Impact Analysis and Mitigation of Voltage Regulation Issues in PV Rich Low Voltage Residential Distribution Networks

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“Behind every young child who believes is a parent who believed first.”

This thesis is dedicated to my dear parents,

Sayedah Hossain (Ammu), and

Prof. Salimur Rahman (Abbu)
Abstract

Modern distribution networks are undergoing major changes with the increased uptake of rooftop photovoltaic (PV) units in low voltage (LV) residential distribution networks. These renewable based distributed energy resources (DERs) impose adverse effects which can propagate from LV to medium voltage (MV) and high voltage (HV) levels. Some of the major areas of concern to network operators include reverse power flow, voltage unbalance, voltage rise, increased harmonics, increased potential of islanding, and component and line overloading. These issues create both an operational mitigation requirement and a need for Distribution Network Service Providers (DNSPs) to adjust LV network design procedures.

In Australia DNSPs are bound by strict regulation to provide supply to customers complying with several power quality standards. Australian Standard AS 61000.3.100 requires the voltage at the consumer point of supply to be within +10%, -6% of the 230 V nominal for single phase LV customers. Since residential peak load is typically observed during evening time and power generated from PV during daytime, rooftop PV does little to reduce peak demand. Increased numbers of rooftop PV systems in future LV feeders, combined with increased demand, means DNSPs need to invest in infrastructure to alleviate issues related to overgeneration or overloading and voltage regulation.

Traditionally, voltage regulation devices such as on-load tap changers (OLTCs), regulators and capacitor banks have been sufficient to regulate voltage within mandated limits. Bidirectional power flow that arises as a result of DER in LV limits the ability of these devices, as LV voltage issues cannot be detected or do not propagate further up the network. Compared to HV/MV networks, residential LV networks experience more variable loads, have inherent unbalance due to the overhead 4-wire structure, and lack visibility with respect to operational states.

This thesis aims to contribute new knowledge and understanding to the field of power distribution network voltage regulation. This includes investigation and analysis of different approaches to voltage regulation in power distribution networks in the literature, and to propose new methods and improvements to existing methods. Specifically, this thesis aims to highlight the shortcomings of the current voltage regulation techniques available to DNSPs in
LV feeder. The case studies to be provided in this thesis presents 24 h time series simulation to investigate the performance with varying load and PV generation.

A detailed analysis of available literature was undertaken to understand the power quality and operational problems that high penetration of renewables can bring to LV networks. To analyze these problems and quantify the impact of proposed mitigation solutions, a time series analysis tool has been developed using OpenDSS, where data obtained from Australian DNSPs was utilized to model a 4-wire LV distribution feeder. An MV network model was also developed and used to analyse the impact of DERs on the on-load tap changer operation of HV/MV zone substation transformers.

In this thesis two main LV voltage regulation mitigation solutions are proposed and analysed: application of distribution STATCOMs; and utilization of model predictive control (MPC) based community energy storage (CES). The STATCOM based solution requires no sophisticated communication infrastructure for control and the CES based solution explores a modern optimal objective-based solution requiring centralized control. A design guide to determine the size of the STATCOM for any general LV feeder is derived depending on demand and penetration level of rooftop solar PV generation. An outcome of the analysis is the ability to derive the optimum droop control of reactive power injection required for voltage support and analysis of the overall LV distribution feeder performance in presence of STATCOM.

For CES control, a two level MPC algorithm is proposed, where the higher-level controller selects the mode of operation considering the future state of the system, and the lower-level controller calculates the optimum CES power. The proposed control method considers feed-in tariff, spot price of energy, and operational costs of the CES, to obtain the cost function for the economic mode of operation.

The proposed voltage regulation techniques are validated through 24-hour power flow simulations capable of capturing the long-term performance of the distribution network, including change in the overall line losses, network unbalance and feeder utilization. The developed analysis tool was utilised to appropriately model modern regulation techniques that are available to DNSPs such as Volt-Watt, Volt-VAr and rule-based CES, to provide a benchmark for comparison of the proposed voltage regulation methods.
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Certification

I, Obaidur Rahman, declare that this thesis submitted in fulfilment of the requirements for the conferral of the degree Doctor of Philosophy (PhD), from the University of Wollongong, is wholly my own work unless otherwise referenced or acknowledged. This document has not been submitted for qualifications at any other academic institution.

Obaidur Rahman

6th December 2022
# Table of Contents

Abstract ................................................................................................................................. ii  
Acknowledgments ................................................................................................................ iv  
Certification .......................................................................................................................... v  
Abbreviations ....................................................................................................................... xi  
Nomenclature ....................................................................................................................... xiii  
List of Figures ....................................................................................................................... xv  
List of Tables ....................................................................................................................... xix  

Chapter 1 Introduction ........................................................................................................ 1  
1.1 Background .................................................................................................................... 1  
1.2 Voltage Regulation Issues in PV Rich Distribution Networks .................................... 2  
1.3 Voltage Regulation Technical Solutions ..................................................................... 3  
1.4 Aims and Objectives ..................................................................................................... 4  
1.5 Thesis Outcomes and Contributions .......................................................................... 5  
1.6 Thesis Layout ................................................................................................................. 6  
1.7 Publications .................................................................................................................. 8  
   1.7.1 Thesis Related Publications ................................................................................... 8  
   1.7.2 Other Publications ............................................................................................... 9  

Chapter 2 Literature Review ............................................................................................... 11  
2.1 Introduction ................................................................................................................... 11  
2.2 Voltage Issues in LV Networks .................................................................................. 12  
2.3 Importance of Detailed Modelling of LV Feeders ...................................................... 14  
2.4 Voltage Regulation in Distribution Networks .......................................................... 16  
   2.4.1 Limitations of Traditional Voltage Regulation Techniques .................................. 16
Chapter 2: The Role of Energy Storage in Future Distribution Networks

2.4.2 Solar PV Inverter Control .......................................................... 17
2.4.3 Demand Response ..................................................................... 19
2.4.4 Low Voltage Regulators .............................................................. 20

2.5 Role of Energy Storage in Future Distribution Networks ................. 20
2.5.1 Distributed BESS ........................................................................ 21
2.5.2 Community Energy Storage .......................................................... 21
2.5.3 Electric Vehicles ....................................................................... 22

2.6 Utilization of FACT devices in Distribution Networks ....................... 23
2.7 Advanced Voltage Regulation Approaches ..................................... 24
2.7.1 Coordinated Voltage Regulation ................................................. 24
2.7.2 Optimized Control of ES for Distribution Network Voltage Regulation .......................................................... 25

2.8 Chapter Summary .......................................................................... 26

Chapter 3: Modelling of Distribution Network Performance with High Penetration of Rooftop PV Systems .......................................................... 28

3.1 Chapter Overview .......................................................................... 28
3.2 Importance of LV Distribution Network Analysis Tool .................... 29
3.3 Distribution Network System Modelling ......................................... 30
3.3.1 Development of Distribution Line Models .................................. 31
3.3.2 Modelling of Three Phase Distribution Transformers .................. 32
3.3.3 Modelling of Loads ................................................................... 33
3.3.4 Modelling of PV Systems ............................................................. 34
3.3.5 Modelling of Energy Storage Devices ........................................ 35
3.3.6 Modelling of STATCOMs ............................................................ 36

3.4 Power Flow Algorithm .................................................................. 38
3.5 Case Studies Parameters ................................................................. 41
    3.5.1 LV Feeder Modelling ............................................................ 41
    3.5.2 MV Network ............................................................................. 42

3.6 Chapter Summary ........................................................................... 44

Chapter 4 Analysis of Distribution Network Voltage Rise Performance with Rooftop Solar PV Systems ................................................................. 45

4.1 Chapter Overview ........................................................................... 45
4.2 PV Impact on LV Networks ............................................................ 46
    4.2.1 Voltage Profiles in PV Rich LV Feeders .................................. 46
    4.2.2 Impact of PV in Practical Networks ........................................ 48
    4.2.3 Three Phase Time Series LV Performance Analysis ............... 50

4.3 MV Simulation Results .................................................................. 56
    4.3.1 MV Network Setup ................................................................. 56
    4.3.2 Voltage Levels in 11 kV MV Feeder ....................................... 57
    4.3.3 Analyzing the Changes in OLTC Operation ........................... 58

4.4 Chapter Summary ........................................................................... 60

Chapter 5 Mitigation of Solar PV Impact in LV Radial Feeders using STATCOMs .... 61

5.1 Chapter Overview ........................................................................... 61
5.2 Mathematical Formulation of Voltage Feeders to Size STATCOMs .......... 61
5.3 Application of STATCOMs in LV Feeders to Improve Voltage Profile .... 64
    5.3.1 Placement of STATCOM in LV Feeders based on Sensitivity Analysis ........................................ 64
    5.3.2 Sizing of STATCOMs .............................................................. 66

5.4 Case Study ..................................................................................... 67
    5.4.1 Improvement of the Voltage Levels in a LV Feeder ............... 68
    5.4.2 Time Series Performance Analysis ......................................... 70
5.4.3 System Unbalance .................................................................................................................. 75
5.4.4 Impact of STATCOM on OLTC Operation ........................................................................... 79

5.5 Chapter Summary .................................................................................................................... 80

Chapter 6 Dual Objective MPC of Community Energy Storage in LV Distribution
Feeders with Rooftop Solar PV ........................................................................................................ 82

6.1 Chapter Overview .................................................................................................................... 82
6.2 Application of MPC in Distribution Network Voltage Regulation .................................... 83
6.3 System Modelling and Formulation ....................................................................................... 84

6.3.1 Power Balance .................................................................................................................... 85
6.3.2 Battery Power Modelling .................................................................................................... 85
6.3.3 Controller Constraints ......................................................................................................... 86
6.3.4 CES Operational Cost Modelling ....................................................................................... 86

6.4 Proposed Algorithm for CES MPC ....................................................................................... 87

6.4.1 MPC Problem Definition ................................................................................................... 87
6.4.2 MPC Objective Function .................................................................................................... 88
6.4.3 Two Level MPC based Controller for the CES ................................................................. 89

6.5 Case Study .............................................................................................................................. 90

6.5.1 LV Feeder Parameters .......................................................................................................... 90
6.5.2 Model Predictive Controller Implementation .................................................................. 91
6.5.3 Input data of the Model Predictive Controller ................................................................ 91
6.5.4 Results and Discussions ..................................................................................................... 93

6.6 Chapter Summary .................................................................................................................... 102

Chapter 7 Comparative Study of Voltage Regulation Techniques in PV Rich
Distribution Networks .................................................................................................................. 103
7.1 Chapter Overview ........................................................................................................... 103
7.2 Modern Voltage Regulation Techniques ........................................................................ 104
    7.2.1 Volt-Watt ............................................................................................................... 104
    7.2.2 Volt-VAr ............................................................................................................... 107
    7.2.3 Rule Based Control of CES ................................................................................... 111
7.3 Indices for Performance Analysis .................................................................................. 115
    7.3.1 Maximum Voltage Deviation ................................................................................ 115
    7.3.2 Feeder Reserve Capacity ....................................................................................... 116
7.4 Comparative Analysis ................................................................................................. 117
    7.4.1 Voltage Management ............................................................................................ 117
    7.4.2 Utilization of LV Feeder ....................................................................................... 121
7.5 Chapter Summary ......................................................................................................... 124
Chapter 8 Conclusion and Recommendations for Future Work ..................................... 126
    8.1 Summary of Key Findings ....................................................................................... 126
    8.2 Direction for Future Research ............................................................................... 129
References .......................................................................................................................... 131
Appendix .............................................................................................................................. 139
    A.1 Formation of LV Feeder in OpenDSS ................................................................. 139
    A.2 Formation of MV Feeder in OpenDSS ................................................................. 143
    B.1 Simulation of Time Series Load Flow for LV Feeder via MATLAB ..................... 145
    B.2 Simulation of Time Series Load Flow for MV Feeder ............................................ 147
    C. Implementation of STATCOM Droop Control ....................................................... 148
    D. Implementation of MPC in MATLAB ..................................................................... 149
    E. Implementation of RBC in MATLAB ..................................................................... 151
## Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>AC</td>
<td>Alternating current</td>
</tr>
<tr>
<td>AFIC</td>
<td>Audio frequency injection control</td>
</tr>
<tr>
<td>BESS</td>
<td>Battery energy storage system</td>
</tr>
<tr>
<td>CES</td>
<td>Community energy storage</td>
</tr>
<tr>
<td>DC</td>
<td>Direct current</td>
</tr>
<tr>
<td>DER</td>
<td>Distributed energy sources</td>
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<tr>
<td>DN</td>
<td>Distribution network</td>
</tr>
<tr>
<td>DNSP</td>
<td>Distribution network service provider</td>
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<tr>
<td>DR</td>
<td>Demand response</td>
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<tr>
<td>EPRI</td>
<td>Electric Power Research Institute</td>
</tr>
<tr>
<td>ES</td>
<td>Energy storage</td>
</tr>
<tr>
<td>EV</td>
<td>Electric vehicle</td>
</tr>
<tr>
<td>FACTS</td>
<td>Flexible AC transmission system</td>
</tr>
<tr>
<td>FRC</td>
<td>Feeder reserve capacity</td>
</tr>
<tr>
<td>HV</td>
<td>High voltage</td>
</tr>
<tr>
<td>Im</td>
<td>Imaginary</td>
</tr>
<tr>
<td>Inv</td>
<td>Inverter</td>
</tr>
<tr>
<td>LV</td>
<td>Low voltage</td>
</tr>
<tr>
<td>LVR</td>
<td>Low voltage regulator</td>
</tr>
<tr>
<td>MEN</td>
<td>Multiple earthed neutral</td>
</tr>
<tr>
<td>MPC</td>
<td>Model predictive control</td>
</tr>
<tr>
<td>MV</td>
<td>Medium voltage</td>
</tr>
<tr>
<td>MVD</td>
<td>Maximum voltage deviation</td>
</tr>
<tr>
<td>NEM</td>
<td>National Energy Market</td>
</tr>
<tr>
<td>N-G</td>
<td>Neutral to ground</td>
</tr>
<tr>
<td>NR</td>
<td>Newton Raphson</td>
</tr>
<tr>
<td>OLTC</td>
<td>On-load tap changer</td>
</tr>
<tr>
<td>OPF</td>
<td>Optimal power flow</td>
</tr>
<tr>
<td>OTS</td>
<td>Off the shelf</td>
</tr>
<tr>
<td>PCC</td>
<td>Point of common coupling</td>
</tr>
<tr>
<td>pf</td>
<td>Power factor</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaic</td>
</tr>
<tr>
<td>RBC</td>
<td>Rule based control</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------</td>
<td>-------------------------------------------</td>
</tr>
<tr>
<td>Re</td>
<td>Real</td>
</tr>
<tr>
<td>SoC</td>
<td>State of charge</td>
</tr>
<tr>
<td>STATCOM</td>
<td>Static synchronous compensator</td>
</tr>
<tr>
<td>ToU</td>
<td>Time of use</td>
</tr>
<tr>
<td>UOW</td>
<td>University of Wollongong</td>
</tr>
<tr>
<td>V2G</td>
<td>Vehicle to grid</td>
</tr>
<tr>
<td>VUF</td>
<td>Voltage unbalance factor</td>
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</table>
Nomenclature

\( \eta_{batt} \) Battery system efficiency
\( \varepsilon \) IEC unbalance factor
\( \alpha \) Angle shift between inverter voltage and grid voltage
\( Z_{\text{line}} \) Feeder impedance
\( \text{ZIP} \) Constant impedance, constant current and constant power load model
\( y_i \) Leakage admittance
\( Y \) Admittance matrix
\( V_{\text{nom}} \) Nominal voltage
\( V_{\text{LL}} \) Line to line voltage
\( V \) Voltage
\( t \) Time
\( \text{Spot} \) Spot price of electricity
\( \text{SoC} \) State of charge
\( \text{SoC}_{\text{min}} \) Minimum SoC threshold for ES device
\( \text{SoC}_{\text{max}} \) Maximum SoC threshold for ES device
\( S_{\text{feeder}} \) Total apparent power in feeder
\( S \) Apparent power
\( Q \) Reactive power
\( P_{\text{dis}} \) Discharging power
\( P_{\text{ch}} \) Charging power
\( P_{\text{CES}} \) Real power flow in Community Energy Storage
\( P \) Real power
\( N_p \) Prediction horizon
\( n \) Neutral conductor
\( k \) Discrete time interval
\( J \) Jacobian matrix
\( I_{\text{stat}} \) STATCOM current
\( I_{\text{spe}} \) Specified current
\( I_{\text{load}} \) Load current
\( I_{\text{inv}} \) Inverter current
\( I_{\text{cal}} \) Calculated current
\( I \) Current
\( G \) Real magnitude of admittance matrix \((G + jB)\)
\( \text{Feed}_{\text{in}} \) ToU feed in tariff
\( B \) Imaginary component of admittance matrix \((G + jB)\)
$a, b, c$  
Refers to the three phases $a$, $b$, and $c$

$\Delta t$  
Time step for time series modelling

$p_{\text{feed}e\text{r} \text{im}}$  
Real power imported from the upstream MV network

$p_{\text{feed}e\text{r} \text{ex}}$  
Real power fed back to the upstream network
List of Figures

Figure 2-1 (a) Time series variation of load and PV output, (b) Voltage profiles in a typical LV feeder .......................................................... 13

Figure 2-2 Basic 4-wire connection in LV feeders ........................................ 15

Figure 2-3 Inverter control functions (a) Volt-Watt (b) Volt-VAr ......................... 18

Figure 3-1 General structure of distribution networks in Australia ..................... 31

Figure 3-2 Connection of a STATCOM to an AC network ............................. 36

Figure 3-3 Control loop used to regulate the reactive power in STATCOMs .......... 37

Figure 3-4 Q-V droop curve for STATCOM's reactive power regulation .............. 38

Figure 3-5 Current injection visualization in future households .......................... 39

Figure 3-6 LV Feeder to be used for the simulations ......................................... 42

Figure 3-7 11 kV MV network to analyse the impact on upstream networks ......... 43

Figure 4-1 Time series variation of load and PV output .................................. 47

Figure 4-2 Voltages along the LV feeder ....................................................... 48

Figure 4-3 Average 99th percentile voltage profiles from 2009 to 2017 .............. 49

Figure 4-4 Time of day when the maximum 99th percentile voltage is observed .... 50

Figure 4-5 Time series load and PV variations per phase .................................. 51

Figure 4-6 Net exchange of power in LV feeder .............................................. 52

Figure 4-7 Time series voltage variations for a 24 h simulation (a) Without PV (b) With PV ........................................................................ 53
Figure 4-8 Variations in the feeder line losses with and without Rooftop PV ..................54

Figure 4-9 Impact of rooftop PV on voltage unbalance .............................................55

Figure 4-10 Daily variation of the neutral to ground voltage .....................................56

Figure 4-11 Variation in the MV line-line voltage (a) Without PV systems (b) With PV
systems .........................................................................................................................58

Figure 4-12 Change in tap operation of the OLTC with and without PV systems ..........59

Figure 5-1 Lumped load model placements in the feeder .............................................63

Figure 5-2 Voltage sensitivities with respect to the placement of the STATCOM ........65

Figure 5-3 Line losses with respect to the placement of the STATCOM .....................66

Figure 5-4 Lumped load model with STATCOM placed at the end of the feeder ........66

Figure 5-5 Voltage along the LV feeder with no STATCOM ......................................69

Figure 5-6 Improved voltage profile of the feeder with a STATCOM .........................70

Figure 5-7 Time series variation of the load and PV output of a typical installation .......71

