Protection System Design for Power Distribution Systems in the Presence of Distributed Generation

A Thesis
Submitted to the Faculty
of
Drexel University
by
Yiming Mao
in partial fulfillment of the requirements for the degree of
Doctor of Philosophy
June 2005
ACKNOWLEDGEMENTS

First, I would like to express my deepest appreciation to my advisor, Dr. Miu, for her support, direction, and belief for this work. This work would not have been possible without her consistent advice and encouragement. The knowledge and experiences that I have learned with her help will not only carry me through my career but through my life. I would like also to thank Dr. Niebur, Dr. Nwankpa Dr. Kwatny and Dr. Halpin for serving on my committee.

Second, I would like to thank my friends and fellow students in CEPE, who have been helpful throughout my graduate years. I would like to acknowledge Tong Shiqiong, Jie Wan, Xiaoguang Yang, Michael Olaleye, Anawach Sangswang, Qinyan Liu, and Chris J.Dafis for their friendships and encouragement over these last challenging years.

Finally, my special thanks to my wife Jihong Hu, my son Alexander and my parents, for their love, patience, and understanding in past years. This work is dedicated to them.
# Table of Contents

LSIT OF TABLES............................................................................................................. vi

LSIT OF FIGURES........................................................................................................... ix

ABSTRACT....................................................................................................................... xi

CHAPTER 1.  INTRODUCTION...................................................................................... 1

1.1. Motivations ........................................................................................................... 1

1.2. Objectives ............................................................................................................ 5

1.3. Summary of Contributions................................................................................... 9

CHAPTER 2. REVIEW OF DISTRIBUTION SYSTEM COMPONENT MODELS .... 10

2.1 Line Models .......................................................................................................... 10

2.1.1 Grounded Line Model .................................................................................. 10

2.1.2 UnGrounded Line Model ............................................................................. 11

2.2 Load Models ........................................................................................................ 12

2.3 Shunt Capacitor Models.................................................................................... 15

2.4 Transformer Models.......................................................................................... 15

2.5 Distributed Generator Models.......................................................................... 18

2.6 Switch Model....................................................................................................... 18

CHAPTER 3. SWITCH PLACEMENT FOR RADIAL DISTRIBUTION SYSTEMS
WITH DISTRIBUTED GENERATION ............................................................................. 19

3.1 Problem Formulations........................................................................................... 21

3.1.1 Maximizing High Priority Loads (Formulation 1).......................................... 25

3.1.2 Servicing All High Priority Loads (Formulation 2)......................................... 25
<table>
<thead>
<tr>
<th>Section</th>
<th>Title</th>
<th>Pages</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.2</td>
<td>Solution Algorithms</td>
<td>26</td>
</tr>
<tr>
<td>3.2.1</td>
<td>Algorithm 1-Maximizing Priority Loads</td>
<td>31</td>
</tr>
<tr>
<td>3.2.1.1</td>
<td>Step 3 - Building Base $T$</td>
<td>31</td>
</tr>
<tr>
<td>3.2.1.2</td>
<td>Step 5 - Adding and Shedding Loads</td>
<td>32</td>
</tr>
<tr>
<td>3.2.1.3</td>
<td>Step 9 - Constraint Handling</td>
<td>36</td>
</tr>
<tr>
<td>3.2.2</td>
<td>Algorithm 2-Servicing All Priority Loads</td>
<td>37</td>
</tr>
<tr>
<td>3.3</td>
<td>Numerical Results</td>
<td>38</td>
</tr>
<tr>
<td>3.3.1</td>
<td>Single DG at bus 59</td>
<td>40</td>
</tr>
<tr>
<td>3.3.2</td>
<td>Multiple DGs at bus 70 and bus 92</td>
<td>42</td>
</tr>
<tr>
<td>3.3.3</td>
<td>Two DGs with Five Priority Loads</td>
<td>44</td>
</tr>
<tr>
<td>3.4</td>
<td>Comments</td>
<td>45</td>
</tr>
</tbody>
</table>

CHAPTER 4. NETWORK EQUIVALENT MODELS FOR SHORT CIRCUIT ANALYSIS

<table>
<thead>
<tr>
<th>Section</th>
<th>Title</th>
<th>Pages</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.1</td>
<td>Network Modeling</td>
<td>49</td>
</tr>
<tr>
<td>4.1.1</td>
<td>General Approach to System Modeling</td>
<td>49</td>
</tr>
<tr>
<td>4.1.2</td>
<td>Initial Condition Boundary Matching (BdM) Models</td>
<td>51</td>
</tr>
<tr>
<td>4.1.2.1</td>
<td>Grounded Portions of a System</td>
<td>52</td>
</tr>
<tr>
<td>4.1.2.2</td>
<td>Ungrounded Portions of a System</td>
<td>53</td>
</tr>
<tr>
<td>4.1.3</td>
<td>Equivalent Circuit (EqC) Models</td>
<td>55</td>
</tr>
<tr>
<td>4.1.4</td>
<td>Transformer Modeling</td>
<td>56</td>
</tr>
<tr>
<td>4.2</td>
<td>Solution Algorithm</td>
<td>58</td>
</tr>
<tr>
<td>4.3</td>
<td>Numerical Results</td>
<td>58</td>
</tr>
<tr>
<td>4.3.1</td>
<td>20-bus System</td>
<td>61</td>
</tr>
</tbody>
</table>
4.3.1.1 Faults in a Grounded Portions of 20-bus System .......... 62
4.3.1.2 Faults in Ungrounded Portions of 20-bus System ........ 66
4.3.2 394-bus System ................................................................................ 69
  4.3.2.1 Faults in a Grounded Portions of 394-bus System .......... 69
  4.3.2.2 Faults in Ungrounded Portions of 394-bus System .......... 75
4.4 Comments ................................................................................................. 79

CHAPTER 5. MULTI-AGENT BASED ADAPTIVE PROTECTION SYSTEM FOR
RADIAL DISTRIBUTION SYSTEMS ................................................... 81
5.1 Previous Work ....................................................................................... 82
5.2 Problem Formulation ............................................................................. 85
5.3 Agent-based Protection System Design ..................................................... 87
5.4 Solution Algorithm ................................................................................... 90
  5.4.1 Terminology and Assumptions ........................................................ 92
  5.4.2 Checks for Topological Changes ....................................................... 95
  5.4.3 Topology Processor ......................................................................... 96
    5.4.3.1 Initializing Process ..................................................................... 101
    5.4.3.2 Adjusting Process ...................................................................... 101
    5.4.3.3 EAG Search Process .................................................................. 104
    5.4.3.4 Examples of the Topology Processor ........................................ 105
  5.4.4 Checks for Load Change ................................................................. 108
  5.4.5 Short Circuit Calculation ................................................................. 109
    5.4.5.1 Equivalent Modeling for the System between CAs ............ 109
    5.4.5.2 Short Circuit Calculation Process ............................................ 119
5.4.6 Coordination Process ................................................................. 121
  5.4.6.1 Overcurrent Relays ...................................................... 121
  5.4.6.2 Distance Relays ............................................................ 122
5.5 Comments .................................................................................. 123

CHAPTER 6. CONCLUSIONS ............................................................ 125
  6.1 Contributions and Conclusions ............................................. 125
  6.2 Future Work .......................................................................... 127

List of References ............................................................................... 130

VITA .................................................................................................. 134
List of Tables

Table 2.1   Load parameters from nominal loads\textsuperscript{[13]} ......................................................... 14
Table 2.2   Load admittance matrices\textsuperscript{[13]} ........................................................................... 15
Table 2.3   Transformer admittance matrices for different connections \textsuperscript{[13]} ..................... 17
Table 3.1   Basic information of test cases ....................................................................... 40
Table 3.2   Case 1 Results with DG at bus 59 & 67\% controllable load .......................... 41
Table 3.3   Case 2 Results with DG at bus 59 & no controllable load ............................. 41
Table 3.4   Case 3 Results with DG at buses 70, 92 & 67\% controllable load................. 43
Table 3.5   Case 4 Results with DG at buses 70, 92 & no controllable load ..................... 43
Table 3.6   Case 5 Results with DG at buses 70, 92 & no controllable load & five priority loads ............................................................................................................... 44
Table 4.1   Results of $|V_f|$ at bus 18 for a single fault at bus 18 of the 20-bus system .... 62
Table 4.2   Results of $|I_f|$ at bus 18 for a single fault at bus 18 of the 20-bus system ..... 63
Table 4.3   $I_f^\text{Diff, CM}\%$ for the fault current flowing along the fault path ................. 64
Table 4.4   $I_f^\text{Diff, Zaw}\%$ for the fault current flowing along the fault path............... 64
Table 4.5   Comparison results of flops for a single fault at bus 18 of the 20-bus system ................................................................................................................. 65
Table 4.6   Results of $|V_f|$ at bus 18 for a single fault at bus 18 of the 20-bus system ... 66
Table 4.7   Results of $|I_f|$ at bus 18 for a single fault at bus 18 of the 20-bus system ...... 67
Table 4.8   $I_f^\text{Diff, CM}\%$ for the fault current flowing along the fault path ................. 67
Table 4.9   $I_f^\text{Diff, Zaw}\%$ for the fault current flowing along the fault path............... 68
Table 4.10  Flop counts for a single fault at bus 18 of the 20-bus system....................... 68
Table 4.11  Comparison results of $|V_f|$ at bus 1179 for a single fault at bus 1179 of the 394-bus system .......................................................... 70

Table 4.12  Results of $|I_f|$ at bus 1179 for a single fault at bus 1179 of the 394-bus system ............................................................................................................. 71

Table 4.13  $I_{f}^{\text{Diff, CM}}\%$ for the fault current flowing along the fault path ......................... 72

Table 4.14  $I_{f}^{\text{Diff, CM}}\%$ for the fault current flowing along the fault path (Continued) ... 72

Table 4.15  $I_{f}^{\text{Diff, Zno}}\%$ for the fault current flowing along the fault path........................ 73

Table 4.16  $I_{f}^{\text{Diff, Zno}}\%$ for the fault current flowing along the fault path (Continued) ... 73

Table 4.17  Comparison results of flops for a single fault at bus 1179 of the 394-bus system ............................................................................................................................................... 74

Table 4.18  Comparison results of $|V_f|$ at bus 1036 for a single fault at bus 1036 of the 394-bus system ............................................................................................................. 75

Table 4.19  Results of $|I_f|$ at bus 1036 for a single fault at bus 1036 of the 394-bus system ............................................................................................................................................... 77

Table 4.20  $I_{f}^{\text{Diff, CM}}\%$ for the fault current flowing along the fault path ......................... 77

Table 4.21  $I_{f}^{\text{Diff, CM}}\%$ for the fault current flowing along the fault path (Continued) .... 77

Table 4.22  $I_{f}^{\text{Diff, Zno}}\%$ for the fault current flowing along the fault path........................ 78

Table 4.23  $I_{f}^{\text{Diff, Zno}}\%$ for the fault current flowing along the fault path (Continued) ... 78

Table 4.24  Comparison results of flops for a single fault at bus 1036 of the 394-bus system ............................................................................................................................................... 79

Table 5.1  The topology lists for CA1 and CA3 ........................................................................... 107
Table 5.2  Subsystem models for different cases......................................................... 111

Table 5.3  Fault currents $I_f$ for a 3LG fault at bus 89 with uniformly distributed loads
................................................................................................................................................... 120

Table 5.4  Fault currents $I_f$ for a 3LG fault at bus 89 with proportionally distributed loads
................................................................................................................................................... 120
List of Figures

Figure 1.1 The framework of this thesis ................................................................. 6
Figure 2.1 Grounded three-phase distribution line model ...................................... 10
Figure 2.2 Grounded wye connected load ............................................................. 12
Figure 2.3 Ungrounded delta connected load ....................................................... 13
Figure 3.1 Illustration of the system impacts of switch placement and network reconfiguration ................................................. 20
Figure 3.2 The general flow chart of the proposed solution algorithms .................. 30
Figure 3.3 A one-line diagram of the 394 bus test system ..................................... 39
Figure 4.1 Original system before lateral and load equivalencing ......................... 49
Figure 4.2 System after lateral ($Z_{la}$) and load ($Z_{L}$) equivalencing ................. 50
Figure 4.3 Final equivalent ($Z_{eq}$) system diagram ............................................. 50
Figure 4.4 Impedance equivalencing for a transformer ....................................... 56
Figure 4.5 A one-line diagram of the 20-bus system ............................................ 61
Figure 4.6 The fault path for the fault at bus 18 ................................................... 63
Figure 4.7 The fault path for the fault at bus 1179 .............................................. 71
Figure 4.8 The fault path for fault at bus 1036 .................................................... 76
Figure 5.1 Agent structure at one bus proposed in [33] ....................................... 85
Figure 5.2 Proposed multi-agent based adaptive protection system ...................... 88
Figure 5.3 Flowchart of the proposed solution algorithm on a CA ...................... 91
Figure 5.4 Example of adjacent zones for a 20-bus system .................................. 93
Figure 5.5 Adjacent zone for CA1 ..................................................................... 94
Figure 5.6 Adjacent zones for CA2 ................................................................... 95
Figure 5.7  Topology structures: (a) standard graph (b) multi-agent structure ................. 97
Figure 5.8 A 20-bus distribution system with multiple sources ....................................... 99
Figure 5.9 Flowchart of the topology processor ............................................................. 100
Figure 5.10 General structure of a CA with multiple adjacent CAs downstream .......... 110
Figure 5.11 CA with no CA downstream ....................................................................... 114
Abstract

Protection System Design for Power Distribution Systems in the Presence of Distributed Generation

Yiming Mao
Karen Miu, Ph.D.

The increasing presence of distributed generation and the steady modernization of power distribution system equipment have presented new opportunities in power distribution system studies. This thesis will focus on the impacts new equipment technology and regulatory changes, such as the move to performance based rates, have on distribution protection system design. Specifically, this thesis addresses three aspects in the design of protection systems. First, to determine new protection device locations, switch placement schemes are proposed which allow systems with DGs to intentionally island in fault scenarios. Second, network equivalent models are proposed to improve the accuracy of short circuit analysis. These techniques are used to size protection devices and to determine protection device settings. Finally, to address distribution protection system design and coordination, a multi-agent based adaptive protection system is proposed. Extensive simulation tests on a 20-bus system and a 394-bus system with single/multiple DGs yield promising results.
CHAPTER 1. INTRODUCTION

Protection systems are vital components of any power system. Its goal is to detect and isolate faults when they occur. By doing so, safe operation of power systems can be achieved, extensive equipment damage can be avoided and the areas affected by faults can be minimized. To realize this, proper placement of protection devices and proper coordination between the relays which control them are necessary. As such, this thesis will address protection system design in power distribution systems.

1.1. Motivations

Power distribution systems are directly linked to customers. Thus the distribution system plays an important role in the overall power system reliability and the perceived reliability to customers. By improving distribution protection systems such that sustained outage times can be reduced, power system reliability can be enhanced.

In the United States, power distribution system companies are required to report to state regulatory committees commonly known as the public utility commissions (PUCs). More specifically, companies are required to report reliability indices quantifying the functional reliability of their power system with respect to end customers. Since distribution utility companies are no longer associated with power generation, there exists a push towards Performance Based Rates (PBR) instead of cost-based rates by several states to encourage distribution companies to maintain and improve system reliability. PBR is measured by reliability indices. The definitions of two commonly reported
reliability indices from IEEE Standard 1366: Guide for Electric Power Distribution Reliability Indices [1] are displayed:

i. a sustained interruption index:

**SAIFI (System Average Interruption Frequency Index)**

\[
SAIFI = \frac{\sum \text{Total Number Customers Interrupted}}{\text{Total Number of Customers Served}}
\]  

(1.1)

ii. a load based index:

**ASIFI (Average Service Interruption Frequency Index)**

\[
ASIFI = \frac{\sum \text{Total Connected kVA of Load Interrupted}}{\text{Total Connected kVA Served}}
\]  

(1.2)

Therefore, reliability is a significant concern in the planning and operation of power distribution systems. Another more recent issue for power distribution companies has been customer perception. Many states have adopted or are planning to adopt customer choice programs, which allow residents to select their energy provider. Thus, in an effort to maintain and improve distribution system reliability and to improve customer service, distribution companies have begun to modernize their distribution systems. Efforts have ranged from the installation of new measurement devices such as automated meter readers (AMR) to the steady automation of power handling equipment such as network switches.

These efforts have lead to a significant increase in knowledge about the power distribution network: e.g. more up-to-date load information and more network device information and capabilities. Historically, averaged and/or monthly peak loads could be obtained periodically from customer billing systems and human meter readers. Also, protection devices were dominated by fuse-fuse and recloser-fuse coordination with some
sectionalizing (normally closed) switches with limited automation capabilities. Traditionally, distribution protection devices are set using offline calculations. These settings are then used for all operating conditions over a specified length of time. However, load fluctuations and even steady load growth within the specified time between device resetting can create undesirable responses by the protection system, such as slow reaction times leading to larger affected areas after a fault. The increase in information and capabilities of loads and distribution protection system components require updating protection devices and/or their settings. In addition, it suggests the possibility of adaptive relaying schemes for power distribution systems.

Another critical motivation has been the restructuring of the energy industry. This has resulted in an increase in distributed generation installed within distribution systems (systems under 115kV.) Several studies have predicted that DG will be up to 20% of all new generation going online by 2010 [2]. Different resources can be used, such as photovoltaic, wind, and fuel cells etc. Its impact on distribution systems may be either positive or negative depending on the system’s operating condition [2, 3], DG’s characteristics and location. Potential positive impacts include:

- improved system reliability
- loss reduction
- deferment of new generation
- improved power quality

However, to achieve the above benefits, enhancements to the existing distribution protection system must be made, and DGs must be properly coordinated with the system.
Unlike co-generators, whose owners’ primary goals, income and economic success are related to energizing their industrial processes, distributed generator (DG) owners primary goal is to supply power into the system. While pre-arranged islanding agreements were made for co-generators to service areas under fault conditions, current operating standards, e.g. IEEE 1547 Standard, demand that DGs are isolated from the network in the presence of a fault.

Several practical reasons have, in the past, justified this standard. For example, in general, the design of existing power distribution protection systems have assumed a single dominate power source, the substation. With most distribution systems operated in a radial manner, then power only flowed in one direction. Consequently, the protection system was designed around these assumptions. Straightforward coordination between devices was implemented, and cost-effective fuses are now prevalent.

With the introduction of DGs, now it is possible for the distribution systems to have power flow in both directions: upstream and downstream. The presence of DGs also substantially changes the short circuit characteristics of distribution systems. It can potentially cause equipment ratings to be exceeded and a loss of existing protection system coordination, such as fuse-fuse coordination and fuse-recloser problem [3].

In order to maintain or improve system reliability of distribution systems with DGs, existing distribution protection systems need targeted upgrades. With the decreasing cost of digital relays in recent years, they have become a viable choice for upgrading analog protection relays in distribution protection systems and updating existing manual sectionalizing switches. With these upgrades and improved load and network monitoring,
intentional islanding for DGs and adaptive relaying techniques can be utilized to improve reliability indices.

It should be noted that this thesis focuses on steady state approaches. Since DGs usually do not have automatic generation control (AGC) installed, the system frequency is dictated by the substation which typically has a much higher capacity and serves a majority of the loads compared to DGs. Thus, a steady common frequency is maintained throughout distribution systems. It is also noted that protection device sizing is often based on steady state analysis at extreme conditions, and reliability indices reported to PUCs are often based on sustained conditions (>5 min), near steady state information.

1.2. Objectives

To design a distribution protection system, three questions often arise:

- Where to install protection devices
- How to calculate settings for those devices
- How to coordinate between those protection devices

This thesis addresses these three questions. The framework of this thesis is shown in Figure 1.1:
Unlike transmission systems, distribution systems are usually unbalanced. Thus, per-phase analysis is not suitable for distribution system analysis. Practical analysis and design of distribution systems will require detailed three-phase models for the system components, such as lines, transformers, switches etc. Thus, in Chapter 2, detailed models for distribution system components are reviewed.

In Chapter 3, to address the question of where to install protection devices, the problem of switch placement is formulated to allow for intentional islanding in fault scenarios for radial distribution systems with distributed generation (DG). Instead of isolating DGs from the system [2] [4-6] in the event of a fault, network reconfiguration using existing and new switches will allow DGs to support an area de-energized after fault isolation. By allowing DGs to support loads, the outage duration and the number of sustained interruptions would decrease for those customers, and the reliability of the system would improve. Two problem formulations were developed in Chapter 3 for the switch placement problem with DGs. The formulations differ in how to address priority...
loads. Accompanying solution algorithms are also provided and tested on a 20-bus system and 394-bus system.

For the second question, which pertains to the sizing and settings of protection devices, two equivalent impedance models are developed in Chapter 4 to model beyond the fault path during the short circuit calculation. Short circuit analysis is a critical tool used in distribution protection systems design and analysis. The two main results from short circuit analysis are the short circuit current and the subsequent post-fault voltage which are the basis of protection device settings. By improving the modeling used in short circuit analysis to incorporate new information acquired by digital relays and new measurement devices, the accuracy of the fault voltage and fault currents can be improved. This leads to better protection system design and consequently improved network reliability.

Traditionally short circuit analysis for power systems omits the loads in the system [7, 8]. Usually, the loads have been omitted because that the loads are assumed to have a very small effect on the short circuit current[9]. Then, only the path from the fault location to the root is considered. However for distribution systems, this assumption is not always accurate and detailed transformer and load models were used for post-fault calculation in [10]. T.H. Chen proposed a Zbus based short circuit approach in [11], which considered loads and laterals during short circuit calculation. The drawbacks of the proposed Zbus based method are the followings:

- Full system information required
- Computational intensive due to the size of the matrix
In order to avoid these drawbacks, new models are needed for adaptive protection systems design to consider loads and laterals beyond fault path in both the short circuit current calculation and the post-fault analysis. In this thesis, two models based on pre-fault system information are developed. They are initial condition boundary matching (BdM) and equivalent circuit model (EqC). They are designed based on the different assumptions on known information about the system. The two models provide choices between speed and accuracy according to the different needs of the system analysis and availability of data.

