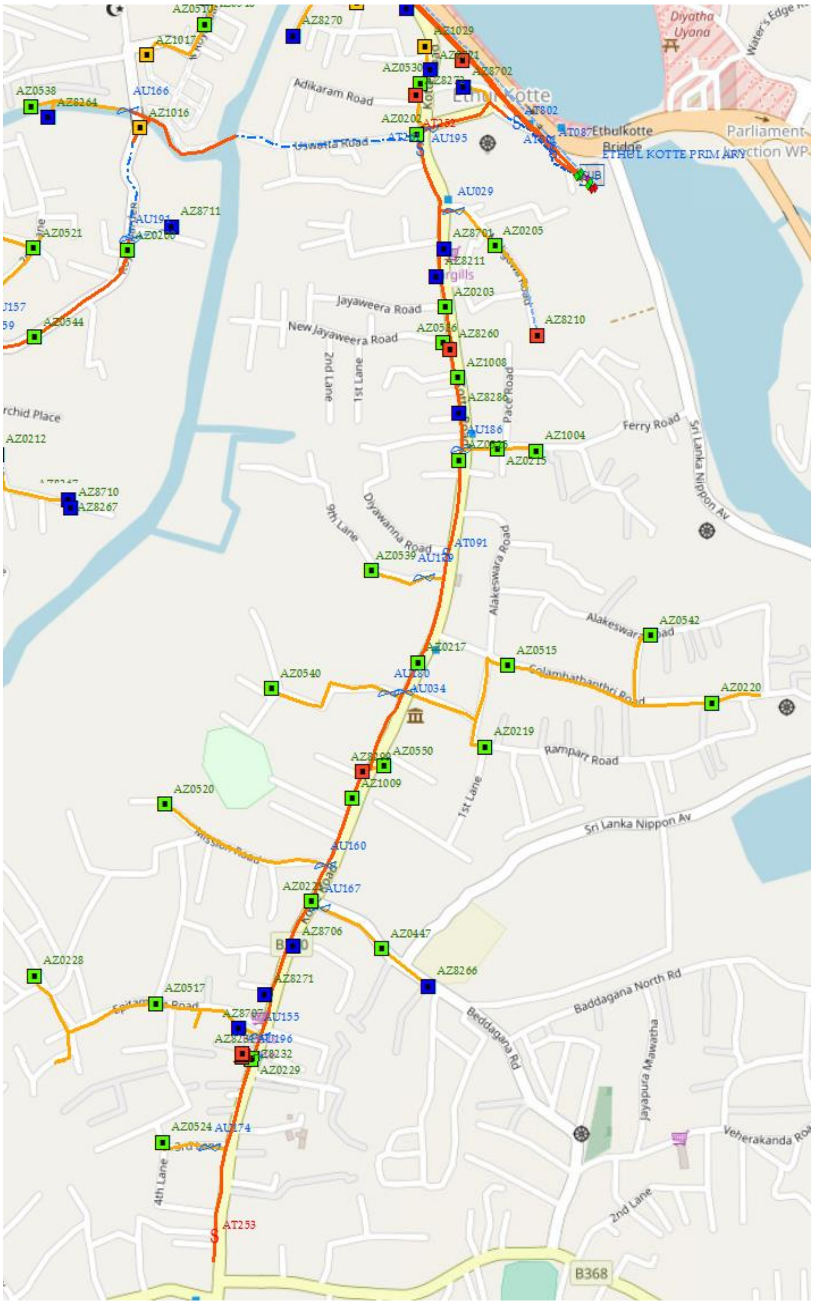

Figure 3.2: Geographical Location of the Test Feeder

Table 3.1: Test Feeder Details

Feeder Name	Ethulkotte – Kalubowila feeder
Source	Ethulkotte Primary Substation
Branch	Kotte Branch
Customer Service Center	Ethulkotte CSC
Total Number of Transformers	42
Domestic	25
Commercial	10
Industrial	06
Mixed	01
Total Transformer Capacity	8150 kVA
Total Feeder Length	6.1 km

3.3. Data Extraction from GIS

As it was observed, in most of the conventional load flow software, the network architecture has to be redrawn in the platform and the parameters has to be manually inserted. But, this method is ineffective in real time network monitoring as the time consumed for modifying the network architecture and inserting the parameters cause major delays and make the real time simulation unfeasible. Therefore, in this research, a tool has been developed to automatically extract the existing network architecture directly from the network database, which is ArcGIS for LECO. This has enabled the state estimation algorithm to grab the most updated picture of this rapidly evolving network within seconds.

3.3.1. LECO Network Database - ArcGIS

ArcGIS is a Geographic Information System (GIS) platform developed by Esri, which has a range of applications in using maps and geographic information. It provides the facility of creating maps with a geographical reference, compiling geographic data, sharing mapped information and managing geographic information in a database.

This software consists of a set of inbuilt tools, which can be used in map based data analysis. These tools can be combined together in the ArcGIS ModelBuilder, feeding the output of one tool into another tool as input, which can also be thought of as a visual programming language for building workflows. Additionally, ArcGIS allows the users to import more advanced tools developed using Python programming language, offering a large degree of freedom for the users to build customized tools.

LECO has been using an in-house developed GIS platform since the early stages. LECO GIS database contains all the network assets at a position accuracy of 500mm. All network asset records including installation, maintenance and customer service data is accessible through this geographical interface based data system. Identifying the wealth of having a better asset database to leverage more advanced geographically diverse asset management system which results efficient and effective distribution network, LECO network is now being migrated to ArcGIS platform.

3.3.2. Data Extraction Tool

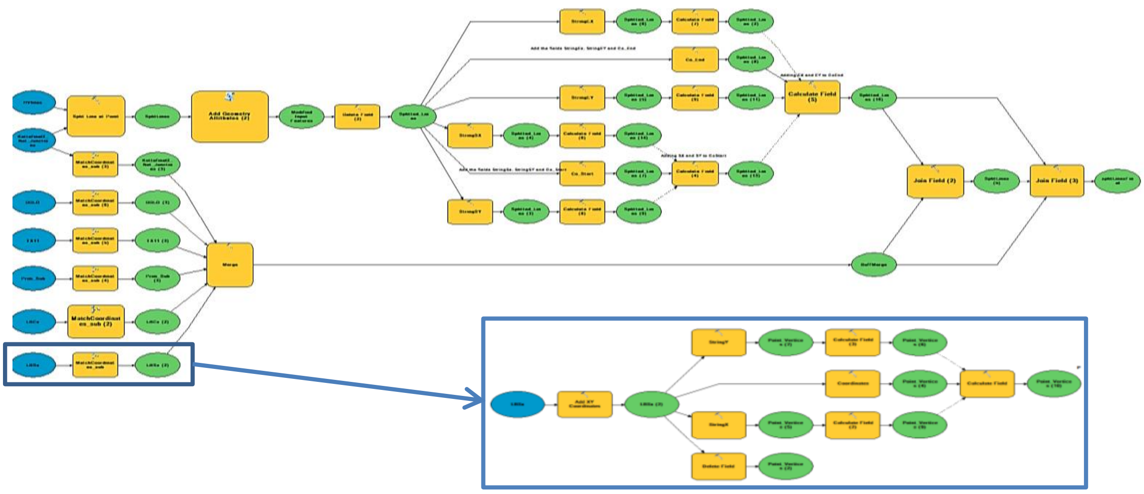

Figure 3.3: Developed Data Extraction Tool in ArcGIS ModelBuilder

The tool shown in Figure 3.3 was developed in ArcGIS ModelBuilder to extract the network topology from the GIS database. The main function of this tool is converting the graphical network in the GIS map into the tabular format, which consist of the data required for running the state estimation algorithm. Flow chart shown in Figure 3.4 illustrates the algorithm developed to construct the tool.

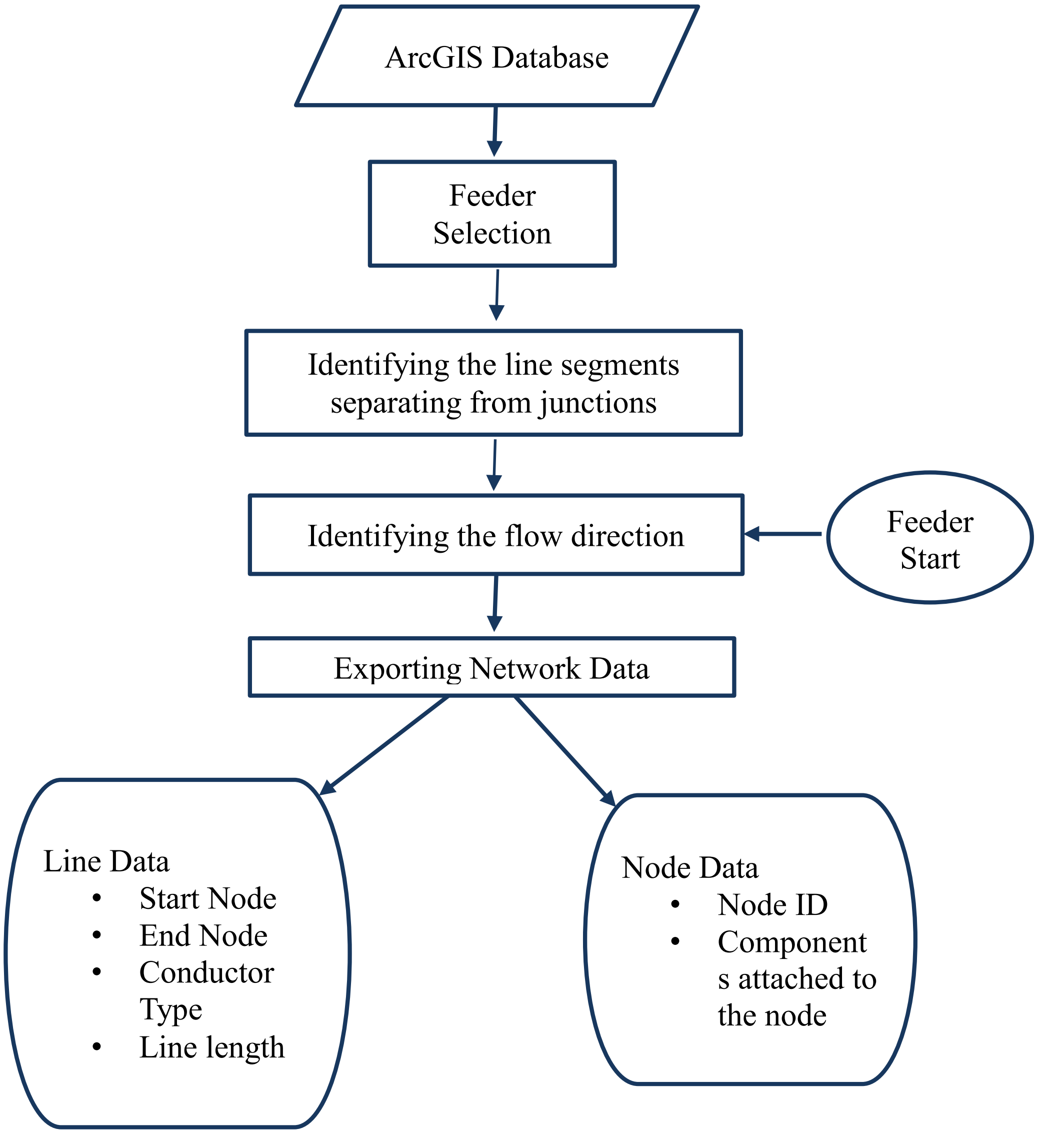

Figure 3.4: Flow Chart Representation of the GIS Data Extraction Tool

Extensive details on each of the steps in the flow chart illustrated in Figure 3.4 is given below.

Step 1: Feeder Selection

As shown in Figure 3.5, a flag is set at the starting point of the feeder which has to be analyzed real time. Then it is traced downstream from the flag point to select the feeder.