Figure 5-8 Defined Q-V droop curve for reactive power regulation of the STATCOM ...72

Figure 5-9 Time series voltage variation at the feeder end for a 24-h simulation ............72

Figure 5-10 Time series variation of the reactive power from the STATCOM ...............73

Figure 5-11 Total reactive power in the feeder ...............................................................74

Figure 5-12 Variation on the line losses with and without STATCOM .......................75

Figure 5-13 Three phase active power contributions from a node in the LV feeder .......76
Figure 5-14 Time series variations of the three phase voltages (a) with no STATCOM (b) with STATCOM ........................................................................................................................................... 77

Figure 5-15 Impact of STATCOM on VUF ........................................................................................................ 78

Figure 5-16 Impact on N-G potential with reactive power management ........................................... 79

Figure 5-17 Changes in the HV/MV OLTC tap operation due to STATCOM operation ...... 80

Figure 6-1 Single line diagram of the LV feeder and CES system setup ................................................. 91

Figure 6-2 Net exchange of active power in LV feeder .................................................................................. 92

Figure 6-3 Associated costs for the MPC controller .................................................................................... 93

Figure 6-4 Operation of the CES with the proposed MPC control (a) Three phase power CES (b) State of charge .................................................................................................................................................. 94

Figure 6-5 Dual mode operation of the proposed MPC controller .............................................................. 95

Figure 6-6 Time series 3-phase voltage variations (a) No control (b) With MPC ....................... 96

Figure 6-7 24-h Time series voltage improvement in the individual phases ............................................. 97

Figure 6-8 Net exchange in active power from the MV/LV transformer ................................................ 98

Figure 6-9 Variations in the feeder line losses with and without MPC controller ................... 99

Figure 6-10 Impact of MPC on VUF .............................................................................................................. 100

Figure 6-11 Variations of the N-G potential with MPC control .............................................................. 100

Figure 6-12 Changes in the HV/MV OLTC tap operation in presence of CES ................... 101

Figure 7-1 Inverter response curve for Volt-Watt mode ........................................................................... 105

Figure 7-2 Impact of Volt-Watt on LV feeder voltage magnitude (at end of feeder) .......... 106
Figure 7-3 Change in feeder active power due to Volt-Watt operation..........................107

Figure 7-4 Inverter response curve for Volt-VAr mode............................................108

Figure 7-5 Impact of Volt-VAr response on LV feeder voltage magnitude.....................110

Figure 7-6 Impact of Volt-VAr response on LV feeder reactive power..........................110

Figure 7-7 Impact of Volt-VAr response on LV feeder active power............................111

Figure 7-8 Impact of RBC CES on LV feeder voltage..................................................113

Figure 7-9 CES performance when controlled by RBC ..............................................115

Figure 7-10 Impact of various voltage regulation techniques on MVD..........................118

Figure 7-11 Graphical presentation of the maximum voltage deviation for the various voltage regulation techniques .................................................................120

Figure 7-12 Impact of various voltage regulation technique on FRC ............................122

Figure 7-13 Graphical presentation of the feeder reserve capacity for the various voltage regulation techniques .................................................................123
List of Tables

Table 3-1 Admittance matrix of typical transformer connections ........................................ 33
Table 3-2 Simulation parameters .......................................................................................... 42
Table 6-1 Algorithm to activate the dual mode operation ...................................................... 90
Table 7-1 Pseudocode for RBC control of CES .................................................................. 112
Table 7-2 Breakdown of MVD to demonstrate voltage improvement ................................. 119
Table 7-3 Breakdown of FRC values to analyze the feeder usage ....................................... 123
Chapter 1

Introduction

1.1 Background

The issue of voltage regulation associated with the extremities of both peak load and significant reverse power flow periods is one of the main power quality challenges Distribution Network Service Providers (DNSPs) face as their distribution networks transform from the present to future grids with widespread integration of solar photovoltaic (PV) generation, both in terms of numbers and capacity. Currently in Australia, PV capacity is 26 GW with over 3 million installations consisting of both distributed rooftop PV and large scaled PV farms [1, 2]. This contributes to a significant proportion of the 55 GW generation capacity in Australia. The proportion of energy supplied from renewable energy sources is expected to increase significantly over the next decade as the energy mix transforms to reduce the harmful environmental effects from large scale non-renewable power generation. This uptake in distributed energy resources (DERs) will introduce various power quality (PQ) challenges that needs to be addressed. Intermittency of solar irradiance also causes variation in available power output and may impose adverse threats in the stable operation of future grids.

Distribution networks deliver electricity supply to residential, commercial and industrial customers while maintaining the steady state voltages within the limits specified by standards and regulations. Distribution networks were originally designed with the assumption that power only flows from upstream transmission and generation assets to downstream MV and LV networks. In conventional (radially structured) distribution networks, the voltage decreases along feeders due to the interaction between load current and line impedance as energy is delivered to the low-end customers. With the increasing prevalence of rooftop solar PV systems in residential LV feeders, a significant proportion of the load can be supplied locally. This reduces the amount of energy required to be delivered to the customers from the
interconnected electricity network. In some cases, the power generated may exceed the local demand, especially during the middle of the day when solar irradiance and hence PV output is at its peak and the residential load demand is relatively low. Under these circumstances, the LV network can operate with a multidirectional power flow, depending on the relative loading and PV production levels. If the problems introduced at LV are not solved locally, operational issues may be induced into the upstream MV and HV networks as well. The overvoltage arising from significant reverser power flow in distribution networks with high R/X ratio can also have detrimental effects on sensitive electrical appliances [3].

Furthermore, unbalanced or uncoordinated connection of single-phase rooftop solar PV units installed at LV residential premises may increase the network unbalance. In Australia, 4-wire multiple earth neutral (MEN) network configuration is typically utilized at LV. Increased levels of unbalance in the system have the potential to overload the neutral conductor current limits and increase the neutral to ground voltage (stray voltage) [4].

DNSPs often introduce PV penetration limits to minimize the adverse effects of DERs. Introduction of these limits contradicts government and industry policy aimed at increasing the amount of power from renewable energy sources. Currently, in Australia many DNSPs limit the maximum size of rooftop solar to 3.5 or 5 kW per household while some DNSPs restrict the size of the PV depending on the feeder or zone substation capacity [5]. Furthermore, in a 24-h period the peak load is usually observed during the evening time when there is no PV generation to support load.

1.2 Voltage Regulation Issues in PV Rich Distribution Networks

DNSPs are bound by requirements to regulate supply voltage magnitudes to within a certain range. Australian Standard AS 61000.3.100 requires the voltage at the consumer point of supply to be within +10, -6% of the 230 V nominal for single phase LV customers [6]. Although residential LV loads contribute around 25% of the total load in the Australian National Energy Market (NEM), the study in [7] demonstrates that residential load plays a key role in increasing the peak demand. Increased numbers of DERs in future LV feeders, combined with the increased number of EVs means DNSPs need to invest in infrastructure to alleviate issues related to both overgeneration and overloading. Peak load is typically observed during evening time, and as demonstrated by [8], the power generated from PV does very little to reduce the peak demand. In terms of minimizing the peak load, DNSPs
may utilize demand side management using high frequency audio frequency injection control (AFIC) signals and/or Time of Use (ToU) tariffs during typical high load periods of the day [9].

Traditional voltage regulation devices such as on-load tap changers (OLTCs), voltage regulators and capacitor banks have historically been sufficient to regulate the voltage within the mandated limits [10]. These devices were designed with the assumption of unidirectional power flow from centralized sources to downstream distribution networks and are located at the HV/MV levels of the network. Bidirectional power flow that arises as a result of distributed generation in LV limits the ability of these devices to regulate voltage, as the LV voltage issues often cannot be detected or do not propagate that far up the network. With the increased magnitude of current flow in networks with DERs, nodes at the LV feeder end may still experience over and under voltages even if the voltage is maintained within the appropriate range at the MV/LV distribution transformer. The long-term power quality monitoring study undertaken on distribution network data in Australia also highlights some of the key PQ issues in PV rich grids [11]. These issues have already become so severe in some parts of Australia that utilities are trialing curtailment (e.g. Volt-Watt) of the solar PV output at peak generation times [11]. Other issues include instances where OLTCs have been observed to reach the limits of their variable tap settings, essentially requiring an increased number of taps to maintain operation, in sites with large amounts of PV installations [12].

1.3 Voltage Regulation Technical Solutions

Over the last decade, a significant volume of research has led to the concept of ‘Smart Grid’. In a broad sense, ‘Smart Grids’ facilitate local energy production with two-way communication between consumers and DNSPs while ensuring power quality, security and reliability. Battery energy storage (ES) is expected to play a key role in these future ‘Smart Grid’ distribution networks. With effective control, batteries can alleviate voltage rise by storing excess power when generation exceeds load and also utilise stored energy to reduce peak load. While ES devices integrated as distributed sources for individual customers is a popular concept, more recently DNSP owned community energy storage (CES) systems are also being trialled. The control of ES is a key aspect for future ‘Smart Grids’. Although heuristic (rule-based) control offers a simple solution with the least infrastructure requirement
and computational burden, optimal control theory-based strategies such as model predictive control (MPC) have gained much popularity recently [13].

Modern DER inverters also have reactive power capabilities which can be used to regulate the voltage. If the Volt-VAr mode is activated, inverters can assist distribution network operation by changing the operating power factor (pf) in accordance with the voltage at their point of connection (PCC). This allows the inverter to regulate the voltage by injecting reactive power during undervoltage and lowering the voltage by absorbing reactive power during reverse power flow. However, as most PV systems are customer owned, this limits a DNSP’s ability to activate Volt-VAr or operate in other available voltage support modes, due largely to the lack of market structure to incentivize the customers for the grid support they would provide [14]. Advancements of modern power electronic devices also allow the use of smaller sized Static Synchronous Compensators (STATCOMs) in LV feeders for voltage regulation. STATCOMs are typically used in transmission systems to provide reactive power support, which fall within the broader topic area of flexible AC transmission system (FACTS) devices. Although STATCOMs increase the total line current by decreasing the operating pf of an LV feeder, they provide a cost-effective solution to facilitate more rooftop PV systems in residential areas. Field trials of LV-STATCOMs in Australian LV networks demonstrated improved voltage regulation, as discussed in [15].

It is evident that rooftop PV systems as “behind the meter” generation units pose a key challenge for DNSPs and require significant infrastructural investments to mitigate resulting voltage regulation issues. Compared to HV and MV networks, LV networks experience more variable loads, have inherent unbalance due to the overhead 4-wire structure and prominence of single-phase loads, and have inadequate data capture capabilities for managing the LV voltage levels. Although numerous solutions on LV voltage regulation techniques can be found in the literature, practical application aspects such as the lack of visibility of the LV network by DNSPs are often ignored.

1.4 Aims and Objectives

This thesis aims to contribute new knowledge and understanding to the field of power distribution network voltage regulation. This includes investigation and analysis of different approaches to voltage regulation in power distribution networks in the literature, and to propose new methods and improvements to existing methods. Specifically, this thesis aims to
highlight the shortcomings of the current voltage regulation techniques available to DNSPs in LV feeder. The case studies to be provided in this thesis presents 24 h time series simulation to investigate the performance with varying load and PV generation. Most of the modern voltage regulation techniques found in the literature do not consider the limitations of practical distribution networks (for example communication) and the relevant standards for DNSPs, which will be addressed in this thesis.

As an initial task of this project, a detailed analysis of the literature was undertaken to understand the problems high integration of renewables can bring to the network. Subsequently, a time series analysis tool was developed using OpenDSS, a script driven software platform developed by the Electric Power Research Institute (EPRI) for distribution network analysis. Data from an Australian DNSP was utilised to model the 3-phase 4-wire (400 V_{LL}) network, where the neutral conductor was explicitly modelled. The developed analysis tool was also extended to appropriately model the modern regulation techniques often used by DNSPs such as Volt-VAr DER inverter control mode and rule-based operation of energy storage.

Two main mitigation solutions are proposed to mitigate the voltage regulation issues in distribution networks, the first solution based on LV-STATCOMs and the latter based on utilisation of MPC based CES in LV feeders. STATCOM based voltage regulation is an economic solution which requires no sophisticated communication infrastructure, while the CES based solution explores a modern optimal objective-based solution. The proposed voltage regulation techniques are validated through 24-h power flow simulations capable of capturing the long-term performance of the distribution network including change in the overall line losses within the feeders. A realistic MV network model was also used to analyze the impact of deploying the proposed solutions on the tap operation of the HV/MV substation transformer.

1.5 Thesis Outcomes and Contributions

As a direct outcome of the above activities, the main contributions of this thesis are summarised as follows-

1. Development of a distribution network analysis tool capable of analyzing the impact of single-phase rooftop solar PV units, where the realistic MV and LV network
configurations were preserved. This included explicitly modelling the neutral conductor for MEN LV feeders, allowing for the detailed investigation of voltage unbalance impacts in distribution networks and how the DER impacts from LV can propagate to MV. A future grid scenario was considered where all the modelled houses are fitted with PV units. The network models were developed using data from a realistic network in Australia and actual load and irradiance data was used for the 24-h time series simulation. Merits of this tool is to have analysis tool that does not rely on predefined modelling of distribution network structures. The developed tool also allows all the variables required for distribution network analysis to be explicitly modelled.

2. Investigation of the application of STATCOM in LV feeders to regulate the voltage levels through reactive power management has been undertaken, utilising the above-mentioned analysis tool. A design guide was developed to determine the optimal size of a STATCOM for any general LV feeder, derived from the feeder demand and penetration level of rooftop solar generation.

3. An outcome of the STATCOM investigation was the ability to determine the optimum location of the STATCOM and derive the optimum droop control curve to identify the levels of reactive power injection required for voltage support.

4. Development of a dual objective MPC based CES control, where both system economics and voltage regulation are addressed. For the proposed CES control, a two level MPC algorithm is proposed, where the higher-level controller selects the mode of operation considering the future state of the system, and the lower-level controller calculates the optimum CES power. The proposed control method considers feed-in tariff, spot price of energy, and operational costs of the CES, to obtain the cost function for the economic mode of operation.

5. And finally, the research benchmarks LV distribution feeder voltage regulation mitigation solutions based on the application of STATCOM and MPC based CES, including performance evaluation in respect to voltage regulation, voltage unbalance and line losses.

1.6 Thesis Layout

The remainder of the thesis is structured as follows-
Chapter 2- provides a literature review of voltage regulation in distribution networks. A detailed summary of rooftop solar PV impact in LV feeders is provided, focusing on the voltage regulation issues in future residential distribution networks and how the bidirectional power flow in LV networks has the potential to introduce power quality issues in the MV/HV networks. This chapter also includes a review of the voltage regulation techniques found in the literature including the application of energy storage devices, utilizing the reactive power capabilities of modern inverters. Discussion on various optimal control-based voltage regulation techniques is provided with a focus on utilizing the relevant Australian distribution network and equipment standards.

Chapter 3- presents the modelling approach used for the simulation study to investigate the voltage regulation issues in LV feeders with high penetration of rooftop solar PV systems. This includes a 3-phase modelling of all the major components in a distribution network including PV inverter system, transformers, distribution lines and loads. The detailed 4-wire modelling implemented for the LV feeder is able to capture the impact on the neutral conductor during high unbalance in the system. The MV network has also been modelled to investigate how the issues in LV can propagate through distribution systems. A future grid scenario is considered with 100% penetration of rooftop solar PV, where all the residential houses were fitted with a single-phase rooftop PV system. The models developed in this chapter are utilized throughout the thesis to analyze the performance of various voltage regulation techniques introduced in this thesis.

Chapter 4- provides a case study to highlight the voltage rise issues addressed in this thesis. The case study also includes investigating the performance of the feeder in terms of variation of the power flow overall and analyzing the change in line losses due to the excess power from the PV systems. The simulation study was extended to include network unbalance and aimed to investigate the variation of the neutral to ground voltage in a multi-grounded distribution network typically used in 3-phase 4-wire MEN feeder design. The analysis was also extended to investigate the variation in tap changing operation of the OLTC transformer used in the upstream HV/MV substation.

Chapter 5- investigates the application of a Static Synchronous Compensator (STATCOM) for improvement of voltage regulation in 4-wire LV distribution feeders through reactive power management. A detailed case study is provided investigating the performance of distribution networks controlled with a STATCOM. The main contribution of this chapter is
the quantification of the impact of the application of STATCOMs in radial 4-wire LV feeders, demonstrating the extent to which voltage can be managed through reactive power control. A design guide to determine the size of the STATCOM for a general feeder is provided depending on the loading and penetration level of rooftop solar generation.

**Chapter 6**- presents a two-level dual-objective model predictive control (MPC) based algorithm to control DNSP owned community energy storage devices in LV residential distribution feeders. The proposed control method considers the feed-in tariff, spot price of energy and storage system operational costs. Both the economics of the system and voltage regulation are addressed. The individual modes of operation are activated by a high-level controller and a low-level controller provides the optimized charging/discharging rates according to the predefined objective cost functions. A case study is presented to demonstrate the efficacy of the proposed control method through a time series power flow simulation.

**Chapter 7**- compares the proposed voltage regulation methods in LV feeders in this thesis to the general distribution network voltage control techniques applied by DNSPs. For this the Volt-VAr method, which provides reactive power support from the inverter, and Volt-Watt method, where the active power is curtailed to keep the voltage deviations according to a predefined graph, were modelled. A heuristic rule-based controller for CES was also modelled as it is widely used to regulate the power from storage devices. A comparative simulation study is undertaken in this chapter to extensively analyze the performance of the investigated voltage regulation techniques.

**Chapter 8**- concludes the thesis summarizing the major outcomes and provides direction for future work that can be done on this topic.

**1.7 Publications**

**1.7.1 Thesis Related Publications**

The following publications were completed during the thesis. All of these journal/conference papers are directly related to voltage regulation in distribution networks and the content of the publications have been utilised in preparation of this dissertation.


An unpublished summary paper based on the latter chapters (Chapter 5 and Chapter 7) of the thesis has also been prepared as part of the thesis undertaking.


1.7.2 Other Publications

The following publications were completed during the candidature but are not directly part of the thesis. All of them are related to power quality and informed the work presented in this thesis:


Chapter 2

Literature Review

2.1 Introduction

With the ever-increasing effects of global warming in the modern world, it is crucial to reduce the production of Greenhouse Gasses (GHGs) from burning fossil fuels and exploit clean, renewable sources of energy [16, 17]. To cope with the effects of global warming the power industry is undergoing major infrastructural changes with the introduction of renewable based DERs, especially solar rooftop PV systems. The integration of renewable based DERs, especially in areas of high penetration of solar rooftop PV systems, can result in operational issues within the LV electricity distribution network, with the most significant being a detrimental impact on voltage regulation.

This chapter summarizes the findings from a critical analysis of the existing literature to clearly understand voltage regulation issues in PV rich LV distribution networks and the level of detailed required for appropriate modelling. The remainder of the chapter is divided into seven sections. Section 2.2 discusses the main causes of voltage rise in PV rich LV feeders, while Section 2.3 highlights the importance of detailed 3-phase 4-wire modelling of LV distribution networks. In Section 2.4, various distribution network voltage regulation techniques are discussed, concentrating on their performance, and addressing the possible limitations in modern networks. In Section 2.5, the chapter investigates the role of different types of energy storage devices in distribution network voltage regulation. Section 2.6 explores small-scaled flexible AC transmission system devices as a means of voltage regulation mitigation and identify ways for the utilization of these devices for the design of future distribution systems. In Section 2.7 some of the advanced voltage regulation techniques requiring a centralised communication infrastructure are presented and Section 2.8 summarizes the chapter with concluding remarks.
2.2 Voltage Issues in LV Networks

Currently, Australia has one of the highest penetrations of solar PV installations across the world with 29% of South Australian and 28% of Queensland residential customers already having rooftop solar PV system installed [18]. This rise in solar PV installations has been driven by government subsidies and high feed-in tariffs offered by energy retailers. Although PV based DERs reduce the amount of power consumed from fossil fuel powered power stations, they may create some adverse technical challenges in terms of operation of LV distribution networks which are often also transferred to the upstream MV and HV networks, as discussed in [19-21].