To address the last question concerning coordination of protection devices, a multi-agent based adaptive protection system for radial systems is presented in Chapter 5. This system is designed to use limited local information to achieve adaptive protection systems. The proposed protection systems are built based on the principle of adaptive relays, which adjust protection system settings according to prevailing power system operating conditions[12]. A particular focus has been applied to develop a topology processor for identifying the multi-agent structure which adapts to changes in network structure. An algorithm which utilizes equivalent models from Chapter 4 to represent the network between adjacent agents is developed to compute individual protection device settings and the coordination between agents.

In Chapter 6, the conclusions from this work are drawn and contributions are outlined. It also provides a discussion of possible future work.
1.3. Summary of Contributions

This thesis provides the following works toward improving distribution protection system design using modern distribution components and in the presence of distributed generation:

- Problem formulations for switch placement for intentional islanding in radial power distribution systems with DGs
- Heuristic solution algorithms used to solve switch placement problem, which utilize analytically obtained decision indices
- Detailed impedance-based equivalent models for improving network representation during on-line and off-line short circuit calculations
- A multi-agent based framework for establishing adaptive coordination between distribution system protection devices, including:
  - a topology processor for automatically adjusting agent structures after fault isolation and/or network reconfiguration, and
  - a distributed, agent-based methodology for computing protection device settings.
- Detailed simulation results on a 20-bus and an actual 394-bus distribution system
CHAPTER 2. REVIEW OF DISTRIBUTION SYSTEM COMPONENT MODELS

In this chapter, three-phase component models for distribution systems are reviewed [13-16]. These models will be used in the problem formulations and computer simulations for multi-phase distribution systems analysis discussed in later chapters. The models for lines, loads, shunt capacitors, transformers, distributed generators and switches are described in detail in the following sections. In this thesis, bold characters represent either vectors or matrices.

2.1. Line Models

Line models are summarized in two categories: grounded line models and ungrounded line models.

2.1.1. Grounded Line Model

Grounded distribution lines are modeled with π–models as shown in Figure 2.1.

![Figure 2.1 Grounded three-phase distribution line model](image-url)
\( Y_{ik}^{\text{phase}} \), the branch admittance matrix for the line between bus \( i \) and bus \( k \) will be:

\[
Y_{ik}^{\text{phase}} = \begin{bmatrix}
Z_{ik}^{-1} + Y_{ik}^{\text{sh}} / 2 & -Z_{ik}^{-1} \\
-Z_{ik}^{-1} & Z_{ik}^{-1} + Y_{ik}^{\text{sh}} / 2
\end{bmatrix}
\]  \hspace{1cm} (2.1)

In Equation (2.1), \( Z_{ik} \) and \( Y_{ik}^{\text{sh}} \) are both \((n_p \times n_p)\) complex matrices, where \( n_p \) is the number of phases on the line. In distribution systems, overhead lines between buses are usually shorter than 50 miles [17], thus line charging is typically neglected, \( Y_{ik}^{\text{sh}} \approx 0 \),

### 2.1.2. Ungrounded Line Model

In ungrounded parts of a system, since there is no ground reference, line-to-line voltages are chosen to be the state variables. In this thesis, \( V^{ab} \) and \( V^{bc} \) are selected and \( V^{ca} \) is redundant and equals to \(-(V^{ab} + V^{bc})\). The dimension of \( Y_k \), the branch admittance matrix, will be reduced from \((3 \times 3)\) to \((2 \times 2)\) and can be calculated using the following equation:

\[
Y_{ik}^{\text{line}} = \left[ \begin{array}{cc}
1 & -1 \\
0 & 1
\end{array} \right] \frac{1}{3} Z_{ik}^{\text{phase}} \left[ \begin{array}{cc}
1 & 0 \\
0 & 1
\end{array} \right]^{-1}
\]  \hspace{1cm} (2.2)

where:

- \( Z_{ik}^{\text{phase}} \in \mathbb{C}^{3 \times 3} \): per unit (p.u.) series impedance matrix between bus \( i \) and \( k \) relating phase to ground voltages to phase currents.
- \( Y_{ik}^{\text{line}} \in \mathbb{C}^{2 \times 2} \): p.u. branch admittance matrix between bus \( i \) and \( k \) relating line-to-line voltages to phase currents.
2.2. Load Models

Static load models employed throughout the thesis are now discussed. Loads are modeled as constant impedance loads, constant power loads, constant current loads or ZIP loads, linear combinations of the previous three. In this thesis, three-phase loads are connected as grounded wye or delta in grounded parts of a system and as delta in ungrounded parts of a system. They are shown in Figure 2.2 and 2.3.

![Figure 2.2 Grounded wye connected load](image)
Table 2.1 shows how to calculate load parameters from nominal values. Note that $\overline{S}_{Lk}$ and $\overline{I}_{Lk}$ are bus injection vectors and the following notation is used:

- subscript \( \text{nom} \) : nominal value
- superscript $^*$ : complex conjugate
- $/$ : element-wise division for vectors
- $\bullet$ : constant values
Table 2.1 Load parameters from nominal loads\[13\]

<table>
<thead>
<tr>
<th>Load Connection</th>
<th>$V_{k,nom}$</th>
<th>$S_{k,nom}$</th>
<th>Load Type</th>
<th>Parameter Calculation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grounded Wye</td>
<td>$V_{k,nom}$</td>
<td>$S_{k,nom}$</td>
<td>Constant $S$</td>
<td>$\overline{S}<em>{kk} = -S</em>{k,nom}$</td>
</tr>
<tr>
<td></td>
<td>$V_{k,nom}$</td>
<td>$S_{k,nom}$</td>
<td>Constant $I$</td>
<td>$\overline{I}<em>{kk} = -S</em>{k,nom} \</td>
</tr>
<tr>
<td></td>
<td>$V_{k,nom}$</td>
<td>$S_{k,nom}$</td>
<td>Constant $Z$</td>
<td>$\overline{y}<em>{kk} = S</em>{k,nom} \</td>
</tr>
<tr>
<td>UnGrounded Delta</td>
<td>$V_{k,nom}$</td>
<td>$S_{k,nom}$</td>
<td>Constant $S$</td>
<td>$\overline{S}<em>{kk} = -S</em>{k,nom}$</td>
</tr>
<tr>
<td></td>
<td>$V_{k,nom}$</td>
<td>$S_{k,nom}$</td>
<td>Constant $I$</td>
<td>$\overline{I}<em>{kk} = (S</em>{k,nom} \</td>
</tr>
<tr>
<td></td>
<td>$V_{k,nom}$</td>
<td>$S_{k,nom}$</td>
<td>Constant $Z$</td>
<td>$\overline{y}<em>{kk} = S</em>{k,nom} \</td>
</tr>
<tr>
<td></td>
<td>$V_{k,nom}$</td>
<td>$S_{k,nom}$</td>
<td>Constant $S$</td>
<td>$\overline{S}<em>{kk} = -S</em>{k,nom}$</td>
</tr>
<tr>
<td></td>
<td>$V_{k,nom}$</td>
<td>$S_{k,nom}$</td>
<td>Constant $I$</td>
<td>$\overline{I}<em>{kk} = (S</em>{k,nom} \</td>
</tr>
<tr>
<td></td>
<td>$V_{k,nom}$</td>
<td>$S_{k,nom}$</td>
<td>Constant $Z$</td>
<td>$\overline{y}<em>{kk} = S</em>{k,nom} \</td>
</tr>
</tbody>
</table>

†where: $U = \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix}$

$\overline{S}_{kk}, \overline{I}_{kk}, \overline{y}_{kk}$: constant power, current and impedance model parameters.

Table 2.2 shows how to build load admittance matrices. It can be seen that it is assumed that there is no coupling between phases of loads for grounded wye connection. For single-phase and two-phase loads, appropriate rows/columns of phases without loads will be eliminated from $Y_{bus}$. 
### Table 2.2 Load admittance matrices

<table>
<thead>
<tr>
<th>Load Connection</th>
<th>$V_k$</th>
<th>Load Admittance Matrix</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grounded Wye</td>
<td>$\begin{bmatrix} V_k^a \ V_k^b \ V_k^c \end{bmatrix}$</td>
<td>$\begin{bmatrix} y_{Lk} &amp; 0 &amp; 0 \ 0 &amp; y_{Lk} &amp; 0 \ 0 &amp; 0 &amp; y_{Lk} \end{bmatrix}$</td>
</tr>
<tr>
<td>UnGrounded Delta</td>
<td>$\begin{bmatrix} V_k^{ab} \ V_k^{bc} \end{bmatrix}$</td>
<td>$\begin{bmatrix} y_{Lk}^{ab} + y_{Lk}^{bc} &amp; -y_{Lk}^{ab} &amp; -y_{Lk}^{bc} \ -y_{Lk}^{ab} &amp; y_{Lk}^{ab} + y_{Lk}^{bc} &amp; -y_{Lk}^{bc} \ -y_{Lk}^{ab} &amp; -y_{Lk}^{bc} &amp; y_{Lk}^{ab} + y_{Lk}^{bc} \end{bmatrix}$</td>
</tr>
</tbody>
</table>

#### 2.3. Shunt Capacitors Models

Shunt capacitors are used for voltage control and reactive power compensation in distribution systems. They are modeled as constant impedance loads with zero resistances, which mimics load models in Table 2.2. In this thesis, it is assumed that in grounded parts of a system, shunt capacitors are grounded wye connected, while in ungrounded parts of a system, they are ungrounded delta connected.

#### 2.4. Transformer Models

A transformer on the branch between bus $i$ and bus $k$ can be modeled using the following admittance matrix:

$$Y_{ik}^{\text{transformer}} = \begin{bmatrix} Y_{ik}^{pp} & Y_{ik}^{ps} \\ Y_{ik}^{sp} & Y_{ik}^{ss} \end{bmatrix} \quad (2.3)$$

In Equation (2.3), $p$ stands for primary side and $s$ stands for secondary side. The value and dimension of a transformer admittance matrix will be affected by the number of phases, its leakage admittance $y_{Lk}$, primary side tap setting $\alpha_k$, secondary side tap setting $\beta_k$ and its connection type. In this thesis, ungrounded sides of a transformer will use $Y_{ik}^{ab}$.
and $V^{bc}$ as state variables and the dimension of the self-admittance sub-matrix $Y_{ik}^{pp}$ or $Y_{ik}^{ss}$ on an ungrounded side can be reduced to $(2\times2)$. Similarly, the dimensions of coupling sub-matrices, $Y_{ik}^{ps}$ and $Y_{ik}^{sp}$, are adjusted accordingly. Thus, if both sides are grounded, the dimension of $Y_{ik}$ will be $(6\times6)$. If one side is ungrounded, the dimension of $Y_{ik}^{\text{former}}$ will be $(5\times5)$. If both sides are ungrounded, the dimension of $Y_{ik}^{\text{former}}$ will be $(4\times4)$.

Table 2.3 summarizes the admittance matrices for different transformer connections. All the values in Table 2.3 are p.u. values.
Table 2.3 Transformer admittance matrices for different connections\(^{[13]}\)

<table>
<thead>
<tr>
<th>Type</th>
<th>Transformer Connection Type</th>
<th>(Y_{ab}^{pp})</th>
<th>(Y_{ab}^{ps})</th>
<th>(Y_{ab}^{ss})</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Grounded Wye</td>
<td>(\frac{y_k}{\alpha_k}) [1 0 0] (\frac{-y_k}{\alpha_k\beta_k})</td>
<td>(\frac{1}{0 1 0})</td>
<td>(\frac{0 1 0}{0 0 1})</td>
</tr>
<tr>
<td></td>
<td>Grounded Wye</td>
<td>(\frac{-y_k}{\alpha_k\beta_k}) [1 0 0] (\frac{y_k}{\alpha_k\beta_k})</td>
<td>(\frac{1}{0 1 0})</td>
<td>(\frac{0 1 0}{0 0 1})</td>
</tr>
<tr>
<td>2</td>
<td>Grounded Wye</td>
<td>(\frac{y_k}{\alpha_k\beta_k}) [2 -1 -1] (\frac{-y_k}{\alpha_k\beta_k})</td>
<td>(\frac{2}{3\alpha_k\beta_k}) [1 2 -1] (\frac{-1}{3\alpha_k\beta_k})</td>
<td>(\frac{1}{-1 -1 2})</td>
</tr>
<tr>
<td></td>
<td>Un grounded Wye</td>
<td>(\frac{-y_k}{\alpha_k\beta_k}) [2 -1 -1] (\frac{y_k}{\alpha_k\beta_k})</td>
<td>(\frac{1}{2 -1 -1})</td>
<td>(\frac{1}{2 -1 -1})</td>
</tr>
<tr>
<td>3</td>
<td>Grounded Wye</td>
<td>(\frac{y_k}{\alpha_k\beta_k}) [1 0 0] (\frac{-y_k}{\alpha_k\beta_k})</td>
<td>(\frac{1}{0 1 0})</td>
<td>(\frac{0 1 0}{0 0 1})</td>
</tr>
<tr>
<td></td>
<td>Delta</td>
<td>(\frac{-y_k}{\alpha_k\beta_k}) [1 0 -1] (\frac{y_k}{\alpha_k\beta_k})</td>
<td>(\frac{1}{-1 1 0})</td>
<td>(\frac{1}{-1 1 0})</td>
</tr>
<tr>
<td>4</td>
<td>Ungrounded Wye</td>
<td>Grounded Wye</td>
<td>Opposite(^\dagger) of type 2</td>
<td>(\frac{1}{2 1})</td>
</tr>
<tr>
<td>5</td>
<td>Ungrounded Wye</td>
<td>Ungrounded Wye</td>
<td>(\frac{-y_k}{\alpha_k\beta_k}) [2 1] (\frac{y_k}{\alpha_k\beta_k})</td>
<td>(\frac{2}{1})</td>
</tr>
<tr>
<td></td>
<td>Ungrounded Wye</td>
<td>(\frac{-y_k}{\alpha_k\beta_k}) [2 1] (\frac{y_k}{\alpha_k\beta_k})</td>
<td>(\frac{1}{1 -1 1})</td>
<td>(\frac{1}{0 1})</td>
</tr>
<tr>
<td>6</td>
<td>Ungrounded Wye</td>
<td>Delta</td>
<td>(\frac{-y_k}{\alpha_k\beta_k}) [1 1 1] (\frac{y_k}{\alpha_k\beta_k})</td>
<td>(\frac{1}{1 1 1})</td>
</tr>
<tr>
<td></td>
<td>Delta</td>
<td>Grounded Wye</td>
<td>Opposite(^\dagger) of type 3</td>
<td>(\frac{1}{2 1})</td>
</tr>
<tr>
<td>7</td>
<td>Delta</td>
<td>Ungrounded Wye</td>
<td>Opposite(^\dagger) of type 6</td>
<td>(\frac{1}{2 1})</td>
</tr>
<tr>
<td>8</td>
<td>Delta</td>
<td>Delta</td>
<td>Same as type 5</td>
<td>(\frac{1}{2 1})</td>
</tr>
<tr>
<td>9</td>
<td>Delta</td>
<td>Delta</td>
<td>Same as type 5</td>
<td>(\frac{1}{2 1})</td>
</tr>
</tbody>
</table>

\(^\dagger\): swap \(Y_{ab}^{pp}\) and \(Y_{ab}^{ps}\) with \(Y_{ab}^{sp}\) and \(Y_{ab}^{ss}\), respectively, then swap \(\alpha_k\) with \(\beta_k\).
2.5. Distributed Generator Models

Three types of Distributed Generators (DGs) models will be employed in the thesis. They are as follows:

- a P|V| Model
- a PQ Model
- an Admittance to Ground Model

In power flow analysis, distributed generators are modeled as P|V| nodes. When their power outputs reach their limits, DGs are modeled as negative PQ loads. In short circuit analysis, distributed generators are modeled as admittance matrices connected to ground with their nominal values provided by vendors. This model are used in compensation-based short circuit analysis algorithm.

2.6. Switch Model

In this thesis, all the switches will be modeled as zero impedance branches. The two end buses for a switch branch will have the same voltages and the current flow in and out this branch will also be the same.
CHAPTER 3. SWITCH PLACEMENT FOR RADIAL DISTRIBUTION SYSTEMS WITH DISTRIBUTED GENERATION

In this chapter, to address the problem of where to install protection devices, switch placement schemes are proposed. The primary goal of the placement schemes is to form self-supported islands after fault isolation in order to improve system reliability for radial distribution systems with distributed generation (DG).

In [18], Billinton and Jonnavithula formulated the switch placement problem to improve system reliability without considering DG and a simulated annealing based method was proposed. Current practices isolate DGs [2, 4-6] in case of faults. However, with proper switch placements, DGs may be allowed to support an isolated area by opening switches during upstream utility outages. As shown in Figure 3.1, when a fault occurs with no self-supported area allowed, all the loads in the area isolated from the substation will lose power. By allowing DG to continuously support loads in the inner region, the reliability of the system would improve. Thus, one of the objectives of this work is to identify corresponding switch locations.
Since standard reliability indices such as SAIDI and SAIFI [19] are based on steady state information, static problem formulations are developed. The switch placement problem with DGs is formulated as a non-differentiable, multi-objective optimization problem subject to electrical, operational and network constraints. In addition, special consideration has been made for customer priority. Since a multi-objective formulation is selected, trade offs between objectives must be made when designing the algorithms.

Graph-based algorithms have been developed to find the boundary of the isolated areas to be supported by DGs. The algorithms incorporate direct load control if available. Their results provide the following critical information:

i. where to install new sectionalizing switches,

ii. which existing switches must be opened or closed,

iii. which loads should be on and off.
3.1 Problem Formulations

The general switch placement problem is formulated as follows:

\[
\begin{align*}
\min_u & \quad \overline{f}_1(V, u) \\
\max_u & \quad \overline{f}_2(V, u) \\
\text{st.} & \quad F(V, u) = 0 \\
& \quad G(V, u) \leq 0
\end{align*}
\]  

(3.1)

where:

\( \overline{f}_1(V, u) \): cost-based objective functions to minimize

\( \overline{f}_2(V, u) \): reliability-based objective functions to maximize

\( V \): continuous state variables representing distribution system bus voltages

\( u \): discrete control variables, switch settings and load settings

\( F(V, u) \): electrical equality constraints

\( G(V, u) \): operational inequality constraints

The discrete control variables, \( u \), in this problem include existing switch status (open/close), new switch locations, new switch status (open/close) and controllable load status (on/off). The search space of this problem is composed of these control variables associated with the isolated area due to faults. In order to minimize network impacts of the proposed switch schemes on the areas without faults, tie switches connected to the isolated area are not considered in this problem. In the formulation, longer-term issues are addressed by switch locations. Shorter-term issues are also considered through direct load control (DLC). In the switch placement problem, five objectives are considered. They are listed in descending order of priority:

(O1). minimize the number of new switches to be installed
min \_u \ N_{\text{new}}(V,u) \quad (3.2)

(O2). maximize the amount of priority load in the island,

max \_u \sum_{k \in N_{\text{HP}}} \left| S_{L_k}^u(V,u) \right| \quad (3.3)

(O3). maximize the number of customers in the island.

max \_u N_{\text{customers}}(V,u) \quad (3.4)

(O4). maximize the amount of total load in the island.

max \_u \sum_{k \in N_L} \left| S_{L_k}^u(V,u) \right| \quad (3.5)

(O5). minimize the number of switch operations

min \_u N_{\text{sw}}(V,u) \quad (3.6)

where:

\( N_{\text{new}} \): the number of new switches to be installed

\( N_{\text{sw}} \): the number of switch operations

\( S_{L_k}^u \): the total load at bus \( k \), which equals to \( V_a (I_k^a)^* + V_b (I_k^b)^* + V_c (I_k^c)^* \)

\( N_{\text{HP}} \): the set of high priority (HP) loads in the resulting island

\( N_L \): the set of load buses in the resulting island

In these five objectives, (3.2) and (3.6) are designed to minimize costs to implement the proposed switch schemes by minimizing the number of new switches installed and the number of operations of the existing switches. Since installing a new switch is very costly, it is listed as the highest priority in this formulation. The other objectives are designed to improve system reliability by maximizing the number of customers and the amount of loads supported by DGs in the isolated area. In order to improve the System
Average Interruption Frequency Index (SAIFI) reliability index, maximizing service area and consequently maximizing the number of customers is set to have higher priority than maximizing the amount of the load served. It should be noted that although switch placement problems are planning problems, shorter-term objectives are included in the objectives as well, such as maximizing total load in the resulting island.

Here, the treatment of priority customers (3.3) can differ. First, maximizing priority loads served can be treated as an objective. However, in a more stringent manner, one can consider the servicing of priority loads as a constraint. With these differences, two formulations are developed which share the other four objectives.

The constraints of the switch placement problem include two parts: electrical equality constraints and operational inequality constraints.

1. Electrical equality constraints include three-phase power flow equations, with DGs modeled as P|V| buses.

   \[ F(V, u) = 0 \]  

   The solution to (3.7) will allow for operational constraint checking.

2. Operational inequality constraints include:
   - voltage magnitude constraints
     \[ V_{k}^{\text{min}} < |V_{k}^{P}| < V_{k}^{\text{max}} \]  
   - current magnitude constraints
     \[ |I_{k}^{P}| \leq I_{k}^{\text{max}} \]
• DG output constraints

\[
\begin{align*}
\max \left\{ P_{Gk}^{\min}, P_{Gk}^{pre} - \alpha_k P_{Gk}^{rat} \right\} & \leq P_{Gk}^{3\phi} \leq \min \left\{ P_{Gk}^{\max}, P_{Gk}^{pre} + \alpha_k P_{Gk}^{rat} \right\} \\
\max \left\{ Q_{Gk}^{\min}, Q_{Gk}^{pre} - \alpha_k Q_{Gk}^{rat} \right\} & \leq Q_{Gk}^{3\phi} \leq \min \left\{ Q_{Gk}^{\max}, Q_{Gk}^{pre} + \alpha_k Q_{Gk}^{rat} \right\} 
\end{align*}
\] (3.10) (3.11)

• Radial network structure

For ease of fault location, isolation, coordination of protection devices and personnel safety, a radial network structure will be preserved in the resulting island.

where:

\[
\begin{align*}
V_{k}^{p} & : \text{the voltage at bus } k, \text{ phase } p, \\
P_{Gk}^{3\phi}, Q_{Gk}^{3\phi} & : \text{the total three-phase real and reactive power generation at bus } k, \\
P_{Gk}^{pre}, Q_{Gk}^{pre} & : \text{the total pre-fault three-phase real and reactive power generation at bus } k, \\
P_{Gk}^{rat}, Q_{Gk}^{rat} & : \text{the power ratings of the generator at bus } k, \\
\alpha_k & : \text{the percentage of quickly adjustable power of the DG at bus } k \text{ with respect to its nominal output}, \\
I_{k}^{p} & : \text{the current flow entering bus } k, \text{ phase } p.
\end{align*}
\]

\(\alpha_k\) represents how much the generator output can vary without significantly impacting power quality such as voltage magnitude and frequency. \(\alpha_k\) depends on the type of generator and system operating conditions. For example for micro-turbine, voltage feedback control is used to maintain the output voltage connected to the systems. Combined with power storage devices such as batteries, they provide limited load tracking capability, which will be represented by \(\alpha_k\) [20]. For those generators with non-adjustable output, direct load control, and power storage solutions can be used to track
the load changes. If a system cannot track load change, an island may not be formed and the DGs are needed to be disconnected from the network during faults. Next, the formulations will be listed in detail.