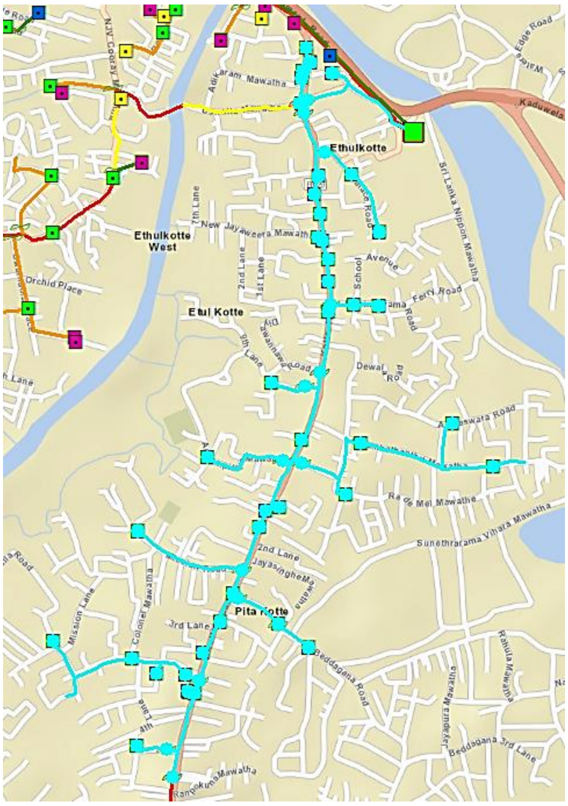

Figure 3.5: Selected Feeder

Step 2: Identifying the Line Segments Separating from Junctions

First, a copy of the selected feeder is generated to avoid alterations in the original network. Then the copied feeder is splitted from the specific nodes such as the junction points, switches and the conductor changing points, which are highlighted in red colour in Figure 3.6. Then the coordinates of those nodes, as well as the end points of the splitted lines are recorded. Those cordinates are compared and matched to find the relevant nodes at the line ends. Further the lengths of the line segments are calculated using the coordinates. Table in Figure 3.7 shows the recorded results.

Figure 3.6: Located Nodes and the Splitted Lines

SplitLines

FID *	Layer	Shape_Length	End1	End1_X	End1_Y	End2	End2_X	End2_Y
1	11kVC115	61.22304	Junction2285	104101.7139	188785.64	Junction2276	104093.7389	188846.1044
2	11kVC115	119.763485	Junction2248	104065.5355	189154.9039	AT0261	104031.0349	189268.0269
3	11kVC115	5.800337	Junction2217	104025.4145	189296.6705	AT0252	104020.1025	189294.341
4	11kVC115	19.567337	Junction2233	104043.3827	189304.4178	Junction2217	104025.4145	189296.6705
5	11kVC115	131.299495	Junction2329	104158.7969	189354.6624	Junction2233	104043.3827	189304.4178
6	11kVC115	66.957685	Junction2271	104087.0651	188912.8097	Junction2261	104077.5685	188979.0659
7	11kVC115	21.270218	Junction2289	104103.5591	188698.2461	Junction2294	104106.1665	188719.3559
8	11kVC115	66.946919	Junction2294	104106.1665	188719.3559	Junction2285	104101.7139	188785.64
9	11kVC115	43.798413	Junction2261	104077.5685	188979.0659	Junction2252	104069.0665	189022.0312
10	11kVC115	62.239146	Junction2252	104069.0665	189022.0312	Junction2247	104065.0539	189084.0024
11	11kVC115	25.913482	Junction2248	104065.5355	189154.9039	AU0029	104091.4108	189156.3101
12	11kVC115	8.308035	Junction2284	104100.917	188850.2875	Junction2276	104093.7389	188846.1044
13	11kVC115	57.198044	Junction2276	104093.7389	188846.1044	Junction2270	104086.8826	188902.8895
14	11kVC115	70.904124	Junction2247	104065.0539	189084.0024	Junction2248	104065.5355	189154.9039
15	11kVC115	167.574767	Junction1996	103717.0156	187601.3278	Junction1963	103668.9163	187441.1282
16	11kVC115	40.145726	Junction2012	103749.9427	187726.4859	Junction2010	103746.5428	187686.4844

Figure 3.7: Recorded Data of the Splitted Line Segments

Step 3: Identifying the Flow Direction

The most challenging task of extracting the network topology is finding the flow direction. Since it was not possible to achieve this using the ArcGIS ModelBuilder, an algorithm was developed using Python programming language. The feeder starting node has to be given as a user input. Table shown in Figure 3.8 gives the output of the tool. There, the two ends of the line segments which were located in step 2 are rearranged according to the flow direction and appended in the two newly inserted columns, ‘From Pole’ and ‘To Pole’.

Table

SplitLines

FID *	End1	End2	FromPole	ToPole
1	Junction2285	Junction2276	Junction2276	Junction2285
2	Junction2248	AT0261	AT0261	Junction2248
3	Junction2217	AT0252	Junction2217	AT0252
4	Junction2233	Junction2217	Junction2233	Junction2217
5	Junction2329	Junction2233	Junction2329	Junction2233
6	Junction2271	Junction2261	Junction2261	Junction2271
7	Junction2289	Junction2294	Junction2294	Junction2289
8	Junction2294	Junction2285	Junction2285	Junction2294
9	Junction2261	Junction2252	Junction2252	Junction2261
10	Junction2252	Junction2247	Junction2247	Junction2252
11	Junction2248	AU0029	Junction2248	AU0029
12	Junction2284	Junction2276	Junction2276	Junction2284
13	Junction2276	Junction2270	Junction2270	Junction2276
14	Junction2247	Junction2248	Junction2248	Junction2247
15	Junction1996	Junction1963	Junction1996	Junction1963
16	Junction2012	Junction2010	Junction2012	Junction2010
17	Junction2010	AU0155	Junction2010	AU0155
18	Junction2038	Junction2012	Junction2038	Junction2012
19	Junction2065	Junction2038	Junction2065	Junction2038

Figure 3.8: Determined Flow Direction

Step 4: Exporting Network Data

State estimation algorithm requires the network topology, including the connectivity data to analyze the feeder. Data tables in Figure 3.9 and Figure 3.10 were exported to be used as the inputs to the state estimation algorithm.

Table

Lines

OBJ	RefName	Shape_Len	End1	End2	FromPole	ToPole
48	11kVB112	0.328689	DDLO_AZ0447_1	AZ0447	DDLO_AZ0447_1	AZ0447
49	11kVB112	0.14584	AZ8232	DDLO_AZ8232_1	DDLO_AZ8232_1	AZ8232
76	11kVC115	119.763485	Junction2250	AT0261	AT0261	Junction2250
77	11kVC115	5.800337	Junction2219	AT0252	Junction2219	AT0252
78	11kVC115	19.567337	Junction2235	Junction2219	Junction2235	Junction2219
79	11kVC115	131.299495	Junction2331	Junction2235	Junction2331	Junction2235
80	11kVC115	66.957685	Junction2273	Junction2263	Junction2263	Junction2273
81	11kVC115	21.270218	Junction2291	Junction2296	Junction2296	Junction2291
108	11kVC115	41.441439	Junction2260	AT0091	AT0091	Junction2260
109	11kVC115	29.189805	AT0261	Junction2219	Junction2219	AT0261
110	11kVC115	162.958912	Junction1965	AT0253	Junction1965	AT0253
111	11kVA143	85.353484	Junction2367	Junction2361	Junction2361	Junction2367
112	11kVA230	173.164955	EK_Prim4	Junction2345	EK_Prim4	Junction2345
113	11kVC113	14.897337	Junction2254	Junction2244	Junction2254	Junction2244
114	11kVC113	10.121094	Junction2273	Junction2262	Junction2273	Junction2262
115	11kVC113	29.730228	Junction2224	Junction2231	Junction2224	Junction2231
116	11kVC113	57.30916	Junction2331	DDLO_AZ8702_1	Junction2331	DDLO_AZ8702_1
119	11kVC113	106.575081	Junction2334	AU0029	AU0029	Junction2334

Figure 3.9: Exported Line Data

Table

Nodes

OBJECTID *	RefName	POINT_X	POINT_Y	FID_
1	LBSx	104031.034	189268.026	AT0261
2	LBSx	103656.217	187363.573	AT253
3	LBSx	104020.102	189294.341	AT0252
4	LBSx	104079.447	188525.288	AT0091
5	LBCx	103842.073	187878.251	AU0167
6	LBCx	103854.373	187956.548	AU0160
17	PRIM_SUB	104346.936	189213.984	NawalaPrim5
86	JunctionPoint	104246.527	188715.200	Junction2364
87	JunctionPoint	104247.388	188927.966	Junction2365
88	JunctionPoint	104425.999	188250.258	Junction2440
89	JunctionPoint	104428.472	188249.095	Junction2444
90	JunctionPoint	104428.563	188253.801	Junction2445
91	JunctionPoint	104460.127	188376.698	Junction2450
92	JunctionPoint	104575.075	188253.419	Junction2474
93	JunctionPoint	104666.805	188268.373	Junction2480
94	DDLO	103903.225	188079.632	DDLO20
95	DDLO	104151.464	188174.159	DDLO21
96	DDLO	104025.581	189296.397	DDLO43
136	Transformer	104086.294	188901.193	AZ8260

Figure 3.10: Exported Node Data

3.4. Data Extraction from RMR Database

State estimation tool requires two inputs, namely the existing network topology from the GIS database and the real time load data from the Remote Meter Reading (RMR) database. In LECO, remote meter readings are stored in an Oracle database and the readings are updated in 15-minutes time intervals. Article 7 gives the guidelines and the coding to extract them and it was adopted with minor modifications to serve the purpose of this research.

3.4.1. Unavailability of RMR

Meters with remote meter reading facilities are not always available at every distribution transformer, or in some instances, the meters simply do not communicate. In those cases, it is necessary to have a methodology to assume an approximate load reading to compensate the absent readings. This section presents a methodology to estimate such load readings and an example has been worked out for the selected test feeder. Statistics of the transformers with meters which facilitate remote reading is given in the Table 3.2.

Table 3.2: Statistics of the Transformers with and without RMR Facility

Transformer type	Total no. of transformers	No. of transformers with RMR	No. of transformers without RMR
Distributional	25	15	10
Industrial	6	6	0
Commercial	10	7	3
Mixed	1	1	0

If the meters with RMR facility are not available for several transformers in a particular category, the load data are estimated using an average, normalized load curve. Several methods of normalizing load curves are available, such as normalizing based on the maximum demand, normalizing based on the total energy consumption etc. As the maximum demand is an instantaneous figure which might have encountered only once within the month and the total energy consumption per day gives an average value based on the monthly consumption, it was decided that normalizing the load curve based on the total energy consumption is more appropriate for this research. When deriving the averaged, normalized load curve based on the total energy consumption, first, the load curves of the transformers with RMR units in the same category were recorded. Then, the entire curve was divided by its area, i.e. the total energy, and derived the normalized curve based on the unit energy consumption. Calculation was done with the assumption, that the power consumption is uniform for the 15-minutes time interval that the particular reading is being taken. Then all the normalized load curves in that category were averaged to obtain the averaged, normalized load curve of the considered transformer type. Such load curves obtained for the Domestic and Commercial transformer categories, for an average week day, are given in Figure 3.11and Figure 3.12.