Distribution networks were originally developed with the assumption that power primarily flows downstream from the upstream generation and transmission sectors to customer loads. DERs allow a significant proportion of LV load to be supplied locally, which can reduce the overall demand on upstream MV networks from individual households. However, with a high penetration of single-phase PV injection in the three-phase system, the power generated from local PV generators may exceed the load demand, which in turn may introduce issues such as reverse power flow in the network. In the literature [22-24], midday voltage rise, component overloading and voltage unbalance have been reported as the major areas of concern as more PV systems are connected in distribution networks. The voltage rise issue would be particularly severe in weak distribution networks with a high R/X ratio [25]. DNSPs are bound by strict rules to regulate supply voltage magnitudes to within a certain range. The Australian Standard AS 61000.3.100 [6] requires the voltage at the consumer point of supply to be within +10, -6% of the 230 V nominal for single phase LV customers (equating to 216.2 V – 253 V).

Figure 2-1(a), developed by the author, depicts the active power variations of a nominal residential LV feeder load and PV output for a typical clear sunny day. Considering a future network scenario where all residential connections incorporate a rooftop solar PV generation system, it is evident that LV feeders will experience a maximum voltage increase corresponding to Scenario 1 and maximum voltage decrease corresponding to Scenario 2. Figure 2-1(b) shows the indicative voltage profiles along a typical LV feeder for the above two scenarios (assuming uniformly distributed PV generation systems and loads). Depending
on the impedance of the conductor and the loading level, the feeder voltage profile may fall outside the mandated voltage limits.

In addition to the overall voltage magnitude, the balance of individual phase voltages is important to LV distribution customers, especially to ensure the efficient operation of three-phase induction motors and similar loads requiring balanced three-phase voltages at their point of supply. Compared to HV and MV networks, LV networks experience more variable loads and have a higher level of inherent unbalance due to their overhead 3-phase 4-wire feeder configuration and connection of predominantly single-phase loads and PV generators. The IEC/TR 61000-3-13 [26] standard defines the voltage unbalance factor (VUF) to be the negative to positive sequence ration. To quantify the voltage unbalance in this thesis, the equivalent formulation of VUF will be utilized. This is defined as:

![Figure 2-1](image)

Figure 2-1 (a) Time series variation of load and PV output, (b) Voltage profiles in a typical LV feeder
\[ VUF = \frac{1 - \sqrt{3} - 6\varepsilon}{\sqrt{1 + \sqrt{3} - 6\varepsilon}} \times 100\% \]  

(2.1)

Where,

\[ \varepsilon = \frac{|V_{ab}|^4 + |V_{bc}|^4 + |V_{ca}|^4}{(|V_{ab}|^2 + |V_{bc}|^2 + |V_{ca}|^2)^2} \]

\(V_{ab}, V_{bc}, V_{ca}\) corresponds to the magnitudes of the line-line voltages for the three-phase system. The use of (2.1) enables a convenient way of estimating the negative to positive sequence ratio (the IEC unbalance factor) from field measurements and/or simulation results where the phase-to-phase voltage magnitudes are more readily available than the individual phase magnitudes and their respective phase angles.

2.3 Importance of Detailed Modelling of LV Feeders

This section will discuss the importance of explicitly modelling 4-wire LV feeders and why the information on the neutral conductor is required in order to ascertain the accurate representation of the operation of LV distribution networks.

In traditional distribution network analysis techniques, the neutral wire is merged into the phase impedance matrix using the Kron’s reduction technique [27] or it is simply neglected by assuming the neutral wire is solidly grounded. In a practical distribution network this may not be realistic, as the neutral grounding resistance varies from a few Ohms to several tens of Ohms [28-30]. Neutral grounding resistances have been reported to be often higher than the distribution network operator design value due to the coupling with underground water pipes. For example, in [31] the authors investigated the increase in neutral grounding resistance in the Australian distribution networks due to the introduction of the plastic water reticulation system, which has mutual coupling with the earth wire. Therefore, the traditional three-phase power flow programs are unable to properly analyze the operation and the grounding effects of the 4-wire distribution network topology and are not ideal for the LV network analysis.

In a highly unbalanced system, the neutral current can be greater than the phase current as reported in [32]. The high neutral currents due to unbalance in LV networks can not only cause safety issues on humans and farm animals but can also have an adverse effect on the
distribution network operation. High neutral phase current may overload the neutral conductor, interfere with communication infrastructure, reduce the sensitivity of the fault relays, and increase the neutral-to-ground voltage. The neutral potential can appear as a noise source for sensitive devices and may cause malfunction for devices requiring a smooth sinusoidal supply. The authors in [33] proposed an integrated 3-wire 4-wire approach for the assessment of the neutral-to-ground voltages in an LV multi-grounded network and analyzed their effects on the upstream network. The network operation was analyzed with a grounding resistance of 5 Ω. The neutral potential of 0.5 V was set as the common mode voltage limit for sensitive devices [34]. The simulation results showed if the PV systems are connected in an unbalanced pattern, a floating voltage of higher than 0.5 V can be induced into the feeder. Figure 2-2 illustrates the basic connection philosophy of this 4-wire MEN system.

![Figure 2-2 Basic 4-wire connection in LV feeders](image)

The importance of suitable modelling of the neutral conductor and resulting currents and voltages is highlighted by the above-mentioned reasons in relation to voltage regulation, thus the modelling in this thesis will consider the neutral conductor in detail.
2.4 Voltage Regulation in Distribution Networks

2.4.1 Limitations of Traditional Voltage Regulation Techniques

Traditional methods used by DNSPs to mitigate issues with voltage regulation in networks with a low level of automation include network upgrades (replacing transformer and conductors), use of on-load and/or off-load taps in transformers, and capacitor banks for reactive power support. Upgrading of problematic networks has been historically used to solve long term voltage regulation issues in distribution networks. Although the new higher rated components may solve voltage issues and increase the hosting capacity of the network, these solutions are expensive and the extent of added advantages offered do not make these solutions economically viable for implementation on a large scale.

On-load tap changers (OLTCs) are commonly found in zone substations where the tap position is controlled to regulate the MV voltage feeder profiles. However, due to their slow response time (at least one minute before operation), the tap changes may not be adequate to compensate the voltage variations caused by intermittency of PV power. Furthermore, the additional tap changes in OLTCs when operated in a PV rich distribution network decreases the lifetime and increases the maintenance cost of the device as discussed in [35]. Another option is changing the position of the off-load tap typically found in LV feeder transformers. However, off-load tap changers need manual intervention (labour and outages) and this approach may not be practically feasible in distribution networks with bidirectional power flow where both undervoltage and overvoltage conditions may be induced as PV penetration increases [36]. Fixed and switched capacitor banks have also successfully been used to mitigate undervoltage issues under high load conditions. However, as capacitors boost the voltage by injecting reactive power, fixed capacitors can exacerbate overvoltage conditions during high reverse power flow. Although switched capacitors can regulate the amount of reactive power injected in discrete steps, it is not a viable option to mitigate overvoltage problems with varying load patterns as these devices do not have the capability to decrease the voltage.

Network reconfiguration is another method used by DNSPs to mitigate voltage regulation issues and increase reliability. Reference [37] discusses various mathematical approaches that can be applied for optimized network reconfiguration including metaheuristic methods such as genetic algorithm and particle swarm optimization (PSO). However, voltage regulation
issues will be observed mainly in non-urban radial structured residential overhead conditions and in most of these network structures multiple transformers are not available to reconfigure the network.

2.4.2 Solar PV Inverter Control

With the advancements of semiconductor-based devices, modern power converters can now be equipped with advanced control functions which can be used for distribution network voltage regulation. In the past, international standards such as IEEE 1547 (pre 2018) and grid codes across the world required inverters to operate at unity power factor and hence they could not be used to provide local voltage regulation support. However, recently standards are being redefined to allow inverters to contribute to voltage control through active and reactive power regulation. For example, IEEE 1547 (2018 version) [38] and Australian Standard AS 4777.2:2020 [14] mandates local voltage regulation through the operation of inverter power quality response modes. Modern inverters have the capability to implement a range of different voltage regulation functions. Some of the PV inverter modes commonly studied in the literature include:

- **Constant Power Factor**
- **Q(V) Control** - where the reactive power is regulated through a function of the measured point of common connection (PCC) voltage, commonly referred to as Volt-VAr control
- **PF(P) and PF(V) Modes** - where the inverter operating power factor is controlled as functions of real power and local voltage
- **P(V) Mode** - where the inverter real power is curtailed when the measured voltage is high, commonly referred to as the Volt-Watt mode

Among the above discussed modes, Q(V) is the most implemented inverter control function. Figure 2-3 shows the droop curves defined in AS 4777.2:2020 for the operation of the Volt-Watt and Volt-VAr functions. Droop control is implemented in these curves which allow VAr injection/absorption depending on the voltage for the Q(V) function and active power curtailment for high voltages in P(V) functions. Recent studies have investigated the performance of distribution network when these voltage regulation techniques are implemented. The simulation study performed on a Hawaiian distribution network [39] concludes that both Volt-Watt and Volt-VAr controls can regulate the voltage in both urban
and rural distribution networks. Reference [40] investigates the use of smart inverter functions for 18 distribution feeders. Not only does the study confirm that inverter control is successful in maintaining distribution network voltage levels, but it also discusses how these advanced settings also have the capability to increase the hosting capacity of feeder. Furthermore, the authors conclude that more research is required to determine the optimized setting for the inverter depending on the feeder characteristics and configuration.

Some of the main challenges when utilizing PV inverters for voltage regulation include customer revenue loss due to active power curtailment, increased apparent power flow and inequity for customers at different points of connection in the network. Active power curtailment due to inverter smart control reduces the instantaneous overall power output of the PV system during periods of over-voltages. While this would tend to suggest that customer revenue from grid feed-in tariffs would be reduced recent studies have demonstrated that significant losses are not imposed by smart inverter control. In an Australian study [41], the results demonstrated that only 2% of energy curtailment was caused by the activation of Volt/Watt and Volt/VAr modes. Activation of reactive power support from inverters also requires higher power ratings for inverters (or reductions in real power output) to supply the required reactive power. In addition, the extra VAr’s in the network, while fundamental to the ability to mitigate voltage, result in higher apparent power flow in the feeder, increasing the losses and utilization of the network assets [41]. Currently most residential PV units are customer owned introducing inverter settings compliance issues. In [42], it is shown that only a fraction of new PV installations are properly audited

![Inverter control functions (a) Volt-Watt (b) Volt-VAr](image-url)
and they are found not to be compliant with the required grid standard. The analysis in [42] also discusses the issue of inequity between customers connected at different nodes in a feeder. For example, if Volt-Watt is activated, the customers towards the end of the feeder will experience more active power curtailment than customers connected near the distribution transformer, introducing inequity between the individual PV systems.

2.4.3 Demand Response

While demand response (DR) techniques are commonly used by DNSPs to reduce the evening peak load, with recent problems associated with voltage regulation, there has been an increased interest in utilizing DR technologies for mitigation of voltage variation [43]. A recent project by an Australian DNSP applied conservation voltage reduction (CVR) to manage voltage levels in distribution network feeders [44]. CVR was implemented through the tap operation in OLTCs controlled by trigger responses from smart inverters. The method of utilizing smart inverters proved to be effective as the voltage information at each connection was available to trigger the required CVR operation. An interesting outcome of the trial of CVR revealed it was more effective in winter compared to summer. The load sensitivity to voltage obtained was 0.75% of energy savings in winter compared to 0.69% in summer. The authors discussed that this could be due presence of more resistive heating load present in winter seasons. Large scale application of this technique is still not an economically feasible option as many distribution networks are not equipped with smart metering technology. Manual adjustment of off-load tap chager will not be economically feasible as voltage profiles along distribution feeders vary throughout the day due to multidirectional power flow in PV-rich distribution networks.

Another DR technique used by Australian DNSPs to reduce the peak load is the application of Audio Frequency Injection Control (AFIC) signals to control residential loads such as water heating as well as network loads such as streetlights. AFIC signalling is implemented by injecting high frequency voltage signals on to the 50 Hz supply which can be detected by relays allowing certain loads to be controlled remotely. The main advantage of the AFIC DR method is it does not require additional communication infrastructure beyond the signal source. Recently researchers have investigated the possible application of AFIC signals for voltage regulation. In [45], the authors proposed the use of DR management of a future distribution network scenario where all the customers are equipped with a PV system and EVs. A multimode control strategy is proposed to regulate the EV charging (with V2G
activated) to ensure the grid assets and distribution networks are better utilized. The results demonstrated that the proposed technique was successful in maintaining the distribution network voltage levels within the desired threshold. The study however did not consider the PQ issues introduced when using the high frequency control signals. Another study investigated the harmonic PQ impacts on PV inverters with AFIC signaling, highlighting the requirement of filtering the AFIC signal to protect the inverters [46].

2.4.4 Low Voltage Regulators

The final voltage regulation technique to be discussed in this section is the use of low voltage regulators (LVR). LVRs have the capability to both increase and decrease the voltage of LV feeders and they are designed with bidirectional capabilities. Typical LVRs can operate within a range of 13% about the nominal voltage with an accuracy of 1 V [47]. The basic design of LVRs include a tap changer and an electronic controller measuring the voltage in both directions to calculate the required tap setting. The main advantage of LVR is it can be installed at different locations of an LV feeder where voltage issues are expected. However, LVRs are quite expensive and may not be economically feasible for low density LV feeders, however they would be effective to mitigate voltage issues in long feeders with a large difference in voltage between the start and end of the feeder. The findings of the trial of LVRs in an Australian distribution network is presented in [48]. Although the outcomes of the project presented promising outcomes, there were scenarios where the LVR operation worsen the voltage conditions. For example, the VUF was higher when the LVR operated in situations where only one or two phases were measured to be outside the allowable voltage.

2.5 Role of Energy Storage in Future Distribution Networks

Energy storage (ES) systems are expected to play a key role in alleviating the main issues related to high penetration of distributed renewable sources such as rooftop solar PVs. With the price of ES devices or battery energy storage systems (BESS) decreasing, they have the potential to dominate the future power industry along with PV systems. With effective control, batteries can alleviate voltage variations by storing excess power when generation exceeds load and utilizing stored energy to reduce peak load [49]. As such, the control of the battery power in distribution networks is a topic of increasing interest. The implementation of BESS in distribution networks can be divided into two main topologies; distributed ES systems where the individual batteries are for each PV system, and central or Community
Energy Storage (CES) with larger storage capacities which can be applied for an entire LV network. Some of the major work on EVs (an alternate form of energy storage) focusing on distribution network voltage regulation is also reviewed in this section.

2.5.1 Distributed BESS

For a typical distributed BESS implementation, the charging/discharging rate is controlled by the local power conditioning system. Customer owned BESS’s are also referred to as ‘off the shelf’ (OTS) BESS. Numerous examples of customer owned distributed (behind the meter) ES devices are documented in [50-53]. Typical charging algorithms include the rule-based approach via detection of the net power flow at the PCC, where the battery is charged if the PV production is higher than the load. From the customer’s perspective the OTS BESS can bring significant benefits, as the power imported from the grid is greatly reduced. However, sometimes the BESS may prematurely be fully charged/discharged under light load or cloudy days, not allowing them to provide local support when the voltage levels are at their worst. Thus, from the perspective of the DNSPs OTS BESS may not be beneficial if the BESS capacity to charge or discharge is not optimally managed. Significant work can be found in the literature addressing the control issues for distributed BESS. In [54], the authors controlled the individual BESS units in a LV feeder through a centralized controller. The results demonstrate that if properly managed distributed BESS can also be used to mitigate PV related voltage issues in distribution networks. Modern OTS BESSs also have the capability of reactive power support. In [55], a four quadrant BESS control approach is utilized to increase the PV hosting capacity of LV feeders.

2.5.2 Community Energy Storage

Compared to customer owned BESS, CES provides freedom for the DNSP to utilize the storage device as required by the distribution network. This makes CES a viable option for the DNSP to invest in as a distribution network support device. Several studies investigate the application of CES in relation to voltage regulation in distribution networks. In [56], a CES is applied in a LV feeder to mitigate a neutral potential rise issue and provide voltage support for the distribution network. In [57], integration of DNSP-owned community BESSs was applied to maximise the hosting capacity of the feeder while ensuring the voltage levels were
maintained. The proposed solution utilized a cost-based multi-objective strategy considering both distribution system and battery recycling costs and three different BESS service functions including voltage regulation, loss reduction, and peak reduction. Furthermore, the optimal size and location of a CES have been investigated in [58] for a BESS system with four-quadrant power control enabling control of both active and reactive power. The effect of battery and converter sizes on current and power losses are studied and the placement of the CES was determined to be an important factor with respect to their overall performance to improve network performance.

2.5.3 Electric Vehicles

The recent increase in the popularity of EVs have raised an unresolved question on how networks must adapt to cope with the significant increase in load, especially because of the unpredictable dynamic behaviour of the load. It is evident from the literature [59-62] that the uncontrolled charging of EV load has the potential to severely affect the normal operation of the current grid. Currently SAE J122 is the most popular among the charging standards used commercially that can support the three levels of plug-in EV charging [59]. EVs will be generally charged during the evening time as people return home from work. It is at this time that the collective charging can impose a severe burden on the hosting capacity of the grid. In [63], a simulation-based study concluded that an increase of 10% in EVs numbers has the potential to increase the peak load by 18% due to residential Level 1 AC uncontrolled charging.

However, researchers have identified the potential to use EVs as a method of supporting grids with high penetrations of renewables. According to the driving behaviour data provided in [64], a majority of vehicles are travelling for only a small amount of time during most days with the vehicles remaining parked either at home or a workplace for a much larger portion of time. The amount of parked time is even greater if there is a second car within a household. As the number of EVs are increasing at an exponential rate, the available battery power could be utilized to support the grid using the concept known as V2G (Vehicle to Grid). During peak evening load vehicle batteries can be used as peak shaving support. In [65], a V2G charging algorithm is proposed where the charging current is controlled depending on the power generated from the PV unit in comparison with the load, and the current was discharged using a triangular function. Future DNSPs need to be able to provide customers
with financial incentives to participate in the program. Although this thesis does not focus on EVs, they are expected to play a major role in future distribution networks.

2.6 Utilization of FACT devices in Distribution Networks

Flexible AC transmission system devices are widely used by TSOs. Recent works have investigated the possibility of using these well-known devices in distribution networks. Some of the common FACT devices considered to solve voltage regulation issues in distribution network include dynamic voltage restorer (DVR), static VAr compensator (SVC), static compensator (STATCOM) and unified power flow controller (UPFC). The use of FACTs in distribution networks is an ongoing research topic; some of the major work completed for voltage regulation, loss minimization and PQ improvement on this topic can be found in [66-69].