3.1.1 Maximizing High Priority Loads (Formulation 1)

\[
\begin{align*}
\min_{u} & \quad N_{\text{new}}(V, u) \\
\max_{u} & \quad \sum_{k \in N_{\text{hp}}} |S_{ik}^{\text{hp}}(V, u)| \\
\max_{u} & \quad N_{\text{customers}}(V, u) \\
\max_{u} & \quad \sum_{k \in N_{L}} |S_{ik}^{\text{L}}(V, u)| \\
\min_{u} & \quad N_{\text{no}}(V, u)
\end{align*}
\]

subject to constraints (3.7)-(3.11) and radiality.

3.1.2 Servicing All High Priority Loads (Formulation 2)

\[
\begin{align*}
\min_{u} & \quad N_{\text{new}}(V, u) \\
\max_{u} & \quad N_{\text{customers}}(V, u) \\
\max_{u} & \quad \sum_{k \in N_{L}} |S_{ik}^{\text{L}}(V, u)| \\
\min_{u} & \quad N_{\text{no}}(V, u)
\end{align*}
\]

subject to (3.7)-(3.11), radiality and

\[
N_{\text{HP}} = N_{\text{HP}}^{\text{pre}} \tag{3.12}
\]
By transforming the objective (3.3) of Formulation 1 into the constraint on the number of high priority loads, it is expected that in some cases, there could be no feasible solution for Formulation 2 while Formulation 1 still has a solution. Despite the difference, the two formulations are similar in many aspects. They both consider customer priority and electrical, operational and network constraints. Also, they have the same search space. As such, their solution algorithms can be similar and they are discussed next. The dimension of the search space is $2^N$, where $N$ is the summation of the possible switch settings and load settings. The solution of this problem is not unique. Due to the high complexity of this problem, a graph based heuristic method is used to solve this problem.

### 3.2 Solution Algorithms

The proposed graph-based solution algorithms for switch placement are based on the following assumptions:

- the system has radial structure
- pre-fault system information is known
- fault and DG locations are known
- faults have been isolated.

In essence, the idea is to first build a graphical representation $T$ of the isolated area to be supported by DGs, which includes DGs and high priority loads. Then if capacity allows it, expand $T$ by closing existing switches or adding new switches. The resulting $T$ will be a pareto optimal solution according to the ranked objectives and satisfy the constraints. Two closely related algorithms emerge to address the previous problem formulations.
First, common terminology used in these two algorithms is introduced:

**T**: the graph representation of the isolated area supported by DG, which includes load status information.

*Boundary Switch*: the open switch on the boundary of the resulting isolated area **T**.

*Controllable Load*: the part of a load under direct load control (DLC).

*Uncontrollable Load*: the part of a load energized when its bus is in service.

**Estimated Total Load Limits**: 

\[
(1 - \beta) \sum_{k \in N_L} (P_{Gk}^{(L)})^{\text{min}} \leq \sum_{k \in N_L} P_{Gk}^{(L)} \leq (1 - \beta) \sum_{k \in N_L} (P_{Gk}^{(L)})^{\text{max}} 
\]  

\[
(1 - \beta) \sum_{k \in N_L} (Q_{Gk}^{(L)})^{\text{min}} \leq \sum_{k \in N_L} Q_{Gk}^{(L)} \leq (1 - \beta) \sum_{k \in N_L} (Q_{Gk}^{(L)})^{\text{max}} 
\]  

where:

- \( N_G \): the set of distributed generators,
- \( \beta \): the percentage of losses on the branches with respect to total power generation.

These limits are defined by scaling distributed generator ratings to avoid overloading or under-loading DGs. The minimum and maximum output of DGs are obtained from (3.10) and (3.11). The estimated total load limits are used as a guide for sizing the area to be serviced by the DGs and to minimize the number of computationally intensive three-phase power flow runs so that the search process can be faster. After each power flow run, \( \beta \) will be updated and the estimated total load limits will be recalculated.

The two algorithms share a common procedure. For each area isolated from the substation, 12 steps may be taken to place switches. Details of select main steps will be outlined in following subsections.
Step 1. Find the separated area formed by fault isolation.

Step 2. Turn off all non-priority controllable loads.

Step 3. Build a base $T$, which includes the buses with DGs, the priority loads in the isolated area, and the buses and branches between them. All the network switches not in $T$ will be open.

Step 4. Store $T$ for later comparison.

Step 5. Check whether estimated total load limits (3.13) and (3.14) are satisfied.
   i. If the lower limits are violated or no violation exists, add loads.
   ii. If the upper limits are violated, shed loads.

Step 6. Check whether shedding/adding loads finds a solution. If yes, go to next step. If no, go to Step 11 and output "No feasible solution”.

Step 7. Run power flow.

Step 8. Check whether there is a constraint violation in $T$.

Step 9. If there is a constraint violation, start the constraint handling process and then go to Step 7. If there is no violation, continue.

Step 10. Update estimated total load limits from the power flow solution.

Step 11. Check whether there are any differences between two $T$s from two consecutive runs. If there is a difference, go to Step 4. Else, continue.

Step 12. If there is a solution found during the process, output the resulting $T$. If not, output “No feasible solution found”.

It should be noted that depending on the location of a fault, the network structure and the load values, it is possible that neither the adding nor shedding loads process will find
a solution. In that case, the algorithm will output the message “No feasible solution found”. A general flow chart for the two algorithms is shown in Figure 3.2.
Figure 3.2 The general flow chart of the proposed solution algorithms
3.2.1 Algorithm 1-Maximizing Priority Loads

Details of select main steps of algorithm 1 from the general process will be presented in the following subsections.

3.2.1.1 Step 3 - Building base $T$

In order to maximize the high priority loads (3.3), base $T$ will be built to include all the high priority loads in the isolated area. It will be used as the starting area for the DG in the search process. Building base $T$ includes the following steps:

Step 3.1 If there is more than one generator in the isolated area, find the paths between them in the pre-fault system configuration.

Step 3.2 Set base $T$ to include all the paths found in Step 3.1.

Step 3.3 Select one of the generators as the start point. Find the paths between all high priority loads and this generator in the pre-fault system.

Step 3.4 Expand base $T$ to include all the paths found in Step 3.3.

Step 3.5 Open all the switches outside $T$ in the isolated area due to a fault.

Step 3.6 Build a boundary switch list for $T$. It includes all the open switches directly connected to $T$.

Step 3.7 Expand $T$ to include all the branches inside the open boundary switches found in Step 3.6.

Controllable loads are not considered here because maximizing the number of customers in the isolated area (3.4) has higher priority than maximizing total loads (3.5).
3.2.1.2 Step 5 – Adding and Shedding Loads

In step 5, the algorithm checks whether the total loads in $T$ satisfy the estimated total load limits in (3.13) and (3.14). If the upper limits of (3.13) and (3.14) are not violated, the algorithm adds loads. If the upper limits of (3.13) or (3.14) are violated, the algorithm sheds loads. Each process is designed to obtain an optimal solution according to the rank of the objectives. The processes of adding and shedding loads are described in detail in the following subsections.

Step 5.i. - Adding Loads

In order to maximize the number of customers in the resulting island (3.4), uncontrollable loads will be added into the system first by closing existing network switches. The process has five steps:

Step 5.i.1 Build the boundary switch list of $T$.

Step 5.i.2 Find the total number of downstream customers for each boundary switch in the pre-fault system configuration.

Step 5.i.3 Try to expand $T$ by closing a boundary switch without exceeding the upper limits of (3.13) and (3.14). The boundary switch, which has the largest number of downstream customers, will be closed first.

Step 5.i.4 If after one open switch is closed the total load is still within the estimated total load power limits, go to Step 5.i.1. If the upper power limits are exceeded, the switch will not be closed and will be removed from the list.

Step 5.i.5 If the boundary switch list is not empty, go to Step 5.i.3 to try to close the
next switch in the list. If it is empty, stop adding uncontrollable loads.

Controllable loads will be added if there is still an estimated margin between the total load in $T$ and the upper estimated total load power limits. The process includes the following steps:

Step 5.i.6 Build a controllable loads list including all the controllable loads in $T$.

Step 5.i.7 The load with the largest amount of controllable, three-phase apparent power will be added first.

Step 5.i.8 Check whether the upper limits of (3.13) or (3.14) are exceeded. If so, turn off the load and remove it from the list. If not, remove it from the list.

Step 5.i.9 If the controllable load list is not empty, go to Step 5.i.7. If it is empty, stop adding controllable loads and go to Step 5.i.10.

The final step of adding loads is to check whether a new switch is needed. The process is as follows:

Step 5.i.10 Check whether (3.13) and (3.14) are satisfied.

Step 5.i.11 If there are no violations, go to Step 5.i.13 output “Adding process finds a solution”. If the lower limits are violated, which means neither uncontrollable loads nor controllable loads can be added into $T$ without violating (3.13) and (3.14), continue to add new switches.

Step 5.i.12 If adding new switches succeeds, controllable loads will be added again to maximize the total load serviced in the resulting isolated area (3.5) and then go to Step 5.i.13 and output “Adding process finds a solution”. If adding new switches fails, go to Step 5.i.13 and output “Adding process fails to find a solution”.


Step 5.i.13 If a solution is found, output the resulting $T$. Otherwise, output “Adding process fails to find a solution” and then go to Step 12.

The details of adding new switches are discussed later.

**Step 5.ii. - Shedding Loads**

If there are controllable loads in $T$, they will be shed first. This is done to maximize the number of customers inside the island (3.4). The process is as follows:

- **Step 5.ii.1** Build a controllable loads list including all the controllable loads in $T$.
- **Step 5.ii.2** The load with the least amount of controllable, three-phase apparent power will be shed first.
- **Step 5.ii.3** Check whether (3.13) or (3.14) in $T$ are violated.
  - a. If not, go to Step 5.ii.10 output “Shedding process finds a solution”.
  - b. If upper limits are exceeded, shed the load and remove it from the list and go to Step 5.ii.4.
  - c. If lower limits are violated, do not shed the load. Go to Step 5.ii.5.
- **Step 5.ii.4** If the controllable load list is not empty, go to Step 5.ii.2. If it is empty, continue to Step 5.ii.5 to shed uncontrollable loads.

If shedding controllable loads does not reduce total loads to within the estimated total load limits, shedding uncontrollable loads from the system will be the next option. The procedure is as follows:

- **Step 5.ii.5** Find all the closed switches in $T$. Build the closed switch list sorted according to the ranking sequence of the following three factors: the total apparent power of priority loads downstream, the number of the
customers downstream and the total apparent power of the loads downstream. The switch with the least of those three factors according to the ranking sequence above will be open first.

Step 5.ii.6 Check whether (3.13) and (3.14) are satisfied.

a. If there is no violation, go to Step 5.ii.10 and output “Shedding process finds a solution”.

b. If a constraint is violated, re-close the switch and remove it from the list. Then go to Step 5.ii.7

Step 5.ii.7 Open the next switch in the list and go to Step 5.ii.7. If the list is empty, continue.

Step 5.ii.8 Add new switches.

Step 5.ii.9 If adding new switches succeeds, go to Step 5.ii.10 and output “Shedding process finds a solution”. If not, go to Step 5.ii.10 and output “Shedding process fails to find a solution”.

Step 5.ii.10 If a solution is found, output the resulting $T$. Otherwise, output “Shedding process fails to find a solution” and then go to Step 12.

Next, the process for adding new switches is detailed.

**Adding New Switches ($N_{nw}$)**

If adding loads or shedding loads using existing switches fails to find a feasible solution, new switches will be placed to form the isolated area both in Step 5.i.12 and Step 5.ii.8. These new network switches will be opened to form the area serviced by the DGs. Note, if adding loads fails to find a solution, the boundary switch with the largest
apparent power downstream loads will be closed to form $T$ and then new switches are added. If shedding loads with existing switches cannot find a solution, new switches will be added without closing any other existing switch.

The process of adding new switches is similar to shedding uncontrollable loads. The difference between them is the search space. Here, the search space will be all the branches in $T$ without switches instead of all the closed switches in $T$. The ramifications might be to shed some priority loads in order to avoid violations of total load power limits. The procedure is as follows:

Step Nsw.1 Build a list of all the branches without switches in $T$.

Step Nsw.2 Order those branches according to total apparent power of its downstream loads.

Step Nsw.3 Add the smallest number of switches from the list, whose operation would release downstream loads to insure the resulting area would be within the limits.

Step Nsw.4 If the resulting $T$ still violates the total load power limits, adding new switches fails. Otherwise, adding new switches succeeds.

### 3.2.1.3 Step 9 - Constraint Handling

If power limits of distributed generators are violated, then the shedding process/adding process will be used to remove the violations. If voltage violations exist, then two techniques will be used to remove voltage violations. First, voltage regulation on the distributed generators will be attempted. If that alone cannot eliminate voltage violation, then the second method of adding or shedding load process will be invoked.
If branch current constraint violations occur, the shedding load process will be applied in the downstream area of overloaded branches. The process will stop when the sum of the load currents in the area is less than the upper limit of the overloaded branch. Finally, the adding load process will be used whose search space is limited to the area outside the original overloaded area which includes overloaded branches and their downstream network.

3.2.2 Algorithm 2-Servicing All Priority Loads

For the second algorithm, servicing all the priority loads becomes a constraint. Due to the similarities between the two problems, the resulting solution algorithms have a lot in common. Therefore, instead of stating Algorithm 2 in detail, only the differences between them will be highlighted. Before starting algorithm 2, check total priority loads against the limits in (3.10) and (3.11). If the upper limits are violated, stop algorithm 2 and output “No island can be found to serve all priority loads”. If not, start algorithm 2.

For the adding process, the only difference between Algorithm 1 and Algorithm 2 is in adding new switches. The branches with priority loads downstream will not be considered as possible new switch locations. For the shedding process, the process will not open any switch with priority loads downstream.

The above solution algorithms integrated with a three-phase power flow solver were coded in Matlab. Some implementation details are discussed. Due to the similarity of these two problems, it is expected if the resulting $T$ of algorithm 1 includes all the priority loads, algorithm 2 will come to the same solution. Therefore, algorithm 2 will only be activated when priority loads needs to be shed in order to form the island. At this
point, the program will try to find both solutions for algorithm 1 and 2. For algorithm 2, adding new switches may be needed in order to keep all priority loads in the resulting island. For algorithm 1, instead of adding new switches, priority loads will be shed to find the answer. Thus, the solutions will be different.

It should be noted that for this non-differentiable multi-objective optimization problem, the solution is not unique. Later on in the numerical results, it can be seen that the solutions are non-inferior solutions.

### 3.3 Numerical Results

A 394-bus radial distribution system is used in all simulation tests in this section. The amount of system load is 24.8 MW and 13.1 MVar. Detailed information about the number of components follows:

- # of lines without breakers: 343
- # of lines with breakers: 69
- # of transformers: 8
- # of loads: 199
- # of unbalanced loads: 187

A one line diagram of the system is shown in Figure 3.3. When faults are on the lines with switches, they are isolated by those switches. Faults on lines without switches are isolated by opening proper upstream and downstream switches. As shown in Figure 3.3, the area inside dashed line will be the area without power if DGs are not allowed to support this isolated area during the fault.
Cases with different fault locations, different number of DGs, and different number and locations of priority loads have been tested. In order to show the effectiveness of the proposed algorithms the fault location remained fixed. During the tests, in order to limits the cost of the installing new switches, at most 2 new switches can be added into the system.

Figure 3.3 A one-line diagram of the 394 bus test system

The basic information for all five cases to be presented is found in Table 3.1:
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\alpha$, percentage of adjustable $P_G$</td>
<td>10%</td>
</tr>
<tr>
<td>Initial $\beta$, percentage of system loss</td>
<td>6%</td>
</tr>
<tr>
<td>Fault Branch</td>
<td>31-34</td>
</tr>
<tr>
<td>The total load in the area isolated by fault</td>
<td>4035.3 KW, 1934.4 KVar</td>
</tr>
</tbody>
</table>

All DGs are assumed to have the same percent of adjustable output, $\alpha$. Priority loads are considered to be uncontrollable. All non-priority loads have the same percentage of controllable load. It should be mentioned that the percentage of uncontrollable load can be set in the range from 0 to 1, and can be set individually to each non-priority load.

### 3.3.1 Single DG at bus 59

The DG at bus 59 had the capacity of 4MVA and had 3.5 MW real power generation before the fault. Two cases are studied where the amount of controllable load is varied.
**Case 1: (Non-priority loads 67% controllable)**

Table 3.2  Case 1 Results with DG at bus 59 & 67% controllable load

<table>
<thead>
<tr>
<th></th>
<th>Algorithm 1</th>
<th>Algorithm 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Install &amp; open new switches</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Open existing switches</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Controllable loads turned off</td>
<td>Bus: 43,45,50, 51,53,56,58,61, 63,69,72,87,89, 80,93,84,85</td>
<td>Bus: 43,45,50, 51,53,56,58,61, 63,69,72,87,89, 80,93,84,85</td>
</tr>
<tr>
<td>The total controllable load turned off</td>
<td>345.4 KW 188.0 KVar</td>
<td>345.4 KW 188.0 KVar</td>
</tr>
<tr>
<td>Buses with priority loads in the area isolated by the fault</td>
<td>Bus: 52,55,58</td>
<td>Bus: 52,55,58</td>
</tr>
<tr>
<td>The total load serviced by the DG</td>
<td>3693.3 KW 1086.7 KVar</td>
<td>3693.3 KW 1086.7 KVar</td>
</tr>
</tbody>
</table>

**Case 2: (Non-priority loads 100% uncontrollable)**

Table 3.3  Case 2 Results with DG at bus 59 & no controllable load

<table>
<thead>
<tr>
<th></th>
<th>Algorithm 1</th>
<th>Algorithm 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Install &amp; open new switches</td>
<td>49-51</td>
<td>49-51</td>
</tr>
<tr>
<td>Open existing switches</td>
<td>47-48</td>
<td>47-48</td>
</tr>
<tr>
<td>Controllable loads turned off</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>The total controllable load turned off</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Buses with priority loads in the area isolated by the fault</td>
<td>Bus: 52,55,58</td>
<td>Bus: 52,55,58</td>
</tr>
<tr>
<td>The total load serviced by the DG</td>
<td>3680.0 KW 1096.7 KVar</td>
<td>3680.0 KW 1096.7 KVar</td>
</tr>
</tbody>
</table>
Remarks:

- Note that both Algorithm 1 and Algorithm 2 yield the same results in both cases. This is because, the solution of Algorithm 1 included all priority loads in the area isolated by fault, which satisfied the constraints of Algorithm 2.
- The difference in total load serviced between Case1 and 2 suggests that more controllable loads may result in a larger area supported by distributed generators and may avoid the installation of a new switch.
- As such, different case studies can be devised whose results provide information on whether implementing DLC (Direct Load Control), adding new network switches or both should be chosen to increase the amount of loads serviced by DGs after fault isolation.

3.3.2 Multiple DGs at bus 70 and bus 92

With the same fault location, two DGs at bus 70 and 92 are assigned. They all had the capacity of 2000KVA and had 1750KW real power generation before fault.
Case 3: (Non-priority loads 67% controllable)

Table 3.4 Case 3 Results with DG at buses 59, 92 & 67% controllable load

<table>
<thead>
<tr>
<th>Install &amp; open new switches</th>
<th>Algorithm 1</th>
<th>Algorithm 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Open existing switches</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Controllable loads turned off</td>
<td>Bus:42,43,46,44,45,51,53,56,58,61,63,69,72,87,80,93,84,85</td>
<td>Bus:42,43,46,44,45,51,53,56,58,61,63,69,72,87,80,93,84,85</td>
</tr>
<tr>
<td>The total controllable load turned off</td>
<td>427.0 KW 232.3 KVar</td>
<td>427.0 KW 232.3 KVar</td>
</tr>
<tr>
<td>Buses with priority loads in the area isolated by the fault</td>
<td>Bus: 52,55,58</td>
<td>Bus: 52,55,58</td>
</tr>
<tr>
<td>Buses with priority loads not included in the result</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>The total load serviced by the DG</td>
<td>3683.3 KW 1063.3 KVar</td>
<td>3683.3 KW 1063.3 KVar</td>
</tr>
</tbody>
</table>

Case 4: (Non-priority loads 100% uncontrollable)

Table 3.5 Case 4 Results with DG at buses 59, 92 & no controllable load

<table>
<thead>
<tr>
<th>Install &amp; open new switches</th>
<th>Algorithm 1</th>
<th>Algorithm 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Open existing switches</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Controllable loads turned off</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>The total controllable load turned off</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Buses with priority loads in the area isolated by the fault</td>
<td>Bus: 52,55,58</td>
<td>Bus: 52,55,58</td>
</tr>
<tr>
<td>Buses with priority loads not included in the result</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>The total load serviced by the DG</td>
<td>3586.7 KW 1060.0 KVar</td>
<td>3586.7 KW 1060.0 KVar</td>
</tr>
</tbody>
</table>
**Remarks:**

- The proposed algorithms can handle the cases with multiple DGs inside the areas isolated by fault.

- The results of Case 3 and 4 with two DGs show the same trend as in Case 1 and 2. If the Algorithm 1 can find a solution without losing any priority load, Algorithm 2 will have the same result as Algorithm 1.

- Again, the results of Case 3 and 4 are consistent with the results of Case 1 and 2. They also demonstrate the benefits of DLC when DGs are employed.