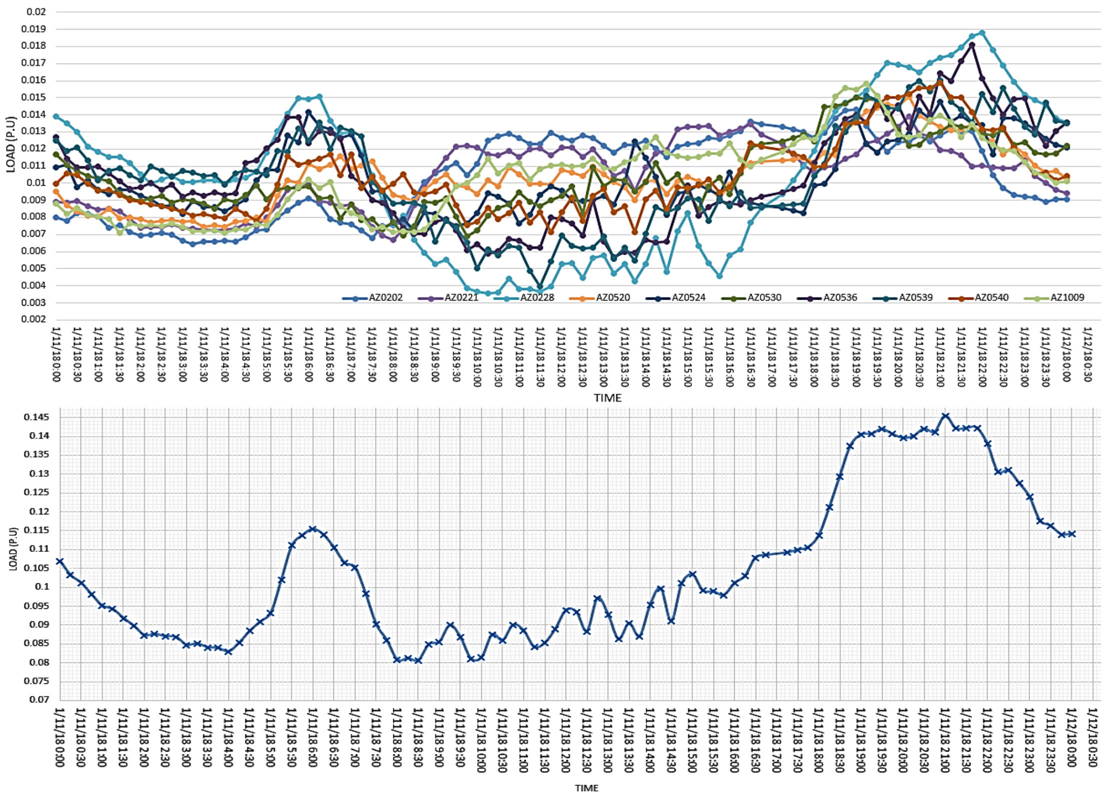

Figure 3.11: Derivation of the Averaged, Normalized Load Curve of the Domestic Transformers

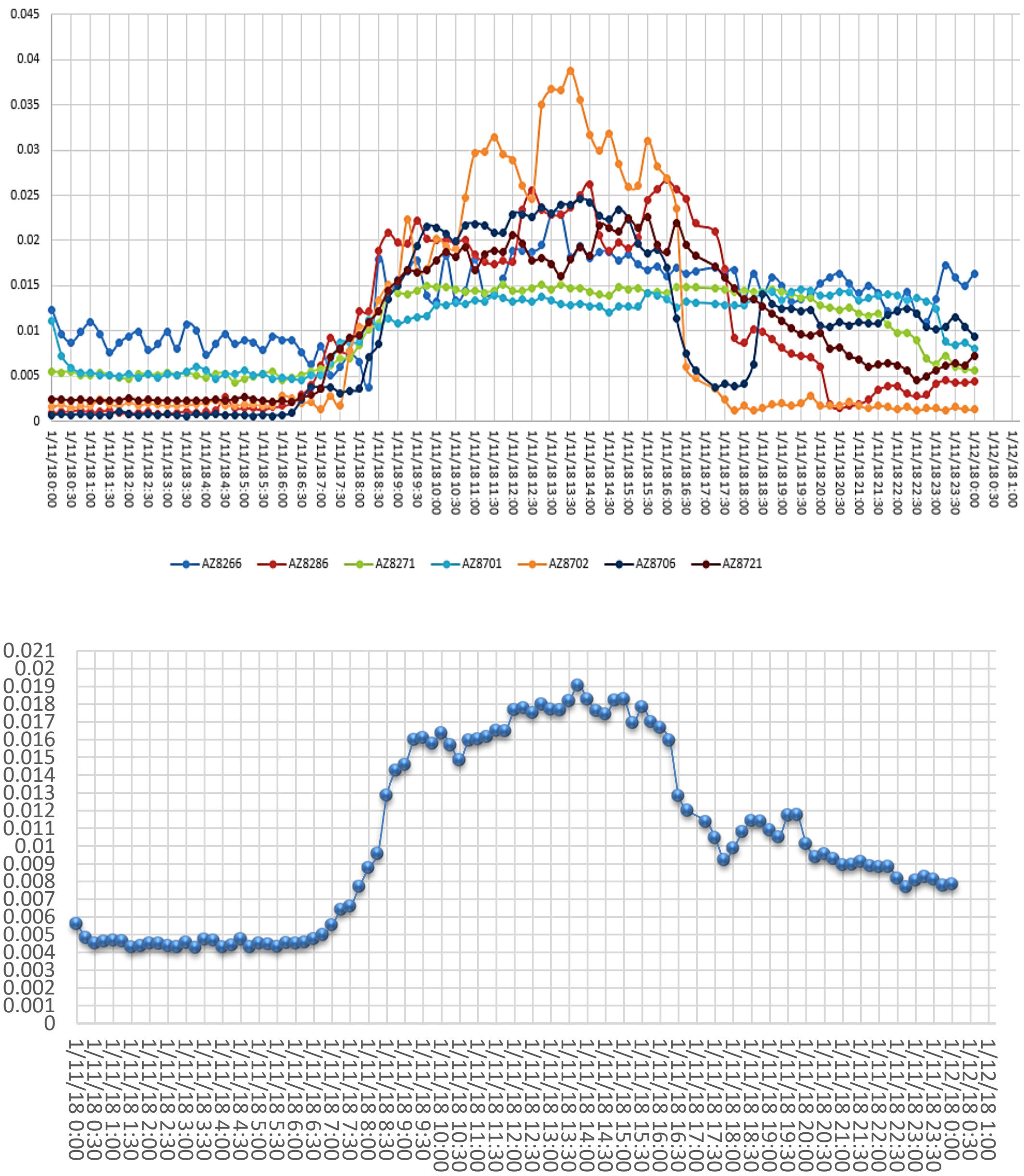

Figure 3.12: Derivation of the Averaged, Normalized Load Curve of the Commercial Transformers

Listed below are the suggestions to increase the accuracy of this load estimation.

a. Considering higher number of transformer load curves to obtain the average curve.

b. Recording the transformer load curves throughout a long period of time, so that average load curves can be determined depending on the day of the week/ season/ weather conditions etc.
c. Clustering the transformers depending on the customer data (type of the customers'/ average monthly consumption etc.) and deriving separate load curves for each of the cluster.

3.5. State Estimation Tool Development

State estimation is an effective technique which can be used for obtaining the best possible estimate of the current network state with a reasonable accuracy, using whatever the available data. Further, it can be used for predicting the system response under different situations.

The state estimation technique which has been proposed here use both real time measurements and pseudo measurements to improve the accuracy of the estimation. While the real time data are obtained from the RMR database, pseudo measurements are generated using a load flow algorithm. The Forward Backward Method of power flow analysis has been used for this purpose. Then, the network state has been derived by optimizing the results using the Weighted Least Square Method of state estimation.

3.5.1. Load Flow Algorithm

Flow chart shown in Figure 3.13 illustrates the algorithm which was used for the load flow calculations in this research.

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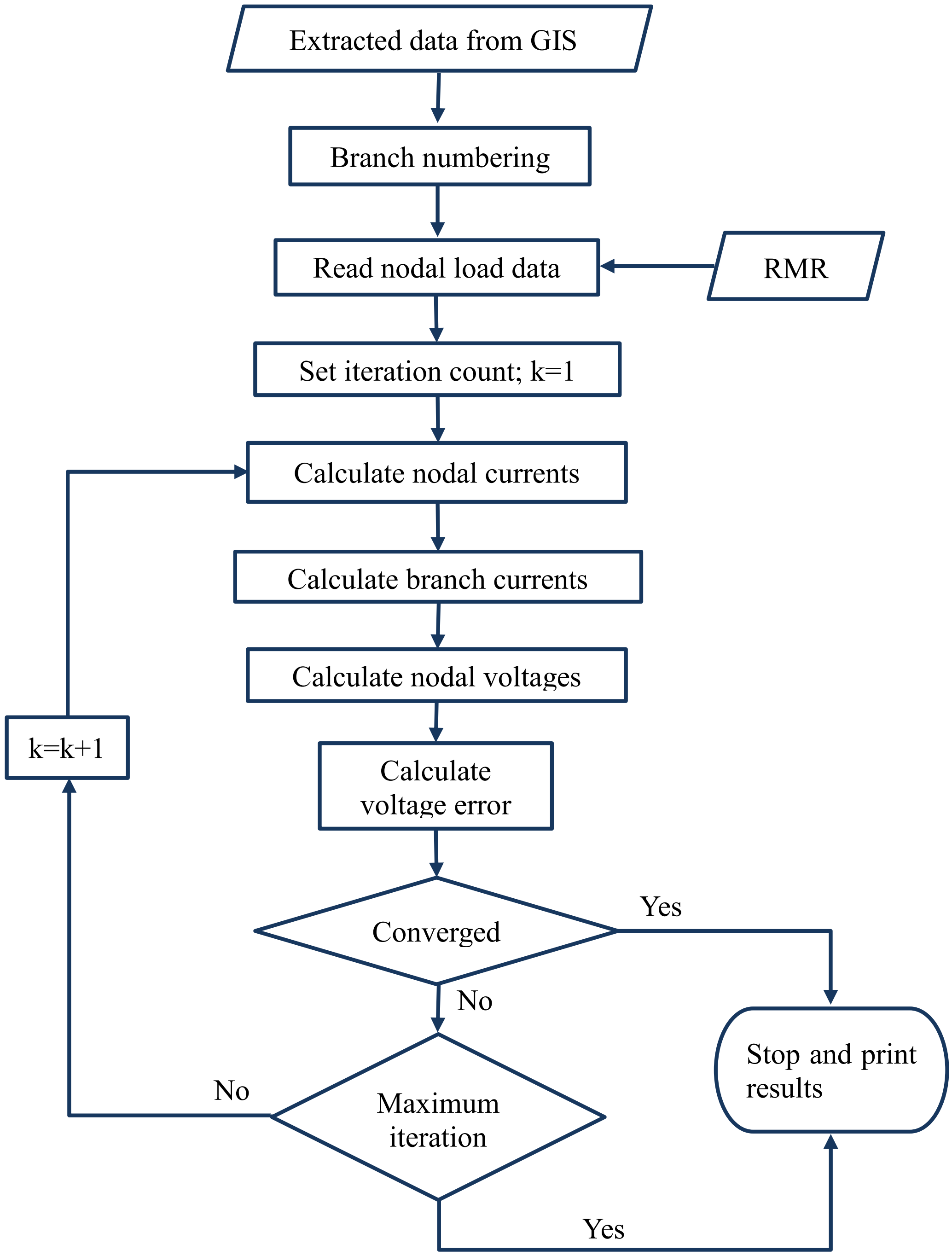


Figure 3.13: State Estimation Algorithm

The initial input for the state estimation is from the GIS database. The network topology exported under the Step 4 of Section 3.3.2. is used for this purpose. Extensive details on the latter steps of the flow chart are given in the below sections.

Step 1: Branch Numbering

Under the first step, the feeder that has to be analyzed is reconstructed logically inside the program. To achieve this, the connectivity data in the input tables from GIS as well as the branch numbering system described in 3 are used.