Of the above-mentioned FACT devices, STATCOMs shows great promise for distribution network applications due to their capability to inject/absorb reactive power. Smaller sized STATCOMs are currently being trialled by DNSPs in Australia. Reference [15] summarizes the findings from the trails by an Australian DNSP, where a combination of 5 kVAr single phase and 20 kVAr three phase systems were applied in LV Feeders. This thesis concentrates on STATCOMs as one of the possible FACT devices which has the potential to be widely employed in LV feeders for voltage regulation. Compared to reactive power support from smart inverter functions, the main advantage of STATCOM is its ability to provide a higher level of VAr support from a single device. Furthermore, the device can be optimally placed at a specific location in LV feeder where the line losses can also be reduced. During their operation STATCOMs also have the capability to improve the transient stability of the system when the system experiences disturbances [70].

The application of STATCOMs at distribution network level is seen to be feasible due to advancements in modern power electronic systems and their reduced costs where they may be extended to mitigate several power quality issues. The ability of a STATCOM to mitigate voltage disturbances caused by varying load dynamics in distribution networks is considered in [71, 72]. The studies are supported by time domain simulations to show the improvement in the voltage at the PCC through reactive power regulation. However, the study does not include distributed generation and system performance considerations, nor does it analyse the change in system losses. In [73], a combined voltage regulation method using both OLTCs
and distribution system STATCOMs to maintain the radial MV network voltage levels is investigated with the STATCOM placed at the end of the MV feeder. The placement of STATCOMs in the network also plays a key role in its efficacy in voltage regulation. The authors in [74] investigate the application of STATCOMs to improve the voltage profile in distribution systems and propose an algorithm to find the best location for the placement of the STATCOM to minimize the line losses in the system. Although the improvement of the voltage levels is investigated, the study does not consider the time varying nature of the loads which requires the STATCOM to operate at different output levels. A similar approach is presented in [75], where stability issues are also introduced and taken into account for finding the optimum location for placement of the STATCOMs. It is evident that STATCOMs are effective in improving voltage regulation, but the main thrust of such work concentrates on control and the internal operation of the device through power electronics. There exists a gap in the literature addressing the long-term performance of STATCOMs when deployed in electricity supply networks, especially their application within LV networks.

### 2.7 Advanced Voltage Regulation Approaches

#### 2.7.1 Coordinated Voltage Regulation

This section will present some of the more advanced and novel voltage regulation approaches proposed for optimized distribution network voltage regulation. Reference [76] provides an extensive review of some of the advanced voltage regulation techniques that can be applied in distribution networks which includes various centralized, distributed and decentralized methods. The work also discusses the fact that although some of the modern techniques may demonstrate excellent performance, many of these methods are not practical solutions due to the absence of communication infrastructure and/or associated costs involved. Significant work can also be found in the literature focusing on the coordination of multiple voltage regulation devices. Reference [77] proposes a distribution network voltage regulation scheme utilizing both OLTCs and distributed ES. The study presented in [78] focusses on the coordination between smart inverter and distributed ES while [79] proposes a centralized voltage regulation method regulating the combined tap operation of OLTCs and LVRs. Researchers have also proposed the use of dynamic control of inverters utilizing a centralized controller. Currently most commercial inverters can only obtain the local feeder information, not allowing it to respond to disturbances at other points in the network. Assuming more
extensive information will be available in future smart grids through a central controller, [80] proposes the implementation of dynamic inverter control coordination strategy allowing multiple inverters to be controlled at the same time for improved performance. Even if the required communication infrastructure is available, some issues have still not been addressed extensively in the literature. For example, proper incentive structures need to be developed before these methods can be applied in real life and more work needs to be done with respect to how the new information can be incorporated into the existing SCADA.

2.7.2 Optimized Control of ES for Distribution Network Voltage Regulation

Another emerging research topic on voltage regulation is the application of modern optimal theory-based control such as Model Predictive Control (MPC) to regulate the charging/discharging power of ES devices for distribution network voltage regulation. MPC or receding horizon optimization is based around optimizing an objective variable with a prediction of future loads and PV generation. The major advantages of utilizing MPC for ES control as discussed in [13] are as follows:

- The ability to include physical constraints into the objective function such as the maximum and minimum state of charge (SoC) levels for the ES device
- The ability to utilize demand, generation, and price forecasting data
- The ability to incorporate multiple objectives to mitigate other distribution network issues including voltage regulation

Although rule based control of ES power imposes low computational burden [50], the ability of MPC to incorporate future states of the system into the algorithm has made it very popular for ES control [81]. There have also been significant improvements in the accuracy of prediction data required for MPC algorithms. In [82] rule based control and MPC are compared to analyse the economic viability of MPC. An MPC based multi objective algorithm is proposed in [83] to mitigate solar PV impacts in distribution networks, where the activation of ES in the feeder is enabled based on sensitivity analysis. Although significant research has been undertaken for development of MPC based algorithms for distributed ES, in terms of application for CES control, only a few examples are available [84-87]. In [87], MPC was applied to CES control to mitigate the effects of high penetration of solar by minimizing the total power in the feeder. In [86], MPC is presented to minimize the operational costs for the optimal control of CES in a microgrid, considering time-varying
pricing and losses in the network. In [85], a closed loop strategy is proposed to adjust the MPC to take prediction errors into the objective function. A key gap in the literature exists on the application of MPC in CES to address both the economic and technical benefits. Specifically, the analysis of these benefits from the perspective of a DNSP.

2.8 Chapter Summary

This chapter provided the literature review related to voltage regulation in PV rich distribution networks. The primary goal of this chapter was to review both traditional and novel voltage regulation technologies available in the literature. In the first half of the chapter, the main contributing factors that cause voltage regulation issues are introduced, along with the importance of detailed 4-wire modelling of LV feeders. The limitations of utilizing existing voltage regulation techniques and some of the implementation challenges are discussed. The main voltage regulation techniques discussed included smart inverter control, utilizing energy storage devices and FACTs devices, and other modern advanced voltage regulation techniques. The findings of this chapter demonstrate how advancements of modern power electronic devices also allow the use of smaller sized Static Synchronous Compensators (STATCOMs) in LV feeders (with high X/R ratios) for voltage regulation. The importance and technical challenges of adopting Energy Storage devices is also explored.

While the literature review demonstrates a significant progress in terms of regulating the distributing network voltage, most solutions were found to concentrate on the application of voltage management devices in MV and HV networks and this thesis aims to work on this research gap by proposing voltage regulation techniques in LV feeders. This ensures the issues are not carried to the upstream networks. It was also found that distribution network studies neglect the detailed network modelling of LV feeder, leading to errors or non-indicative results which will be addressed in this thesis. The main thrust of distribution network studies concentrates on control and the internal operation of related devices through power electronics. There exists a gap in the literature addressing the long-term performance of PV rich network, especially within LV networks. The case studies to be provided in this thesis presents 24 h time series simulation to investigate the performance with varying load and PV generation. Most of the modern voltage regulation techniques found in the literature
do not consider the limitations of practical distribution networks (for example communication) and the relevant standards for DNSPs, which will be addressed in this thesis.
Chapter 3

Modelling of Distribution Network Performance with High Penetration of Rooftop PV Systems

3.1 Chapter Overview

Recently there have been a significant increase in the number of rooftop solar PV systems installed in residential households. In terms of distribution system operation they can cause unwanted adverse effects such as reverse power flow, voltage rise and voltage unbalance that can result in operational requirements not being met in distribution networks. As such it is essential to reassess the performance of distribution networks which were originally designed for one way (upstream to downstream) power flow. The purpose of this chapter is to provide a comprehensive approach to modeling the distribution network, taking into account both steady-state and dynamic effects. This is necessary for conducting a power flow study and modeling control applications.

The three-phase power flow modelling approach to be used in this thesis is based on the current mismatch variant of the Newton-Raphson to be used to assess the effect of high penetration of single-phase PV units. A comprehensive three-phase detailed model of the key components in the grid suitable for DN analysis is also presented. Although this thesis focusses on assessing the impacts of PV on distribution system performance, the presented modelling approach can also be applied to investigate the long-term effects of other types of distributed generation such as fuel cell, supercapacitors, wind power systems as well as emerging loads such as EVs. The case study parameters for modelling the LV and MV feeders for DN performance analysis presented in this chapter will be utilized in the
subsequent chapters throughout the thesis. The major components of the three-phase distribution network are modelled in detail with realistic parameters.

The importance of creating a distribution network analysis tool and component models are introduced in this chapter. The main software tools used for developing the distribution network analysis tool included MATLAB and OpenDSS. All the component matrix modelling presented in this chapter are modelled in MATLAB and OpenDSS was used to solve the power flow problem using the MATLAB OpenDSS COM interface feature. Although the power flow can easily be solved using script-based power flow equations from MATLAB, OpenDSS is used due to its flexibility and COM interface allows all the control algorithms to be implemented through MATLAB. For the 24 h simulation, power flow is solved for each time instance. In this thesis, 1 min resolution data is utilized for general time series simulations.

The remainder of the chapter is divided into five sections: in Section 3.2 the importance of developing a detailed LV analysis tool is discussed, focusing on why it is important to extensively model LV feeders. Section 3.3 presents the modelling of the key components found in a typical distribution system and the basic modelling of the devices used to mitigate voltage regulation issues. Section 3.4 also talks about the implementation of the power flow algorithm used to analyze the performance of DNPs. The distribution network parameters to be used as case study scenarios for both MV and LV feeders are presented in Section 3.5. These LV and MV models will be used for case studies throughout the thesis. Section 3.6 concludes the outlining the key contributions.

3.2 Importance of LV Distribution Network Analysis Tool

In future DNPs, excess PV generation may lead to reverse power flow and increase the magnitude of the supply voltage at the consumer’s point of connection. This voltage rise issue along with voltage unbalance makes it essential to perform a comprehensive reassessment of distribution system performance in order to find solutions and propose strategies to address these issues. As distribution systems operate at different voltage levels, the analysis tool developed in this chapter will also be developed to appropriately model 3-wire MV and 4-wire LV networks. The tool also is also capable of modelling how PQ problems introduced in LV propagate to the upstream MV network, and the impact of high
penetration of PV on the operation of the on-load tap changer (OLTC) systems applied in MV and HV substations.

A power flow analysis is one of the essential analysis tools in distribution management planning. In the past, various power flow algorithms have been proposed for power system analysis [32, 88-90], these algorithms include the popular Newton-Raphson, Gauss-Seidel, fast decoupled and backward forward substitution based iterative methods. Although the Backward-Forward substation-based algorithm [32] provides excellent convergence properties for distribution networks with a relatively high R/X ratio, it is not generally suitable for meshed networks. Because the majority of rooftop solar systems are single-phase PV units a three-phase power flow analysis is required to evaluate any voltage unbalance issues. The three-phase power flow algorithm based on the current injection mismatch variant of the Newton-Raphson algorithm [88] is applied in this thesis. The advantage of this algorithm is that it can be applied both for radial and mesh networks and the simple current injection-based approach provides an effective method to investigate the overall effect of loads, rooftop PVs at different nodes in the DN.

3.3 Distribution Network System Modelling

Typical three-phase distribution networks consist of a combination of three-phase series (LV and MV lines, transformers) and shunt (grounding elements, shunt capacitors, loads) elements in each node of the network. To gain a complete understanding of how each of the elements operate, mathematical models for the key components are developed in this section.

The basic topology of a distribution network is shown in Figure 3-1 using a 4-bus system. Figure 3-1 shows that the power initially flows through a 3-wire medium voltage (MV) line, the MV/LV transformer, and then through 4 wire Low Voltage (LV) feeders to supply the LV households where the rooftop single-phase PV systems are usually installed. The Multiple Earth Neutral (MEN) structure in 4-wire LV networks is also demonstrated.
3.3.1 Development of Distribution Line Models

The models of the MV and LV lines in the distribution networks are usually undertaken using a 3x3 admittance matrix consisting of the self-admittances in the diagonal elements and the mutual coupling admittances in the off-diagonal elements. For LV distribution lines the contribution of the neutral wire is generally merged into the three phases using Kron’s Reduction method [91]. However, with increased network unbalance due to single phase PV injections it is important to investigate the effect of solar PV on the neutral voltage and currents to analyse the impact of system unbalance in distribution networks. If the neutral wire needs to be expressed explicitly the LV network impedance can be represented using a 4x4 admittance matrix where the neutral grounding impedance can be added. This is not explicitly modelled in commercially available distribution network analysis tools. For LV feeders in most countries, a multi grounded approach is utilized, and this is applied for modelling the 4th neutral conductor. Now, the matrices required to model the admittance data for solving the power flow equations for distribution network voltage and currents will be introduced. The matrices used to model the LV and MV lines can be expressed as:

\[
Y_{MV} = \begin{pmatrix}
  y_{aa} & y_{ab} & y_{ac} & 0 \\
  y_{ba} & y_{bb} & y_{bc} & 0 \\
  y_{ca} & y_{cb} & y_{cc} & 0 \\
  0 & 0 & 0 & 0
\end{pmatrix}
\]  

(3.1a)

\[
Y_{LV} = \begin{pmatrix}
  y_{aa} & y_{ab} & y_{ac} & y_{an} \\
  y_{ba} & y_{bb} & y_{bc} & y_{bn} \\
  y_{ca} & y_{cb} & y_{cc} & y_{cn} \\
  y_{na} & y_{nb} & y_{nc} & y_{nn} + y_{ng}
\end{pmatrix}
\]  

(3.1b)
where, the diagonal elements, \( y_{aa}, y_{bb} \) and \( y_{cc} \), are the self-admittances of the three phases of the lines and the off-diagonal elements represents the mutual coupling admittances between the phases a, b and c. The subscripts n and g refer to the neutral and ground phase respectively. The numerical values of the individual admittances can be obtained using Carson’s Line equation with the per unit length impedances or obtained from DNSPs for practical system modelling.

3.3.2 Modelling of Three Phase Distribution Transformers

Transformers play a vital role in distribution networks as the voltage levels need to be stepped down at several points in the distribution system. Common three-phase transformer connection arrangements at the distribution level include delta-star grounded, star-delta, star-star, and delta-delta. To appropriately model a three-phase transformer for the power flow analysis, both the leakage and the core losses of the transformer need to be considered. In [92, 93] the parameters used for the common three phase connections are derived as given in (3.2).

\[
Y_1 = \begin{pmatrix} y_t & 0 & 0 \\ 0 & y_t & 0 \\ 0 & 0 & y_t \end{pmatrix}, \quad Y_2 = \frac{1}{3} \begin{pmatrix} 2y_t & -y_t & -y_t \\ -y_t & 2y_t & -y_t \\ -y_t & -y_t & 2y_t \end{pmatrix},
\]

\[
Y_3 = \frac{1}{\sqrt{3}} \begin{pmatrix} -y_t & y_t & 0 \\ 0 & -y_t & y_t \\ y_t & 0 & -y_t \end{pmatrix}, \quad Y_4 = \frac{1}{3} \begin{pmatrix} y_t & -y_t & 0 \\ -y_t & 2y_t & -y_t \\ 0 & -y_t & y_t \end{pmatrix}.
\] (3.2)

In (3.2), \( y_t \) represents the leakage admittance of the individual phases. To incorporate the neutral phase in the combined modelling of MV and LV a 4\(^{th}\) zero row and column can be added resulting in 4x4 matrices. Table 3-1 presents the primitive admittance matrix depending on the connection type of the three-phase transformer being used. The superscript ‘T’ represents the transpose matrix operator. The overall structure of the transformer admittance matrix can be expressed as:

\[
Y_{\text{Transformer}} = \begin{pmatrix} Y_{PP} & Y_{PS} \\ Y_{SP} & Y_{SS} \end{pmatrix}
\] (3.3)
where the subscripts P and S represents primary and secondary sides of the transformer respectively.

Table 3-1 Admittance matrix of typical transformer connections

<table>
<thead>
<tr>
<th>Connection</th>
<th>Y_{PP}</th>
<th>Y_{PS}</th>
<th>Y_{SP}</th>
<th>Y_{SS}</th>
</tr>
</thead>
<tbody>
<tr>
<td>Star-G Star-G</td>
<td>Y_1</td>
<td>Y_1</td>
<td>Y_1</td>
<td>Y_1</td>
</tr>
<tr>
<td>Star-G Star</td>
<td>Y_2</td>
<td>Y_2</td>
<td>Y_2</td>
<td>Y_2</td>
</tr>
<tr>
<td>Star-G Delta</td>
<td>Y_1</td>
<td>-Y_3</td>
<td>Y_2</td>
<td>-Y_3^T</td>
</tr>
<tr>
<td>Star Star</td>
<td>Y_2</td>
<td>Y_2</td>
<td>Y_2</td>
<td>Y_2</td>
</tr>
<tr>
<td>Star Delta</td>
<td>Y_2</td>
<td>-Y_3</td>
<td>Y_2</td>
<td>-Y_3^T</td>
</tr>
<tr>
<td>Delta Delta</td>
<td>Y_2</td>
<td>Y_2</td>
<td>Y_2</td>
<td>Y_2</td>
</tr>
</tbody>
</table>

3.3.3 Modelling of Loads

Modelling the overall load of a customer is a complex task because a typical house contains a range of different electrical appliances. Load rating, type and operating principle need to be considered. The well-known ZIP model is applied to represent the loads. In the ZIP model the total power consumption of a mixed load is composed of the combination of constant power, constant current and constant impedance [94] load types. The voltage dependency of the total consumption of active and reactive power of each phase can be expressed by the equation:

\[ P_{ZIP} = P_0 \left( \left( \frac{V}{V_0} \right)^2 P^Z + \frac{V}{V_0} P^I + P^P \right) \]  \hspace{1cm} (3.4a)

\[ Q_{ZIP} = Q_0 \left( \left( \frac{V}{V_0} \right)^2 Q^Z + \frac{V}{V_0} Q^I + Q^P \right) \]  \hspace{1cm} (3.4b)

where, \( P^P + P^I + P^Z = 1 \) and \( Q^P + Q^I + Q^Z = 1 \) \hspace{1cm} (3.4c)

where:
- \( P^Z, P^I \) and \( P^Z \) are the proportions of active power contributions from the constant impedance, constant current and constant power load types.
- \( V \) and \( V_0 \) are the line to neutral voltage of the customer supply and the nominal voltage respectively.
The reactive power components can be expressed similarly. Additionally, the time series use of power varies from one customer to the other.

### 3.3.4 Modelling of PV Systems

Modern rooftop solar PV systems consist of PV panels generating DC power through the conversion of solar energy. This DC power is then converted into AC by means of an inverter to supply loads or be exported into the grid if any form of storage is not available. PV systems are generally configured to operate at unity power factor and thus the reactive power from the inverter can be expected to be zero. However, most modern inverters also have the capability to provide reactive power support and the reactive power limit depends on the apparent power rating of the inverter. As a current injection-based load flow approach will be utilized to represent rooftop PV systems. The required overall current from the inverter, operating both at leading and lagging power factor, can be expressed as:

\[
I_{\text{inv}} = \begin{cases} 
\left( \frac{P_{\text{inv}} + j \sqrt{S_{\text{inv}}^2 - P_{\text{inv}}^2}}{V} \right)^* & \text{(lagging)} \\
\left( \frac{P_{\text{inv}} - j \sqrt{S_{\text{inv}}^2 - P_{\text{inv}}^2}}{V} \right)^* & \text{(leading)} 
\end{cases} 
\]  

(3.5)

Where:

- The subscript \textit{inv} in the variables \( I, P \) and \( S \) corresponds to the inverter current, real power and apparent power respectively;
- The \( j \) operator represents the imaginary section in Cartesian Coordinates; and
- \( * \) is the complex conjugate operator.