### 3.3.3 Two DGs with Five Priority Loads

In the last case, the two DGs are sized and located as in Case 3 and 4. However, five different priority loads were assigned.

*Case 5: (Non-priority loads 100% uncontrollable)*

<table>
<thead>
<tr>
<th>Install &amp; open new switches</th>
<th>Algorithm 1</th>
<th>Algorithm 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Open existing switches</td>
<td>47-48, 61-62</td>
<td>None</td>
</tr>
<tr>
<td>Controllable loads turned off</td>
<td>None</td>
<td>None</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Buses with priority loads turned off</th>
<th>0</th>
<th>0</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Buses with priority loads in the area isolated by the fault</th>
<th>Bus: 43, 52, 55, 68, 100</th>
<th>Bus: 43, 52, 55, 68, 100</th>
</tr>
</thead>
<tbody>
<tr>
<td>Buses with priority loads not included in the result</td>
<td>Bus: 43, 52, 55</td>
<td>None</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>The total load serviced by the DG</th>
<th>3446.7 KW</th>
<th>3586.7 KW</th>
</tr>
</thead>
<tbody>
<tr>
<td>953.3 KVar</td>
<td>1060.0 KVar</td>
<td></td>
</tr>
</tbody>
</table>
Remarks:

- Since Algorithm 1 has the freedom to shed priority loads, no new switch is added; however, the DG cannot service all priority loads.
- Since Algorithm 2 is constrained to service all priority loads, a new switch must be added in order to service them. In this case, more total load was also served.
- These solutions provide two options to meet different needs. You can choose to install new switches or lose some priority loads.
- The results in Table 3.6 show the characteristic of a pareto optimization. By trying to improve a solution with respect to one objective, one or more objectives could be worsened. The results in Table 3.6 showed that when objective (3.2) is improved, objective (3.3) worsened, vice versa.

3.4 Comments

In this chapter, the switch placement problem to improve system reliability for radial distribution systems with DGs after a fault was formulated. A multi-objective optimization problem was presented. In order to improve reliability, the problem included maximizing the amount of load to be continuously supported by the DG in isolation from the substation. In order to consider costs, the problem included minimizing the number of new switches to be placed. Customer priority and constraints are also considered in the formulation.

Graph-based heuristic solution algorithms were designed to evaluate new switches, operate existing switches, and invoke direct load control in order to form the service
areas for the DGs. The algorithms are flexible to accommodate changes in the treatment of priority loads.

Detailed tests on an unbalanced 394-bus radial distribution system were performed. Highlights in this chapter include test cases with different numbers and sizes of DG, different priority loads and different amounts of direct load control. The simulation results demonstrate the effectiveness of the proposed algorithms to service priority customers and to avoid unnecessary new switch placements.

In this chapter, the switch placement problem has been formulated without considering tie switches connect to the isolated area. Future work can include considering tie switches, and further combining service restoration and switch placement together to solve the same problem. It can also be an application of this work on DG placement and sizing. The algorithms determine the boundary of the resulting island, which switch should be operated, whether new switches are needed and which load should be on/off. Although it is noted that an operating procedure to implement the results are not provided, future work can also include improving the algorithms so that feasible switch sequence are provided.

The proposed algorithms provide protection device location. Thus, the next step will be to address the problem of calculating protection device settings. In the next chapter, network equivalent models are introduced to address this problem. The models are used in short circuit analysis to provide improved calculation of fault voltages and currents.
CHAPTER 4. NETWORK EQUIVALENT MODELS FOR SHORT CIRCUIT ANALYSIS

In this chapter, to improve the calculations to determine protective device settings, two types of network equivalencing techniques for modeling beyond the fault path during short circuit analysis for radial distribution systems are proposed. The primary goal of these models is to improve accuracy of short circuit analysis by considering laterals and loads during short circuit analysis.

As stated in Chapter 1, short circuit analysis traditionally considers only the fault path. In addition, loads are frequently omitted assuming they are a very small effect on the short circuit currents. This is not always accurate in distribution systems. The $Z_{bus}$ based short circuit calculation method in [11] which considered the loads and laterals has its own drawbacks. It needs full system information and is also computational intensive due to the size of $Y_{bus}$ matrix for three phase unbalanced distribution systems. Thus, the main thrust of this chapter is to model beyond the fault path during short circuit analysis without the drawbacks of the $Z_{bus}$ based method so that the models can be used in adaptive protection system design in the following chapter. For this, a form of representation of all network components: laterals and loads, is required. In this thesis, equivalent models are developed for:

- grounded and ungrounded loads
- grounded and ungrounded laterals
- transformers of various connection types
In [11], two types of models, specifically, initial condition boundary matching (BdM) and equivalent circuit (EqC) models of the components are determined from pre-fault conditions. Different models are presented in order to serve different applications of SCA: on-line or planning purposes. For example, online applications such as network reconfiguration for service restoration or loss reduction may need fast and accurate SCA to update network protection devices control settings. In contrast, more detailed equivalent circuit models can be used for planning purposes.

The models are incorporated within a compensation-based method based from [7] for radial distribution system short circuit analysis. Faults in both grounded and ungrounded portions of a system are considered. Since significant imbalance exists in power distribution systems, no real advantage emerges from modeling and analyzing the system using symmetrical components [21]. Symmetrical components method can transform an unbalanced system into three separated sequence networks and only couple them at limited unbalanced points to make calculation simpler. In distribution systems, unbalanced mutual coupling between phases of lines create multiple couplings between sequence networks. Thus, the advantage of using sequence networks does not always prevail. Consequently, the models and compensation-based method in this chapter use phase coordinates.

The chapter is organized in the following manner. Details of the models for loads, laterals and transformers are discussed in the following section. In section 4.2, the compensation-based method utilizing the models is presented. In section 4.3, simulation results from short circuit analysis using the different types of modeling are compared with those obtained using the conventional symmetrical component method, the
compensation method and the $Z_{bus}$ based method. In this thesis, the traditional symmetrical component method [17] refers to the method that does not include the loads and branching laterals during short circuit calculations. Floating-point operation counts are also provided as a part of the results to analyze computational performance. In section 4.4, general comments about the modeling effects are made.

4.1 Network Modeling

A general approach to network modeling for short circuit analysis is now discussed. Following this, two types of models are presented.

4.1.1 General Approach to System Modeling

Before introducing the specific models, the general approach to network modeling is presented. The following example illustrates the concept:

1. A generic radial system structure is shown in Figure 4.1, with a fault occurring at bus 18.

![Figure 4.1 Original system before lateral and load equivalencing](image_url)
2. After lateral and load equivalencing along the fault path, the system will be reduced to Figure 4.2:

![Figure 4.2 System after lateral (Z_{lat}) and load (Z_{L}) equivalencing](image)

3. Determine combined equivalent $Z_{eq}$ by placing $Z_{lat}$ and $Z_{L}$ in parallel if there is a load on that bus. Figure 4.3 shows the result.

![Figure 4.3 Final equivalent (Z_{eq}) system diagram](image)

4. Calculate $I_f$, for example, using the compensation-based method.

From this general process, it can be seen that models for laterals, loads, and transformers are needed. The rest of section 4.1 progresses as follows:

- Initial condition boundary matching (BdM) models are introduced first. They include:
  - Grounded and ungrounded lateral equivalent models
Grounded and ungrounded load equivalent models

- Equivalent circuit models for grounded/ungrounded laterals and loads are introduced.
- A suitable transformer model is derived. The boundary between an ungrounded portion and a grounded portion of a system usually is a transformer branch. Thus, in order to handle faults in an ungrounded portion of a system, appropriate transformer models were needed.

### 4.1.2 Initial Condition Boundary Matching (BdM) Models

The first models proposed apply BdM to determine the equivalents of loads and laterals. The pre-fault system voltages and currents from power flow solution are assumed to be known and treated as initial conditions. Equation (4.1) describes the relationship between a lateral equivalent impedance matrix and the initial conditions:

\[ Z_{lat}^k I_{k}^{pre} = V_{k}^{pre} \]  \hspace{1cm} (4.1)

where:

- \( Z_{lat}^k \): lateral equivalent impedance matrix for laterals branching from bus \( k \)
- \( V_{k}^{pre} \): pre-fault voltage at bus \( k \),
- \( I_{k}^{pre} \): pre-fault current flowing into the lateral at bus \( k \).

The dimension of \( Z_{lat}^k \) is \( 3 \times 3 \) for a three-phase grounded lateral and is \( 2 \times 2 \) for a three-phase ungrounded lateral. Similarly, load impedances are also calculated using pre-fault information. The models of grounded and ungrounded lateral and load are now presented.
4.1.2.1 Grounded Portions of a System

For a fault occurring in a grounded portion of the system, we calculate equivalent impedance matrices using pre-fault phase voltages and phase currents. For example, the pre-fault information at a three-phase bus $k$ is:

$$V_{pre}^{k} = \begin{bmatrix} V_{a,pre}^k & V_{b,pre}^k & V_{c,pre}^k \end{bmatrix}^T$$ \text{ and }

$$I_{pre}^{k} = \begin{bmatrix} I_{a,pre}^k & I_{b,pre}^k & I_{c,pre}^k \end{bmatrix}^T$$

Grounded Lateral Equivalencing

The lateral which is composed of lines and loads branching off the fault path at bus $k$, is modeled as a lumped $(3\times3)$ equivalent impedance matrix, $Z_{lat}^{k}$, shown as:

$$Z_{lat}^{k} = \begin{bmatrix} y_{a,aa}^{lat} & y_{a,ab}^{lat} & y_{a,ac}^{lat} \\ y_{b,ba}^{lat} & y_{b,bb}^{lat} & y_{b,bc}^{lat} \\ y_{c,ca}^{lat} & y_{c,cb}^{lat} & y_{c,cc}^{lat} \end{bmatrix}^{-1} = \begin{bmatrix} Z_{lat,aa}^{k} & Z_{lat,ab}^{k} & Z_{lat,ac}^{k} \\ Z_{lat,ba}^{k} & Z_{lat,bb}^{k} & Z_{lat,bc}^{k} \\ Z_{lat,ca}^{k} & Z_{lat,cb}^{k} & Z_{lat,cc}^{k} \end{bmatrix}$$ \hspace{1cm} (4.2)

where:

$$f_{pq} = f_{pq}(y_{a,aa}^{lat}, y_{b,bb}^{lat}, y_{c,cc}^{lat})$$, a known linear function.

With initial conditions known, we have three equations, which limits the number of unknowns to 3. In other words, except three diagonal elements, there are no new unknowns we can add and still have a solvable equation. Therefore, in (4.2), mutual admittances are modeled as known linear functions of self-admittances. With no mutual coupling, $Z_{lat}^{k}$ is a diagonal matrix. With mutual coupling, $Z_{lat}^{k}$ is a $(3\times3)$ full matrix and
additional information must be used to determine these linear functions. For example, the information can come from prior knowledge or the line parameters of that lateral. By using (4.2), the number of unknowns for a three-phase lateral would be 3. Then, assuming measurements are available, $Z_{k}^{lbu}$ can be determined by solving (4.1).

**Grounded Load Equivalencing**

With mutual impedances assumed to be zero, a diagonal, load impedance matrix, $Z_{k}^{load}$, can be determined. For a load connected along the fault path, diagonal element $Z_{k}^{load,pp}$ represents the load equivalent impedance at bus $k$, phase $p$:

$$Z_{k}^{load,pp} = |V_{k}^{p,prep}| / (S_{k,not}^{p})^*$$  \hspace{1cm} (4.3)

where:

$S_{k,not}^{p}$ is the nominal complex load at bus $k$, phase $p$.

In equation (4.4), pre-fault values are used to determine $Z_{k}^{load,pp}$. In distribution systems, available measurements on a recloser/switch at the beginning of the lateral can also be used to determine lateral equivalent impedances.

**4.1.2.2 Ungrounded Portions of a System**

The lack of a common reference in three-phase ungrounded portions of a system requires the use of two independent line-to-line voltages as variables. Here we select $V^{ub}$ and $V^{hc}$. Thus, only $I^{t}$ and $I^{b}$ will be used in the calculation.
Ungrounded Lateral Equivalenting

For ungrounded laterals, (4.2) reduces to:

\[ Z_{k}^{\text{lat}} = \begin{bmatrix} y_{k}^{ab,\text{lat}} & f_{\text{ab},bc} \\ f_{\text{bc},ab} & y_{k}^{bc,\text{lat}} \end{bmatrix}^{-1} \] (4.5)

where:

\[ f_{ij,pq}^{} \text{, a linear function.} \]

Equation (4.2) can also be used here to calculate \( Z_{k}^{\text{lat}} \). The major difference is that for grounded laterals, the voltages are pre-fault phase to neutral voltages, while here they are line-to-line voltages. The dimensions of pre-fault voltage and current vectors are also reduced from \((3 \times 1)\) to \((2 \times 1)\). Again, additional information is needed to determine the linear functions on off-diagonal elements.

Ungrounded Load Equivalenting:

In this thesis, ungrounded loads are assumed to be three-phase delta connected. The following are used to calculate the equivalent load impedance matrix:

\[ y_{Lk}^{\text{pre}} = (S_{Lk,\text{nom}}^{pq} / |V_{Lk,\text{pre}}^{pq}|^2 \] (4.6)

\[ Z_{k}^{\text{load}} = \begin{bmatrix} y_{Lk}^{ca} + y_{Lk}^{ab} & y_{Lk}^{ca} \\ -y_{Lk}^{ab} & y_{Lk}^{bc} \end{bmatrix}^{-1} \] (4.7)

where:

\[ V_{Lk,\text{pre}}^{pq} : \text{pre-fault line-to-line voltages between phase } p \text{ and phase } q \text{ of each phase at bus } k. \]

\[ S_{Lk,\text{nom}}^{pq} : \text{nominal complex load between phase } p \text{ and phase } q \text{ at bus } k. \]
Using the above equations, BdM provides lumped equivalent impedance matrices for laterals branching off the fault path and for loads connected along the fault path from initial condition values. BdM models do not require detailed information about all network loads and branches; thus, models can be determined quickly from pre-fault data.

If detailed information about all individual network components in a system are available and used in the short circuit current calculation, the results may be more accurate. Based on this idea, Equivalent Circuit (EqC) models were derived and are presented next.

4.1.3 Equivalent Circuit (EqC) Models

Equivalent circuit models account for all the nodes in the system. The method determines an impedance matrix for each load using pre-fault conditions and each branch in the network. These impedances are connected in parallel and series and combined to form equivalent impedance matrices for feeders and laterals in the network. Since each individual component is modeled before the lumped equivalent impedance is formed, results that are more accurate are expected from this method than from BdM. Since a Thevenin equivalent is defined for single-phase linear circuit not for three-phase unbalanced circuit, equivalent circuit models (EqC) are approximations.

The equivalent impedance matrix for two impedance matrices in series is the summation of those two matrices. The equivalent impedance matrix of two impedance matrices in parallel is calculated by placing the corresponding elements of the two impedance matrices in parallel. The equivalent impedance matrix $Z_{eq}$ of two impedance matrices $Z_{eq}^i$ and $Z_{eq}^j$ in parallel is calculated using the following equation:
\[ Z_{eq}^{pq} = 1/(1/Z_{eq}^{j,pq} + 1/Z_{eq}^{j,pq}) \]  

(4.8)

where:

\[ Z_{eq}^{pq} : \text{the phase } p, \text{ phase } q \text{ element of } Z_{eq}. \]

### 4.1.4 Transformer Modeling

Transformer admittance matrix models in phase coordinates have been investigated, for example in [13, 14, 22]. However, these models cannot be used directly with line or lateral impedance matrices which range from (3×3) if grounded or (2×2) if ungrounded. The network transition at a transformer is shown in Fig. 4. An equivalent circuit model is now derived for the transformer branch.

The relationship between \( V_i, V_k \) and \( I_i, I_k \) can be stated as the following:

\[
\begin{bmatrix}
I_j \\
I_k
\end{bmatrix} = \begin{bmatrix}
Y_{pp} & Y_{ps} \\
Y_{sp} & Y_{ss}
\end{bmatrix} \begin{bmatrix}
V_i \\
V_k
\end{bmatrix}
\]  

(4.9)

\[ I_k = -Z_{eqk}^T V_k \]  

(4.10)
Here, \( I_i \) and \( V_i \) are the primary side current and voltage vectors; \( I_k \) and \( V_k \) are the secondary side current and voltage vectors. \( Y_{pp}, Y_{ps}, Y_{sp} \) and \( Y_{ss} \) are the sub-admittance matrices of the transformer branch admittance matrix; their dimensions vary from \((3 \times 3)\) to \((2 \times 2)\) depending on the connection type of the three-phase transformer as stated in Chapter 2.

From (4.9) and (4.10), as in [13] solve for relationship between \( V_k \) and \( V_i \), then substitute it into the top equation of (4.9):

\[
V_k = -(Y_{ss} + Z_{eqk}^{-1})^{-1} Y_{sp} V_i 
\quad (4.11)
\]

\[
I_i = (Y_{pp} - Y_{ps} (Y_{ss} + Z_{eqk}^{-1})^{-1} Y_{sp}) V_i 
\quad (4.12)
\]

Thus the equivalent impedance seen from the primary side is:

\[
Z_{eqi} = (Y_{pp} - Y_{ps} (Y_{ss} + Z_{eqk}^{-1})^{-1} Y_{sp})^{-1} 
\quad (4.13)
\]

Similarly, if calculate equivalent impedance seen from secondary side of the transformer, (4.14) will be the equation to use:

\[
Z_{eqi} = (Y_{ss} - Y_{sp} (Y_{pp} + Z_{eqk}^{-1})^{-1} Y_{ps})^{-1} 
\quad (4.14)
\]

Equations (4.13) and (4.14) can be used to incorporate three-phase transformers in compensation-based short circuit analysis. In the compensation-based method [7], with sources shorted, \( Z_f \), a complex fault equivalent impedance matrix is needed. (4.14) will be used in BdM to calculate the fault impedance matrix \( Z_f \) EqC models use (4.13) to obtain \( Z_{lat} \) and (4.14) to calculate \( Z_f \).
4.2 Solution Algorithm

The general approach to modeling the entire network can be incorporated into a compensation-based method in a straightforward manner for radial distribution system short circuit analysis. The steps of the method are as follows:

Step 1. Solve for the pre-fault three-phase power flow solution.
Step 2. Input the fault information.
Step 3. Find the path from the fault location to the root.
Step 4. Use the pre-fault conditions to determine the network equivalent models, either BdM models or EqC models, resulting in: $Z_{lat}$ and $Z_{L}$ for each bus in the fault path. Then determine $Z_{eq}$ matrices.
Step 5. Form the compensation fault impedance matrix $Z_{f}$.
Step 6. Use a compensation method to calculate $I_{f}$.
Step 7. Calculate post-fault voltages.
Step 8. Output the results of the short circuit calculation.

4.3 Numerical Results

Based on the solution algorithm in section 4.2, a distribution system short circuit analysis program has been developed in Matlab. The program can be used in balanced and unbalanced radial distribution systems. It can solve three-phase line to ground (3LG) faults, double-line to ground (DLG) faults, single line to ground (SLG) faults, and line-to-line (LL) faults.

The methods were tested on two unbalanced distribution systems: a 20-bus system and a 394-bus system. To show the effectiveness of the proposed models, comparison
results between the symmetrical component method, the traditional compensation method where loads and laterals are omitted, and the compensation method using the two proposed modeling techniques, are presented in the following subsections. The comparison results of fault-on voltages for different methods are also provided to show the effects on accuracy of short circuit calculation of the proposed models. Also, the fault currents flowing through the fault path between source and the fault location using EqC model are provided to show the effects of lateral equivalent along the path. Finally, the number of floating point operations for each method is also listed to compare the number of calculations needed for each method.

Before showing the detail simulation results, some assumptions made during the calculation are listed:

- For grounded lateral equivalencing, mutual admittances are neglected and are set to zeros.
- For ungrounded lateral equivalencing, the lateral is modeled as an equivalent delta connected load. It is assumed that the equivalent load admittances $y_{l,k}^{ab} = y_{l,k}^{ca}$ in (4.7). Based on this assumption comparing (4.5) and (4.7), the functions for mutual admittances would be:

$$f_{ab,he} = y_{k}^{ab, lat} / 2$$
$$f_{he,ab} = - y_{k}^{ab, lat} / 2$$

(4.15)

- For single phase and two-phase laterals and loads, large impedances are used for corresponding diagonal and off-diagonal elements in $Z_{eq}$ to simulate open circuits.

Post-fault voltage calculations are determined using a three-phase power flow solver using constant impedance and constant current load models. Therefore, no convergence
problems were encountered. The results can also be used to assess the accuracy of the short circuit current calculations. For example, phase-to-ground faults are expected to have fault-on voltages close to zero at the fault bus.

Since protection devices needs to detect faults located other than their terminal for coordination purpose, the fault current flowing along the fault path is also of interest. Instead of showing the results of fault current along the path from different methods, two \( I_f^{\text{Diff}} \%s \) are calculated with different purposes. \( I_f^{\text{Diff,CM}} \% \) is used to measure the fault current magnitude percentage difference along the fault path between the results of EqC and CM. It can be calculated using (4.16) and can be used to show the effectiveness of the laterals and loads connected to the fault path. Using (4.17), \( I_f^{\text{Diff,Zbus}} \% \) is calculated to measure the fault current magnitude percentage difference along the fault path between the results of EqC and \( Z_{\text{bus}} \). It is used to show the accuracy of proposed models.

\[
I_f^{\text{Diff,CM}} \% = \frac{|I_{f,\text{EqC}} - I_{f,\text{CM}}|}{I_{f,\text{CM}}} \times 100\% \tag{4.16}
\]

\[
I_f^{\text{Diff,Zbus}} \% = \frac{|I_{f,\text{EqC}} - I_{f,\text{Zbus}}|}{I_{f,\text{Zbus}}} \times 100\% \tag{4.17}
\]

In the next section, the following abbreviations are used:

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCM</td>
<td>Symmetrical Component Method</td>
</tr>
<tr>
<td>CM</td>
<td>Compensation Method</td>
</tr>
<tr>
<td>Z_{bus}</td>
<td>( Z_{\text{bus}} ) based method</td>
</tr>
<tr>
<td>LL</td>
<td>A phase to B phase</td>
</tr>
<tr>
<td>DLG</td>
<td>A phase, B phase to ground</td>
</tr>
<tr>
<td>3LG</td>
<td>A,B,C phases to ground</td>
</tr>
<tr>
<td>SLG</td>
<td>A phase to ground fault</td>
</tr>
<tr>
<td>Flop</td>
<td>Floating point operation count</td>
</tr>
</tbody>
</table>
Now, detailed testing results on a 20 bus system and 394 bus system will be presented.