Figure 3.14 shows a typical radial distribution feeder with assigned nodes at junction points, switching points, conductor changing points and a single voltage source at the starting node. In this tree structure, the line segments defined by the starting node and a consecutive node is assigned to Level 1. The adjacent line segments in downstream to those in Level 1 are assigned to Level 2 and all the lines are assigned into layers, likewise.

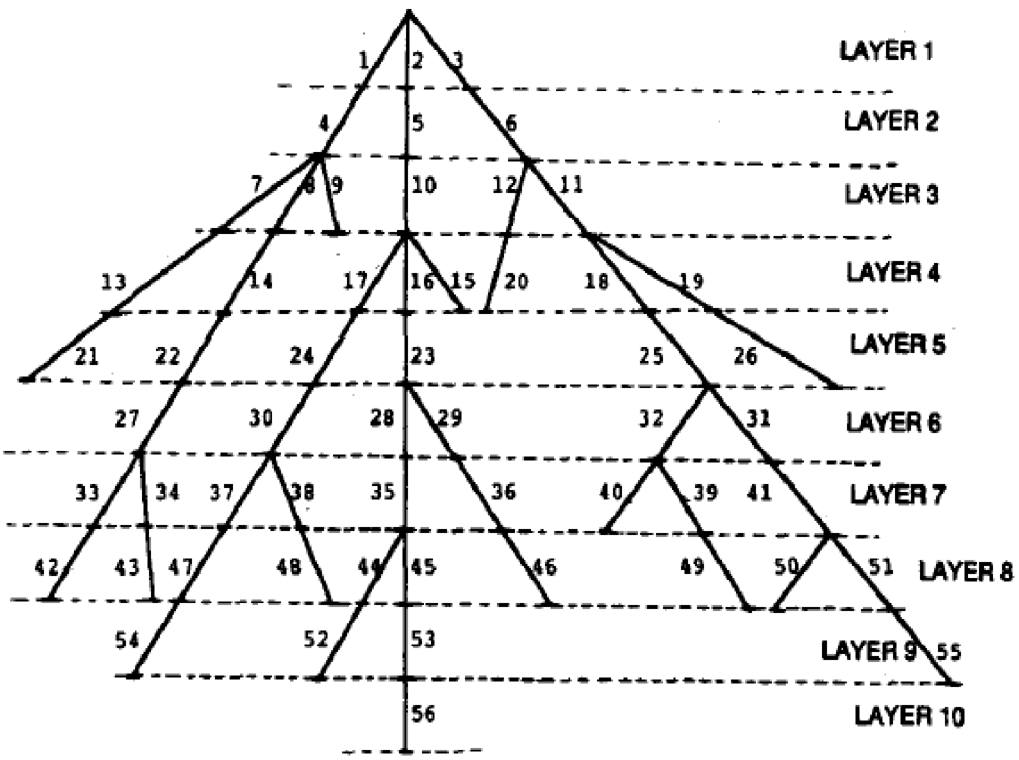
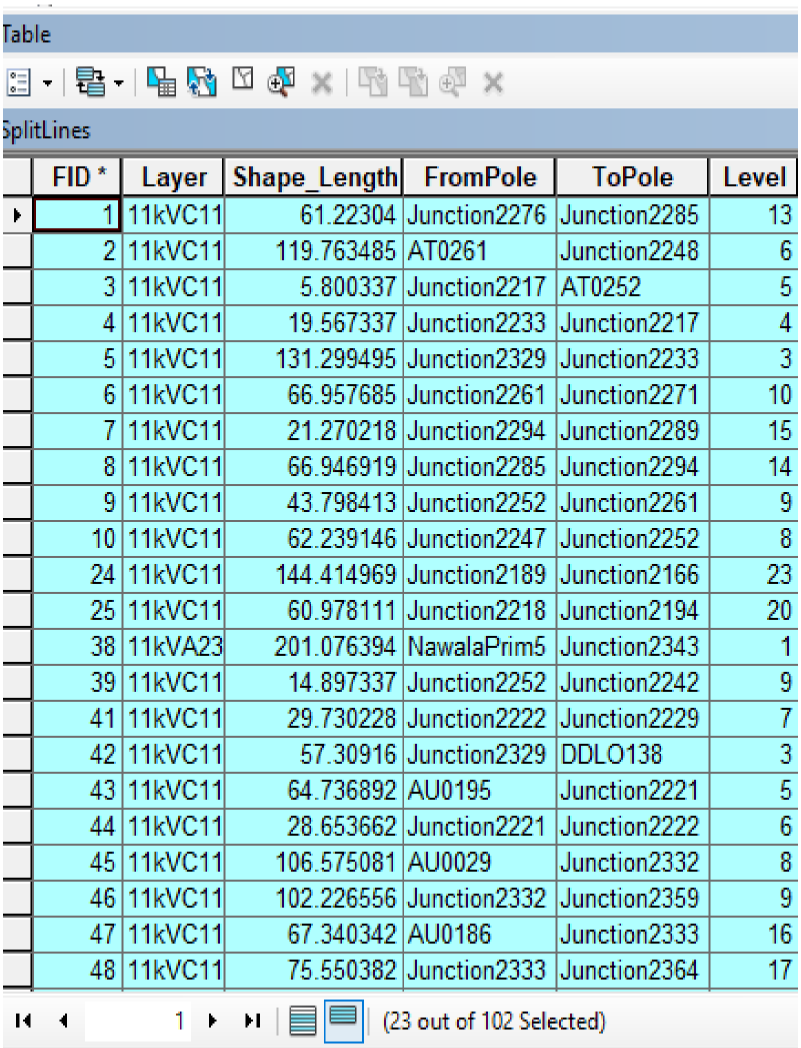


Figure 3.14: Branch Numbering of a Typical Distribution Feeder 3

Figure 3.15 shows the results obtained by running the algorithm for the test feeder.



Table

SplitLines

FID *	Layer	Shape_Length	FromPole	ToPole	Level
1	11kVC11	61.22304	Junction2276	Junction2285	13
2	11kVC11	119.763485	AT0261	Junction2248	6
3	11kVC11	5.800337	Junction2217	AT0252	5
4	11kVC11	19.567337	Junction2233	Junction2217	4
5	11kVC11	131.299495	Junction2329	Junction2233	3
6	11kVC11	66.957685	Junction2261	Junction2271	10
7	11kVC11	21.270218	Junction2294	Junction2289	15
8	11kVC11	66.946919	Junction2285	Junction2294	14
9	11kVC11	43.798413	Junction2252	Junction2261	9
10	11kVC11	62.239146	Junction2247	Junction2252	8
24	11kVC11	144.414969	Junction2189	Junction2166	23
25	11kVC11	60.978111	Junction2218	Junction2194	20
38	11kVA23	201.076394	NawalaPrim5	Junction2343	1
39	11kVC11	14.897337	Junction2252	Junction2242	9
41	11kVC11	29.730228	Junction2222	Junction2229	7
42	11kVC11	57.30916	Junction2329	DDLO138	3
43	11kVC11	64.736892	AU0195	Junction2221	5
44	11kVC11	28.653662	Junction2221	Junction2222	6
45	11kVC11	106.575081	AU0029	Junction2332	8
46	11kVC11	102.226556	Junction2332	Junction2359	9
47	11kVC11	67.340342	AU0186	Junction2333	16
48	11kVC11	75.550382	Junction2333	Junction2364	17

1 (23 out of 102 Selected)

Figure 3.15: Assigned Levels from the State Estimation Tool

Step 2: Calculating Nodal Currents

After defining the feeder structure, feeder state calculations begin. The calculations are based on the forward-backward method of power flow analysis. The process is started with the backward sweep, where the branch currents are calculated in the backward direction of the feeder, i.e. from the load ends to the source. Under that, first, the currents injected from the nodes at the load ends has to be calculated.

In calculating load currents, it was realized that the transformers at the load ends can be approximated as different types of loads. Initially, all the loads are determined as

Delta connected loads as the primary side is always Delta wound in all the distribution transformers in Sri Lanka.

When the distribution transformers that falls in the industrial category are considered, they mainly supply power to the industrial customers, such as the factories, workshops etc. In such premises, the power is mainly drawn by motor loads which can be considered as constant power loads. Therefore, in calculating the nodal load currents, industrial transformers are assumed as constant power loads. Current calculation is shown in Equation 3-1. Phase ‘a’ is taken as the reference phase.

$$\mathrm{I_{ab}} = \left(\frac{\mathrm{S_{3\emptyset}}}{3 * \mathrm{V_{ab}}}\right)^{*}$$

$$\mathrm{I_{ca}} = \left(\frac{\mathrm{S_{3\emptyset}}}{3 * \mathrm{V_{ca}}}\right)^{*}$$

$$\mathrm{I_{node}} = \mathrm{I_{ab}} - \mathrm{I_{ca}} \qquad \text{Equation 3-1}$$

Where;

I_{xy} = Line current in between x and y phases
V_{xy} = Line to line voltage in between x and y phases
$S_{3\emptyset}$ = Three phase power
I_{node} = Nodal voltage of the reference phase

When the Domestic type transformers are considered, majority of the customers who consume power through the transformer are domestic customers, i.e. normal households. In the households, most of the loads connected are lighting and heating loads, which falls in the category of constant impedance loads. Therefore, the domestic transformers are approximated to constant impedance loads when calculating the nodal load currents. Calculations were done using the Equation 3-2.

$$\mathrm{Z_{const}} = \frac{\mathrm{V_{initial}^2}}{\left(\mathrm{S_{3\emptyset}^*}/3\right)}$$

$$\mathrm{I_{ab}} = \frac{\mathrm{V_{ab}}}{\mathrm{Z_{constant}}}$$

$$I_{ca} = \frac{V_{ca}}{Z_{constant}}$$

$$I_{node} = I_{ab} - I_{ca} \qquad \text{Equation 3-2}$$

Where;

Z_{const} = Constant phase impedance

$V_{initial}$ = Initial phase voltage at the node

$S_{3\emptyset}$, I_{node}, I_{xy}, V_{xy} carry the same meaning as in Equation 3-1.

Main contribution of the commercial type transformers is to power commercial buildings such as shops and shopping malls. Most of the loads in these buildings are AC loads and lighting loads, which can be approximated as constant current loads. Mixed type transformers are not dedicated to supply power to a specific customer category. Therefore, the loads connected to the transformer are diversified. Thus, in general, all those can be approximated as constant current loads. Therefore, both the commercial transformers and mixed type transformers are assumed as constant current loads in calculating the nodal currents. Equation 3-3 was derived for the calculation.

For the 1st iteration;

$$I_{ab} = \left(\frac{S_{3\emptyset}}{3 * V_{ab}}\right)^{*} = I_{ab,\,constant}$$

$$I_{ca} = \left(\frac{S_{3\emptyset}}{3 * V_{ca}}\right)^{*} = I_{ca,constant}$$

$$I_{node} = I_{ab} - I_{ca} \qquad \text{Equation 3-3}$$

Where $I_{xy,\,constant}$ gives the line current between phase x and y for the 1st iteration. Since the load is a constant current load, it is assumed that the magnitude of this line current remains constant despite of the changes in the voltage or the power. Therefore, the Equation 3-4 was derived to calculate the currents after the 1st iteration.

$$I_{ab} = |I_{ab,constant}|\angle(\angle V_{ab} - \angle V_{ab,initial})$$

$$I_{ca} = |I_{ca,constant}|\angle(\angle V_{ca} - \angle V_{ca,initial})$$

$$\mathrm{I_{node}} = \mathrm{I_{ab}} - \mathrm{I_{ca}} \qquad \text{Equation 3-4}$$

All the parameters carry the same meanings as in the previous equations.