De-rating factors have also been considered to relate inverter real power and DC power produced from the PV panels. These derating factors take into account aspects such as the efficiency of the inverter, impacts of dirt on panels and power mismatch due to multiple panel coordination. The level of reactive power support from the PV system is controlled by the apparent power rating of the inverter. The DC power from the maximum power point tracking (MPPT) algorithm can be obtained from the characteristic graph of current \((I_{\text{DC}})\)
versus the operating voltage \( V_{DC} \) of the individual panels. The functions of the voltages and currents from the panels can be mathematically represented as a function of the following parameters [95]:

\[
V_{DC} = f(t, p) \tag{3.6}
\]
\[
I_{DC} = g(t, G, p, V_{DC}, I_{DC}) \tag{3.7}
\]

In (3.6), \( f \) is a function to calculate the operating voltage of the PV panel from the irradiance data, \( t \) represents the operating temperature and \( p \) corresponds to a matrix of the various PV electrical parameters such as short circuit current, voltage and current coefficients and the internal resistances of the modules. In (3.7) \( g \) is a function to determine the panel output DC current from the ambient conditions and the implementation of the MPPT algorithm. The \( G \) in (3.7) stands for the irradiance level of the Sun at any particular instance.

### 3.3.5 Modelling of Energy Storage Devices

Energy storage (ES) is expected to play a key role in addressing issues imposed by solar PV systems in future DNs. In addition, the price of storage devices (e.g. lithium-ion batteries) are decreasing. With effective control, batteries can alleviate voltage rise by storing excess power when generation exceeds load and utilizing stored energy to reduce peak load (observed during the evening). Numerous examples of customer owned distributed (behind the meter) ES devices are documented [50-53]. In [96], a review of ES control strategies identifies the different control types as: rule based control (RBC), optimal control, agent-based modelling and model predictive control (MPC). MPC or receding horizon optimization is based on optimizing the objective variable with a prediction of future loads and PV generation. BES systems are connected to the grid through a DC-AC bidirectional converter to convert the battery DC power to AC. Modern storage devices are also capable of providing reactive power support [97].

In terms of modelling the real power contribution \( P \), the required \( P \) from the ES device depends on the algorithm used to control the device. From a time domain perspective, the State of Charge (SoC) at time, \( t \), can be modelled as:

\[
\text{SoC}(t + \Delta t) = \text{SoC}(t) - \left( \eta_{\text{batt}} \frac{P_{\text{ch}}^{\text{ES}}(t)}{P_{\text{dis}}^{\text{ES}}(t)} \right) \Delta t \tag{3.8}
\]
In (3.8), $P_{ch}^{ES}(t)$ and $P_{dis}^{ES}(t)$ are the charging and discharging powers from the ES respectively, $\Delta t$ is the time step used for the time series power flow and $\eta_{batt}$ is the efficiency of the power converter system.

### 3.3.6 Modelling of STATCOMs

#### 3.3.6.1 Basic Operation Principle of STATCOMs

Figure 3-2 illustrates connection of STATCOM to a simple 2-bus LV distribution network. The basic structure of the STATCOM includes a voltage source inverter which is connected to the network by means of a coupling transformer. The STATCOM includes a capacitor to maintain the DC side voltage and to provide a mechanism for reactive power transfer. The inverter for a single phase STATCOM can either be a two-level H-Bridge connection or multilevel converter which can help reduce injected harmonics.

![Figure 3-2 Connection of a STATCOM to an AC network](image)

Neglecting any impact of harmonics associated with the switching of the STATCOM, the inverter side voltage in the can be represented as:

$$e_d = kV_{dc} \cos \alpha \tag{3.9}$$

$$e_q = kV_{dc} \sin \alpha \tag{3.10}$$

where, $k$ represents the factor which relates the DC voltage to the line-neutral voltage of the grid, and $\alpha$ is the phase shift between the inverter voltage and grid voltage in the $d$-$q$ frame.

In terms of reactive power regulation, the control variables $k$ and $\alpha$ can be regulated by controlling the switching signals of the inverter. However, based on the results presented in [98] it is evident that controlling both parameters was not economical due to the low efficiency achieved and high harmonic content in the inverter side voltage. Hence, in practice
only the angle $\alpha$ is controlled to regulate the reactive power from the STATCOM. Figure 3-3 illustrates how a proportional integral (PI) controller can be applied to regulate the reactive component of the current ($i_q$) [99], where $n$ is the number of switches depending on the STATCOM design.

![Control loop used to regulate the reactive power in STATCOMs](image)

**Figure 3-3 Control loop used to regulate the reactive power in STATCOMs**

### 3.3.6.2 Modelling the Reactive Power from STATCOM

STATCOMs regulate the voltage by either absorbing reactive power (akin to a reactor) to reduce the voltage or injecting reactive power (akin to a capacitor) to increase the voltage. To demonstrate the performance of the STATCOM system with varying loads and PV output, a Q-V droop curve is applied to specify the level of reactive power injection/absorption required to maintain appropriate voltage regulation as shown in Figure 3-4. $Q_{\text{max}}$ and $Q_{\text{min}}$ is the maximum amount of reactive power the STATCOM can absorb and generate, and $V_{\text{max}}$ and $V_{\text{min}}$ corresponds to the voltage limits the region between which the Q is controlled linearly according to the measured voltage.
Here, the STATCOM is considered as a reactive power load and hence a negative Q in the droop curve corresponds to reactive power being injected. The amount of reactive power required for a certain amount of voltage regulation depends on the distribution network configuration (i.e. reactance) and where the STATCOM is connected in the network. The related mathematical formulation along with the size of the STATCOM depending on the load levels is derived in Chapter 5. To model the STATCOM in OpenDSS, it was modelled as a PV inverter system, with real power set to 0 and the Volt-VAr mode activated to model the reactive power from the STATCOM according to the droop curve specifications.

3.4 Power Flow Algorithm

In the current mismatch variant based three-phase power flow algorithm, the convergence of the specified and calculated currents is used to calculate the different node voltages. The Cartesian coordinate system is used to represent the three-phase current and voltage vectors, where the network equations will be solved using the Newton-Raphson technique. Based on this model, for a converged power flow program the difference between the specified and the calculated currents for each phase approaches zero. The specified currents can be calculated from the overall real and apparent power injections from each of the component as shown in Figure 3-5. The current mismatch variable represented by ΔI can be expressed as:

$$\Delta I = I^{spe} - I^{cal} \approx 0$$  \hspace{1cm} (3.11)
Figure 3-5 Current injection visualization in future households

Here, $I^{spe}$ and $I^{cal}$ are the vectors of the three-phase specified and calculated currents respectively at a bus. The specified current in a bus can be calculated from the apparent power and the bus voltage of the load, PV system and the storage component. The individual contributions from the different components of a customer can be used to mathematically obtain the specified current from:

$$I^{spe} = -I^{Load} + I^{PV}(±I^{ES})(±I^{Stat})$$ (3.12)

In (3.12), $I^{Load}$, $I^{PV}$, $I^{ES}$ and $I^{Stat}$ are the bus current injections from the load, the PV system, energy storage system and STATCOM respectively. The load current has been expressed with a negative sign to illustrate that it is drawing current from the grid. As storage devices and STATCOM will be investigated as a mitigation strategy, the current contribution from batteries ($I^{ES}$) and reactive current from STATCOM ($I^{Stat}$) are also included. The current from the battery will be negative during charging as it behaves like a load and positive when it is discharged for evening peak load support.

The calculated currents of the three phases of an arbitrary node, $m$, can be attained from the general network equation:

$$I^{cal}_{m} = \sum_{n=1}^{k} Y_{mn}V_{n}$$ (3.13)

where,
- $Y$ is the admittance matrix from bus $m$ to $n$ and
- $k$ is the total number of buses in the system.

Equation (3.13) can be expanded to express the current mismatch, in bus $m$, in real and imaginary components using the equations:

$$
\Delta I_{m}^{Re} = \frac{P_m V_m^{Re} + Q_m V_m^{ima}}{(V_m^{Re} + jV_m^{ima})^2} - \sum_{n=1}^{k} \left( G_{mn} V_n^{Re} - B_{mn} V_n^{ima} \right) \tag{3.14}
$$

$$
\Delta I_{m}^{Im} = \frac{P_m V_m^{ima} + Q_m V_m^{Re}}{(V_m^{Re} + jV_m^{ima})^2} - \sum_{n=1}^{k} \left( G_{mn} V_n^{ima} - B_{mn} V_n^{Re} \right). \tag{3.15}
$$

In (3.14) and (3.15), the superscripts $Re$ and $Im$ represents the real and imaginary components of the corresponding current and voltage vectors. $G_{mn}$ and $B_{mn}$ are $4 \times 4$ matrices which represent the real and imaginary magnitudes of the admittance matrix. The individual current, voltage, real and reactive power elements in (3.11) and (3.12) are $4 \times 1$ matrices where each row corresponds to individual phase measurements. The 4th element corresponds to the neutral conductor in MEN systems. The overall real and reactive power for a given bus is the sum of the PV output, the load demand, and the output of the energy storage system. Once the current mismatch vectors of the individual buses are computed, they can be used to obtain the voltage update vector using the Newton-Raphson iterative technique. The main advantage of using the current mismatch technique in Cartesian coordinates is because the Jacobian matrix is very similar to the admittance matrix with only the diagonal elements requiring an update. The voltage update vector can be related to the current mismatch using:

$$
\begin{bmatrix}
\Delta V_{abc}^{Re}_{m} \\
\Delta V_{abc}^{Im}_{m}
\end{bmatrix} = \text{inv}(J) \times 
\begin{bmatrix}
\Delta I_{abc}^{Re}_{m} \\
\Delta I_{abc}^{Im}_{m}
\end{bmatrix} \tag{3.16}
$$

where $J$ is the $8 \times 8$ Jacobian Element. Here each bus is defined with 4 wires (three phases and neutral) and all the elements are represented using both real and imaginary components making the $J$ matrix $8 \times 8$. The imaginary and real components of the current mismatch matrix are inverted using the formation of the Jacobian matrix which only requires an update in the diagonal elements. This simplifies the power flow solution. The details on how to calculate
the Jacobian are provided in [88] and this method is utilized in this thesis. To find the solution for the power flow, the voltages in the buses are updated iteratively until the current mismatch vector reaches a predefined tolerance.

3.5 Case Studies Parameters

This section presents the modelling of both the LV and MV feeders to analyze the impact of high penetration of rooftop PV systems in future distribution systems. The LV feeder to be used is a 300 m radial overhead line where the neutral conductor is grounded at several points with a MEN configuration. For the MV feeder a 3-wired heavily loaded 14.25 km feeder fitted with an OLTC is used. The feeders have been chosen to represent a practical network from NSW, Australia with realistic feeder design and cable data. The models of both the LV and MV feeders will be used through the remaining chapters of the thesis. The OpenDSS script for the formation of the LV and MV feeder can be found in Appendix A.1 and Appendix A.2 respectively.

3.5.1 LV Feeder Modelling

To demonstrate the voltage issue due to integration of solar PV in LV feeders, a typical overhead 4-wire feeder from NSW, Australia has been modelled. In practice, LV feeders have an almost infinite range of configurations including underground networks in city centres. Overhead feeder parameters are used as overhead network is commonly used in residential networks. In addition, the high R/X ratio associated with overhead network construction means the worst voltage scenarios can be expected in overhead systems. The case study feeder length is 300 m and it is supplied by an 11 kV/400 V delta-star distribution transformer with 4% reactance (200 kVA transformer). The line-to-neutral voltage at the distribution transformer busbar was selected to be 240 V (10 V higher than the 230 V nominal voltage used in Australia). In order to demonstrate the worst-case scenario, the LV feeder is heavily loaded with 60 loads (houses) across the three phases. With a length of 300 m, this results in 15 m between each load based on there being 20 loads per phase. A peak load of 3 kW per connection is applied and a single phase 5 kW rooftop PV systems was also connected at each load point. Figure 3-6 shows the basic single line structure of the radial LV feeder to be used for the case study.
For 4-wire modelling a 4x4 matrix was defined for the line impedance and as such the case study explicitly models the neutral conductor. To model the earth explicitly a 5-wire approach needs to be used which would not produce significant changes in the obtained voltages of the floating neutral. The conductor used for forming the network had a positive sequence resistance and reactance of 0.583 Ω/km and 0.3523 Ω/km (cable type- Banana-6/3.75ACSRGZ) respectively, giving an overall R/X ratio of 1.65. A grounding resistance of 0.5 Ω was used to model the neutral to ground connection [56]. The cable impedance, line geometry and grounding resistance values were used to form the 4x4 impedance matrix in order to model the 4-wire system using Carson’s equations [25]. Table 3-2 summarizes the key parameters used in the model.

<table>
<thead>
<tr>
<th>Simulation parameters</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Load</td>
<td>3 kW at 0.95 pf</td>
</tr>
<tr>
<td>PV System</td>
<td>5 kW default unity pf</td>
</tr>
<tr>
<td>Length of Feeder</td>
<td>300 m with 15 m between load connections</td>
</tr>
<tr>
<td>Line Impedance</td>
<td>0.583 + j0.3523 Ω/km</td>
</tr>
<tr>
<td>Grounding Impedance</td>
<td>0.5 Ω</td>
</tr>
</tbody>
</table>

3.5.2 MV Network

Figure 3-7 illustrates the single line diagram of the network structure used to model the MV components applied in the case study. The system parameters have been selected to replicate an Australian 11 kV distribution system. The above-described LV feeders are connected in the numbered nodes in the network as shown. The conductor used for forming the network had a positive sequence resistance and reactance of 0.31 Ω/km and 0.35 Ω/km respectively, this leads to a lower R/X ratio compared to the conductor and lines used in the LV feeder.
The distance between each of node was set to 750 m giving a total MV network length of length 14.25 km. Combined modelling of MV and LV networks allows the impact of LV PV systems on the immediate upstream network operation to be evaluated. The mitigation strategies proposed in this thesis will also be tested in the MV network to analyse overall system performance.

OLTCs are typically used in zone substation transformers (HV/MV) to regulate the distribution network voltage levels within the statutory limits. In NSW, OLTCs are used to step down the voltage from 66 kV/33 kV to the 11 kV used in MV networks. A star-star connection is generally deployed in these zone substation transformers. The target voltage, bandwidth and time delay are the key parameters in the operation of the OLTC. Zone substation transformers traditionally had 7x -1.5% taps and 14x +1.5% taps, as distribution systems mostly required to boost the voltage for downstream power flow. According to [100], the time delay used by Australian DNSPs is 60 s to ensure the OLTC does not operate during transient events. The voltage bandwidth used in the modelling is 2.8% and the tap position is varied if the secondary voltage is not within the bandwidth set. The time delay setting needs to be lower than the delay set at the transmission level to avoid instability in the tap changing operation.
3.6 Chapter Summary

This chapter presents the modelling approach for three phase power flow analysis to reassess the distribution network performance with a high penetration of single-phase PV units integrated. A detailed 4-wire model has been implemented for the LV feeder which is capable of capturing the impact on the neutral conductor during high unbalance in the system, and which will be utilised in the remaining chapters. The analysis tool will also be used for STATCOM, small scale battery, and community scale battery energy storage simulations in the latter chapters of this thesis.

Detailed three-phase mathematical models of all the major components in the grid including lines, transformers, rooftop PV, STATCOM and ES devices are formulated for use in the three-phase power flow equations.

The model of a case study MV network and LV network, which represent the behaviour of typical Australian networks, has also been introduced to investigate how the issues in LV can propagate through distribution systems. Realistic feeder design and cable data from an Australian DNPSP was used for the developing the case study parameters for this thesis.
Chapter 4

Analysis of Distribution Network Voltage Rise Performance with Rooftop Solar PV Systems

4.1 Chapter Overview

This chapter presents the simulation results from investigation into the voltage rise issue in future PV rich distribution networks. A time series power flow study has been performed utilizing the MV and LV models defined in Chapter 3. Realistic load and irradiance data from an Australian DNSP was used as the input data for the study. The main aim of this chapter is to demonstrate the voltage regulation issues associated with the problem identification of the thesis. A future scenario is considered where all residential customers on the modelled network are fitted with a rooftop PV system. All the analysis carried out in this chapter is in accordance with the Australian grid design and standards, however the process used here is equally applicable to many distribution networks all over the world.

In the first half of the chapter, the impact of small-scale rooftop PV on the performance of LV feeders is studied. A 24 h power flow case study is used to demonstrate time series performance of LV as the load consumption and PV generation varies. The results demonstrate both midday voltage rise during peak PV production and how a typical evening peak load can decrease in the supply voltage. As expected, the results also showed that for a uniformly distributed radial feeder, the maximum voltage variation was observed at customers connected at the end of the feeder. The case study also included the impact of unbalanced loading and the impact of connecting rooftop PV units in an unbalanced pattern. For the investigation of network unbalance both the voltage unbalance factor and Neutral-Ground (N-G) potential is analysed. The second half of the chapter concentrates on MV
distribution network performance. A realistic 19 bus network was used for the case study which replicates an 11 kV network from NSW, Australia. The analysis in this section includes investigating the change in tap operation of the OLTC at the 33/11 kV distribution substation and the variation of the voltage levels in the 11 kV with significant rooftop PV injection.

4.2 PV Impact on LV Networks

4.2.1 Voltage Profiles in PV Rich LV Feeders

Modelling the overall load of a customer is a complex task because a typical house contains a range of different electrical appliances and ratings, types and operating principles, and time of use need to be considered. As discussed, voltage regulation issues in distribution networks are expected to be worst in residential overhead LV and MV feeders. Hence, the load data to be used in this thesis has been selected to imitate a typical residential household. Although a typical household would have more step (on/off) type loads, the household load is represented by a curve which closely matches an aggregate of households (statistical representation of a household) to ensure the resulting voltage profile aligns with results presented in field data from references. To demonstrate the performance of DNs in terms of varying loads and PV output, a 24 h time series simulation is used for the case study LV feeder. The data used for the simulations was 1 min interval data provided by a DNSP in NSW, Australia measured at the MV/LV distribution transformer. The load data used had a peak value of 3 kW and the rooftop PV system had a rating of 5 kW. The irradiance data was configured to represent the characteristics of a summer day, without cloud passing events. No cloud passing events were introduced as this thesis focuses on steady state voltage regulation.

Figure 4-1 shows the active power variation of the load and PV output throughout the day. Although some modern loads may be capacitive in nature, the load was operated at a lagging power factor of 0.95. The PV system was operated at unity power factor to demonstrate the voltage rise situation without any smart inverter functions operational. It was assumed that the loads in the LV feeder are uniformly distributed. This may not imitate a real-life scenario, but it is a common technique used for distribution network analysis as the worst-case scenarios of voltage rise and drop can be demonstrated [33]. The general patterns for the time series power flow can also be observed highlighting the time of day when these issues are to be expected.
According to Australian Standard AS 61000.3.100 [6], the line-to-neutral voltage at LV should be within 0.94 and 1.10 pu of the 230 V nominal value. This allows the individual line-neutral voltages to vary between 216.2 V and 253 V. Two scenarios have been identified in the plot shown in Figure 4-1 to investigate the most extreme voltage deviations during maximum reverse power flow and the evening peak load. They can be described as:

1) Midday when there is maximum PV production and minimum load. Here the PV systems are operated at 5 kW and the load is at 55% of its peak value. The value of 55% was selected based on the load data shape provided by a DNSP in NSW, Australia. This represents the maximum voltage rise scenario with significant reverse power flow in the network.

2) Evening Peak with the load with no PV production. Here each load is operated at 3 kW (at 0.95 lagging) and there is no production from the PV systems. This represents the maximum voltage drop scenario.