4.3.1. 20-bus System

The structure of the 20-bus system is shown in Figure 4.5:

![Figure 4.5 A one-line diagram of the 20-bus system](image)

The number of the components in the system are:

- # of lines without breakers = 11
- # of lines with breakers = 8
- # of transformers = 2
- # of loads = 9
- # of unbalanced loads = 2

The total load of this system is 2.37 MW and 1.56 MVar. The following results were obtained when faults occurred within grounded or ungrounded portion of the 20-bus system. The results include the comparison results on the fault-on voltage at the faulted bus and fault current at the fault location. They also include fault current differences along the fault path between EqC and CM, EqC and $Z_{bus}$. Here, $Z_{bus}$ based method is used as benchmarks to be compared with the other less computational intensive methods. The comparison results of the number of flops are also provided.
4.3.1.1 Faults in a Grounded Portion of 20-bus System

In this subsection, faults occurred at bus 18 in grounded portion of the 20-bus system.

First, comparison results of the fault-on voltages at fault bus are shown.

Table 4.1 Results of $|V_f|$ at bus 18 for a single fault at bus 18 of the 20-bus system

<table>
<thead>
<tr>
<th>Type of fault</th>
<th>SCM</th>
<th>CM</th>
<th>BdM</th>
<th>EqC</th>
<th>$Z_{bus}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>3LG A</td>
<td>0.005</td>
<td>0.005</td>
<td>0.0003</td>
<td>0.0003</td>
<td>2.20E-14</td>
</tr>
<tr>
<td>B</td>
<td>0.0052</td>
<td>0.0019</td>
<td>0.0003</td>
<td>0.0002</td>
<td>2.50E-14</td>
</tr>
<tr>
<td>C</td>
<td>0.0053</td>
<td>0.0014</td>
<td>0.0003</td>
<td>0.0004</td>
<td>3.30E-14</td>
</tr>
<tr>
<td>LL A</td>
<td>0.4977</td>
<td>0.4964</td>
<td>0.5003</td>
<td>0.5003</td>
<td>0.5000</td>
</tr>
<tr>
<td>B</td>
<td>0.5</td>
<td>0.5013</td>
<td>0.4998</td>
<td>0.4998</td>
<td>0.5000</td>
</tr>
<tr>
<td>C</td>
<td>0.9988</td>
<td>0.9988</td>
<td>0.9986</td>
<td>0.9986</td>
<td>0.9986</td>
</tr>
<tr>
<td>DLG A</td>
<td>0.0009</td>
<td>0.0048</td>
<td>0.0003</td>
<td>0.0003</td>
<td>0.0000</td>
</tr>
<tr>
<td>B</td>
<td>0.0013</td>
<td>0.0017</td>
<td>0.0003</td>
<td>0.0003</td>
<td>0.0000</td>
</tr>
<tr>
<td>C</td>
<td>1.1121</td>
<td>1.1122</td>
<td>1.1122</td>
<td>1.1122</td>
<td>1.1122</td>
</tr>
<tr>
<td>SLG A</td>
<td>0.0046</td>
<td>0.0046</td>
<td>0</td>
<td>0</td>
<td>0.0000</td>
</tr>
<tr>
<td>B</td>
<td>1.0491</td>
<td>1.0491</td>
<td>1.0497</td>
<td>1.0497</td>
<td>1.0497</td>
</tr>
<tr>
<td>C</td>
<td>1.0867</td>
<td>1.0867</td>
<td>1.0865</td>
<td>1.0865</td>
<td>1.0865</td>
</tr>
</tbody>
</table>

Remarks:

- The results of BdM and EqC in Table 4.1 are more in line with expected voltage values than SCM and CM. For example, for the 3LG fault, the fault voltages at bus 18 are expected to be zero. Both proposed methods yield $|V_f|$ closer to zero than the first two methods, since they both model beyond the fault path.

- It can also be seen that $Z_{bus}$ yielded the most accurate results with respect to fault-on voltage at Bus 18. The reason is that the $Z_{bus}$ method considers the loads and
laterals along the fault path and does not have any approximations during the
calculation as BdM and EqC.

Next, the fault path and fault currents at the fault location will be discussed.

![Fault Path Diagram](image)

Figure 4.6 The fault path for the fault at bus 18

Table 4.2 Results of $|I_f|$ at bus 18 for a single fault at bus 18 of the 20-bus system

| Type of fault | $|I_f|$ (A.) |
|---------------|-------------|
|               | SCM | CM | BdM | EqC | Zbus            |
| 3LG A         | 6523.4 | 6525.5 | 6542.7 | 6541.9 | 6541.1 |
| 3LG B         | 6523.4 | 6534.4 | 6544 | 6543.2 | 6542.1 |
| 3LG C         | 6523.4 | 6536.6 | 6542.1 | 6541.3 | 6542.2 |
| LL A          | 5660.4 | 5651.0 | 5666 | 5665.2 | 5664.6 |
| LL B          | 5660.4 | 5651.0 | 5658.7 | 5658.0 | 5657.4 |
| DLG A         | 6305.7 | 6293.2 | 6308.8 | 6308.1 | 6308.7 |
| DLG B         | 6092.1 | 6090.6 | 6100.3 | 6099.8 | 6098.2 |
| SLG A         | 5693.8 | 5693.8 | 5707.7 | 5707.7 | 5707.7 |

**Remarks:**

- Figures 4.6 showed the fault path between fault location and the source. $Z_{eq}$’s at Bus 2 and Bus 3 are lateral equivalents. $Z_{eq}$’s at Bus 15 and Bus 17 are load equivalents.
Table 4.2 displays the calculated current flowing through bus 18 from different methods. The results showed that all five methods yield very close results. The differences between them are less than 0.3%. The results also showed that EqC and BdM yield almost identical results in this case.

Third, comparison results of the fault currents along the fault path will be presented.

Table 4.3 $I_{f_{\text{Diff,CM}}}^\%$ for the fault current flowing along the fault path

<table>
<thead>
<tr>
<th>Type of fault</th>
<th>$I_{f_{\text{Diff,CM}}}^%$</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1-2</td>
</tr>
<tr>
<td>3LG</td>
<td></td>
</tr>
<tr>
<td>A</td>
<td>0.26%</td>
</tr>
<tr>
<td>B</td>
<td>0.13%</td>
</tr>
<tr>
<td>C</td>
<td>0.07%</td>
</tr>
<tr>
<td>LL</td>
<td></td>
</tr>
<tr>
<td>A</td>
<td>0.25%</td>
</tr>
<tr>
<td>B</td>
<td>0.13%</td>
</tr>
<tr>
<td>DLG</td>
<td></td>
</tr>
<tr>
<td>A</td>
<td>0.24%</td>
</tr>
<tr>
<td>B</td>
<td>0.15%</td>
</tr>
<tr>
<td>SLG</td>
<td></td>
</tr>
<tr>
<td>A</td>
<td>0.25%</td>
</tr>
</tbody>
</table>

Table 4.4 $I_{f_{\text{Diff,2\omega}}}^\%$ for the fault current flowing along the fault path

<table>
<thead>
<tr>
<th>Type of Fault</th>
<th>$I_{f_{\text{Diff,2\omega}}}^%$</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1-2</td>
</tr>
<tr>
<td>3LG</td>
<td></td>
</tr>
<tr>
<td>A</td>
<td>0.01%</td>
</tr>
<tr>
<td>B</td>
<td>0.02%</td>
</tr>
<tr>
<td>C</td>
<td>-0.02%</td>
</tr>
<tr>
<td>LL</td>
<td></td>
</tr>
<tr>
<td>A</td>
<td>0.01%</td>
</tr>
<tr>
<td>B</td>
<td>0.01%</td>
</tr>
<tr>
<td>DLG</td>
<td></td>
</tr>
<tr>
<td>A</td>
<td>-0.01%</td>
</tr>
<tr>
<td>B</td>
<td>0.03%</td>
</tr>
<tr>
<td>SLG</td>
<td></td>
</tr>
<tr>
<td>A</td>
<td>0.00%</td>
</tr>
</tbody>
</table>
Remarks:

- Table 4.3 presented the difference between the resulting currents along the fault path between EqC and CM. The maximum difference between two methods is less than 0.3% in this case. It is shown that current differences % does not change much along the fault path. In this small case, the effect of the load and laterals along the path is not apparent shown due to size of the system.

- Table 4.4 showed the fault current difference along the fault path between EqC and \(Z_{bus}\). The maximum difference is less than 0.04%. It shows that EqC yield very close results compared to \(Z_{bus}\) method.

Last, comparison results of the number of floating-point operations (flops) will be shown.

<table>
<thead>
<tr>
<th>Type of fault</th>
<th>Flops</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>SCM</td>
</tr>
<tr>
<td>3LG</td>
<td>8932</td>
</tr>
<tr>
<td>LL</td>
<td>9006</td>
</tr>
<tr>
<td>DLG</td>
<td>9048</td>
</tr>
<tr>
<td>SLG</td>
<td>8978</td>
</tr>
</tbody>
</table>

Remarks:

- From Table 4.5, it can be seen that BdM and EqC need more flops than SCM and CM, which implies longer computational time. This is because that more time is needed to model beyond the fault path. It also showed that BdM is much faster than EqC due to their different models. EqC needs information on every lateral in the system while BdM only needs information on the laterals branching off the fault.
path. Thus, BdM modeling may be more suitable for online applications and EqC modeling may be more suitable for planning purposes.

- Table 4.5 showed that $Z_{bus}$ based method needs more calculation than the other four methods.

### 4.3.1.2 Faults in Ungrounded Portion of 20-bus System

In order to create an ungrounded area in this 20-bus system, the connection of the transformer on branch 2-3 is changed from GY/GY to GY/$\Delta$. The fault remains at bus 18. It is noted that for SLG faults in ungrounded portions of a system, no short circuit current will flow. In addition, DLG faults in ungrounded portions of a system will have the same result as LL faults. Therefore, only results of 3LG and LL/DLG faults are shown for the faults in ungrounded portion of a system. Also, for faults in ungrounded portions of a system, only $I_f^a$ and $I_f^b$ are determined and $I_f^c$ is calculated using the following:

$$I_f^c = -I_f^a - I_f^b$$  \hspace{1cm} (4.18)

First, comparison results of the fault-on voltages at the fault bus are shown.

| Type of fault | $|V_f|$ (p.u.) |
|---------------|---------------|
|               | SCM | CM | BdM | EqC | $Z_{bus}$ |
| 3LG AB        | 0.0027 | 0.0028 | 0.0005 | 0.0005 | 5.50E-14 |
| 3LG BC        | 0.0027 | 0.0028 | 0.0001 | 0.0001 | 3.79E-14 |
| LL AB         | 0.0026 | 0.0029 | 0.0005 | 0.0005 | 0 |
| LL BC         | 0.8654 | 0.8656 | 0.8649 | 0.8644 | 0.8644 |
| /DLG AB       | 0.0026 | 0.0029 | 0.0005 | 0.0005 | 0 |
| /DLG BC       | 0.8654 | 0.8656 | 0.8649 | 0.8644 | 0.8644 |
Remarks:

- Table 4.6 again shows that BdM and EqC yielded $|V_f|$ closer results to expected values than SCM and CM. It also shows that $Z_{bus}$ based method is the most accurate one.

Next, the fault path and fault currents at the fault location will be discussed.

Table 4.7 Results of $|I_f|$ at bus 18 for a single fault at bus 18 of the 20-bus system

<table>
<thead>
<tr>
<th>Type of Fault</th>
<th>SCtM</th>
<th>CM</th>
<th>ICBM</th>
<th>EqC</th>
<th>$Z_{bus}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>3LG A</td>
<td>6533.3</td>
<td>6533.3</td>
<td>6538</td>
<td>6537.8</td>
<td>6542.0</td>
</tr>
<tr>
<td>3LG B</td>
<td>6533.3</td>
<td>6531.3</td>
<td>6541.3</td>
<td>6541.2</td>
<td>6541.7</td>
</tr>
<tr>
<td>LL A</td>
<td>5656.8</td>
<td>5657.3</td>
<td>5665.8</td>
<td>5665.7</td>
<td>5666.6</td>
</tr>
<tr>
<td>LL B</td>
<td>5656.8</td>
<td>5657.3</td>
<td>5665.9</td>
<td>5665.8</td>
<td>5666.6</td>
</tr>
</tbody>
</table>

Remarks:

- Since the fault location did not change, the fault path will be the same as shown in Figure 4.6. Table 4.7 also showed the similar trend for currents at the fault location as in grounded case that five methods yielded very close results.

Third, comparison results of the fault currents along the fault path will be presented.

Table 4.8 $I_{f,\text{Diff,CM}}^\%$ for the fault current flowing along the fault path

<table>
<thead>
<tr>
<th>Type of Fault</th>
<th>1-2</th>
<th>2-3</th>
<th>3-17</th>
<th>17-18</th>
</tr>
</thead>
<tbody>
<tr>
<td>3LG A</td>
<td>0.11%</td>
<td>0.11%</td>
<td>0.07%</td>
<td>0.07%</td>
</tr>
<tr>
<td>3LG B</td>
<td>0.15%</td>
<td>0.14%</td>
<td>0.15%</td>
<td>0.15%</td>
</tr>
<tr>
<td>LL A</td>
<td>0.15%</td>
<td>0.15%</td>
<td>0.15%</td>
<td>0.15%</td>
</tr>
<tr>
<td>LL B</td>
<td>0.16%</td>
<td>0.15%</td>
<td>0.15%</td>
<td>0.15%</td>
</tr>
</tbody>
</table>
Table 4.9 $I_f^{\text{Diff, Zbus}} \%$ for the fault current flowing along the fault path

<table>
<thead>
<tr>
<th>Type of Fault</th>
<th>$I_f^{\text{Diff, Zbus}} %$</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1-2</td>
</tr>
<tr>
<td>3LG A</td>
<td>-0.03%</td>
</tr>
<tr>
<td>3LG B</td>
<td>-0.01%</td>
</tr>
<tr>
<td>LL A</td>
<td>0.00%</td>
</tr>
<tr>
<td>LL B</td>
<td>0.00%</td>
</tr>
</tbody>
</table>

Remarks:

- Table 4.8 also showed the similar trend as Table 4.3 that the $I_f^{\text{Diff, CM}} \%$ at the fault location is a good indicator for the $I_f^{\text{Diff, CM}} \%$ along the fault path. Table 4.9 shows the similar trend as in Table 4.4 that EqC yield very close results compared to $Z_{\text{bus}}$ method. The maximum difference is less than 0.06%.

Last, comparison results of the number of flops will be shown.

Table 4.10 Flop counts for a single fault at bus 18 of the 20-bus system

<table>
<thead>
<tr>
<th>Type of fault</th>
<th>SCm</th>
<th>CM</th>
<th>BdM</th>
<th>EqC</th>
<th>Zbus</th>
</tr>
</thead>
<tbody>
<tr>
<td>3LG</td>
<td>8519</td>
<td>16646</td>
<td>21049</td>
<td>28418</td>
<td>20139</td>
</tr>
<tr>
<td>LL/DLG</td>
<td>8593</td>
<td>15515</td>
<td>19496</td>
<td>26865</td>
<td>20153</td>
</tr>
</tbody>
</table>

Remarks:

- Table 4.10 shows that SCM and CM are faster than BdM and EqC and BdM is faster than EqC.

- Table 4.10 also showed that in this small system case, $Z_{\text{bus}}$ based method needs more calculation than the other methods except EqC method. The reason could be...
that in this small system case, the amount of calculation for building and factorizing $Y_{bus}$ is relatively small.

Proposed models with the other three methods were also tested on a realistic three phase unbalanced 394-bus system. The followings are the results.

### 394-bus System

The models are also tested for large-scale systems. Detailed information about a 394-bus system and the number of the components follows:

- # of lines without breakers = 343
- # of lines with breakers = 69
- # of transformers = 8
- # of loads = 199
- # of unbalanced loads = 187

The load and shunt capacitances of this system totals 24.8 MW and 13.1 MVAR. In the 394-bus system, the fault path is much longer than 20-bus system. Thus, the buses without loads or switch-to bus will be removed from the results of $I_f^{Diff}$% since the current will not change values when they flowing through them.

#### Faults in a Grounded Portion of 394-bus System

The comparison results of the short circuit calculation for different types of faults at grounded bus 1179 of the five methods are stated. There are 16 buses between the fault bus and the source. First, comparison results of the fault-on voltages at fault bus are shown.
Table 4.11 Comparison results of $|V_f|$ at bus 1179 for a single fault at bus 1179 of the 394-bus system

| Type of fault | $|V_f|$ (p.u.) | SCM | CM | BdM | EqC | Zbus |
|---------------|---------------|-----|----|-----|-----|------|
| 3LG A         | 0.0709        | 0.071 | 0.0136 | 0.0111 | 0.0001 |
| 3LG B         | 0.0702        | 0.0744 | 0.0138 | 0.0127 | 0.0005 |
| 3LG C         | 0.0721        | 0.082 | 0.01 | 0.0084 | 0.0027 |
| LL A          | 0.4164        | 0.4194 | 0.481 | 0.4823 | 0.4726 |
| LL B          | 0.5342        | 0.5302 | 0.4649 | 0.4628 | 0.4724 |
| LL C          | 0.94          | 0.94 | 0.9401 | 0.9402 | 0.9402 |
| DLG A         | 0.4646        | 0.0581 | 0.0315 | 0.0162 | 0.0002 |
| DLG B         | 0.3257        | 0.0941 | 0.0166 | 0.0084 | 0.0001 |
| DLG C         | 1.1194        | 1.0337 | 1.0378 | 1.0412 | 1.0426 |
| SLG A         | 0.3199        | 0.079 | 0.0217 | 0.0062 | 0.0002 |
| SLG B         | 0.9913        | 0.9811 | 0.9896 | 0.9898 | 0.9903 |
| SLG C         | 1.0571        | 1.02 | 1.0176 | 1.0195 | 1.0198 |

Remarks:

- From the results of the fault voltages in Table 4.11, it can be seen that BdM and EqC are closer to expected values than SCM and CM. And EqC yield closer $|V_f|$ to expected value compared with the results of BdM.

- As expected, $Z_{bus}$ yielded the closest $|V_f|$ to the expected value compared to the other four methods. The reason why they are not the expected values is that during the calculation, the assumption is made that the voltages on the phases without fault will not change at the fault location. The assumption neglected the couplings between faulted phase and phases without faults.

Next, the fault path and fault currents at the fault location will be discussed.
Figure 4.7 The fault path for the fault at bus 1179

Table 4.12 Results of $|I_f|$ at bus 1179 for a single fault at bus 1179 of the 394-bus system

<table>
<thead>
<tr>
<th>Type of fault</th>
<th>SCM</th>
<th>CM</th>
<th>BdM</th>
<th>EqC</th>
<th>Zbus</th>
</tr>
</thead>
<tbody>
<tr>
<td>3LG A</td>
<td>3595.6</td>
<td>3591.1</td>
<td>3753</td>
<td>3722.7</td>
<td>3715.5</td>
</tr>
<tr>
<td>3LG B</td>
<td>3595.6</td>
<td>3582.4</td>
<td>3754.1</td>
<td>3725.9</td>
<td>3715.9</td>
</tr>
<tr>
<td>3LG C</td>
<td>3595.6</td>
<td>3563.2</td>
<td>3750.2</td>
<td>3722.5</td>
<td>3710.8</td>
</tr>
<tr>
<td>LL A</td>
<td>3083.6</td>
<td>3110</td>
<td>3248.9</td>
<td>3222.3</td>
<td>3215.1</td>
</tr>
<tr>
<td>LL B</td>
<td>3083.6</td>
<td>3110</td>
<td>3258.5</td>
<td>3233.5</td>
<td>3226.2</td>
</tr>
<tr>
<td>DLG A</td>
<td>3976.7</td>
<td>3461.1</td>
<td>3582.6</td>
<td>3561.9</td>
<td>3594.2</td>
</tr>
<tr>
<td>DLG B</td>
<td>4127.6</td>
<td>3312.9</td>
<td>3488.6</td>
<td>3501.7</td>
<td>3469.9</td>
</tr>
<tr>
<td>SLG A</td>
<td>4289</td>
<td>3085</td>
<td>3195.1</td>
<td>3247.3</td>
<td>3267.5</td>
</tr>
</tbody>
</table>

Remarks:

- In Figure 4.7, the fault path for the fault at 1179 is shown. All the $Z_{eq}$s are lateral equivalents, which equivalent the branches and loads in the laterals.
- In Table 4.12, it can be seen that there are much larger differences between the results of different methods than in the case of 20-bus system. It reaches almost 6% in DLG case.