Step 3: Calculating Branch Currents

After calculating nodal currents, the branch currents are calculated starting from the branches in the last layer and moving towards the branches connected to the starting node. The currents are calculated using the equation in Equation 3-5, which is a direct application of Kirchhoff's Current Law.

$$\mathrm{I_{branch}} = \sum \text{Currents in the branches emanating from the node} \qquad \text{Equation 3-5}$$

Step 4: Calculating Node Voltages

After calculating branch currents in the backward sweep, the voltage at the starting node is set to the rated voltage, which is 11 kV for the case study, and the nodal voltages are calculated in the forward sweep, using the Kirchhoff's Voltage Law in Equation 3-6.

$$\mathrm{V_{node}} = \mathrm{V_{previous\ node}} - \mathrm{I_{branch}} * \mathrm{Z_{conductor}} * \mathrm{l_{branch}} \qquad \text{Equation 3-6}$$

Step 5: Error Calculation

After the forward sweep, the error between the current iteration and the previous iteration is calculated using the Equation 3-7.

$$\mathrm{V_{error}} = \sum \frac{\mathrm{Weight_{node}} * (\mathrm{V_{previous\ iteration}} - \mathrm{V_{current\ iteration}})^2}{\text{number of nodes}} \qquad \text{Equation 3-7}$$

When assigning the weights, a higher weight has to be assigned for those with real time measurements and a lower weight should be assigned for the values estimated using the normalized load curves. In this research, the weights were assigned as follows.

When the remote meter readings are available:

$W_{RMR} = 1$

When the remote readings are not available and the load is estimated using the normalized load curve:

$$W_{est} = W_{RMR} x \ \frac{N_{RMR}}{N_{est} \ x \ N_{tot}}$$

Equation 3-8

Here;

W_{RMR} = Weight assigned to a node with remote meter readings

W_{est} = Weight assigned to a node where the load was estimated using the normalized load curve

N_{RMR} = Number of loads with remote readings in the particular transformer category, which were used to derive the normalized load curve

N_{est} = Number of estimated loads using the normalized load curve.

N_{tot} = Total number of loads in the particular transformer category

So the weight decays exponentially, when the availability of remote readings decreases.

Using the derived equation, and the statistics in Table 3.2, the corresponding weights for each transformer category can be calculated. Assuming $W_{RMR} = 1$;

$$W_{\text{Distribution}} = W_{RMR} x \ \frac{15}{10 \ x \ 25} = 0.06 W_{RMR} = 6\% \ w.r.t. W_{RMR}$$

$$W_{\text{Commercial}} = W_{RMR} x \ \frac{7}{3 \ x \ 10} = 0.23 W_{RMR} = 23\% \ w.r.t. W_{RMR}$$

$$W_{\text{Industrial}} = W_{\text{Mixed}} = W_{\text{RMR}} = 100\% \ w.r.t. W_{RMR}$$

3.5.2. Verification of the Algorithm

After developing the algorithm, it was verified using the IEEE 13 bus system.

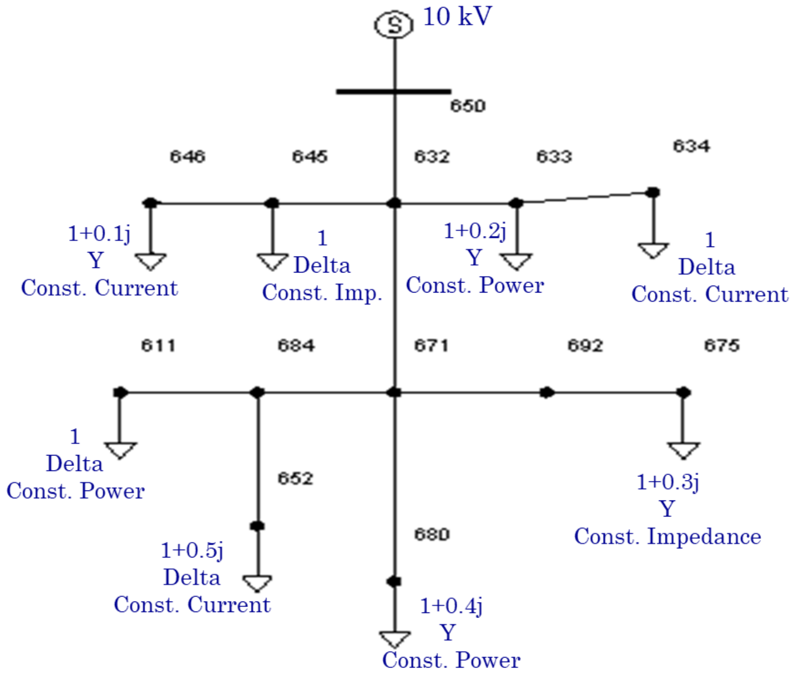


Figure 3.16: IEEE 13 Bus System

The system was modelled in PSS/ADEPT - Power System Simulator/ Advanced Distribution Engineering Productivity Tool (Version 4.0- Copyright 1998-2002 Power Technologies, Inc.) and the results were compared with the results obtained from the developed algorithm. The comparison is shown in Figure 3.17 and Figure 3.18.

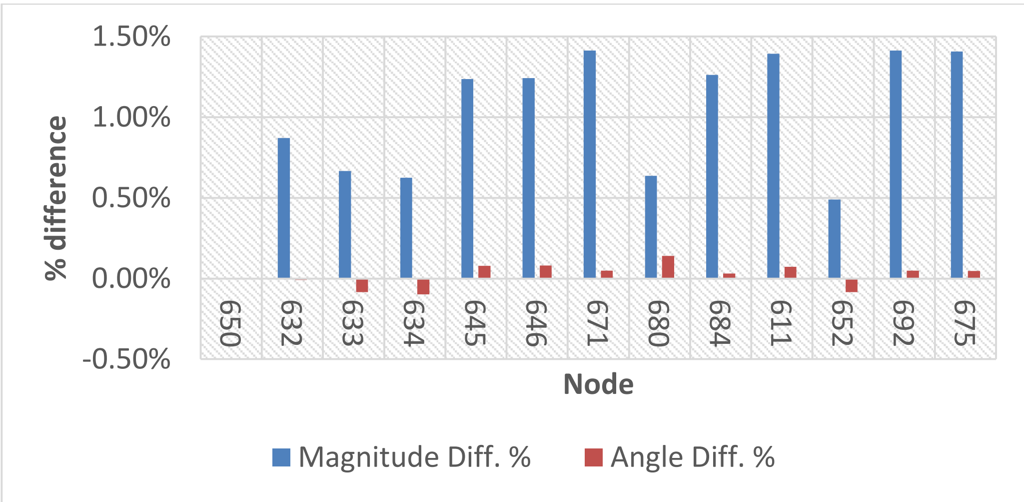


Figure 3.17: Difference in Nodal Voltage

Maximum percentage difference in magnitude = 1.41%

Maximum percentage difference in angle = 0.14%

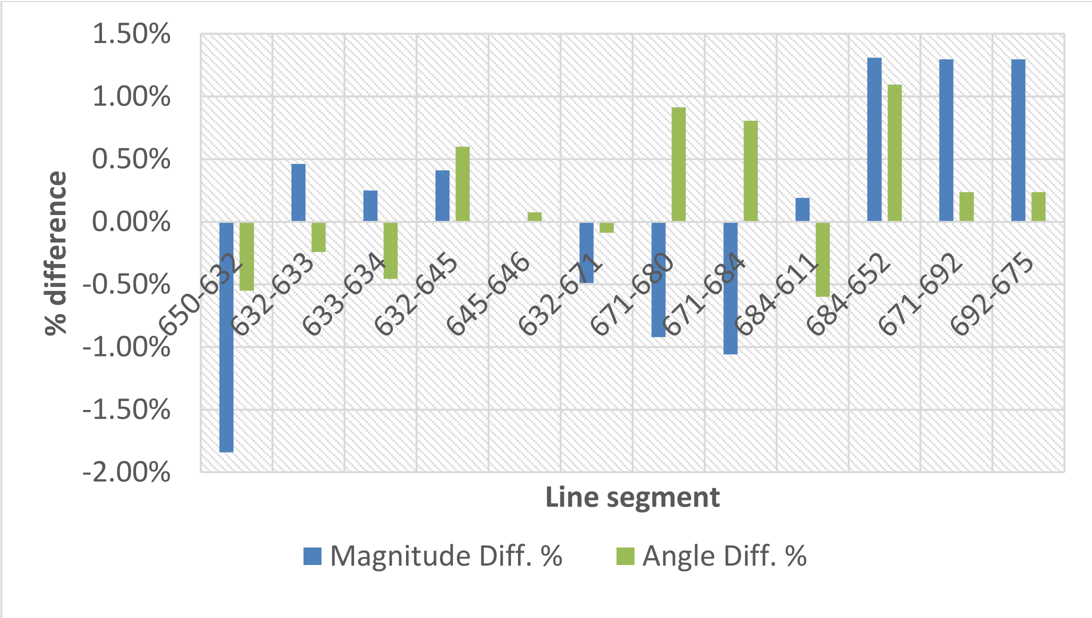


Figure 3.18: Difference in Branch Currents

Maximum percentage difference in magnitude = -1.84%

Maximum percentage difference in angle = 1.09%

3.5.3. State Estimation Algorithm

When considering the calculated results for the branch currents and voltages from the load flow algorithm (pseudo measurements), and the measurements taken for the same using the remote metering units, it can be observed that some values are redundant. This makes the network over determined. Further, there are certain errors associated with the measurements due to the errors in the meters, asynchronous data transmission etc. The state estimator is designed to produce the 'best estimate' of the system voltages and currents, using the available measurements, while recognizing that there are errors in the measured quantities and there may be redundant measurements for some parameters.

Out of the several methods that were studied, the method which was determined as the best method to achieve the objectives of this research is the 'Weighted Least Squares

Criterion'. Here, the objective is to minimize the sum of squares of the weighted deviations of the estimated measurements, from the actual measurements.

In this section Z_{measured} refers to a value obtained from a measuring device or a pseudo measurement calculated from the load flow algorithm. Z_{true} is the actual value of the quantity, which is unknown. Ƞ is the measurement error, which resembles the uncertainty of the measurements. The relationship between these parameters can be shown as in the Equation 3-9.

$$Z_{measured} = Z_{true} + \eta \qquad \text{Equation 3-9}$$

So that;

$$\eta = Z_{measured} - Z_{true}$$

If all the above parameters are represented as vectors and if the measurement residual is denoted by J(x), then the Equation 3-10 can be written.

$$J(x) = \frac{[\eta^2]}{2} = \frac{[[Z_{measured}] - [H][x_{est}]]^T[[Z_{measured}] - [H][x_{est}]]}{2}$$

Equation 3-10

Where;

$$[Z_{true}] = [H][x_{est}] \qquad \text{Equation 3-11}$$

Where;

X_{est} = vector of estimated state variables

H = measurement function coefficient matrix

Assigning weights for each measurements, the Equation 3-10 can be reconstructed as in Equation 3-12.

$$J(x) = \frac{[[Z_{measured}] - [H][x_{est}]]^T\ [W]\ [[Z_{measured}] - [H][x_{est}]]}{2}$$

Equation 3-12

Here, the weight matrix, $[W] = [R]^{-1}$ where [R] is the measurement covariance matrix, which is described in a latter part of this section.

Since the objective of the Weighted Least Square Method of State Estimation is minimizing the measurement residual, the solution of x, which gives the minimum J(x) can be can be derived as in Equation 3-13.

$$[x_{est}] = [[H]^T[R]^{-1}[H]]^{-1}[H]^T[R]^{-1}[Z_{measured}] \qquad \text{Equation 3-13}$$

Where;

X_{est} = vector of estimated state variables
H = measurement function coefficient matrix
R = measurement covariance matrix
$Z_{measured}$ = vector of measured values

3.5.3.1. Determining the Weights

The Probability Density Function (PDF) of η, is assumed as a normal distribution function with zero mean and modelled by the Equation 3-14. The reason for assuming it as a normal distribution function is that, it is the distribution function which will result when many factors contribute to the overall error.

$$PDF(\eta) = \frac{1}{\sigma\sqrt{2\pi}} \exp\left(\frac{-\eta^2}{2\sigma^2}\right) \qquad \text{Equation 3-14}$$

Here, σ is the standard deviation and σ^2 is the variance.