Figure 4-2 plots the voltage profile along the feeder for the two scenarios, where the blue line and orange line plot scenario 1 and scenario 2 respectively. As a uniform loading approach was utilized (i.e. loads are distributed uniformly along the feeder length) the node at the end of the feeder experienced the maximum voltage variations. In addition, for this modelling
scenario, more than half of the customers connected to this feeder will experience overvoltage conditions at midday. For both cases the voltages towards the end of the feeder are shown to be well outside the allowable range. The maximum voltage observed is 259.2 V for maximum PV production and the voltage decreased to 212.1 V during the maximum evening load. The maximum and minimum voltage obtained here will be utilized when designing the size and operating limits of devices that will be applied in the following chapters of the thesis.

![Figure 4-2 Voltages along the LV feeder](image)

### 4.2.2 Impact of PV in Practical Networks

In this section the 99\textsuperscript{th} percentile voltage recorded in LV feeders will be presented to highlight the capability of PV to change the trend of future voltage profile. The data was provided by a DNSP in NSW for the Power Quality Compliance Audit project [101]. Since the current penetration levels in many feeders may not be high enough to cause significant reverse power flows, voltage rise is not apparent from real life network data. In many cases the monitored data are in strong parts of the distribution network, where the network impedance may not be high enough to induce significant voltage rise. Figure 4-3 depicts the average 99\textsuperscript{th} percentile voltage profile of an LV feeder from 2009 to 2017. It can be observed that over the years the shape of the profile is changing, with significant higher voltages recorded during PV generation (midday) in comparison to light load periods (early morning),
indicating the generation from PV units at daytime. However, if the voltage magnitudes are considered only, there has been little increase in the overall magnitude of the voltage, other than where there is a step decrease for 2017. This is mainly because the nominal voltage in LV feeders is being gradually adjusted from 240 V to 230 V. Recently DNSPs have also introduced aggressive voltage regulation to facilitate the rooftop PV systems. Some of the techniques applied includes adjustment to the fixed tap of the MV/LV distribution transformer and decreasing the MV voltage set points. This method may not be sustainable since the peak load in distribution networks is also on the rise and reduction of the distribution transformer voltage may introduce significant under voltage periods.

The impact of PV generation on voltage is further analyzed by observing the time of day when the maximum voltage occurs. Figure 4-4 shows the time of day when the maximum voltage of the sites was recorded from 2009 to 2017. The overall trend is apparent here as in 2019 only 23% of the sites recorded maximum voltage at daytime whereas in 2017 60% of the sites recorded its maximum voltage at daytime. The results here, highlights the observation made above that the overall voltage profile of LV feeders is changing with the uptake of rooftop PV units. In the future, as the penetration levels increase, significant voltages rises are expected to be observed and the simulation results presented in this chapter will aim to highlight such a scenario.
4.2.3 Three Phase Time Series LV Performance Analysis

4.2.3.1 LV Feeder Loading and PV Generation

DNSPs typically aim to distribute the load equally in the three phases but due to the randomness in the electricity usage from customer to customer, this can result in an unbalance factor. To illustrate the effect of unbalanced PV allocation in the network, the load and PV size in each household was increased by 10% in phase A and decreased by 10% in phase C. This resulted in the PV size being 5.5 kW, 5 kW and 4.5 kW and peak load being 3.3 kW, 3 kW and 2.7 kW in phases A, B and C respectively. Figure 4-5 shows the active power time series variations of the load and PV power in the three phases of the distribution network. Since both the load and PV production is highest in phase A, it is expected that both the overvoltage and undervoltage conditions will be worst in phase A compared to phases B and C; this is reflected in the graphic.
The LV feeder considered in this study has 20 nodes with a spacing of 15 m between the individual loads. Considering a three-phase distribution network, this results in the feeder supplying power to 60 individual households. Figure 4-6 plots the net exchange of real power in the individual phases based on time of day. As expected, for both forward and reverse power flow, the peaks were observed in phase A. This refers to the overall active power measured at the distribution transformer. The general phenomenon of modelling the PV generation as a negative load was applied here. The plot also demonstrates the multidirectional power flow that will be a feature of future distribution networks. During a significant proportion of the day, there was reverse power flow in the network. For both forward and reverse power flow the peak power at the LV transformer was measured to be approximately 60 kW in each phase. The plot in Figure 4-6 also demonstrates that PV systems do not reduce the overall peak power in the feeder as PV generation is not present during the evening when peak loads are most common. In terms of power unbalance, both before and after the maximum reverse power flow, the difference of power between the phases decreased as the PV production varied.
4.2.3.2 LV Feeder Performance with Rooftop PV

As observed from the plot of the voltage profile (Figure 4-2), it is evident that the voltage at the end of the feeder experiences the maximum voltage deviation as power is carried to and from the individual households along the feeder. Figure 4-7 illustrates the variations of the steady state 24 h node voltages at the end of the feeder, where the time series power flow simulations were undertaken both with and without PV systems.

Without PV systems, the traditional voltage regulation issue in radial LV feeders is observed in Figure 4-7 (a). With the highest loading, phase A experienced the maximum voltage drop, during the peak evening load when the voltage was observed to be 209.3 V. This is significantly below the lower voltage limit of 216.2 V as prescribed by AS 61000.3.100. However, this can be easy solved by DNSPs by setting the tap of the off-load tap changer to increase voltage at the start of the feeder. The recommended setting of 240 V was used for the simulations, which can be increased to ensure the voltage at the end of the feeder does not fall below 216.2 V. Capacitor banks are often used to boost the end of feeder voltage as well.
With PV systems connected throughout the feeder, multidirectional power flow induces both overvoltage and undervoltage in the system as seen in Figure 4-7 (b). In phase A, the highest line-to-neutral voltage recorded was 262.1 V and during peak load the voltage decreased to 209.3 V. This results in a total voltage deviation of 52.8 V. This demonstrates the need for a dynamic voltage regulation device capable to both buck and boost the feeder voltage if successful mitigation of voltage variation is to be achieved. It is also evident, that due to the large difference in the sending and receiving end voltage, devices operating by stepping the voltage profile such as OLTCs and LVRs may not be a long-term solution to the voltage regulation problem.

Figure 4-7 Time series voltage variations for a 24 h simulation (a) Without PV (b) With PV
Figure 4-8 shows variations in the feeder line losses with and without rooftop PV, which illustrates how the overall line losses vary throughout the day. As the PV production increases, the loads can be supplied locally and hence it can be seen that the line losses decrease as power is not required to be carried by the feeder conductor. However, during maximum reverse power flow at midday, the feeder has to carry the excess power from the households to the upstream MV network and hence the line losses increase as seen from the orange plot. Without any production from PV, the feeder line losses are identical with and without rooftop PV systems in the LV network. For the 24 h case study presented, the total energy lost from line losses without PV was 203 kWh and with PV it was 132 kWh. In terms of distribution network performance, this reduction of 35% of the line losses is one of the key advantages of distributed rooftop PV systems as the loads can be supplied locally for a significant proportion of the day. The analysis of line losses will be used a measure to quantify the efficacy of different voltage regulation techniques in the latter chapters of this thesis.

![Figure 4-8 Variations in the feeder line losses with and without Rooftop PV](image)

To quantify the voltage unbalance in the system, the definition of the voltage unbalance factor (VUF) according to the IEC/TR 61000-3-13 [26], will be utilized. This has already
been defined in equation (2.1) of Chapter 2. Figure 4-9 plots the variations in VUF measured at the end of the feeder, where the voltage difference between the phases was measured to be highest. The maximum VUF was measured to be 3% during the peak evening load. It was found that the VUF decreased when the PV was operating. This is because when the loads are supplied with the power produced from the PV units, there is a decrease in the distance that power being carried by the feeder has to flow and hence the deviation of the voltage between the phases decreases. During midday, the VUF with PV increased to around 1% which was lower than the VUF obtained without any rooftop PV units installed.

![Figure 4-9 Impact of rooftop PV on voltage unbalance](image)

The impact of rooftop PV on the neutral to ground (N-G) voltage in a 4-wire LV MEN system has been investigated. If the currents are unbalanced, the resulting N-G voltage can become an issue of serious concern. The neutral potential can appear as a noise source for sensitive devices and may cause malfunction for devices requiring a smooth sinusoidal supply. In traditional distribution network analysis, the neutral conductor is merged using Kron’s reduction technique or assumed to be solidly grounded. From a practical perspective this assumption is not realistic, especially if there is high unbalance in the system. The neutral grounding resistance has been also reported to usually be higher than the design value of the distribution network operator due to the coupling with underground water pipes. Unlike the
phase voltages, the N-G voltage is typically highest towards the start of the feeder as the neutral conductor currents are higher at this location. Figure 4-10 shows the variation in the neutral-grounding potential at the 400 V bus-bar of the 11 kV/400 V transformer supplying the feeder with grounding resistances of 0.05 Ω and 0.5 Ω. It can be seen that for an almost solidly grounded neutral design the N-G voltage does not exceed 0.2V, which is well below the maximum allowable N-G threshold for most sensitive equipment. However, if the grounding resistance is assumed to be 0.5 Ω, the unbalance due to the PV and load may increase the N-G potential to exceed 0.5 V as seen from the orange plot in Figure 4-10. When analyzing the capabilities of different voltage mitigation techniques in the latter chapters of this thesis, N-G voltage will be one metric used to quantify the improvement in network unbalance.

![Figure 4-10 Daily variation of the neutral to ground voltage](image)

**4.3 MV Simulation Results**

**4.3.1 MV Network Setup**

In this section, the performance of the MV network will be analyzed in order to investigate if the issues introduced due to PV integration in LV networks can be propagated to the upstream distribution network. The MV network described in Section 3.5.2 has been used for the power flow simulations presented in this section. The 11 kV network replicating a
practical MV network has a total length of 14.25 km, with 750 m between the buses. As seen from the MV network in Figure 3-7, there were 19 buses in total with an OLTC connected at the zone substation to regulate the voltage. For the simulation, the 300 m LV feeder previously described was connected to each bus of the network. This led to a total of 19 LV feeders connected to the MV network through a delta-star 11 kV/400 V step down transformer. The peak rated power for the MV network was 3.42 MW. The zone substation OLTC transformer in used for the analysis in this section consists of 7x -1.5% taps and 14x +1.5% taps. The parameters of the OLTC used for the MV network simulation replicate those of a typical OLTC used in Australian MV networks. The presence of more taps available to boost the voltage demonstrates that traditional distribution systems mostly required boost functionality to account for the voltage drop due to downstream power flow.

4.3.2 Voltage Levels in 11 kV MV Feeder

Figure 4-11 shows the line-line voltages in the MV network with and without rooftop PV systems in the residential case study distribution network. Here the line-line (L-L) voltages were measured at bus 19 as this is the bus that experiences the maximum voltage variations in the MV network. This is because bus 19 is furthest from the zone substation. For both the scenarios considered in this case study, the L-L voltages were observed to be maintained within the allowable threshold of +−10% of the nominal 11 kV. Without PV systems, the tap changing operation can be observed from the sudden change in voltage levels as identified in Figure 4-11 (a). Figure 4-11 (b) shows that during the daytime when there is significant generation from the 5 kW PV sources installed at the individual LV customers, the MV L-L voltages during the daytime increased significantly. This demonstrates that reverse power flow from LV feeders does have the capability to cause voltage rise in the upstream MV network. The increased number of steps in the measured voltage also demonstrate that the OLTC is forced to operate more frequently in order to maintain the voltages within the tolerance band within the MV network. It is well known that utilization of increased number of taps of the OLTC will decrease its overall lifetime and may require early replacement or maintenance as they were not designed to operate in a multidirectional distribution network. This increased operation of the OLTC and the corresponding required increases in maintenance and possible loss of life further emphasizes that the issues introduced due to PV integration in LV network needs to be addressed locally to ensure the MV network operation is not impacted.
Figure 4-11 Variation in the MV line-line voltage (a) Without PV systems (b) With PV systems

4.3.3 Analyzing the Changes in OLTC Operation

In this section the tap position of the OLTC will be further analyzed to gain a quantitative understanding of the degree to which the operation of a zone substation OLTC may change in
future PV rich distribution networks. Figure 4-12 plots the tap position of the OLTC transformer, the blue plot shows the operation of the OLTC in a traditional system with only loads and the orange plot shows the variations of the tap changes when the customer at LV were fitted with rooftop PV systems. It is seen that when there is no production from PV at night the tap position of both the case study scenarios are the same (i.e. there is overlapping of the plots). However, as the PV generation increases during the daytime, the OLTC needs to lower its tap position to buck the voltage levels. Without PV systems the OLTC required 5 tap changes as seen from the blue plot. With PV systems, the OLTC needed to make 14 tap changes. This led to a total of 19 tap change required by the OLTC. Overall, this is an increase of almost 4 times compared to the scenario without PV generation. Traditional OLTCs were not designed to operate this frequently and this demonstrates that increased OLTC maintenance will be required and/or loss of life may be encountered.

![Figure 4-12 Change in tap operation of the OLTC with and without PV systems](image-url)

OLTC operating to mitigate the voltage rise in MV due to reverse power flow
4.4 Chapter Summary

This chapter presented the simulation results used to investigate the voltage rise issue in future PV rich distribution networks. In the first half of the chapter, the impact of small-scaled rooftop PV on the performance of LV feeders was investigated based on the case study network introduced in Chapter 3.

A 24 h power flow case study on the simulated network was used to demonstrate time series performance of LV as the load consumption and PV generation varies. In terms of voltage profile, the maximum voltage observed was 259.2 V and the voltage minimum was 212.1 V during the maximum evening load. This demonstrates how a future LV network fitted with rooftop PV systems experiences both overvoltage and undervoltage periods.

In terms of distribution network line losses, a reduction of 35% was obtained from the 24 h simulation. This demonstrates one of the key advantages of distributed rooftop PV systems as the loads can be supplied locally for a significant proportion of the day. The analysis of line losses quantities assists in establishing the efficacy of different voltage regulation techniques, which is further investigated in the latter chapters of this thesis. It was found that PV production decreased the VUF measurements in the day time however the high neutral currents induced during reverse power flow periods may increase the N-G potential if the grounding resistance is high within the MEN 4-wire structure.

In the final section of this chapter the impact of rooftop PV on the MV network operation is analysed. It was found that rooftop PV systems do have the potential to significantly increase the number of tap changes required to maintain the MV network voltages. Traditional OLTCs were not designed to operate this frequently and this demonstrates that increased OLTC maintenance will be required.

The simulation results demonstrates that without mitigation PV units in LV feeders will cause both overvoltage and undervoltage conditions. Overvoltage or undervoltage conditions can cause damage to electrical equipment, reduce the efficiency of electrical devices, and even pose safety risks. In addition, voltage regulation is important for ensuring the reliability and stability of the distribution network, as voltage fluctuations can cause power outages and other disruptions. The outcomes of this chapter highlight the importance of voltage regulation in distribution networks, discussed in the latter chapters of this thesis.
Chapter 5

Mitigation of Solar PV Impact in LV Radial Feeders using STATCOMs

5.1 Chapter Overview

As a mitigation strategy to address the issues of voltage rise and unbalance, this chapter investigates the application of a Static Synchronous Compensator (STATCOM) in 4-wire LV distribution feeders, through reactive power management. To demonstrate the performance of the STATCOM device with varying loads and PV output, a Q-V droop curve was applied to specify the level of reactive power injection/absorption required to maintain appropriate voltage regulation. The simulation study presented analyses the impact of STATCOM operation on voltage regulation compared to a case with no reactive power control. Compared to other solutions identified in existing literature, this STATCOM based solution utilises localised control only and thus requires no sophisticated communication infrastructure.

The remainder of the chapter is divided into four sections: in Section 5.2 a mathematical model based on lumped load model is presented which can be used to specify the optimum size of the STATCOM. Section 5.3 discusses how STATCOMs may be used to improve voltage regulation and the design process used to determine the rating and location of STATCOMs in an LV feeder. Section 5.4 summarizes the results from a case study undertaken on a typical 4-wire LV feeder and investigates the efficacy of STATCOMs for the improvement of voltage regulation. Section 5.5 concludes the chapter and summarizes the key findings.

5.2 Mathematical Formulation of Voltage Feeders to Size STATCOMs

In traditional electricity supply paradigms, LV distribution networks have had highly predictable impact on MV and HV networks due to the fact that LV networks could be
considered as a load only. However, the recent rapid uptake of rooftop PV systems in LV networks has changed this behaviour making understanding of the performance of LV distribution networks essential for future grid planning. The nature of two-way power flow in LV networks may require mitigation of voltage regulation problems, which is the focus of this chapter, rather than depending on the control devices in the upstream HV and MV networks, e.g. on load tap changers (OLTC) at MV zone substations. The LV distribution network design considered in this thesis is a radial 4-wire feeder (400 V_{LL} nominal voltage) supplied by a delta-star transformer connected to a 3-wire MV network (11 kV_{LL} nominal voltage). This section formulates the voltage deviations from the perspective of the LV distribution network when considering high penetration levels of renewables.

LV feeders vary greatly in length, loading and topology including underground (dense urban loads and newer developments) and overhead (most existing residential loads). No prescriptive classification of LV feeders can be found in the literature.

To derive a generalized equation to calculate the total voltage deviations a feeder with nominal resistance $R \ \Omega/km$, reactance $X \ \Omega/km$, and total length of $l \ km$ is considered. It assumed that loads are uniformly distributed, as per standard design practice. At a particular time ($t$) of the day the total feeder complex power ($S$) can be expressed as:

$$S_{Feeder}(t) = P_{Load}(t) - P_{PV}(t) + jQ_{load}(t)$$  \hspace{1cm} (5.1)

where $P_{Load}$, $P_{PV}$ and $Q_{Load}$ represent the total real power of customer load, real power of PV installations and customer load reactive power respectively. The common convention of modelling generation as a negative load is used. Although modern inverters have reactive power control capabilities, for the purposes of this study it is assumed that the PV systems operate at unity power factor to ensure there is no active power curtailment from the renewable generation source. This aligns well with the operating mode for the majority of PV installations connected to Australian LV networks up until the most recent version of inverter standard AS/NZS 4777.2 became mandatory in late 2021 (which required voltage regulation modes to be enabled).