Third, comparison results of the fault currents along the fault path will be presented.
Table 4.13 $I_{f}^{\text{Diff,CM}}\%$ for the fault current flowing along the fault path

<table>
<thead>
<tr>
<th>Type of fault</th>
<th>$I_{f}^{\text{Diff,CM}}%$</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1000-1003</td>
</tr>
<tr>
<td>3LG A</td>
<td>5.25%</td>
</tr>
<tr>
<td>3LG B</td>
<td>5.41%</td>
</tr>
<tr>
<td>3LG C</td>
<td>5.73%</td>
</tr>
<tr>
<td>LL A</td>
<td>3.98%</td>
</tr>
<tr>
<td>LL B</td>
<td>7.02%</td>
</tr>
<tr>
<td>LL C</td>
<td>5.73%</td>
</tr>
<tr>
<td>DLG A</td>
<td>3.98%</td>
</tr>
<tr>
<td>DLG B</td>
<td>7.02%</td>
</tr>
<tr>
<td>DLG C</td>
<td>5.73%</td>
</tr>
<tr>
<td>SLG A</td>
<td>3.98%</td>
</tr>
<tr>
<td>SLG B</td>
<td>7.02%</td>
</tr>
<tr>
<td>SLG C</td>
<td>5.73%</td>
</tr>
</tbody>
</table>

Table 4.14 $I_{f}^{\text{Diff,CM}}\%$ for the fault current flowing along the fault path (Continued)

<table>
<thead>
<tr>
<th>Type of fault</th>
<th>$I_{f}^{\text{Diff,CM}}%$</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1149-1171</td>
</tr>
<tr>
<td>3LG A</td>
<td>3.92%</td>
</tr>
<tr>
<td>3LG B</td>
<td>4.28%</td>
</tr>
<tr>
<td>3LG C</td>
<td>4.74%</td>
</tr>
<tr>
<td>LL A</td>
<td>3.68%</td>
</tr>
<tr>
<td>LL B</td>
<td>4.48%</td>
</tr>
<tr>
<td>DLG A</td>
<td>3.08%</td>
</tr>
<tr>
<td>DLG B</td>
<td>6.01%</td>
</tr>
<tr>
<td>SLG A</td>
<td>5.42%</td>
</tr>
</tbody>
</table>
Table 4.15 $I_f^\text{Diff} Z_{\text{sw}}$% for the fault current flowing along the fault path

<table>
<thead>
<tr>
<th>Type of fault</th>
<th>$I_f^\text{Diff} Z_{\text{sw}}$%</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1000-1003</td>
</tr>
<tr>
<td>3LG A</td>
<td>0.42%</td>
</tr>
<tr>
<td>3LG B</td>
<td>0.54%</td>
</tr>
<tr>
<td>3LG C</td>
<td>0.52%</td>
</tr>
<tr>
<td>LL A</td>
<td>0.33%</td>
</tr>
<tr>
<td>LL B</td>
<td>0.67%</td>
</tr>
<tr>
<td>DLG A</td>
<td>0.10%</td>
</tr>
<tr>
<td>DLG B</td>
<td>0.80%</td>
</tr>
<tr>
<td>SLG A</td>
<td>-0.47%</td>
</tr>
</tbody>
</table>

(Continued)

Table 4.16 $I_f^\text{Diff} Z_{\text{sw}}$% for the fault current flowing along the fault path (Continued)

<table>
<thead>
<tr>
<th>Type of fault</th>
<th>$I_f^\text{Diff} Z_{\text{sw}}$%</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1149-1171</td>
</tr>
<tr>
<td>3LG A</td>
<td>0.23%</td>
</tr>
<tr>
<td>3LG B</td>
<td>0.30%</td>
</tr>
<tr>
<td>3LG C</td>
<td>0.35%</td>
</tr>
<tr>
<td>LL A</td>
<td>0.24%</td>
</tr>
<tr>
<td>LL B</td>
<td>0.29%</td>
</tr>
<tr>
<td>DLG A</td>
<td>-0.82%</td>
</tr>
<tr>
<td>DLG B</td>
<td>0.89%</td>
</tr>
<tr>
<td>SLG A</td>
<td>-0.61%</td>
</tr>
</tbody>
</table>

Remarks:

- Table 4.13-4.14 showed the comparison results between EqC and CM on short circuit currents flowing through the fault path. It can be seen that starting from fault location, the $I_f^\text{Diff,CM}$% are larger than the ones in 20-bus systems. The
maximum $I_{f}^{\text{Diff.CM}}$% reached 7.1% on the branch 1000-1003 for the DLG fault as shown in Table 4.13.

- Except the larger differences, Table 4.13 and 4.14 showed a trend of increasing $I_{f}^{\text{Diff.CM}}$% toward the source in the same voltage level, which showed the accumulated effects of laterals and loads along the path. It should be noted that although the percentage is not very high, due to their higher current base, the real value of difference is not small. In this case, it exceeds 160 A in SLG fault. It will affect the settings of the protection devices and the selection of device capacity.

- Table 4.15 and Table 4.16 showed the similar trend as in Table 4.13 and 4.14 except that differences are smaller. It showed that EqC yielded very close results compared to the results of $Z_{\text{bus}}$ method.

Last, comparison results of the number of flops will be shown.

Table 4.17  Comparison results of Flops for a single fault at bus 1179 of the 394-bus system

<table>
<thead>
<tr>
<th>Type of fault</th>
<th>Flops</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>SCM</td>
</tr>
<tr>
<td>3LG</td>
<td>19956</td>
</tr>
<tr>
<td>LL</td>
<td>20030</td>
</tr>
<tr>
<td>DLG</td>
<td>20072</td>
</tr>
<tr>
<td>SLG</td>
<td>20002</td>
</tr>
</tbody>
</table>
Remarks:

- Table 4.17 showed the similar trend as in grounded fault in 20-bus system. BdM and EqC need more calculation than SCM and CM. BdM is much faster than EqC according to the results.
- Table 4.17 shows that $Z_{bus}$ based method needs more calculation than other four methods. EqC is almost 3.5 times faster than $Z_{bus}$ based method and yet its results have less than 0.9% error as shown in Table 4.15 and Table 4.16. This showed that EqC can obtain accurate results with less calculation time.

4.3.2.2 Faults in an Ungrounded Portion of 394-bus System

The results of the short circuit calculation for different types of faults at ungrounded bus 1036 using the five methods are stated in Table 4.19. There are 10 buses between the fault bus and the source. First, comparison results of the fault-on voltages at fault bus are shown.

Table 4.18 Comparison results of $|V_f|$ at bus 1036 for a single fault at bus 1036 of the 394-bus system

<table>
<thead>
<tr>
<th>Type of fault</th>
<th>$V_f$ (p.u.)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>SCM</td>
</tr>
<tr>
<td>3LG AB</td>
<td>0.044</td>
</tr>
<tr>
<td>3LG BC</td>
<td>0.0446</td>
</tr>
<tr>
<td>LL AB</td>
<td>0.0462</td>
</tr>
<tr>
<td>/DLG BC</td>
<td>0.8617</td>
</tr>
</tbody>
</table>
Remarks:

- From the results of the fault voltages in Table 4.18, it can be seen that the resulting $|V_f|$ of BdM and EqC are closer to expected values than SCM and CM. The results of EqC are closer to expected values than BdM. For example, the LL fault results in the Table 4.18 show that the line-to-line fault voltage $V_{ab}$ of EqC is closer to zero than BdM. This is expected because EqC models are more detailed.

- Table 4.18 also showed that $Z_{bus}$ based method yielded the closest $|V_f|$ to the expected values. The reason why they are not the expected values is that during the calculation, the assumption is made that the voltages on the phases without fault will not change at the fault location. The assumption neglected the couplings between faulted phase and phases without faults.

Next, the fault path and fault currents at the fault location will be discussed.

Figure 4.8 The fault path for fault at bus 1036
Table 4.19 Results of $|I_f|$ at bus 1036 for a single fault at bus 1036 of the 394-bus system

| Type of fault | Type of fault | $|I_f|(A)$ |
|---------------|---------------|-----------|
|               | SCM           | CM        | ICBM      | EqC        | Zbus       |
| 3LG A         | 1123.8        | 1123.8    | 1134      | 1132.8     | 1135.8     |
| 3LG B         | 1123.8        | 1123.7    | 1142.3    | 1138.1     | 1137.5     |
| LL/DLG A      | 971.5         | 973.8     | 984.72    | 986.65     | 984.98     |
| LL/DLG B      | 971.5         | 973.8     | 987.35    | 984.43     | 984.98     |

Remarks:

- Figures 4.8 showed the fault path for this case. Similarly as the fault at bus 1179, the $Z_{eq}$s are all lateral equivalents. Table 4.19 showed BdM, EqC and $Z_{bus}$ yielded very close results of $|I_f|$.

Third, comparison results of the fault currents along the fault path will be presented.

Table 4.20 $I_f^{Diff, CM} \%$ for the fault current flowing along the fault path

<table>
<thead>
<tr>
<th>Type of Fault</th>
<th>$I_f^{Diff, CM} %$</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1000-1003</td>
</tr>
<tr>
<td>3LG A</td>
<td>1.38%</td>
</tr>
<tr>
<td>3LG B</td>
<td>1.13%</td>
</tr>
<tr>
<td>LL/DLG A</td>
<td>1.45%</td>
</tr>
<tr>
<td>LL/DLG B</td>
<td>0.41%</td>
</tr>
</tbody>
</table>

Table 4.21 $I_f^{Diff, CM} \%$ for the fault current flowing along the fault path (Continued)

<table>
<thead>
<tr>
<th>Type of Fault</th>
<th>$I_f^{Diff, CM} %$</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1030-1033</td>
</tr>
<tr>
<td>3LG A</td>
<td>2.29%</td>
</tr>
<tr>
<td>3LG B</td>
<td>1.91%</td>
</tr>
<tr>
<td>LL/DLG A</td>
<td>2.32%</td>
</tr>
<tr>
<td>LL/DLG B</td>
<td>4.82%</td>
</tr>
</tbody>
</table>
Table 4.22 $I_{f \text{ diff}}^{\text{Zbus}} \%$ for the fault current flowing along the fault path

<table>
<thead>
<tr>
<th>Type of Fault</th>
<th>$I_{f \text{ diff}}^{\text{Zbus}} %$</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1000-1003</td>
</tr>
<tr>
<td>3LG A</td>
<td>-0.01%</td>
</tr>
<tr>
<td>3LG B</td>
<td>-0.09%</td>
</tr>
<tr>
<td>LL/DLG A</td>
<td>0.03%</td>
</tr>
<tr>
<td>LL/DLG B</td>
<td>-0.06%</td>
</tr>
</tbody>
</table>

Table 4.23 $I_{f \text{ diff}}^{\text{Zbus}} \%$ for the fault current flowing along the fault path (Continued)

<table>
<thead>
<tr>
<th>Type of Fault</th>
<th>$I_{f \text{ diff}}^{\text{Zbus}} %$</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1030-1033</td>
</tr>
<tr>
<td>3LG A</td>
<td>-0.06%</td>
</tr>
<tr>
<td>3LG B</td>
<td>-0.07%</td>
</tr>
<tr>
<td>LL/DLG A</td>
<td>0.02%</td>
</tr>
<tr>
<td>LL/DLG B</td>
<td>-0.58%</td>
</tr>
</tbody>
</table>

Remarks:

- The results in Table 4.20 and Table 4.21 showed the similar trend as in the previous case, which is $I_{f \text{ diff}}^{\text{CM}} \%$ has the increasing trend in same voltage level. This is the evidence of the effect of the laterals and loads along the fault path.

- Table 4.22 and Table 4.23 showed $I_{f \text{ diff}}^{\text{Zbus}} \%$ between EqC and $Z_{bus}$. As in the grounded fault case, the differences are much smaller than the ones between EqC and CM. This shows the accuracy of the proposed EqC model.

Last, comparison results of the number of flops will be shown.
Table 4.24 Comparison results of Flops for a single fault at bus 1036 of the 394-bus system

<table>
<thead>
<tr>
<th>Type of fault</th>
<th>Flops</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>SCM</td>
</tr>
<tr>
<td>3LG</td>
<td>7736</td>
</tr>
<tr>
<td>LL/DLG</td>
<td>7810</td>
</tr>
</tbody>
</table>

Remarks:

- BdM is much faster than EqC. It can be seen from Table 4.24 that with EqC modeling it requires three times more flops than BdM.
- Table 4.24 also showed the similar trend as in grounded case that \(Z_{bus}\) based method needs much more calculation than \(EqC\) method and yet the results of \(EqC\) have less than 0.9% error as shown in Table 4.22 and Table 4.23.

394-bus system used here is a realistic power distribution system. And since the faults are chosen randomly, the results should show the typical characteristic of short circuit analysis. Although the number will change case by case, the trend should be similar. And it can be seen throughout the four tested cases, the loads and laterals should be accounted to improve accuracy of short circuit analysis.

4.4 Comments

In this chapter, three-phase, equivalent models for laterals, loads and transformers for radial grounded and ungrounded distribution networks are presented. Two types of models have been proposed: Initial Condition Boundary Matching (BdM) and Equivalent Circuit (EqC). Both models utilize pre-fault network conditions for short circuit analysis.
in radial distribution systems. These models can handle faults in networks that have both grounded and ungrounded areas.

The models are incorporated into a compensation-based method and tested on two unbalanced, radial distribution systems. It can be seen from the results that equivalent lateral and load modeling beyond the fault path do affect the short circuit current and in some cases the effects could be large. The results showed that BdM and EqC yielded very close results. They also show that BdM and EqC improve short circuit analysis compared with SCM and CM that do not consider entire system information; and BdM can be employed without significantly increasing computational burden. Thus, BdM modeling may be used for online applications to improve short circuit analysis without sacrificing too much speed. EqC modeling may be used for planning purposes. Both equivalent models may be used to reduce the network size and applied to analysis techniques to determine protection device settings. The results also showed that although $Z_{bus}$ based method yielded more accurate results than the other four methods, it needs much more calculation than the other four methods. In addition, the results showed that the differences between the results of EqC and $Z_{bus}$ based method were less than 0.9% in all tested cases.

In next chapter, to address the distribution protection systems structure design problem, adaptive protection system based on a multi-agent structure is proposed. Protection system settings calculation is distributed among local coordination agents so that protection system can adapt to the changes in the system quickly and accurately.
CHAPTER 5. MULTI-AGENT BASED ADAPTIVE PROTECTION SYSTEM FOR RADIAL DISTRIBUTION SYSTEMS

In this chapter, to address distribution protection systems design and coordination, a multi-agent based adaptive protection system is proposed. Traditionally, distribution protection systems are designed based on off-line studies. The system may not respond as desired when operating in a situation not anticipated in off-line studies. In this chapter, adaptive protection systems for distributed network are addressed.

Distribution protection systems are composed of relays and power handling devices like reclosers, sectionalizing switches or fuses. The idea of adaptive protection systems stems from the definition of adaptive relaying. In [12], Phadke and Horowitz defined adaptive relaying as a protection philosophy. This philosophy permits and seeks to make adjustments in various protection functions automatically in order to make them more attuned to prevailing power system conditions. The multi-agent based adaptive protection system for radial distribution systems is designed based on this principle. In order to implement adaptive protection systems, two things are essential. They are:

- Microprocessor-based relays
- Reliable communication systems

Microprocessor-based relays are programmable devices with extensive logic, memory, data transfer, communication, and reporting capability [23]. These features make adaptive protection systems feasible. Reliable communication systems allow for the coordinating process between relays possible by transferring any data/information necessary across the power system network. The advances in microprocessor based relays and communication systems in recent years made it plausible to implement adaptive
protection systems. However, questions about the design of protection system structure remain:

- What functions should individual components have?
- What data should be transmitted?
- Which protection devices should communicate with each other?

The answers to these three questions will be used to define the protection system structure. In this chapter, a multi-agent based adaptive protection system is developed to address the above three questions. The implementation of the proposed protection system will provide primary and secondary settings for protection relays in distribution systems, such as over-current relays and distance relays.

This chapter is organized in the following manner. In section 5.1, some previous work of designing protection systems are reviewed. In section 5.2, the problem formulation of a multi-agent based adaptive protection system design was presented. In section 5.3, a multi-agent based adaptive protection system structure is detailed. In section 5.4, a distributed solution algorithm is detailed to take advantage of a unique feature of three phase radial distribution systems. Finally, in section 5.5, general comments about the design are made.

## 5.1 Previous Work

Many researchers have investigated two significant aspects of protection system design: coordination schemes and protection system structures. Previous work in these two areas is reviewed separately in this section.
Coordination Schemes

Generally, a protection system coordination scheme’s primary objective is to determine graded settings to achieve selectivity [24]. Selectivity is defined such that the settings should enable only those protection devices closest to a fault to operate and to remove a faulted component in [24]. If selectivity is achieved, the loss of load or the number of the customers due to mis-coordination can be minimized. Some previous work for coordination schemes for distribution systems is briefly reviewed.

Historically, centralized structure is used for protection systems in distribution systems. In [25], Hsu and Yi proposed a heuristic method to find a coordination scheme between switches and fuses to accommodate network reconfiguration over a study period. In [26], So and Li proposed a time coordination method to find coordination schemes for over-current relays in ring-fed distribution networks. They developed a modified evolutionary method to solve this problem. In these two papers, off-line studies were used to decide the coordination schemes.

With the modernization and introduction of new intelligent electric devices in distribution systems, adaptive protection systems are proposed in this thesis. Thus, an open question is what kind of structure is suitable to realize adaptive distribution protection systems. Before a structure can be chosen, some previous work in protection system design is reviewed.

Protection System Structure

Many research efforts have focused on centralized protection systems [27-31]. The idea is to send all the information to a central computer to decide whether to change the
settings in a protection system according to the power system operating conditions. Centralized protection systems often require detailed modeling for each component in the system to carry out fault analysis. With the introduction of agent-based system, researchers have tried to reduce the calculation burden on the central system by distributing certain functions to local agents.

An agent is defined as a computer program that takes independent actions based on the events in the surrounding environments in [32]. In this paper, Nagata and Nakayama et al. proposed a multi-agent system structure to solve the switching problem in normal state operations. In [33], Coury and Thorp et al. discussed the adaptation of the setting of distance relays for multi-terminal lines employing agents. Although adaptive distance relays are proposed to address protection in transmission systems, the proposed structure in [33] is of interest, and is shown in Figure 5.1. The concepts and ideas can be extended into the design of distribution protection systems design.
The papers reviewed in this section implicitly shared a common assumption, which is if selectivity is achieved, the loss of customers and loads due to mis-coordination can be minimized. In the following section, the protection system structural design problem will be formulated explicitly based on this assumption.

5.2 Problem Formulation

The objectives are stated and are selected based on two reliability indices, which are used by PUCs to measure the performance of distribution utility companies. Repeating from Chapter 1, they are the:

Sustained interruption index

\[ \text{SAIFI (System Average Interruption Frequency Index)} \]

\[ \text{SAIFI} = \frac{\sum \text{Total Number Customer Interrupted}}{\text{Total Number of Customers Served}} \] (5.1)
Load based index

**ASIFI (Average Service Interruption Frequency Index)**

\[
\text{ASIFI} = \frac{\sum \text{Total Connected kVA of Load Interrupted}}{\text{Total Connected kVA Served}} \quad (5.2)
\]

Based on the definitions of these two indices, the distribution protection system design problem is formulated as the following:

\[
\min_u \sum_{i=1}^{V_{\text{loc}}} N^i_{\text{customer loss}}(V, u) \quad (5.3)
\]

\[
\min_u \sum_{i=1}^{V_{\text{loc}}} S^i_{\text{loss}}(V, u) \quad (5.4)
\]

subject to relay operational constraints, which depend on relay type

where:

- \(V\): three phase voltages on each node
- \(u\): relay settings throughout the system
- \(F_{\text{loc}}\): the set of possible fault locations.

Several points are now addressed. Relay settings depend on the type of the relays. In distribution systems, two kinds of relays are common and considered in this thesis. They are:

1. Over-current relays

   \(u = \{I_{\text{pickup}}, I_{\text{primary}}, I_{\text{secondary}}\}\) and a family of relay characteristic for each over-current relay.

2. Distance relays

   \(u = \{Z_{\text{primary}}, Z_{\text{secondary}}\}\)
In addition, the operational constraints require that coordination time intervals (CTI) [24] between primary protection and secondary protection must be satisfied. CTI is defined as:

\[ CTI = \text{relay detection time} + \text{relay pickup time} + \text{the margins for error} \]

To address this problem, a multi-agent based protection system is identified. This agent-based system adapts to measured operating conditions. Also, it will employ standard coordination scheme to achieve selectivity. First, the identification of which agents should communicate will be discussed.

### 5.3 Agent-based Protection System Design

Based on the previous work, a multi-agent based adaptive protection system structure is designed. However, in this thesis, special consideration of the characteristics of radial distribution systems is made. Specifically, sensitivity analysis in [34] showed that power and current measurements are most sensitive to the load changes of buses on the path to the substation and downstream of the measurement bus. This implies that the system can be decomposed into subsystems at the measurement locations.

With a multi-agent system, agents with processing abilities can calculate primary settings for protection devices in subsystems without the reliance on a central station. The fault calculation results for subsystems can then be transmitted to other agents to obtain desired coordination between protection devices. With this multi-agent structure, the amount of centralized calculations could be reduced.

Therefore, a multi-agent based adaptive protection system for radial distribution systems is proposed. The structure based on multi-agent system proposed by Nagata and Nakayama [32] *et al.*, is shown in Figure 5.2:
As shown in Figure 5.2, the system is a two-layer hierarchical structure. The lower layer includes all the equipment agents while the upper layer includes all the coordination agents (CAs). The definitions in [33] are applied in this thesis. The functionality of agents is problem dependent. In real power distribution systems, an equipment agent could be an AMR device collecting measurements and a coordination agent could reside in an upgraded, or new distribution component such as a micro-processor based digital relays along side a breaker to perform certain functions. In this thesis, they are defined as follows:

*Coordination Agent* (CA): An agent resides with a device, which can change the topological structure of a system, such as sectionalizing switches, reclosers, and/or circuit breakers. It can collect information from equipment agents or from other coordination agents to determine which information should be sent to other CAs.
*Equipment Agent* (EAG): This is an agent, which resides with power system equipment such as a transformer or a load. Its function is to monitor the operating condition of its corresponding equipment.

The structure shown in Figure 5.2 is a basic component of the proposed multi-agent based adaptive protection system. The multi-agent system structure will be constructed according to the electric connectivity of the underlying distribution systems. The resulting multi-agent system is able to determine primary and secondary settings of a protection system adaptively according to power system operating conditions.

With the proposed multi-agent structure, the goal is to perform fault analysis based on limited information with acceptable precision. Each CA uses the information it has collected to determine appropriate primary and secondary settings of relays. This can be achieved by using limited information to build equivalent models for each subsystem. On-line fault analyses can then be conducted with reasonable precision. By doing so the analysis process of the whole system can be sped up since the problem is divided into many smaller problems with much lower dimension.

With the proposed multi-agent system, coordination agents need to exchange necessary information with other agents so that fault analysis can be conducted in a subsystem according to power system operating conditions. First, CAs must exchange topological information with other CAs to establish the multi-agent system structures. Next, CAs will collect measurement information from other CAs and EAGs to build subsystem models for fault analysis. Equivalent impedance models from Chapter 4 can be used to model loads or laterals based on the measurements from a CA or an EAG to
help build subsystem models. Then, after fault analysis is done, CAs will coordinate with other CAs by exchanging protection settings based on the established multi-agent structure. The details for each process will be introduced in the following section.