In the Equation 3-13, R is defined as the measurement covariance matrix. It is a diagonal matrix which has the corresponding measurement variances, σ^2, as the diagonal elements. When R^{-1} is taken, it results in another diagonal matrix which has $1/\sigma^2$ as the diagonal elements. Since $1/\sigma^2$ is defined as the weight of that particular measurement, R^{-1} is in the other hand can be defined as the 'Weight Matrix', [W], of the weighted least square method. When calculating the numerical values of the measurement weights for the test feeder, the latter described method was followed.

As it was justified in the first part of this section, the PDF of measurement errors is assumed to be a normal distribution function, which is illustrated in the Figure 3.19.

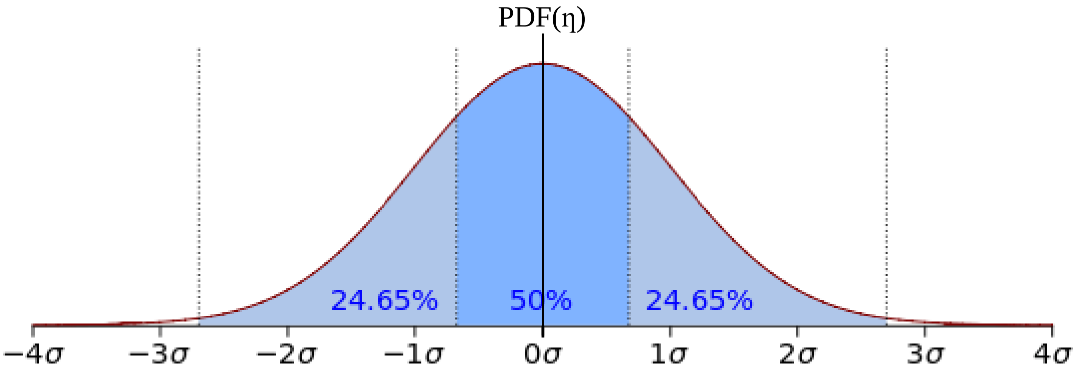


Figure 3.19: Probability Distribution Function of η

As it is shown in the figure, it can be calculated that the integration of the normal distribution function in between -3σ and +3σ is equal to 99%. If we assumed that the accuracy of the meter, which is ±0.5% for the smart meters which are fixed at the distribution transformers is assured 99% of the time, then;

$$3\sigma = 0.005$$
$$\sigma \approx 0.002$$
$$\sigma^2 = 4 \times 10^{-6}$$

Hence the weight of the measurements taken from the RMR meters,

$$w_m = 1/\sigma^2 = 2.5 \times 10^5$$

Weight of the pseudo measurements obtained from the load flow is calculated using the results obtained in page 28.

Table 3.3: Weight Calculation

	Weight	Variance
With RMR	W_m	$1/W_m$
Commercial transformers (without RMR)	$0.23\ W_m$	$4.3/W_m$
Domestic transformers (without RMR)	$0.06\ W_m$	$16.7/W_m$
Using the properties of the variance;		
For the total	$0.045W_m$	$22/W_m$
	1.125×10^4	

3.5.3.2. State Estimation Algorithm

According to the above criteria, the algorithm for state estimation using the weighted least square method can be illustrated as in Figure 3.20.

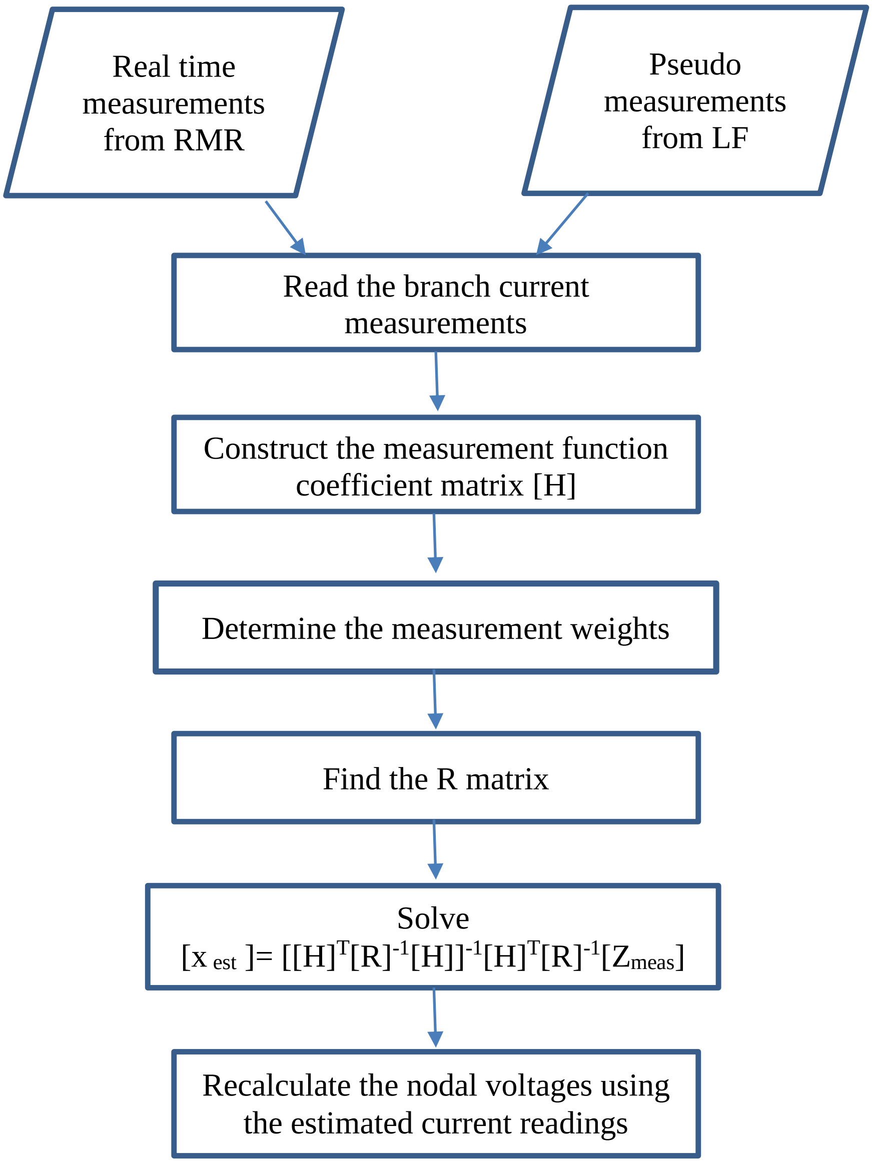


Figure 3.20: State Estimation Algorithm

3.5.4. Bad Data Identification

Once the system state has been identified, a numerical value is obtained for an estimate, x. This estimated value can be used to check if there is any residual in the measurements which stands out.

$$\eta_i = Z_{i,meas} - h_i(x_{est}) \qquad \text{Equation 3-15}$$

Where;

x_{est} = estimated values of the state variable

$h_i(x_{est})$ = calculated true value of the corresponding measurement using the measurement function

$Z_{i,meas}$ = measured value

η_i = measurement error

The normalized residual follows the standard normal distribution. If some measurement error is greater than a pre-determined value, then it is an indication that the particular measurement is incorrect.

3.6. Graphical User Interface

Upon the successful development, this tool is supposed to be used as a practical control center software of a medium scale distribution company, which facilitate the control actions and the decision making process. Therefore, upon developing the algorithms, a graphical user interface was created for the convenience of the operator. The tool runs on ArcGIS platform and the user interfaces are shown in Figure 3.21 and Figure 3.22.

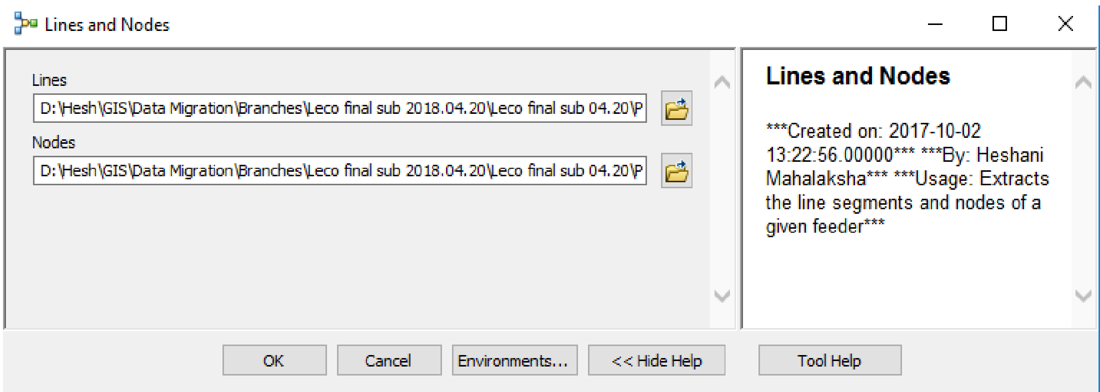


Figure 3.21: GUI for Extracting the Network Topology

Purpose

- Extracting the network topology (lines and nodes with the connectivity data) from the GIS database.

Inputs

- Location for saving the extracted files containing the ‘lines’ and ‘nodes’ data.

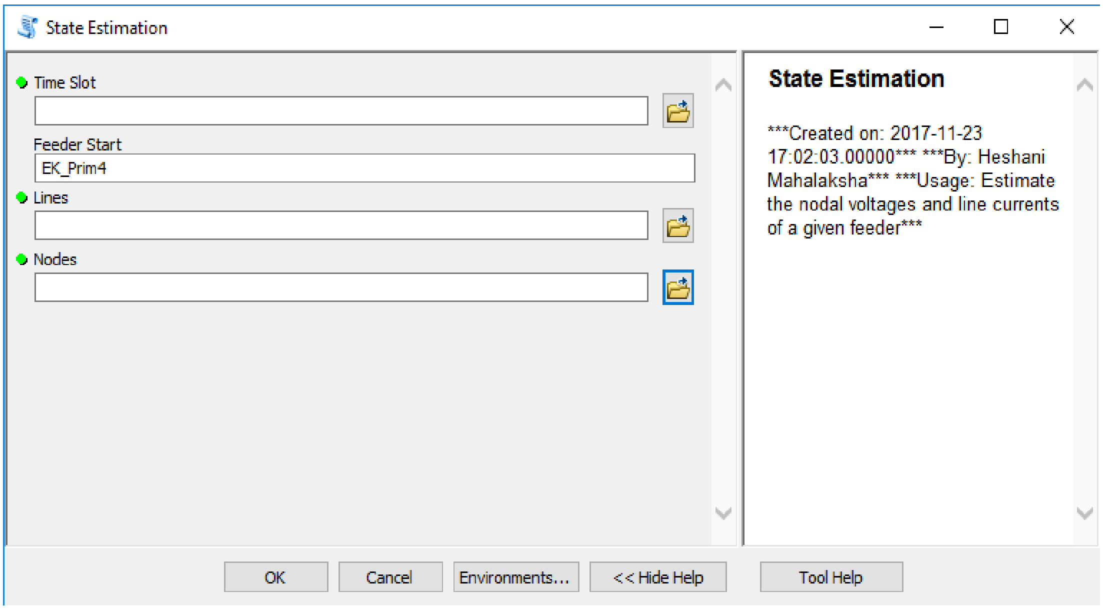


Figure 3.22: GUI for the State Estimation Tool

Purpose

- Estimating the line currents and the nodal voltages of the feeder.