For the formulation of measuring the level of deviation in voltage levels along the feeder, an exact lumped load model is used [25]. Assuming loads are uniformly distributed, this model lumps the load into two segments, simplifying the network used to calculate the approximate
voltage deviation in the feeder. Figure 5-1 depicts the single line diagram of the model detailed in [91] where a distribution network feeder with multiple nodes can be modelled by placing two-thirds of the total apparent power (measured at the LV transformer) at 0.25 \( l \), where \( l \) is the total length of the feeder, and the remainder at the end of the feeder. Here, \( V_S \) and \( V_R \) are the feeder sending and receiving end voltage magnitudes respectively.

\[ V_S \] \hspace{1cm} \frac{1}{4}l \hspace{1cm} \frac{3}{4}l \hspace{1cm} V_R \]

\( 2/3S_{\text{Feeder}} \)

\( 1/3S_{\text{Feeder}} \)

Figure 5-1 Lumped load model placements in the feeder

Assuming a constant current model for both the PV and loads, the voltage drop along the total feeder can be defined as:

\[
\Delta V_{\text{Feeder}} = I_1 \left( \frac{1}{4}lZ_{\text{line}} \right) + I_2 \left( \frac{3}{4}lZ_{\text{line}} \right)
\]

(5.2)

where,

\[
I_1(t) = \left( \frac{(P_{\text{Load}}(t) - P_{\text{PV}}(t) + jQ_{\text{Load}}(t))}{V_{\text{nom}}} \right)^* 
\]

\[
I_2(t) = \frac{1}{3} \left( \frac{(P_{\text{Load}}(t) - P_{\text{PV}}(t) + jQ_{\text{Load}}(t))}{V_{\text{nom}}} \right)^* 
\]

In (5.2), \( Z_{\text{line}} \) \((R+jX)\) is the impedance of the line per unit length, and \( V_{\text{nom}} \) represents the nominal voltage supply. For an Australian LV distribution network \( V_{\text{nom}} \) is 230 V. According to [25], in distribution network studies the phase difference between \( V_S \) and \( V_R \) is negligible, which means that the voltage drop \( \Delta V_{\text{Feeder}} \) can be approximated by the real component of (5.2). Hence, the difference between the voltage magnitude between the sending end and far end of the feeder can be represented as:

\[
\Delta V_{\text{Feeder}} = \frac{l}{2V_{\text{nom}} \left( (P_{\text{Load}} - P_{\text{PV}})R + Q_{\text{Load}}X \right)}
\]

(5.3)
It can be seen that (5.3) provides a simple method to calculate the total voltage drop experienced in a general LV feeder with uniform loading. A positive value of $V_{Feeder}$ in (5.3) indicates voltage drop as power flows downstream. The above single-phase equivalent model of the feeder can be easily modified to accommodate three-phase unbalanced circuits.

### 5.3 Application of STATCOMs in LV Feeders to Improve Voltage Profile

#### 5.3.1 Placement of STATCOM in LV Feeders based on Sensitivity Analysis

The primary objective of the application of STATCOMs, addressed in this thesis, is to mitigate the effects of steady state voltage deviations due to solar PV integration. The placement of STATCOMs in the LV distribution network is determined based on voltage sensitivity analysis performed using the Newton-Raphson (NR) load flow technique [102, 103]. The bus voltage magnitude and the corresponding angle sensitivities $\Delta V$ and $\Delta \delta$ to real and reactive power can be established using the elements of the inverse Jacobian matrix associated with the converged solution:

$$
\begin{bmatrix}
\Delta \delta \\
\Delta V
\end{bmatrix}
= 
\begin{bmatrix}
S_{\delta p} & S_{\delta q} \\
S_{\delta p} & S_{\delta q}
\end{bmatrix}
\begin{bmatrix}
\Delta P \\
\Delta Q
\end{bmatrix}
$$

(5.4)

of which the sub matrices $[S_{\delta p}]$ and $[S_{\delta q}]$ are the bus angle sensitivities to active and reactive powers respectively and $[S_{vp}]$ and $[S_{vq}]$ are corresponding sensitivities associated with bus voltage magnitudes. The well-known sparse-matrix optimizations can be used in the simplification of calculations. From (5.4), the elements of $[S_{vq}]$ are the key parameters in terms of placement of STATCOMs, which can be interpreted as the magnitude of voltage change for the particular node per unit change in reactive power. Figure 5-2 shows the sensitivity of voltage magnitudes to reactive power for the 300 m long LV feeder, the parameters of which are presented in Section 3.5, which is used in the case study in this chapter. The conductor used for forming the case study feeder has a positive sequence resistance and reactance of 0.583 $\Omega$/km and 0.352 $\Omega$/km respectively. The voltage sensitivity magnitudes were obtained via the Perturb and Observe method proposed in [103] which involves injection of a small value of reactive power (Q) at each bus bar. The ratio of the $\Delta V_{Feeder}$ and the Q injected was then calculated.
If voltage sensitivity is considered as the main factor to decide the location of the STATCOM, the optimum location is the end of the feeder. However, in terms of minimizing the line losses the optimum placement is not at the end of the feeder. The study presented in [104] determined that the optimal place for a capacitor bank to reduce line losses in a radial distribution network would be at a location two-thirds from the sending end of a feeder. However, [104] does not consider voltage improvement as a factor when determining placement of the capacitor banks.

In order to investigate the relationship between feeder line losses and location of the STATCOM, a 24-h time series simulation with varying loads and PV output was considered. Figure 5-3 shows the overall percentage change in line losses ($I^2R$), for the time series simulation as the STATCOM is placed in different positions along the feeder. In Figure 5-3, a negative value corresponds to an overall increase in losses. The placement of STATCOM at the end of the feeder increases the line losses by 11% compared to not using a STATCOM. Considering that the main purpose of the STATCOM in LV distribution networks is to improve the voltage levels, it was decided to place the STATCOM at the end of the test feeder for the remainder of the studies undertaken in this chapter.

Figure 5-2 Voltage sensitivities with respect to the placement of the STATCOM
5.3.2 Sizing of STATCOMs

Assuming there is no change in active power in the distribution network under study, in theory the voltage change due to the change in reactive power can be calculated as the product of $S_{vq}$ and $\Delta Q$ from (5.6). However, this cannot be applied in the case of STATCOMs as the reactive power from the device will be significant and sensitivity analysis-based sizing requires the $\Delta Q$ to be less than 2% in order to apply (5.6) according to [83]. This is because the calculated $S_{vq}$ is for the current state of the system and significant change in either $P$ or $Q$ changes the overall sensitivity of the system.

To calculate the correct sizing of the STATCOM, (5.3) derived for $V_{Feeder}$ in Section 5.2 can be applied. With the STATCOM placed at the end of the feeder the updated model of the feeder is shown in Figure 5-4.
By observing the power flows separately in the two segments of the lumped model, the maximum voltage change in the feeder can be expressed by:

$$\Delta V_{\text{Feeder}} = \left( \frac{l}{2V_{\text{nom}}} ((P_{\text{Load}} - P_{\text{PV}})R + Q_{\text{Load}}X) \right) + \frac{ix}{V_{\text{nom}}} Q_{\text{Stat}}$$  \hspace{1cm} (5.5)

where, $Q_{\text{Stat}}$ is the reactive supplied by the STATCOM. $Q_{\text{Stat}}$ is modelled as a load where a positive value indicates the STATCOM is consuming (absorbing) reactive power to decrease the voltage, whereas a negative value of $Q_{\text{Stat}}$ indicates reactive power injected by the STATCOM to increase the voltage. Comparing (5.5) with (5.3) the contribution to the change in the voltage drop in the feeder due to the STATCOM ($\Delta V_{\text{Stat}}$) can be expressed as:

$$\Delta V_{\text{Stat}} = \frac{ix}{V_{\text{nom}}} Q_{\text{Stat}}$$  \hspace{1cm} (5.6)

which forms the basis for the level of $Q$ required to manage the voltage such that it is maintained within limits. For reactive power regulation, with varying loads and PV output, only the voltage at the end of the feeder needs to be measured to design the reactive power control droop curve for a specific feeder. For the sizing of the STATCOM, the maximum and minimum voltages need to be calculated at the end of the feeder for the maximum reverse power flow and peak load scenarios, and (5.6) can be used to determine the rating of the STATCOM depending on the maximum voltage improvement ($\Delta V_{\text{Stat}}$) required.

### 5.4 Case Study

To demonstrate the voltage improvement capability of STATCOMs in LV feeders, a typical overhead 4-wire feeder from NSW, Australia has been modelled. The feeder length is 300 m and it is supplied by an 11 kV/400 V delta-star distribution transformer with 4% reactance. The specific details of the simulation parameters can be found in Section 3.5.1. The line-to-neutral voltage at the distribution transformer busbar was selected to be 240 V (10 V higher than the 230 V nominal voltage used in Australia) to allow for voltage drop within the LV feeder, as is typical in design processes. This is also often the voltage level measured in Australian networks given the incremental transition to the recently adopted 230 V standard. The STATCOM droop control used for the simulation study can be found in Figure 5-8. The reason for including the voltage limits of 220 V and 250 V in the droop curve to ensure that
the reactive power capabilities are used most effectively, by regulating voltage before it reaches the IEC voltage limits. By doing so, the STATCOM's rated Q can be fully utilized.

5.4.1 Improvement of the Voltage Levels in a LV Feeder

To demonstrate the voltage improvement capabilities of the STATCOM, the voltage profile of the feeder will be analyzed. According to the Australian Standard AS 61000.3.100 [105], the line-to-neutral voltage range is between 0.94 and 1.10 pu of the 230 V nominal. This allows the line-neutral voltage magnitudes to be between 216.2 V and 253 V. Before the connection of the STATCOM, two extreme scenarios were simulated:

1) Midday when there is maximum PV production and minimum load. Here the PV systems generate at 5 kW and the load was assumed to be 55% of its peak value (at 0.95 lagging power factor) which was selected based on the load data profiles provided by a Distribution Network Service Provider (DNSP) in NSW, Australia. This represents the maximum voltage rise scenario.

2) Evening peak load with no PV production. In this case each load was assumed to be consuming 3 kW (at 0.95 lagging power factor) and there is no PV output. This represents the maximum voltage reduction (drop) scenario.

Figure 5-5 shows the voltage profile along the feeder for these two scenarios. In both scenarios the voltages towards the end of the feeder can be seen to be outside the allowable range.
The maximum voltage observed is 259.2 V during maximum PV production and the voltage decreased to 212.1 V during the maximum evening load. These values have been used to calculate the amount of reactive power required to maintain the voltage magnitudes within the mandated limits using (9). For design purposes, the rating of the STATCOM was predicated on reducing the voltage magnitude at the end of the feeder to 250 V for the voltage rise case and 220 V for the maximum voltage drop case, leading to $\Delta V_{\text{Stat}}$ of 9.2 V and -7.9 V respectively. For the feeder used in this case study, this resulted in an inductive reactive power rating of 19.9 kVAr to mitigate the voltage rise and a capacitive reactive power rating of 17.2 kVAr to mitigate the voltage reduction.

Figure 5-6 shows the improved voltage profile of the feeder with the STATCOM operating using the above rating. It can be seen that the voltage is now within the prescribed range.
5.4.2 Time Series Performance Analysis

In this section, to demonstrate the performance of the STATCOM on the feeder with varying loads and PV output, a 24-h time series simulation is considered in relation to the LV study feeder. The data used for the simulations was 1-min interval data provided by a DNSP in NSW, Australia. Figure 5-7 shows the active power variation of the load and PV output data throughout the day for a typical installation. The load was operated at a lagging power factor of 0.95 and the PV system generated at unity power factor to ensure the maximum utilization of the renewable energy source. The two extreme scenarios considered to investigate the maximum voltage deviations are identified in the plot considering the net exchange of real power.
As the load and PV output varies throughout the day, the reactive power from the STATCOM must be regulated to control the voltage. A Q-V based droop curve is utilized to regulate the amount of reactive power injected or absorbed by the STATCOM. The maximum reactive power to mitigate the voltage deviations was previously calculated to be +19.9 kVAr and -17.2 kVAr to manage the voltage within the stipulated limits. The rating of the STATCOM has therefore been selected to be 20 kVAr. It should be noted that the reactive power calculations using the lumped load model provides a close approximate and the exact Q level required will vary.

Given that the relationship between the voltage deviation of the STATCOM and the level of reactive power sourced or absorbed is linear according to (5.6), a linear Q-V droop curve will be utilized about the nominal voltage of 230 V. Figure 5-8 shows the droop curve applied to regulate the amount of reactive power in the case study.
For the case study feeder, the voltage at the end of the feeder experiences the maximum voltage deviation from the nominal value as the distributed load and the PV generation varies. Figure 5-9 shows the voltage on phase A of the household connected to the end of the feeder with and without the STATCOM operating. It is evident that the STATCOM applied using the defined droop curve is successful in maintaining voltage levels between the mandated voltage limits voltage limits of 216.2 V and 253 V.

Figure 5-9 Time series voltage variation at the feeder end for a 24-h simulation

Figure 5-10 shows the required reactive power injected/absorbed from the STATCOM in order to mitigate the voltage deviation issues. As seen maximum reactive power is absorbed
by the STATCOM during midday when PV generation is at maximum. During the peak load at approximately 21:00, the STATCOM supplies maximum reactive power according to the defined droop curve in order to support the voltage.

![Time series variation of the reactive power from the STATCOM](image)

Figure 5-10 Time series variation of the reactive power from the STATCOM

In order to evaluate the efficacy of the STATCOM, the performance of the system with and without the reactive power regulation needs to be investigated. Figure 5-11 shows the total three-phase reactive power in the LV feeder, with and without the STATCOM. During the daytime as the solar PV output surpasses the requirements of the local load the overall reactive power (Q) in the feeder increases as the STATCOM absorbs reactive power to mitigate the voltage rise issue. Conversely, with no PV production, when the STATCOM injects reactive power to boost the voltage the overall reactive power in the feeder decreases as seen in Figure 5-11. Due to the operation of the STATCOM, at midday, the extra reactive power in the network increased the feeder rms current in phase A from 0.25 kA to 0.28 kA; a 12% increase in the peak current. However, during peak load in the evening the current in the feeder decreased from 0.29 kA to 0.27 kA, i.e. a 6.8% reduction.
1) The total reactive power in the feeder is reduced when the STATCOM is injecting reactive power as the loads will absorb the reactive power from the STATCOM instead of it being supplied it from the grid. Even though the real power in the system has not changed, with lower reactive power the losses will be lower as the current in the feeder is reduced lowering the $I^2R$ line losses.

2) When the STATCOM absorbs reactive power to mitigate voltage rise, the amount of reactive power flow in the network increases as more reactive power is drawn from the upstream grid. This increased reactive power will increase the overall current in the feeder and increases the overall losses in the system.

Over the whole 24 h period considered in this case study the overall maximum increase in line losses due to the STATCOM was found to be 11.1%.
5.4.3 System Unbalance

5.4.3.1 Voltage Unbalance

This section investigates the performance of the STATCOM with respect to mitigating unbalance due to unbalanced connection of loads and PV production systems across the three phases of the feeder. Voltage unbalance in LV networks is an important power quality problem which has the potential to propagate to upstream networks. In order to introduce unbalance into the case study network, the PV size and peak load for each installation connected to phase B was reduced by 10% and phase C by 20% compared to phase A. Figure 5-13 depicts the 3-phase net exchange of active power for a particular node in the feeder. Due to the larger load and size of the PV system, the active power contribution from phase A is higher for both reverse power flow and conventional downstream power flow.
In order to investigate the ability of the STATCOM to mitigate voltage unbalance three single-phase 20 kVar STATCOMs are connected to the end of the 4-wire LV feeder considered in this study. As the voltage in the three phases varies over the 24-h study period the reactive power in the individual STATCOMs is regulated according to the droop curve defined in Figure 5-8. Figure 5-14 depicts the three-phase line-neutral voltages with and without the application of STATCOMs in the system. Analysing Figure 5-14(a), the difference in voltage levels across the three phases can be seen, indicating higher voltage unbalance in the system as individual phases absorb/inject different power values. With the reactive power regulation activated, it is evident from Figure 5-14(b), that the three-phase voltages can be successfully controlled to reduce the voltage unbalance in the network.
Figure 5-14 Time series variations of the three phase voltages (a) with no STATCOM (b) with STATCOM

To quantify the voltage unbalance in the system, the definition of voltage unbalance factor (VUF) according to the IEC/TR 61000-3-13 (defined in Chapter 2) is utilized [26]. Figure 5-15 shows the variations in VUF measured at the end of the feeder. Due to the reduction of load and PV size in phases B and C, the maximum VUF is seen to be 3%, with no STATCOM applied. Through the reactive power provided by the STATCOMs, as evident from Figure 5-15 the overall VUF of the system has decreased. With the STATCOM operating, the maximum VUF has reduced to 1%.

Over a short period at approximately 9:00 in the morning and 16:00 in the afternoon, the VUF with the STATCOMs in operation was measured to be higher compared to the VUF measured with no STATCOM. To explain this, the net active power given in Figure 5-13 needs to be considered. It is seen that during these two instances, the net active power is close to zero indicating minimal voltage drop in the feeder, and the voltage at the end of the feeder
is close to 240 V (close to the sending end voltage due to minimal power flow in the feeder) from Figure 5-14(a). The VUF without the STATCOM was also measured to be quite low during this time. Because the droop control applied in this study was designed about the nominal voltage of 230 V, even with little voltage drop in the feeder the STATCOMs absorbs reactive power to reduce the voltage to 230 V. During this operation, the reactive power from the individual single phase STATCOMs increases the VUF by a small margin.

![Figure 5-15 Impact of STATCOM on VUF](image)

5.4.3.2 Neutral to Grounding Potential

The impact of the reactive power regulation, as would be the case for implementation of a STATCOM device, on the neutral-to-ground (N-G) voltage in a 4-wire MEN system is investigated in this section. If the currents are unbalanced, the resulting N-G voltage can become an issue of serious concern. In traditional distribution network analysis, the neutral conductor is accommodated using Kron’s reduction technique or assumed to be solidly grounded. From a practical perspective this assumption is not realistic, especially if there is high unbalance in the system.

Unlike the phase voltages, the N-G voltage is typically highest towards the start of the feeder as the neutral conductor currents are higher at this location. Figure 5-16 shows the variation in the neutral-grounding potential at the 400 V busbar of the 11 kV/400 V transformer supplying the feeder. The N-G resistance was assumed to be 0.5 Ω.
Interestingly, the N-G voltage of the system was observed to be higher during the daytime when the reactive power required to be absorbed to mitigate the voltage rise issue. In the case study PV size in phase A is higher than phase B which is higher than phase C. This means that the phase A current was higher during the middle of the day when compared to the other two phases. With reactive power regulation the STATCOM in phase A will absorb a higher magnitude of reactive power compared to phase B and phase C leading to higher unbalance in the system current. This leads to the N-G voltage increasing due to an increase in the neutral current. This is demonstrated in the orange graph of Figure 5-16 which plots the N-G voltage with the reactive power regulation applied. With no PV generation, however, the N-G voltage is lower when the STATCOM is operating due to lower reactive power and hence lower current in the system.

![Figure 5-16 Impact on N-G potential with reactive power management](image)

**5.4.4 Impact of STATCOM on OLTC Operation**

To study the impact of using a LV STATCOM on the operation of the MV network the changes in the tap operation of the nearest HV/MV transformer has been investigated. The details of the OLTC parameters and the MV network can be found in Section 3.5.2. As expected, due to the application of STATCOMs, fewer taps were required to maintain the MV voltage levels as illustrated in Figure 5-17. The total number of tap changes for a 24-h simulation was reduced from 19 to 13. The increased number of tap changes is already a
significant concern for DNSPs and fewer tap operations with the application of STATCOM will increase the lifetime of OLTCs.

Figure 5-17 Changes in the HV/MV OLTC tap operation due to STATCOM operation

5.5 Chapter Summary

This chapter investigated the feasibility of application of STATCOM based reactive power regulation to maintain the steady-state voltage levels within prescribed limits in radial 4-wire LV feeders. A future grid scenario is considered with 100% penetration of rooftop solar PV, where all the residential houses were fitted with a single-phase rooftop PV system. An exact lumped load model has been utilized to provide a guideline for approximate sizing of the STATCOM required for a general LV radial feeder to control the steady state voltage levels such that they are within the range specified by the relevant Australian standard.

From the equations derived through circuit analysis, the magnitude of voltage improvement from the STATCOM was found to be dependent on the effect of reactance in the line and amount of reactive supplied by the device. For establishing the rating of the STATCOM, two extreme scenarios of maximum voltage rise (midday) and maximum voltage drop (evening) have been considered or absorbed to maintain the voltage levels within the prescribed lower
and upper limits. For the 300 m feeder used for the case study presented the rating of the STATCOM required to maintain voltage levels within the prescribed range was determined to be 20 kVAr. For time-series variation of PV and load output, a Q-V droop control was applied to regulate the reactive power supplied by the STATCOM.