5.4 **Solution Algorithm**

To solve the optimization problem, the underlying assumption that if the protection devices can be set and coordinated properly according to system operating conditions, customer loss and load loss due to mis-coordination between protection devices can be minimized, is made. Therefore, the key to solve this problem is to find proper settings for protection devices in a distribution system.

Based on the proposed multi-agent structure, an algorithm located on each CA is designed to find appropriate primary and secondary relay settings under different power system operating conditions. The proposed algorithm for each CA follows the flow chart shown in Figure 5.3. It is assumed there is no error on the status information for each CA. In addition, system topological change and load changes are used to trigger the determination of settings.
The solution algorithm includes five major blocks:

- Checks for topological changes
- Topology processor
- Checks for load changes
- Short circuit analysis
- Coordination process

A topology processor is presented to establish the multi-agent structure detailed. With multiple sources in a distribution system, power can flow in both directions: upstream or downstream with respect to a source. Therefore, there are multiple multi-agent system structures to reflect the coordination relationship between CAs corresponding to different
power sources. Short circuit analysis is used to calculate relay settings based on limited local information. A coordination process is used to decide which information should be transmitted between CAs to achieve proper coordination. This process will depend on the type of relays used.

Each block of the solution algorithm will be discussed in the following subsections. But first, some common terminology and assumptions are stated.

5.4.1. Terminology and Assumptions

The solution algorithm must be performed on each CA. In order to explain the procedure, the following common characteristics of the $i^{th}$ coordination agent, CA$_i$, in a distribution system, are listed:

*Adjacent CA:* a CA such that a path connecting it with CA$_i$ can be found with no other CA on it.

*Adjacent Zone:* the portion of the system between CA$_i$ and its adjacent CAs.

*Neighboring EAG:* an EAG located in the adjacent zone of CA$_i$.

*Monitoring zone:* an adjacent zone in which all the EAGs are monitored by CA$_i$.

Based on these definitions, the following assumptions are made:

- The distribution power network has a radial system structure.
- Protection devices have or have been retrofitted to include microprocessor-based relays.
- A reliable communication system exists.
• CAs are located with devices which can change the topological structure of a system. Since CAs reside with devices such as switches, reclosers and/or circuit breakers, the CA terminology will imply those devices in this thesis.

• Every generator will connect to the system through a switch/circuit breaker. Therefore, it is assumed that there is always a CA resident with or associated with a DG.

• Adjacent CAs and neighboring EAGs for a CA are known from the underlying power distribution systems.

It should be noted that the open/close status of a CA is not used to identify adjacency. CAs are identified to be adjacent solely based on their locations. However, when searching the topology of a system, the CA status will be needed. In a radial distribution system, the CAs associated with sources only have one adjacent zone, while other CAs have two adjacent zones. The above information can be obtained from historical circuit diagrams.

The following example is used to illustrate the definitions. A 20-bus radial structure system is shown in Figure 5.4.

Figure 5.4 Example of adjacent zones for a 20-bus system
Based on the CA locations, the system in Figure 5.4 is divided into 4 zones. They are marked by the shaded areas in Figure 5.4 with different patterns. Each CA will have different adjacent zones.

For each closed CA, the terminology can now be illustrated. For example, for CA1, the following results are shown in Figure 5.5:

Adjacent CA: CA2, CA3, CA5

Adjacent Zone: Zone 1

Neighboring EAGs in Zone 1: EA1, EA2, EA3

Monitoring zone: Zone 1

Figure 5.5 Adjacent zone for CA1

Since CA1 resides at the terminal of a source, it only has one adjacent zone. This is not true for CA2. As shown in Figure 5.6, CA2 has two adjacent zones.
Adjacent CA: CA1, CA3, CA5, CA6

Adjacent Zone: Zone 1, Zone 2

Neighboring EAG in Zone 1: EA1, EA2, EA3,

Neighboring EAG in Zone 2: EA4

Monitoring zone: Zone 2

The results of other closed CAs in Figure 5.4 progress in a similar manner. With the assumptions stated and the common concepts explained, details of the five main blocks will be presented next.

5.4.2. Checks for Topological Changes

Topological changes will not only affect the settings on each CAs in the affected area, it will also change the coordination relationship between CAs. For example, for over-current relays, the role of primary and secondary relay could be changed due to topological changes in the system. Topological changes for a CA can be caused by several reasons. They are listed as follows:
• CA status change: CA is opened or closed

• Parent CA change: Parent CA is an upstream CA for a given CA with respect to a source. Parent CA change could be that the parent CA for a given CA is removed or added.

• Starting CA change: a starting CA is a CA residing with a source. These CAs have the ability to initialize a search. This is required if, for example, a distributed generator is turned on. Power could flow in both directions with multiple sources in a system. CAs must adapt to this change by coordinating in both directions if necessary. This change must be recognized to allow multiple sources to operate in parallel in distribution systems.

CA status changes can be detected by itself. For the last two cases, a CA can be notified by a message sent by other CAs. Once network changes are confirmed, a topology processor will be triggered. The topology processor developed in this thesis will be explained in the following section.

5.4.3. Topology Processor

The topology processor is designed to adjust CA parameters to establish the proposed multi-agent system structure according to topological changes. CAs will exchange topological information with each other in order to establish the multi-agent structure. Before the detailed process can be explained, the concepts used in the process are presented first. To represent a network topology structure of a distribution system, graph theory is used. A graph can be represented by using adjacency lists or an adjacency
matrix. Graph theory assumes that edges are defined between vertices and cannot connect directly to each other, for example, Figure 5.7 (a).

The proposed multi-agent system will have a topological structure as in Figure 5.7 (b), in which CAs reside on a subset of vertices. To define this structure, the common definition of an adjacency list is modified in this thesis. A modified adjacency list for CAs identifies CAs to be adjacent if a path exists between them without encountering another CA.

An example to distinguish between a standard adjacency list and a modified adjacency list is now illustrated. In Figure 5.7 (a), the adjacency lists are defined as follows:

1: 4
2: 4
3: 4
4: 1,2,3

While in Figure 5.7 (b), the modified adjacency lists are:

1: 2,3
2: 1,3
3: 1,2

The topology processor in this chapter is designed based on this modified adjacency list. Seven lists are constructed on a CA to store given information. They are:
The topology processor will generate four additional lists to form the structure of the agent-based protection system. They are:

(8) Start list: the starting CA for initializing process
(9) Parent list: upstream adjacent CA towards a source
(10) Children list: downstream adjacent CAs with closed switch/reclosers
(11) Monitoring zone list: the zone is monitored by a CA

By identifying a parent CA, child CAs, and starting CA for any given CA, the multi-agent based structure in Figure 5.2 can be established. Then, the structure can be used to identify the coordination relationship between CAs.

A starting CA identifies where a topology search starts from. This is very useful in multiple source cases, since a CA could play a different role depending on where the topology search starts from. To illustrate this please see Figure 5.8, where there are two sources in the system. If the search started from CA1, CA4 will be a child CA of CA3. But if the search started from CA7, CA4 will be the parent CA for CA3. These scenarios show that two CAs could exchange parent and child relationships depending on the starting point. Therefore, if there are multiple sources in a system, it is necessary to begin
a topology search from each CA on a source and to build multiple start lists, parent lists, children lists and Monitoring zone lists for any given CA in the system.

Figure 5.8 A 20-bus distribution system with multiple sources

It is also possible that for different starting CAs, the parent CA is the same. Since the coordination between CAs will not change unless the parent CA changes, it is not necessary to create lists (9) to (11) for the other source. One group of lists (8) to (11) will be used in this case with multiple sources in the start list. For example, in Figure 5.8, it can be seen that no matter which CA a search starts from: CA1 or CA7, CA2 will always be the parent CA for CA6. Therefore, at CA6, there will be only one group of lists (8) to (11) and its start list will include both CA1 and CA7.

In this chapter, the lists generated by the topology processor will be grouped by the contents of the parent list. Each group will include a set of lists (8) to (11). Since in radial distribution systems, each CA will have only one parent for any given starting CA. Thus,
except for CAs at a source, once the parent list is empty, the parent list will be deleted with the corresponding (9) to (11) lists in the group.

Three processes run on a CA to determine the agent-based system structure. The first is an initializing process, which is used to initially establish the topology structure throughout the system. The second is the adjusting process, which is used to adjust CA parameters to reflect topological changes occurring in a distribution system. It will be triggered when a CA changes status or its parent CA changes. The third is the EAG searching process, which is used to identify EAGs monitored by a CA. The flow chart of the topology processor is shown in Figure 5.9.

![Figure 5.9 Flowchart of the topology processor](image)

Now, the three processes will be detailed.
5.4.3.1 Initializing Process

This process initially establishes lists (8) to (11). The initializing process always starts from a CA residing with a source. It assigns itself as a starting CA and the parent CA for all the other closed CAs in its modified adjacency list. Its parent CA list will be empty. The closed adjacent CAs are then added to its children list. The adjusting process will be triggered for the CAs in its children list to establish lists (8) to (11) for each CA throughout the system.

The initializing process will be triggered in two cases:

Case 1. At the beginning stage to establish the multi-agent system structure.

Case 2. When a new source is connected to the system by closing a CA.

It is assumed that during the initializing process no topology changes are occurring in the system. Multiple searches can start simultaneously from different CAs.

5.4.3.2 Adjusting Process

Three scenarios will trigger the adjusting process:

- CA\textsubscript{i} is opened
- CA\textsubscript{i} is closed
- CA\textsubscript{i}’s parent CA is changed

The detailed steps under each scenario are described below.
**CAi is opened**

Step 1. CAi will send a message to its parent CA to remove itself from the children list of its parent CA.

Step 2. CAi will send messages to all the CAs in its children list to remove itself from their parent CA lists. Once a parent list is empty, the other three lists in the group will be deleted along with the empty parent list. If CAi has multiple groups of lists (8) to (11), the same procedure in Step 2 will be used for each group.

**CAi is closed**

Step 1. Check whether CAi resides with a source.
   
i. If so, build a start list with itself included. Build an empty parent list. Build a children list including all the closed CAs in its modified adjacency list. Build a Monitoring zone list with a single zone in it. The above four lists will prepare CAi to initialize a topology search starting from itself. Then go to Step 2.
   
   ii. If not, go to Step 2.

Step 2. Identify potential parents for CAi. Build a candidate parent list including all the closed CAs in CAi’s modified adjacency list having power before CAi is closed.

Step 3. Find the CAs in the candidate parent list built in Step 2 whose parent CA is not in CAi’s modified adjacency list. If a CA in the candidate parent list has multiple parent lists, all of them will be searched. For each CAj satisfying the above condition, the following steps will be taken at CAi.
i. Create a new group of lists (8) to (11) at CA\textsubscript{i}.

ii. Assign the CA\textsubscript{j} into the parent list of CA\textsubscript{i}.

iii. Request starting CA from CA\textsubscript{j} then add it to the start list.

iv. Send a message to CA\textsubscript{j} to add CA\textsubscript{i} into the CA\textsubscript{j}’s children list.

v. Add all the closed CAs in CA\textsubscript{i}’s modified adjacency list into the children list.

vi. Remove CA\textsubscript{j} and the CAs with the same parent CA as CA\textsubscript{i} from the children list.

vii. If there is any CA in the children list, CA\textsubscript{i} will send messages to these child CAs to add CA\textsubscript{i} as their new parent CA. Also, CA\textsubscript{i} will send its start list to its child CAs.

CA\textsubscript{i} ’s parent is changed

There are two possible ways to change a parent CA. They are:

- CA\textsubscript{i} receives a message to remove a parent and the parent’s corresponding starting CA from CA\textsubscript{i}’s respective lists
  
i. Identify the lists (8)-(11) which has the parent CA to be removed.
  
ii. CA\textsubscript{i} will send messages to its children to remove CA\textsubscript{i} from their parent lists.
  
iii. Remove the starting CA in the message from CA\textsubscript{i}’s start list.
  
iv. If the start list is empty, the lists (8) to (11) will be removed from CA\textsubscript{i}. If it is not empty, keep the lists.
• CAi receives a message to add a parent and the parent’s corresponding starting CA to CAi’s respective lists

Two scenarios arise. First, in a system with multiple sources, for some CAs it is possible that searches from different starting CAs will identify the same parent. Therefore, it is possible that CAi already has the proper information in lists (9) to (11). Second, it is also possible that CAi does not have any parent list which includes the parent CA to be added. The following steps can be taken to handle these two scenarios.

i. Check whether there already exists a parent list which includes the parent CA to be added.
   a) If so, add the starting CA to the start list at CAi.
   b) If not, generate lists (8) to (11). Add the parent CA into the parent list and add the starting CA into start list. Use the same procedure in the scenario “CAi is closed” to find child CAs and the monitoring zone.

ii. Send messages to the CAs in the children list to add CAi as their new parent CA and the corresponding starting CA in the start list.

5.4.3.3 EAG Search Process

A pre-determined time interval will be used to make sure that the topological structure has been completely established between CAs. Then, the EAG search process will start. If there are multiple groups of lists (8) to (11) due to multiple sources in a system, for each group of lists, the following steps are taken to find the corresponding Monitoring zone.
Step 1. Determine which zone’s adjacent CA list does not include the parent CA in the parent list.

Step 2. Assign this zone as the Monitoring zone for the group of lists.

In order to illustrate how the process works, in subsection 5.3.2.4, examples are given for the system shown in Figure 5.8.

5.4.3.4 Examples of the Topology Processor

Example 1: If CA2’s parent CA is changed, the topology processor will be triggered.

For CA2, the following five lists are known:

(1) CA No.: 2
(2) Modified Adjacency List: CA1, CA5, CA3, CA6
(3) Neighboring EAGs in zone 1: EA1, EA2, EA3
(4) Zone 1 adjacent CAs: CA1, CA2, CA3, CA5,
(5) Neighboring EAGs in zone 2: EA4
(6) Zone 2 adjacent CAs: CA2, CA6
(7) CA status: closed

When CA1 starts the initializing process by assigning itself as CA2’s parent CA, the topology processor on CA2 is triggered by this event. First, build a list of the adjacent closed CAs; they are CA1, CA3, and CA6. Then, its parent CA1 is removed from that list. Since CA3 has the same parent as CA2, it is also removed. Thus CA2 will have CA6 in its children list. Now determine which zone CA2 should monitor. It is clear that its Zone 2 adjacent CAs list does not include its parent CA1. Therefore, Zone 2 will be assigned as its monitoring zone. The following are the results:
Start list1: CA1
Parent list1: CA1
Children list1: CA6
Monitoring zone1: Zone 2

The number is added behind the name of the list to identify the lists (8) to (11) in the same group. A similar process will happen when search starting from the other source CA7 reaches CA2. The following are the results:

Start list2: CA7
Parent list2: CA3
Children list2: CA6
Monitoring zone2: Zone 2

Example 2: If CA6 is open and CA2 is closed, the topology processor will be triggered.

This time CA2 is closed to pick up loads in Zone 2 with CA6 open. All other CAs statuses are the same as in Figure 5.8. First, the topology lists on adjacent closed CAs were given in Table 5.1.
Table 5.1 The topology lists for CA1 and CA3

<table>
<thead>
<tr>
<th></th>
<th>CA1</th>
<th>CA3</th>
</tr>
</thead>
<tbody>
<tr>
<td>CA No.</td>
<td>1</td>
<td>3</td>
</tr>
<tr>
<td>Modified Adjacency List</td>
<td>CA2, CA5, CA3</td>
<td>CA1, CA2, CA5, CA4</td>
</tr>
<tr>
<td>Adjacent EAGs in zone 1</td>
<td>EA1, EA2, EA3</td>
<td>EA1, EA2, EA3</td>
</tr>
<tr>
<td>Zone 1 adjacent CAs:</td>
<td>CA1, CA3, CA5, CA2</td>
<td>CA1, CA3, CA5, CA2</td>
</tr>
<tr>
<td>Adjacent EAGs in zone 2</td>
<td>Empty</td>
<td>EA5</td>
</tr>
<tr>
<td>Zone 2 adjacent CAs:</td>
<td>Empty</td>
<td>CA3, CA4</td>
</tr>
<tr>
<td>CA Status</td>
<td>Closed</td>
<td>Closed</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>CA1</th>
<th>CA3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Start list1</td>
<td>CA1</td>
<td>CA1</td>
</tr>
<tr>
<td>Parent list1</td>
<td>Empty</td>
<td>CA1</td>
</tr>
<tr>
<td>Children list1</td>
<td>CA3</td>
<td>CA4</td>
</tr>
<tr>
<td>Monitoring zone1</td>
<td>Zone 1</td>
<td>Zone 2</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>CA7</th>
<th>CA7</th>
</tr>
</thead>
<tbody>
<tr>
<td>Start list2</td>
<td>CA7</td>
<td>CA7</td>
</tr>
<tr>
<td>Parent list2</td>
<td>CA3</td>
<td>CA4</td>
</tr>
<tr>
<td>Children list2</td>
<td>Empty</td>
<td>CA1</td>
</tr>
<tr>
<td>Monitoring zone2</td>
<td>Empty</td>
<td>Zone 1</td>
</tr>
</tbody>
</table>

Step 1. Check whether CA2 is with a source. It is not. Then go to Step 2.

Step 2. In CA2’s modified adjacency list, find all the closed CAs with power before CA2 is closed. They are CA1 and CA3.

Step 3. Find CAs in the list from Step 2 whose parent is not in CA2’s modified adjacency list. For CA1, the first group of lists, which is shaded with the empty parent list, is identified. For CA2, the second group of lists, which is also shaded with CA4 in the parent list is identified. Thus for each group, Step 3 still will be taken.

First, for the four lists in CA1:

i. A new group of lists (8) to (11) are created for CA2.

ii. Put CA1 in the parent list and CA2 in CA1’s children list.

iii. Put CA1 in CA2’s start list.
iv. Build a children list including all the closed CAs in CA2’s modified adjacency list.

Therefore, the resulting four lists for CA2 are:

| Start list1 | CA1 |
| Parent list1 | CA1 |
| Children list1 | Empty |
| Monitoring zone1 | Zone 2 |

Similarly, for the four lists in CA3, the results are:

| Start list2 | CA7 |
| Parent list2 | CA3 |
| Children list2 | Empty |
| Monitoring zone2 | Zone 2 |

5.4.4. Checks for Load Change

In distribution systems, loads are constantly changing. These load changes affect the operating condition of the system. Consequently, the settings of protection devices may also be affected depending on the level of change.

In this work, a threshold in the percentage of load change incurred is selected. These thresholds can be obtained through off-line system studies. They can be either real/reactive power changes or current magnitude changes measured by CA or other EAGs. When load changes exceed the threshold, short circuit analyses are conducted to provide updated settings of each CA. This process will be explained in the following subsection.
5.4.5. Short Circuit Calculation

In order to coordinate between CAs, short circuit analysis is needed. Since adaptive protection systems adjust settings using on-line studies, speed is very important here. By dividing a system into subsystems according to the locations of CAs, the size of the short circuit analysis problem can be reduced. This is advantageous to the calculation speed for online implementation. In order to carry out short circuit calculation in a subsystem between CAs, models for the subsystem must be established. Therefore, this section is divided into two subsections.

- Equivalent modeling for the system between CAs
- Short circuit calculation process

5.4.5.1 Equivalent Modeling for the System between CAs

To establish equivalent models for the subsystems between CAs, network information and load information are needed. Based on different assumptions on the availability of this information, different models can be formed.

As shown in Figure 5.10, one CA can have multiple adjacent CAs downstream. \( N_{ca} \) is the number of downstream adjacent CAs of CA\( i \). It is assumed that every CA has real-time measurements of voltage, current and power. There are four cases with different assumptions on available information about the system in between. They are as follows:
Figure 5.10 General structure of a CA with multiple adjacent CAs downstream

Case 1:

A1. No network information is available;
A2. No load information is available for the loads not monitored by EAGs;
A3. Real-time measurements are available on adjacent CAs and EAGs.

Case 2:

A1. The network information about the path between adjacent CAs is known, including branch impedances and bus locations;
A2. No load information is available for the loads not monitored by EAGs;
A3. Real-time measurements are available on adjacent CAs and EAGs.

Case 3:

A1. The network information about the path between adjacent CAs is known, including line impedance and bus locations;
A2. Historical information is available for the loads connected along the path and the branches branching from the path not monitored by EAGs;

A3. Real-time measurements are available on adjacent CAs and EAGs.

Case 4:

A1. The network information about the paths between adjacent CAs is known, including line impedance and bus location;

A2. Real-time measurements are available for the loads connected along the path and the branches branching from the path;

A3. Real-time measurements are available on adjacent CAs and EAGs.

Since the assumptions on available information are different between the above cases, different models are needed. In Table 5.2, proposed models are listed for the different cases.

<table>
<thead>
<tr>
<th>Case</th>
<th>CA with multiple CAs down <strong>stream</strong></th>
<th>CA with no CAs Downstream</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 1</td>
<td>• Load lumped at the end</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• PI model</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Equal branch impedances and uniformly distributed load</td>
<td>N/A</td>
</tr>
<tr>
<td>Case 2</td>
<td>Subsystem with uniformly distributed load</td>
<td></td>
</tr>
<tr>
<td>Case 3</td>
<td>Subsystem</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• with proportionally distributed load</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• with Load Estimation (LE)</td>
<td></td>
</tr>
<tr>
<td>Case 4</td>
<td>State Estimation (SE) model</td>
<td></td>
</tr>
</tbody>
</table>
In this chapter, the focus will be on Case 2 and Case 3. This is because it is reasonable to assume that some network information about the paths between adjacent CAs is known, for example line impedances and bus location. It is unlikely that no network information is known when a protection system is constructed as in Case 1. For Case 4, since no information is missing, state estimation (SE) in [34] can be used to obtain the states and nodal load for the system between CAs.