Inputs :

- Name of the feeder starting node
- Saved location of the network topology (path for the ‘lines’ and ‘nodes’ files generated from tool 1)
- Time slot (Optional – Except for giving the load data as real time inputs, this tool can be run offline using the saved data in an excel sheet. In such a scenario, the execution time has to be given as a user input. Time slot has been defined in a way such that the time period from 0000h to 0015h is slot 1, next 15-minutes period is slot 2 and likewise. This enables to use the tool in analyzing hypothetical scenarios, providing a base for further studies.)

When developing the user interface, the tool was splitted into two parts, one for extracting the network topology and the other part for the state estimation. The purpose of doing so is to optimize the process by avoiding redundant extractions of the network and hence reducing the execution time. If no modifications have been done to the network topology in GIS after the previous extraction, then the same data can be used for the state estimation tool without the necessity of re-extracting the network.

CHAPTER 4

RESULTS AND ANALYSIS

As the result of a successful run, tool provides the line currents and nodal voltages in the complex form. The output is mainly presented in the attribute tables of ‘lines’ and ‘nodes’. Additionally, the voltage and current magnitudes can be displayed on the network map.

ID *	RefName	POINT_X	POINT_Y	FID_	LD_TYPE	PF	Level	ReadTime	T_Slot	REG_VALUE	UNIT	NodeVoltage
4	LBSx	104079.44	188525.28	AT0091	<Null>	0.92	17	<Null>	<Null>	<Null>	<Null>	(10947.38-28.43j)
15	LBCx	104091.41	189156.31	AU0029	<Null>	0.92	8	<Null>	<Null>	<Null>	<Null>	(10969.48-13.37j)
16	LBCx	104107.03	188719.36	AU0186	<Null>	0.92	16	<Null>	<Null>	<Null>	<Null>	(10953.1-24.54j)
17	PrimarySu	104320.42	189225.33	EK_Prim4	<Null>	0.92	1	<Null>	<Null>	<Null>	<Null>	(11000+0j)
92	Junction	104460.12	188376.69	Junction2452	<Null>	0.92	31	<Null>	<Null>	<Null>	<Null>	(10934.74-34.58j)
93	Junction	104575.07	188253.41	Junction2476	<Null>	0.92	30	<Null>	<Null>	<Null>	<Null>	(10934.63-34.6j)
94	Junction	104666.80	188268.37	Junction2482	<Null>	0.92	31	<Null>	<Null>	<Null>	<Null>	(10934.63-34.6j)
133	DDLO	104247.32	188927.39	DDLO_AZ8210_191	<Null>	0.92	12	<Null>	<Null>	<Null>	<Null>	(10969.22-13.43j)
134	DDLO	104061.35	189034.86	DDLO_AZ8211_192	<Null>	0.92	11	<Null>	<Null>	<Null>	<Null>	(10964.23-16.93j)
135	DDLO	103699.60	187610.90	DDLO_AZ8231_204	<Null>	0.92	37	<Null>	<Null>	<Null>	<Null>	(10930.09-40.01j)
136	DDLO	104101.41	188785.11	DDLO_AZ8286_220	<Null>	0.92	15	<Null>	<Null>	<Null>	<Null>	(10955.46-22.93j)
147	Transform	103741.71	187721.21	AZ8271	C	0.92	32	7:00:00 PM	77	67.12	kVA	(10930.97-39.42j)
150	Transform	103554.39	188069.46	AZ0520	D	0.92	31	7:00:00 PM	77	102.04	kVA	(10932.36-37.93j)
151	Transform	103537.84	187703.92	AZ0517	D	0.92	40	<Null>	<Null>	<Null>	<Null>	(10928.08-40.36j)
153	Transform	104073.32	188912.51	AZ0536	D	0.92	14	7:00:00 PM	77	65.42	kVA	(10959.98-19.81j)
163	Transform	104023.76	189366.92	AZ8272	I	0.92	8	7:00:00 PM	77	62.19	kVA	(10976.08-8.66j)
168	Transform	104459.90	188377.43	AZ0542	D	0.92	33	<Null>	<Null>	<Null>	<Null>	(10934.73-34.58j)
172	Transform	103903.74	188079.76	AZ1009	D	0.92	28	7:00:00 PM	77	100.41	kVA	(10935.92-36.13j)
177	Transform	104039.62	189456.68	AZ1029	M	0.92	11	7:00:00 PM	77	30.6	kVA	(10975.8-8.67j)

Figure 4.1: Estimated Nodal Voltages

Figure 4.1 illustrates the nodal voltages appended in the attribute table of ‘nodes’. Column 1 to 6 has been extracted from the GIS database. They denote the GIS identification number, category of the point, x and y coordinates of the point according to the Kandawala coordinate system, field ID of the component and the load type of the transformer respectively. If the corresponding point is not a transformer, then the load type is given as a null value. Column 7 denotes the power factor which has been set to the default value of 9.2. Column 8 denotes the ‘level’ of the node, which was assigned by the branch numbering algorithm. Column 9 to 12 were extracted from the RMR database and null values appear at the nodes where the remote reading meters are not installed or when the installed meter at the particular node does not communicate. Column 9 denote the time of taking the readings which is 7.00 p.m. for this instant and column 8 denotes the corresponding time slot. The required register value of the smart meter and its units have been appended in the next two columns. The input we take for the state estimation is the load reading at the node. Thus the column ‘Reg_value’ denotes the load reading for this case and its units are ‘kVA’. The last column denotes the estimated voltage in Volts, which is the final output of the tool.

ID *	RefName	BRANCH	Shape_Len	Node1	Node2	FromNode	ToNode	Level	Current
36	11kVB112	PITAKOTTE	0.470662	DDLO_AZ0220_95	AZ0220	DDLO_AZ0220_95	AZ0220	31	(-5.5+2.36j)
35	11kVB112	PITAKOTTE	0.550743	Junction2476	DDLO_AZ0220_95	Junction2476	DDLO_AZ0220_95	30	(-5.5+2.36j)
34	11kVB112	PITAKOTTE	0.373596	DDLO_AZ0542_94	AZ0542	DDLO_AZ0542_94	AZ0542	32	(-4.47+1.92j)
135	11kVC113	PITAKOTTE	2.733053	Junction2446	Junction2442	Junction2442	Junction2446	28	(-9.97+4.29j)
18	11kVB112	PITAKOTTE	0.399919	DDLO_AZ1004_68	AZ1004	DDLO_AZ1004_68	AZ1004	19	(-3.74+1.6j)
17	11kVB112	PITAKOTTE	0.476332	Junction2366	DDLO_AZ1004_68	Junction2366	DDLO_AZ1004_68	18	(-3.74+1.6j)
122	11kVC113	PITAKOTTE	75.550382	Junction2335	Junction2366	Junction2335	Junction2366	17	(-3.74+1.6j)
32	11kVB112	PITAKOTTE	0.306181	DDLO_AZ0515_93	AZ0515	DDLO_AZ0515_93	AZ0515	28	(-3.73+1.6j)
31	11kVB112	PITAKOTTE	0.32749	Junction2350	DDLO_AZ0515_93	Junction2350	DDLO_AZ0515_93	27	(-3.73+1.6j)
134	11kVC113	PITAKOTTE	45.348676	Junction2327	Junction2350	Junction2327	Junction2350	26	(-13.7+5.89j)
136	11kVC113	PITAKOTTE	243.942169	Junction2442	Junction2350	Junction2350	Junction2442	27	(-9.97+4.29j)
112	11kVA230	PITAKOTTE	173.164955	EK_Prim4	Junction2345	EK_Prim4	Junction2345	1	(-132.93+59.87j)
16	11kVB112	PITAKOTTE	0.396229	DDLO_AZ0215_67	AZ0215	DDLO_AZ0215_67	AZ0215	18	(-7.56+3.24j)
15	11kVB112	PITAKOTTE	0.379074	Junction2335	DDLO_AZ0215_67	Junction2335	DDLO_AZ0215_67	17	(-7.56+3.24j)
141	11kVC113	PITAKOTTE	71.932541	Junction2324	Junction2311	Junction2311	Junction2324	25	(-4.75+2.04j)
61	11kVB112	PITAKOTTE	0.270934	AZ8211	DDLO_AZ8211_192	DDLO_AZ8211_192	AZ8211	11	(-0.71+0.56j)
66	11kVB112	PITAKOTTE	3.006287	AZ8266	DDLO_AZ8266_132	DDLO_AZ8266_132	AZ8266	32	(-0.15+0.12j)

Figure 4.2: Estimated Branch Currents

Figure 4.2 illustrates the branch currents appended in the attribute table of ‘lines’. Column 1 contains the GIS identification number of the corresponding line segment. Column 2 contains the line type, which is associated with the conductor impedance. 3rd column has the branch name which is ‘Pitakotte’ for the test case. Column 4 denotes the calculated length of the line segment in meters. Next two columns contain the respective nodes at the two ends of the line and they have been rearranged according to the flow direction in the adjacent two columns. Column 8 has the assigned line level by the branch numbering algorithm. The last column has the estimated line currents in Amperes and the considered reference direction is the backward direction.

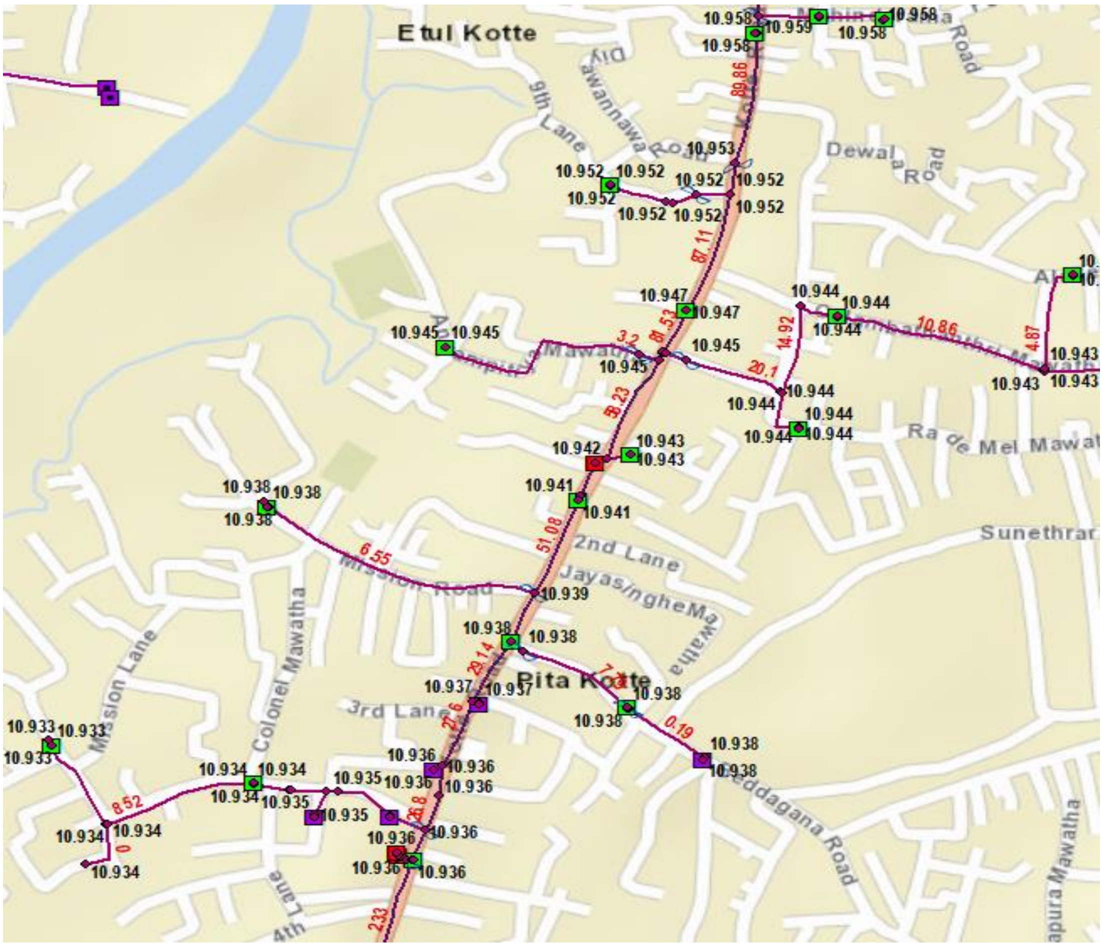


Figure 4.3: Displaying the Network State on the Map

Figure 4.3 shows the displayed network state on the map. The voltage magnitudes in kV are displayed in black colour near the nodes and the current magnitudes which are in A are displayed in red colour, near the lines.