The difference between Case 2 and Case 3 is the amount of available load information. In Case 2, no load information is known while in Case 3 historical load information is known. In both cases, in order to build equivalent subsystem models, the value of individual load without measurements must be estimated. The total values of those loads in the subsystem between CAs must first be calculated. For ease in presentation, it is assumed that EAGs only measure power injections to the path between CAs. There are two scenarios based on the location of a CA:

(i) A CA with multiple CAs downstream
(ii) A CA with no CAs downstream

Detailed processes to compute total load for a subsystem under these two scenarios are now explained as follows:

(i) Computing the total load for the subsystem between CAs

Let us define the subsystem between CA$i$ in Figure 5.10 and its adjacent downstream CAs as subsystem $i$. Based on the theorem of conservation of complex power, we can calculate how much power is consumed by the loads without measurements in subsystem $i$ using the following equations:
\[ P_{\text{load}} = (P_{CAi} - \sum_{j \in M_{CA}} P_{CAj} - \sum_{k \in M_{EAG}} P_{EAGk}) \times (1 - \alpha_{P\text{loss}}^i) \]  \hspace{1cm} (5.5)

\[ Q_{\text{load}} = (Q_{CAi} - \sum_{j \in M_{CA}} Q_{CAj} - \sum_{k \in M_{EAG}} Q_{EAGk}) \times (1 - \alpha_{Q\text{loss}}^i) \]  \hspace{1cm} (5.6)

where:

- \( P_{\text{load}} \in \mathbb{R}^3 \): the total real power of the load in subsystem \( i \) on each phase.
- \( Q_{\text{load}} \in \mathbb{R}^3 \): the total reactive power of the load in subsystem \( i \) on each phase
- \( P_{CAj} \in \mathbb{R}^3 \): the three-phase real power measurements on CA\( j \)
- \( Q_{CAj} \in \mathbb{R}^3 \): the three-phase reactive power measurements on CA\( j \)
- \( M_{CA} \): the set of downstream adjacent CAs of CA\( i \) with respect to a source
- \( P_{EAGk} \in \mathbb{R}^3 \): the three-phase real power measurements on EAG\( k \)
- \( Q_{EAGk} \in \mathbb{R}^3 \): the three-phase reactive power measurements on EAG\( k \)
- \( M_{EAG} \): the set of EAGs measuring the power injections to the paths between CAs and monitored by CA\( i \).
- \( \alpha_{P\text{loss}}^i \in \mathbb{R}^3 \): the percentage of real power losses in system \( i \) on each phase
- \( \alpha_{Q\text{loss}}^i \in \mathbb{R}^3 \): the percentage of reactive power losses in system \( i \) on each phase

Note that the orientation of complex power measurement is always flowing downstream with respect to a source. \( \alpha_{P\text{loss}}^i \) and \( \alpha_{Q\text{loss}}^i \) can be obtained from off-line studies.

(ii)  Computing the total load for the subsystem downstream of a CA

For a CA with no CAs downstream, Figure 5.11 depicts a generic subsystem.
In this case, real-time measurements may only be available on CA\textsubscript{i} and its monitored EAGs. Then, the total subsystem load is calculated using actual measurement at CA\textsubscript{i}.

\begin{equation}
P_{load} = (P_{CAi} - \sum_{k \in M_{EAG}} P_{EAGk}) \times (1 - \alpha_{Ploss})
\end{equation}
\begin{equation}
Q_{load} = (Q_{CAi} - \sum_{k \in M_{EAG}} Q_{EAGk}) \times (1 - \alpha_{Qloss})
\end{equation}

With the total load for the subsystem between CAs calculated, the models for individual loads in a subsystem for Case 2 and Case 3 are presented next:

**Case 2: (Uniformly Distributed Load)**

In this case, no load information is available on the load not monitored by EAGs. But the network information about the path between adjacent CAs is known, including branch impedances and bus locations. Also, real-time measurements are available on adjacent CAs and monitored EAGs.

With the total load calculated, it will be divided evenly to the buses along the paths between adjacent CAs. The following equations are used:
\[ P_{\text{load},j} = P_{\text{load}} / N_{\text{bus}} \]
\[ Q_{\text{load},j} = Q_{\text{load}} / N_{\text{bus}} \]  

(5.9)

where:

\[ P_{\text{load},j}, Q_{\text{load},j} \in \mathbb{R}^2 \]: three-phase real and reactive power of the load at bus \( j \)

\( N_{\text{bus}} \): the number of load buses and branching buses on the paths between \( \text{CA}_i \) and its adjacent downstream CAs not monitored by EAGs.

Since lateral equivalents should include losses, the following equation will be used to approximate the amount of losses, which should be added to the lateral equivalents:

\[ \Delta P_{\text{Loss},j} = \left( P_{\text{load}} / N_{\text{bus}} \right) \times \alpha_{P_{\text{Loss}}} \]
\[ \Delta Q_{\text{Loss},j} = \left( Q_{\text{load}} / N_{\text{bus}} \right) \times \alpha_{Q_{\text{Loss}}} \]  

(5.10)

where:

\( \Delta P_{\text{Loss},j}, \Delta Q_{\text{Loss},j} \): real and reactive power loss of the lateral connected to bus \( j \).

**Case 3: (Proportionally Distributed Load/LE)**

In this case, historical load information is available on the load not monitored by EAGs. The network information about the path between adjacent CAs is known, including branch impedances and bus locations. In addition, real-time measurements are available on adjacent CAs and monitored EAGs.

First, instead of distributing load equally to the buses on the paths between adjacent CAs as in Case 2, total load can be distributed proportionally according to historical load information. The following equations are used to proportionally distribute load:
\[ P_{\text{load},j} = P_{\text{load}} \times \lambda_{P,j} \]
\[ Q_{\text{load},j} = Q_{\text{load}} \times \lambda_{Q,j} \]

where:

\[ \lambda_{P,j}, \lambda_{Q,j} \in \mathbb{R}^3 \]: real and reactive load distribution factors for the load on each phase at bus \( j \).

The distribution factors must satisfy the following equations:

\[ \sum_{j \in \mathcal{N}_{\text{bus}}} \lambda_{P,j}^p = 1 \]
\[ \sum_{j \in \mathcal{N}_{\text{bus}}} \lambda_{Q,j}^p = 1 \]  \hspace{1cm} (5.12)

where:

\[ \lambda_{P,j}^p, \lambda_{Q,j}^p \in \mathbb{R} \]: real and reactive load distribution factor for the load at phase \( p \) of bus \( j \).

Similar as in uniformly distributed load case, losses must be added back to lateral equivalents. The following equations are used:

\[ \Delta P_{\text{Loss},j} = P_{\text{load}} \times \alpha_{\text{Loss}} \times \lambda_{P,j} \]
\[ \Delta Q_{\text{Loss},j} = Q_{\text{load}} \times \alpha_{\text{Loss}} \times \lambda_{Q,j} \]  \hspace{1cm} (5.13)

where:

\[ \lambda_{P,j}, \lambda_{Q,j} \in \mathbb{R}^3 \]: real and reactive load distribution factor for the load of bus \( j \).

Another option is to perform load estimation \cite{34} on the subsystems based on available network and load information. The results will provide estimated nodal load values.

Since short circuit analysis typically uses impedance models, a brief discussion on how loads can be transformed from power form to impedance form based on three
different load types are also presented. All the information needed for carrying out the transformation is either from the measurements of EAGs or CAs or from calculations based on those measurements. The calculations are discussed below.

**Constant Z Load**

\[
Z_{\text{load},j}^p = \frac{|V_{\text{nom},j}^p|^2}{(S_{\text{load},j}^p)^*} \tag{5.14}
\]

where:

\(Z_{\text{load},j}^p\): load impedance at phase \(p\) of bus \(j\);

\(S_{\text{load},j}^p\): load complex power at phase \(p\) of bus \(j\);

\(V_{\text{nom},j}^p\): nominal voltage at phase \(p\) for the load on bus \(j\);

\(*\): complex conjugate.

**Constant S Load**

\[
Z_{\text{load},j}^p = \frac{|V_{\text{load},j}^p|^2}{(S_{\text{load},j}^p)^*} \tag{5.15}
\]

where:

\(V_{\text{load},j}^p\): load voltage at phase \(p\) of bus \(j\).

In this model, voltages on each bus along the path between adjacent CA are needed. In order to obtain voltages, one iteration of a \textit{VI} backward-forward sweep [35] to get an approximate voltage on each bus is performed. The process can be summarized as follows:
Step 1. Calculate both voltage and current backwards towards CA\textsubscript{i} from downstream adjacent CAs. The calculation is only conducted along the paths between CAs.

Step 2. If a discrepancy is found on the voltage of the bus at a branching bus, in other words, if a different path results in different voltages for the same bus, an approximate voltage value is needed. Here, the value will be calculated using the average of the voltages at the branching bus. Thus, the voltage at the branching bus can only be determined when backward calculation along all the paths downstream of CA\textsubscript{i} have been finished.

Step 3. Calculate \( V \) and \( I \) forward from CA\textsubscript{i} to its adjacent downstream CAs.

**Constant I Load**

\[
Z_{\text{load},j}^p = \frac{S_{\text{load},j}^p}{|I_{\text{load},j}^p|^2} \quad (5.16)
\]

where:

\( I_{\text{load},j}^p \): load current at phase \( p \) of bus \( j \).

For those loads and laterals with measurements, BdM model from Chapter 4 can be used to calculate equivalent impedance matrix for them. Combined with available network information and estimated loads values, subsystem models can be established to prepare for fault analysis.
5.4.5.2 Short Circuit Calculation Process

The same process described in Chapter 4 will be used here to calculate short circuit current and fault-on voltage according to the requirements of different protection devices. For example, only short circuit currents are needed for overcurrent relays while for distance relays, both voltages and currents are needed to set the protection device.

In order to carry out fault analysis in the system between CAs using a compensation based method, the following information is needed:

(i) Equivalent models for the system between CAs

(ii) The fault impedance between a source and CA$i$

The process of calculating fault impedances starts from the CAs residing with sources. Then, each CA will calculate a fault impedance matrix for each child CA based on the fault impedance obtained from its parent CA and the equivalent models for the system between CAs. Then, the impedance matrix will be transmitted to child CAs. The process will be executed periodically to reflect the changes of the system including topological information and load values.

In order to show the effectiveness of the proposed equivalent subsystem models for the system between CAs, numerical tests on the 394-bus system in Chapter 4 were performed. In this test, the short circuit current results from the uniformly distributed load model and the proportionally distributed load model are compared with the results from the EqC model. Error% in equation (5.17) are calculated to compare results.

\[
\text{Error}\% = \left( \frac{|I_f|_{\text{proposed model}} - |I_f|_{\text{EqC}}}{|I_f|_{\text{EqC}}} \right) \times 100\% \quad (5.17)
\]
In the numerical tests, the subsystem between switch 66-67 and switch 89-90 was the subject. There are five buses and four loads between the two switches. A three-phase to ground fault is set at bus 89. Results for uniformly distributed loads and proportionally distributed loads are now presented.

(i) Uniformly distributed load

Table 5.3 Fault currents $I_f$ for a 3LG fault at bus 89 with uniformly distributed loads

|    | $|I_f|$ (p.u.) | $|I_f|$ (p.u.) | Error % |
|----|---------------|---------------|---------|
| A  | 0.4004        | 0.3981        | -0.5724 |
| B  | 0.3993        | 0.3970        | -0.5812 |
| C  | 0.3998        | 0.3963        | -0.8820 |

(ii) Proportionally distributed load

Table 5.4 Fault currents $I_f$ for a 3LG fault at bus 89 with proportionally distributed loads

|    | $|I_f|$ (p.u.) | $|I_f|$ (p.u.) | Error % |
|----|---------------|---------------|---------|
| A  | 0.4004        | 0.3984        | -0.5002 |
| B  | 0.3993        | 0.397         | -0.5754 |
| C  | 0.3998        | 0.4013        | 0.3822  |

Remarks:

- Table 5.3 and Table 5.4 show that both models yield fairly accurate results with less than 0.6% of fault current magnitude compared with the results of EqC model.
• Comparing the results in Table 5.4 with the results in Table 5.3, it can be seen that the proportionally distributed load model yields slightly better results. This is expected because more knowledge on the subsystem loads exists.

• The source of the error may be attributed to the models for branching laterals. For example, even when measurements are available, omitted mutual impedances between phases can affect the accuracy of the results.

5.4.6. Coordination Process

As stated at the beginning of section 5.4, it is assumed that if protection devices are properly coordinated according to power system operating condition, customer loss and load loss due to mis-coordination will be minimized. Thus, the coordination process is a necessary step toward the objectives. This process is used to decide which protection system settings should be transmitted between CAs to achieve proper coordination. There are two types of relays used most in power distribution systems. They are over-current relays and distance relays. Coordination processes for these two types of relays are now discussed. In order to explain the procedure clearly, CAi is used to represent a general CA in the system.

5.4.6.1. Overcurrent Relays

For primary settings, CAi will calculate the short circuit currents of the fault at 80% of the path between CAi and its child CAs. If CAi has more than one child CA, the short circuit currents seen by CAi will be calculated for each child CA when fault is at the 80% of the paths between CA and its child CA. The maximum current of those currents will
be selected as CA\textsubscript{i}'s primary settings. Primary settings can be calculated simultaneously at each CA.

For secondary settings of CA\textsubscript{i}, the following procedure can be used. If CA\textsubscript{i} does not have any child CA, there is no need for secondary settings since it has no child CAs to backup. Else, CA\textsubscript{i} will wait until it receives the information on the time-current characteristic such as time inverse curves and primary settings from its child CAs. Then, CA\textsubscript{i} will start to coordinate with its child CAs according to CTI requirements. If CA\textsubscript{i} has more than one CA in its children list, for each case it will choose the child CA with largest short circuit phase current to coordinate with. If a three-phase switch is designed to open/close all phases at the same time, any violation of any of the phase settings will open all phases. If there is only one setting allowed for a three-phase switch, the largest current of three phases will be chosen to avoid over-reaching.

\textbf{5.4.6.2. Distance Relays}

For distance relays, two impedances are needed to coordinate between primary and secondary zones. A fault is set at the 80\% of the path between two CAs. Calculation is needed for the impedance seen by CA\textsubscript{i} and its parent CA: CA\textsubscript{j}. The impedance value seen by CA\textsubscript{i} will be CA\textsubscript{i}'s primary setting. The 90\% of the impedance value seen by CA\textsubscript{j} will be CA\textsubscript{j}'s secondary setting. If CA\textsubscript{j} has multiple downstream CAs, it will collect primary setting information from all its child CAs. The impedance with the smallest magnitude will be selected from those settings.
The solution algorithm will be executed periodically to check whether there is a need to change protection system settings. If there is no topological change, the topology process will not be triggered. If there is a switch/recloser status change, the adjusting process will be triggered immediately. If load changes exceed pre-determined thresholds, new settings will be calculated and settings on protection devices will be updated.

5.5 Comments

In this chapter, a multi-agent based approach to adaptive protection systems for radial distribution systems has been developed. The structure of the proposed multi-agent based system is introduced. It is composed of coordination agents and equipment agents. By transferring necessary data between agents, the protection system settings can be adjusted according to power system operating conditions.

This protection system design problem is formulated as a multi-objective optimization problems with two objectives defined based on the definitions of two common reliability indices: SAIFI and ASIFI. A multi-agent based solution algorithm for this multi-objective optimization problem was also discussed. The solution algorithm includes checks for topology changes, a topology processor, checks for load changes, short circuit calculation and a coordination process.

The agent-based design uses limited local information to realize the goal of adaptive protection systems. A topology processor is presented to establish the multi-agent structure by identifying adjacent CAs. Equivalent modeling is introduced to obtain a fairly accurate system model for the subsystem between CAs. Equivalent lateral and load models in Chapter 4 are used here to obtain equivalent impedance models for loads and
laterals connected to the fault path. The proposed models are tested on a three-phase 394-bus radial distribution system. The results showed that the models are very close to the ones obtained from full model. Coordination processes for over-current relays and distance relays were also discussed.

The method identifies several key points needed for using multi-agents to perform adaptive relaying. Between adjacent CAs, topology information will be exchanged to build the multi-agent structure. Each CA has fault analysis capability to determine primary settings for protection relays. Measurement information on EAGs and CAs are also exchanged between CAs and/or a CA and EAGs to build subsystem models required to perform fault analysis. The resulting primary settings and time-current characteristics of the relays are exchanged between CAs so that CAs can decide secondary settings for coordination. The multi-agent solution algorithm presented a method for achieving adaptive distribution protection systems.
CHAPTER 6. CONCLUSIONS

The objective of this work is to improve protection system design for radial power distribution systems in the presence of distributed generation. This thesis focused on the impacts on protection systems by new technologies and regulatory changes such as implementation of performance based rates. It is recognized in this thesis that in order to accommodate those changes, it is necessary to re-evaluate and to improve distribution protection systems design in the presence of DGs. With these objectives in mind, in this chapter, the contributions made in this thesis are summarized and conclusions are drawn. In addition, future work will be discussed.

6.1. Contributions and Conclusions

This thesis provided work toward improving distribution protection system design using modern distribution components and in the presence of distributed generation. First, to address the question where to install protection devices, a switch placement problem is formulated for intentional islanding in radial distribution systems with DGs. The following work has been presented in this thesis to solve this problem:

- Problem formulations for switch placement for intentional islanding in radial power distribution systems with DGs
- Graph-based heuristic switch placement solution algorithms, which utilize analytically obtained decision indices
- Detailed simulation results on a 394 bus system with different numbers and sizes of DGs, different priority loads and different amounts of direct load control
The formulation and results of the algorithms provided information on the locations of new switches, the control scheme of existing switches and direct load control schemes to form an island after a fault. The simulation results demonstrate the effectiveness of the proposed algorithms to service priority loads and avoid unnecessary new switch placements.

Second, to address the question how to calculate size and settings for protection devices, the following work has been presented:

- Detailed impedance-based equivalent models for improved network representation during on-line and off-line short circuit calculations
- Detailed simulation results on a 20-bus system and a 394 bus system with different kinds of faults in grounded and ungrounded portion of the system

Comparison simulation results showed that initial condition boundary matching (BdM) and equivalent circuit (EqC) yielded more accurate short circuit analysis results compared to symmetrical component method (SCM) and compensation based method (CM) with limited system models. BdM and EqC yielded close results to the \( Z_{bus} \) method while at the same time needed much fewer floating-point operations. This demonstrated that BdM and EqC are more suitable to on-line calculations than other methods, with BdM required the lowest computational burden.

Finally, to address the problem of how to coordinate between protection devices, the following work has been presented:

- A multi-agent based framework for establishing adaptive coordination between distribution system protection devices including:
a topology processor for automatically adjusting agent structures after fault
isolation and/or network reconfiguration

− equivalent models for modeling the subsystems between coordination agents
  (CAs)

− a distributed, agent-based methodology for computing protection device
  settings

The solution algorithm answered the question on what function each CA performs, which
data should transmitted between CAs and between CAs and EAGs. Each CA also has
fault analysis capability to determine primary settings for protection relays. Between CAs,
topology information is exchanged to build the multi-agent structure. CAs collect
measurement information from adjacent EAGs and CAs to build a subsystem model in
order for CAs to perform fault analysis. The resulting primary settings and time-current
characteristics of the relays are exchanged between CAs so that CAs can decide
secondary settings coordination. This solution algorithm enables adaptive settings for
protection systems according to the system operating conditions and appears promising.

6.2. Future Work

Many areas of future work can be extended from the ideas and contents of Chapter 3
to 5. Several ideas for future work stem from the switch placement schemes presented in
Chapter 3. The switch placement schemes presented can also be applied to the sizing and
placement of DGs. Previous work in this area usually focused on reducing the cost with
DG placement. With the proposed switch schemes, the benefits of the presence of DGs
for supporting loads after a fault in the system can be more carefully quantified. This will
affect the DG placement problem. In addition, future work includes studying and utilizing network reconfiguration together with intentional islanding. Their combination may produce advanced switch schemes, which service more loads. Future improvement could also include determining step-by-step operating procedures to implement switching.

Also, in this thesis, DGs were modeled as PV buses. This model is only valid for generators with Automatic Generation Control (AGC) and voltage control, which may not be common on small DGs. Studies on how resulting switch placement schemes will be affected by using other types of DGs with different control schemes, such as fuel cell and micro-turbine distributed generators are needed. The results will be helpful for utility companies to identify the best choice of DG type to implement the resulting switch placement and islanding schemes in distribution systems.

With respect to intentional islanding, possible future extensions for this work will be in the transient analysis of distribution systems with DGs. It would be interesting to investigate how different types of DG can track load changes. An important question includes “Can DGs maintain the power quality inside the resulting island?” The transient analysis can also be used in distribution fault analysis. Dynamic equivalent models for distribution systems may allow for fast transient analysis with reasonable precision compared to integration techniques on the whole system. This will further help power engineers size and set protection devices.

In Chapter 5, the threshold of load changes was assumed to be provided. In the future, it would be beneficial to establish procedures for obtaining these thresholds. In addition, it would be very helpful to see how changes in the thresholds affect the protection
devices settings. Sensitivity analysis of the protection devices settings to the threshold would be critical in fully implementing adaptive distribution protection systems.
List of References


VITA

Full Name: Yiming Mao

Education:

Ph.D       Electrical Engineering           Drexel University PA USA                       06/2005
M.S.       Electrical Engineering           Southeast University, Nanjing China        07/1998
B.S.        Electric Engineering              Southeast University,Nanjing, China        07/1995

Research interests:

Power system analysis, power distribution system analysis, power distribution system automation and
distribution protection systems

Publications:

• Mao, Y.; Miu, K.N., “Switch placement and sizing for radial distribution systems with distributed

• Mao, Y.; Miu, K.N., “Switch placement to improve system reliability for radial distribution
systems with distributed generation”, IEEE Transactions on Power Systems, vol. 18, Nov. 2003,
pp. 1346 – 1352

• Miu, K.N.; Mao, Y., “Network equivalent models for short circuit analysis”, Proceedings of IEEE

• Miu, K.N.; Nwankpa, C.; Mao, Y.; Yang, X.; “Definition of hardware/software interface for small-scale machinery R&D task 2 of simulation-stimulation Interface for machinery R&D final report”, Nov. 2001, Office of Naval Research(ONR) Grant #N000140010904

• Yang, X.; Bruni, C.; Cheung, D.; Mao, Y.; Sokol, G.; Miu, K.N.; Nwankpa, C.; “Setup of RDAC-a
reconfigurable distribution automation and control laboratory”, Proceedings of IEEE Power

• Mao, Y.; Miu, K.N., “Radial distribution system short circuit analysis with lateral and load
equivalencing: solution algorithms and numerical results”, Proceedings of IEEE Power