4.1. Verification of the Results

In order to verify the results, the model was run on a particular day and the results were compared with the actual measurements taken at the same location on an average day. Figure 4.4 illustrates the current profile at the feeder starting point, obtained by running the model on Thursday, 03rd May, 2018, which has been compared with the measured values at the same point on an average week day. The maximum percentage difference encountered, with respect to the measured data, is 17.52% at 0545h and the average deviation is 5.8%.

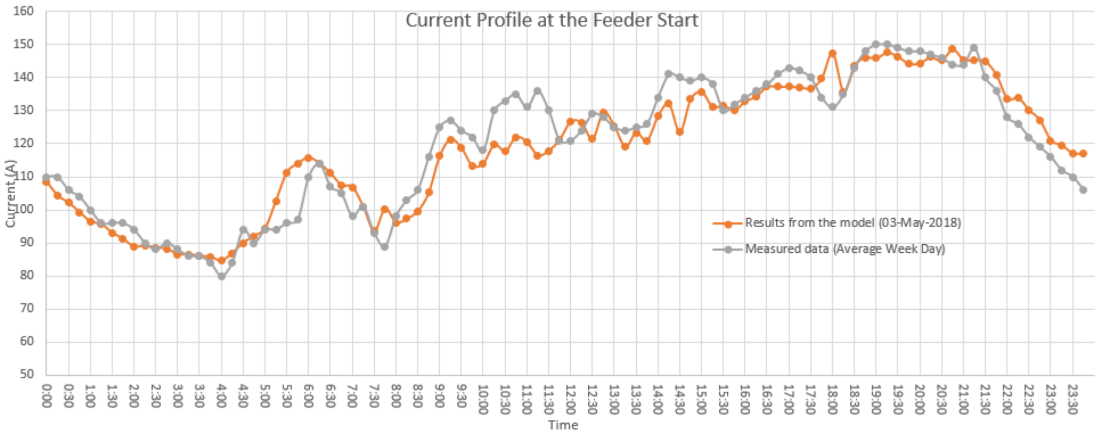


Figure 4.4: Verification of the Current Estimation

Similarly, Figure 4.5 shows the verification of the estimated voltages. The tool output, which was obtained on 03rd May, 2018 was compared with the measured data obtained on the same day at the transformer node, AZ0228. The maximum percentage difference encountered, with respect to the measured data is 0.274% at 0600h and the average deviation is 0.027%.

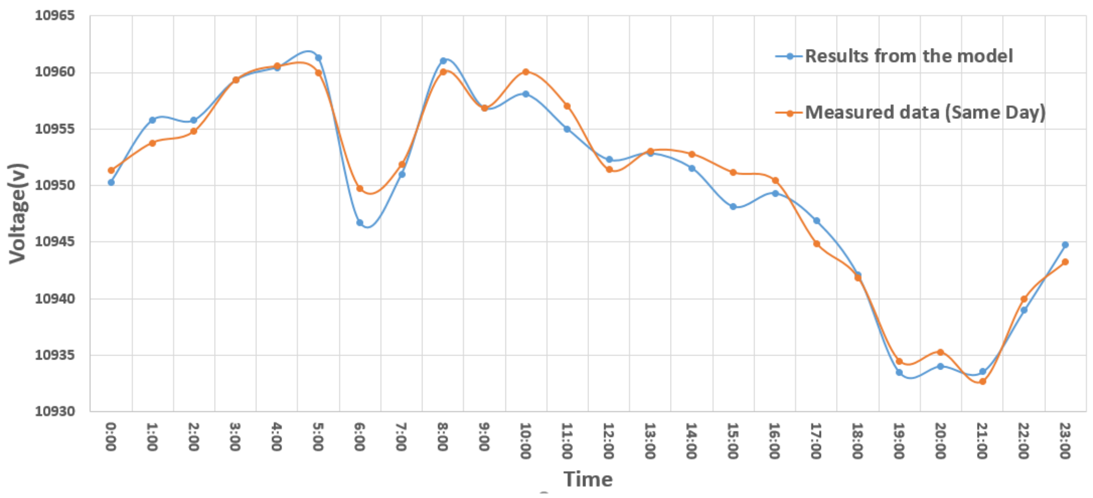


Figure 4.5: Verification of the Voltage Estimation

Further to the results obtained for the verification purpose, the voltage profile along the longest path of the feeder, from the primary substation to the transformer AZ0228, was obtained in every hour and plotted against the feeder length. The results are shown in Figure 4.6.

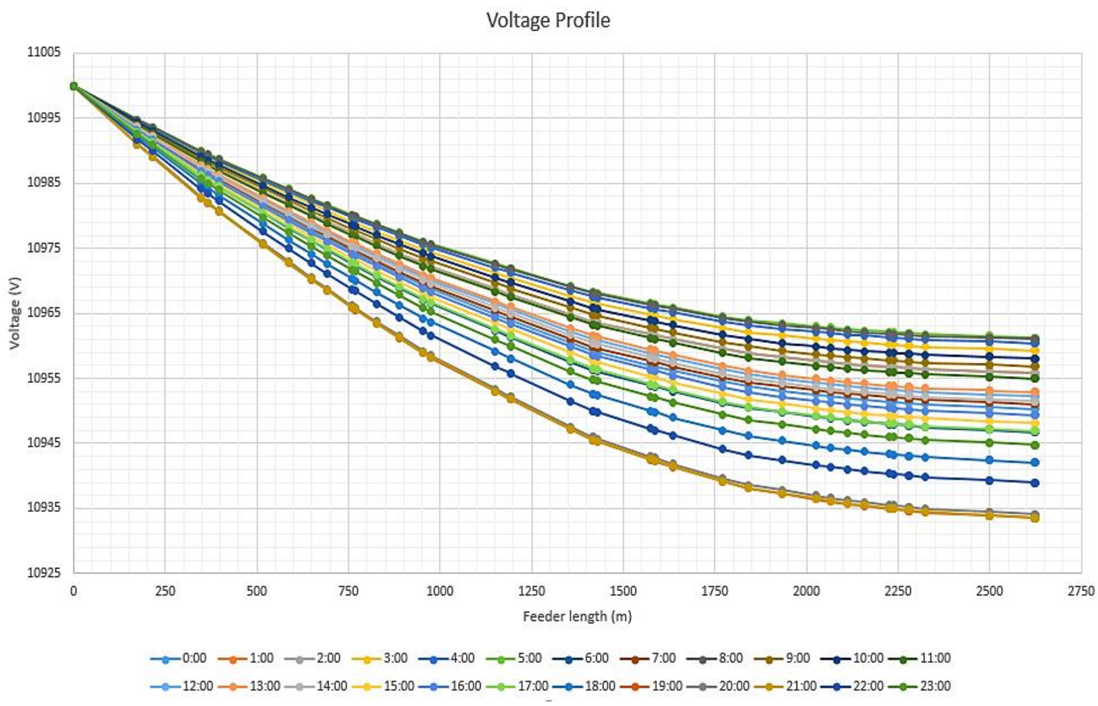


Figure 4.6: Variation of the Voltage Profile along the Longest Feeder

According to the results, the maximum voltage drop which has occurred at the feeder end is 0.61% at 2100h.

Likewise, the tool can be used as a base to analyze the system under different scenarios, and thus will facilitate in distribution planning as well as in operation.

CHAPTER 5

CONCLUSION

To sustain the arising revolution of the distribution system, the utilities have to foresee the challenges and adopt new technologies to make their planning, monitoring and controlling systems more sophisticated. In implementing this, an initial requirement would be an updated, real time, accurate network monitoring system at the distribution control center. Despite the higher costs associated with the popular real time network monitoring systems, state estimation technique proves to be a promising, low cost solution, which is capable of providing the best possible estimate for the current network state.

A methodology based on the weighted least square method of state estimation has been developed in this research, which can be adopted by a medium scale distribution company, to derive an accurate, real time, network status map for their distribution control center. The proposed methodology has been validated using a case study done on the 11 kV distribution network of LECO.

Upon execution, the tool provides the estimations for feeder currents and nodal voltages. The results are displayed in the attribute tables, as well as on the map itself. These results have been verified with the actual measurements taken for the same. Under this, the current values obtained at the feeder starting node on a particular week day were compared with the same obtained on an average week day. The maximum percentage difference encountered, with respect to the measured data, is 17.52% and the average deviation is 5.8%. Similarly, the voltage results obtained at the transformer node, AZ0228 was compared with the measurements taken for the same, on the same day. The maximum percentage difference encountered, with respect to the measured data is 0.274% and the average deviation is 0.027%. Hence it can be concluded that the developed tool can be used in determining the current network state successfully.

In addition to the real time analysis of the network, this tool can be used as a base case for further analysis of the system. In this, the system can be simulated under desired hypothetical situations, by modifying the network topology and feeding the data manually. Thus, the tool manifest to be a successful planning tool, which can be used in long term and short term network planning and operation.

5.1. Limitation of the Study and Proposals for Future Work

Identified limitations of this study are listed below with the proposals for future work.

In the absence of real time measurements, the loads were estimated using the averaged, normalized load curve for the respective transformer category. Since the main focus of this research is on developing the methodology, certain approximations and assumptions have been made in deriving the load curve. Following methods are suggested to use to increase the accuracy of this load estimation.

- Considering higher number of transformer load curves to obtain the average curve.
- Recording the transformer load curves throughout a long period of time, and using those data to derive the average load curves depending on the day of the week/ season/ weather conditions etc.
- Clustering the transformers depending on the customer data (type of the customers'/ average monthly consumption etc.) and deriving separate load curves for each of the cluster.

In verifying the accuracy of the current estimation at the feeder starting point, the estimated values on a particular day were compared with the measured values on a similar day, due to the practical difficulty in obtaining the manual measurements on the desired day. This constrain will be removed in the near future with the installation of load break switches (LBS) or auto-reclosers (AR) with remote reading facility, at the feeder starting point.

In the state estimation algorithm, only the meter accuracy was considered in determining the measurement variance and hence the weights. The effect of other factors, such as the asynchronous data transmission, issues in the communication channel etc. were considered negligible, as the weight of the pseudo measurements was calculated as a ratio of that of the real time measurements. Studying the exact effect of asynchronous data transmission in the measurement variance would be an interesting future study.

A load flow algorithm based on the forward backward method of power flow analysis has been used for obtaining the pseudo measurements required for the state estimation algorithm. A common assumption of the popular methods for power flow analysis, such as the Newton Raphson method and the Gaussian Seidal method is that, the R/X (resistance/ reactance) ratio of the lines are small and hence the line resistance can be neglected. Even though this is valid for the transmission lines, the R/X ratio is larger in the distribution lines. This will make the elements in the admittance matrix, complex numbers. So, the calculations may require high processing power as well as high execution time, and may result in convergence issues. Therefore, the forward backward method of power flow analysis was selected as the most suitable method for the purpose of this research. The algorithm has been developed for the radial networks, as the distribution system normally consists of radial feeders. It can be modified to operate under the weekly meshed conditions as well, and the reference [4] proposes a compensation based technique which can be referred in such future developments.

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