The case study LV feeder was also used to demonstrate the voltage improvement capabilities of the STATCOM through a 24-h time series simulation. The simulation results demonstrated that the STATCOM was successful in maintaining voltage levels within the prescribed range during reverse power flow and peak evening load. The maximum line-to-neutral voltage (end of the feeder) during midday was reduced from 259.1 V to 249 V and during the peak evening load the STATCOM was successful to boost up the voltage from 212.1 V to 219.2 V.

In terms of system unbalance, use of individual STATCOMs on each phase was found to be successful in mitigating the voltage unbalance. Across a 24 h simulation the peak VUF was reduced from 3% to 1%. As a 4 wire MEN modelling approach was developed the impact of the STATCOM on the neutral-to-ground voltage was also analyzed. It was observed N-G voltage increased during PV generation. This, however, is at the cost of increased line losses when reactive power was absorbed when PV power exceeded the load, due to an increased flow of Q in the network. However, during high loads the losses were decreased as the reactive power injected by the STATCOM was absorbed by the households due to lagging power factor in most loads.

Analysis as also been undertaken with respect to the impact of deployment of the STATCOM device on tap changer operations at the nearest HV/MV transformer. For a 24-h simulation the total number of tap changes was reduced from 19 to 13. In addition, this STATCOM based voltage management only requires the voltage to be measured at the connection point and no sophistication communication infrastructure. This provides a comparative economical solution to improve distribution network voltage levels in presence of high number of PV systems.
Chapter 6

Dual Objective MPC of Community Energy Storage in LV Distribution Feeders with Rooftop Solar PV

6.1 Chapter Overview

Energy storage devices have the potential to mitigate the adverse effects of rooftop solar in LV distribution feeders by storing excess energy during the day and providing peak shaving support at high loads. This chapter presents a two-level dual-objective model predictive control (MPC) based algorithm to control DNSP owned community energy storage devices in LV residential distribution feeders. The proposed control method considers the feed-in tariff, spot price of energy and storage system operational costs in the derived objective function of the controller. The controller determines the charging/discharging power of the storage device through a two-level controller, where the individual modes of operation are activated by a high-level controller and a low-level controller provides the optimized charging/discharging rates according to the predefined objective cost functions. A case study is presented utilizing the 300 m 4-wire LV feeder defined in Section 3.5.1. The simulation results are used to demonstrate the efficacy of the proposed control method through a time series power flow simulation. The analysis of the results includes both the system economics and voltage regulation from the DNSP’s perspective.

The remainder of the chapter is divided into five sections. Section 6.2 discusses how model predictive control can be an effective tool for voltage regulation in distribution networks. Section 6.3 formulates the mathematics of the optimization problem including the system model and controller constrains. In Section 6.4, the objective functions of the algorithm are defined, demonstrating the implementation of the two-layer MPC for the selection of the dual
mode operation. Section 6.5 summarizes the outcomes of the case study to demonstrate the economic and technical benefits of the proposed algorithm. Section 6.6 concludes the paper summarizing the key outcomes and providing the concluding remarks of the proposed algorithm.

6.2 Application of MPC in Distribution Network Voltage Regulation

Energy storage (ES) is expected to play a key role to address the operational issues imposed by solar PV systems in future distribution networks. In addition, the price of storage devices (e.g. lithium-ion) are on the decline [106]. With effective control, batteries can alleviate voltage rise by storing excess power when generation exceeds load and utilizing stored energy to reduce peak load (observed during the evening) [49, 107]. Numerous examples of customer owned distributed (behind the meter) ES devices are documented [50-53]. In [96], a review of ES control strategies identifies the different types as: rule based control (RBC), optimal control, agent-based modelling and model predictive control (MPC).

MPC or receding horizon optimization is based around optimizing the objective variable with a prediction of future loads and PV generation. Although ES control strategies such as RBC imposes least computational burden [50], the ability of MPC to incorporate future states of the system into the algorithm has made it very popular in the research community [81]. There have also been significant improvements in the accuracy of prediction data required for MPC algorithms. In [82] RBC and MPC are compared to analyse the economic viability of MPC, where the authors demonstrate the advantages of implementing a MPC ES controller through a LV distribution network simulation study. An MPC based multi-objective algorithm is proposed in [83] to mitigate solar PV impacts in distribution networks, where the activation of ES in the feeder is selected based on sensitivity analysis.

It is evident that distributed ES has potential to mitigate solar PV impacts in distribution networks. However, these devices are typically owned by individual customers and a mutual agreement needs to be made to allow a DNSP to utilize ES to solve network related issues. Even if the DNSPs provide financial incentives to customers, many users may opt not to invest in ES devices. Recently, community energy storage (CES) systems have become popular for DNSPs [108-110]. CES devices are generally located at the edge of the grid, close to the residential customers. The CES can act as a backup power source for customers and can also be used to mitigate power quality issues. In [56], CES is used in a 4-wire LV
network to alleviate neutral-to-ground voltage arising from high unbalance. The authors in [111], demonstrated benefits of utilizing a CES to support electric vehicle loads. In [110], the authors investigated the environmental (reduction in emissions) and economic viability of application of CES in future distribution networks.

Although significant research has been undertaken for development of MPC based algorithms for distributed ES, in terms of application for CES control, only a few examples are available [84-87]. In [87], MPC was applied to CES control to mitigate the effects of high penetration of solar by minimizing the total power in the feeder. In [86], MPC is presented to minimize the operational costs for the optimal control of CES in a microgrid, considering time-varying pricing and losses in the network. In [85], a closed loop strategy is proposed to adjust the MPC to take prediction errors into the objective function.

A key gap in the literature exists on the application of MPC in CES to address both the economic and technical benefits, in particular from the perspective of a DNSP. This chapter proposes MPC based CES control, where both system economics and voltage regulation are addressed by proposing a dual objective mode of operation. For the proposed CES control, a two level MPC algorithm is proposed, where the higher-level controller selects the mode of operation considering the future state of the system, and the lower-level controller calculates the optimum CES power. The proposed control method considers feed-in tariff, spot price of energy, and operational costs of the CES, to obtain the cost function for the economic mode of operation.

6.3 System Modelling and Formulation

This main objective of the model predictive controller is to obtain an optimized value of the control input to regulate the system towards a predefined trajectory over a finite prediction horizon. An objective function is used to define the requirements of the system the controller is aiming to optimize. The main advantage of MPC includes the ability to incorporate physical constraints of the system such as power demand, generation from the rooftop PVs, and thresholds of CES state of charge (SoC). In this section, the different system dynamics considered in the study are defined, including the constraints the algorithm needs to incorporate into the control strategy.
6.3.1 Power Balance

The power balance constraint to ensure the overall power flow of the total feeder load, PV generation, and battery and grid power at time \( k \) is defined as:

\[
P_{\text{Load}}^\text{Feeder}(k) = P_{PV}^\text{Feeder}(k) + P_{\text{batt}}^\text{CES}(k) + P_{\text{grid}}^\text{Feeder}(k)
\]  

(6.1)

where, \( P_{\text{Load}}^\text{Feeder} \) is total active power of LV feeder load, \( P_{PV}^\text{Feeder} \) is total LV feeder PV production, \( P_{\text{batt}}^\text{CES} \) is power flow to/from the CES, and \( P_{\text{grid}}^\text{Feeder} \) is the total MV power exchange.

One mode of the proposed control includes minimizing the DNSP economic costs. This means the total grid power needs to be separated as per (6.2) to consider both forward and reverse power flow scenarios. Operating costs for the DNSP are different for the two scenarios, as the electricity market spot price, and payment to the customer, have individual rates.

\[
P_{\text{grid}}^\text{Feeder}(k) = P_{\text{im}}^\text{Feeder}(k) + P_{\text{ex}}^\text{Feeder}(k)
\]  

(6.2)

In (6.2), \( P_{\text{im}}^\text{Feeder} \) is total import power from the upstream network and \( P_{\text{ex}}^\text{Feeder}(k) \) is total export power back to MV.

The battery power can be split into charging and discharging. This allows charging/discharging power to be used separately when forming the objective function for the MPC algorithm.

\[
P_{\text{batt}}^\text{CES}(k) = P_{\text{ch}}^\text{CES}(k) + P_{\text{dis}}^\text{CES}(k)
\]  

(6.3)

6.3.2 Battery Power Modelling

In the proposed controller, the predicted load and PV data within the prediction horizon is utilized to ensure the SoC of the battery is optimally managed. If the storage system’s efficiency is assumed to be constant for both charging and discharging, the power balance to model the SoC of the battery can be defined as:

\[
\text{SoC}(k+1) = \text{SoC}(k) - \left( \eta_{\text{batt}} P_{\text{ch}}^\text{CES}(k) + \frac{P_{\text{dis}}^\text{CES}(k)}{\eta_{\text{batt}}} \right) \Delta t
\]  

(6.4)
where, \( SoC(k+1) \) is the predicted SoC of the CES at the next discrete time step, \( SoC(k) \) is the current SoC of the CES, and \( \eta_{batt} \) is the efficiency of the battery system. \( \Delta t \) is the time step or the sampling rate used.

### 6.3.3 Controller Constraints

A key advantage of using MPC is the system constraints can be incorporated within the design of the controller. For the control of ES in a LV distribution network, this includes limiting the charging/discharging power of the storage device, setting limits to the amount of power that can be imported or exported by the feeder from the upstream MV network and including the minimum and maximum threshold of the State of Charge that the ES can operate within. The following constraints needs to be maintained to include the physical limitations of the system components.

\[
\begin{align*}
-p_{ch \, max}^{CES} & \leq p_{ch}^{CES}(k) \leq 0 \quad (6.5a) \\
0 & \leq p_{dis}^{CES}(k) \leq p_{dis \, max}^{CES} \quad (6.5b) \\
0 & \leq p_{im \, Feeder}^{Feeder}(k) \leq \infty \quad (6.5c) \\
-\infty & \leq p_{ex \, Feeder}^{Feeder}(k) \leq 0 \quad (6.5d) \\
SoC_{min} & \leq SoC(k) \leq SoC_{max} \quad (6.5e)
\end{align*}
\]

In (6.5), \( p_{ch \, max}^{CES} \) and \( p_{dis \, max}^{CES} \) are the maximum rated charging/discharging power of the CES, \( SoC_{min} \) and \( SoC_{max} \) are the minimum/maximum SoC in kWh respectively to protect the CES from excess charging/discharging.

### 6.3.4 CES Operational Cost Modelling

The operational cost of the CES is modelled according to the economic model proposed in [82]. This incorporates a dollar rate based on the charging and discharging of the CES. As CES will often be a high-cost asset, it is important to include the operational cost to use the CES. The operational cost \( Cost_{ch}^{CES} \) of using the CES in $/kWh can be defined as:

\[
Cost_{ch}^{CES} = \frac{C_{CES}}{2n_{cycles}(SoC_{max} - SoC_{min})}
\]
In (6), $n_{cycles}$ is the total number of cycles the device can operate over its lifetime, and $C_{CES}$ is the CES total purchase cost. The total number of cycles of a typical battery storage can be found in the equipment datasheet. The equation is divided by 2 as $n_{cycles}$ typically includes both charging and discharging cycles.

**6.4 Proposed Algorithm for CES MPC**

**6.4.1 MPC Problem Definition**

The proposed MPC controller aims to utilize the power in a CES to minimize the total operational cost to the DNSP and ensure the feeder voltage is regulated. For the LV network, a radial overhead feeder is considered. For radial feeders, it has been already been demonstrated in Section 5.3.1 that the highest voltage sensitivity is observed at the end of the feeder if the transformer busbar is considered as the swing bus [103]. Thus, the CES is connected at the end of the feeder to maximize voltage improvement throughout the feeder, assuming the busbar voltage is maintained by control devices in the HV/MV network. Typically, LV distribution networks will have more than one feeder extending from the distribution substation, however due to the assumptions in this study the behaviour of each feeder is identical and thus only one feeder with appropriate loading and generation need be modelled.

The proposed control algorithm consists of two distinct modes, i.e. an economic mode and voltage control mode. The overall algorithm is divided into two layers, where the higher-level controller selects the mode which the controller will be operating at. The higher-level controller utilizes binary signals to select the operating mode of the controller. The lower-level controller implements the objective function of the MPC depending on the mode selection. The output of the lower-level controller will be the power the CES should be operating at. As a rolling horizon prediction data is being utilized, it is ensured that CES is not over/under utilized and will be prepared for events such as peak loads and days when there will be very little solar energy available.
6.4.2 MPC Objective Function

The objective of the MPC controller suggested is to make use of the energy available in a CES in order to decrease the overall operational expenses for the DNSP while also maintaining the voltage of the feeder at a stable level. The economic control mode (mode 1) aims to regulate the power in the CES to minimize the total operational costs over the prediction horizon of the rolling optimization control. If the voltage control mode is activated, the objective of the controller is to ensure the CES operates to minimize the voltage deviation throughout the feeder. This is achieved by minimizing the overall grid power in the MV/LV transformer, where the CES is solely controlled to ensure the power exported or imported from the grid is zero. In this section, the cost functions of the two modes are defined. For the economic mode, the total operational cost to the DNSP will be minimized. The costs considered in this study includes:

1) Price for the DNSP to purchase energy from the market according to the spot price, which varies throughout the day depending on a variety of factors.
2) Price to be paid to customers when PV generation exceeds the load. The cost for this depends on the feed-in tariff offered to the customer by the DNSP or Energy Retailer.
3) Operational cost to charge/discharge the CES.

The cost function $Cost_{eco}(k)$ for economic mode is defined as:

$$Cost_{eco}(k) = P_{im}\text{Feeder}(k)\Delta t \times Spot(k) + P_{batt}^{CES}(k)\Delta t \times Cost_{ch}^{CES} + P_{ex}\text{Feeder}(k)\Delta t \times Feed_{in}$$  \hspace{1cm} (6.7)

where, $Spot(k)$ is the spot price to buy energy for the DNSP and $Feed_{in}$ is the feed-in tariff offered to the customers for selling excess power from their PV generation.

In mode 2, the CES is regulated to minimize the voltage deviation in the feeder. This is implemented by minimizing the overall power consumption from the grid through appropriate charging/discharging of the CES. The cost function for this mode can be defined as:

$$Cost_{vol}(k) = \left( p_{grid}^{Feeder}(k) - p_{grid}^{Ref}(k) \right)$$  \hspace{1cm} (6.8)
In (6.8) $P_{grid}^{Ref}$ is the reference power that $P_{bat}^{CES}$ should be controlled to steer the system towards. To minimize the grid power $P_{grid}^{Ref}$ can be set to 0. This ensures the CES supplies the feeder, and overall consumption from the grid is minimised. For the overall algorithm, the objective function that needs to be minimized can be described as:

$$J = \min \sum_{j=k}^{N_p-1} \mu_{eco}(k)Cost_{eco}(k) + \mu_{vol}(k)Cost_{vol}(k)$$  \hspace{1cm} (6.9)$$

where, $N_p$ is the prediction horizon to incorporate the forecasted data into the optimization problem, $\mu_{eco}$ and $\mu_{vol}$ are binary signal arrays produced by the high-level controller to activate a particular mode of operation. The prediction horizon in MPC is defined as the finite time period over which the future behavior of the system is predicted. For the simulation study presented in this chapter $N_p$ was selected to be 48 hours.

6.4.3 Two Level MPC based Controller for the CES

In this section, the operation for the higher-level controller to select the mode of operation is discussed. The algorithm first initiates the binary variables of the two modes, $\mu_{eco}$ and $\mu_{vol}$, to 1 and 0, respectively. This ensures the controller operates the CES to minimize the total operational costs to the DNSP. The predicted load and generation for the feeder ensures the SoC of the CES is optimally managed, e.g. if a high load is expected within the prediction horizon the CES will hold its charge to discharge during the peak load. After the optimum operating power of the CES is computed using MPC, a load flow is performed to obtain the voltage with the optimized variables. If the voltage is predicted to be outside statutory limits, the time at which the voltage is outside the limit is recorded, and $\mu_{vol}$ is set to 1 to activate voltage control mode at that time instant. The step-by-step selection process of individual modes is described in Table 6-1.
Table 6-1 Algorithm to activate the dual mode operation

<table>
<thead>
<tr>
<th>Step 1</th>
<th>Initialize the $\mu_{eco}(k)$ and $\mu_{vol}(k)$ to 1 and 0 to activate the economic mode of operation, where $k \in N_p$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Step 2</td>
<td>Using current and predicted load, generation, and operation costs of the system, apply MPC using the $\mu_{eco}$ and $\mu_{vol}$ values to obtain the optimized values of $P_{batt}^{CES}$ throughout $N_p$</td>
</tr>
<tr>
<td>Step 3</td>
<td>Apply power flow with the $P_{batt}^{CES}$ values to obtain the feeder voltages for $N_p$</td>
</tr>
<tr>
<td>Step 4</td>
<td>Record the time where voltage is outside the limits, this is $T_{out}$. Update $\mu_{eco}(k)$ and $\mu_{vol}(k)$ to 0 and 1 where $k \in T_{out}$</td>
</tr>
<tr>
<td>Step 5</td>
<td>Apply the optimized value of $P_{batt}^{CES}$ to the CES</td>
</tr>
<tr>
<td>Step 6</td>
<td>Set $k=k+1$ and initialize $\mu_{eco}(k+N_p)$ and $\mu_{vol}(k+N_p)$ to 1 and 0 to activate default mode where voltage regulation is not required.</td>
</tr>
<tr>
<td>Step 7</td>
<td>Restart at Step 2 for $k+1$</td>
</tr>
</tbody>
</table>

6.5 Case Study

6.5.1 LV Feeder Parameters

To demonstrate the efficacy of the proposed control algorithm, the 300 m MEN 4-wire LV feeder will be used in this section. As discussed before, the feeder is powered from an 11 kV/400 V delta/star grounded transformer and the voltage at the transformer busbar was assumed to be 240 V. This is 10 V higher than the nominal 230 V used in Australia to account for the voltage drop for typical downstream power flow. The loads, rooftop PV units and unbalance of the system have been modelled identically to the approach described in Section 4.2.3.1. The CES unit was connected to the end of the feeder with a total capacity of 450 kWh, where the minimum and maximum SoC of the CES was assumed to be 45 kWh and 405 kWh, respectively. In terms of percentage this resulted in the SoC constraint of the CES to be between 10% and 90%. Figure 6-1 shows the single-line diagram of the system set up. The efficiency of the community energy storage conversion system was assumed to be a constant 90% for both charging and discharging periods.
Figure 6-1 Single line diagram of the LV feeder and CES system setup

6.5.2 Model Predictive Controller Implementation

The MPC algorithm was solved using the linear integer programming solver in MATLAB and the relevant power flow calculations were performed in OpenDSS. The MPC was developed using 30-min interval data and the power flows were performed with 1-min interval data. For the implementation of the MPC, the prediction horizon was taken to be 24 h. As a 30-min interval data was utilized this resulted in the value of $N_p$ to be 48. The relevant codes for the simulation for the proposed MPC algorithm can be found in Appendix D.

For the implementation of the MPC controller, it is assumed that the feeder load, generation and associated operational costs for the DNSP can be perfectly predicted. In a practical scenario, this predicted data will be subject to errors. However, the main aim of this study is to demonstrate the performance of the algorithm and hence prediction errors have not been considered for this study. It is also assumed that the MPC controller can easily access the required information of the current state of the system (such as load/PV power and voltages along the feeder) through smart meters or other required infrastructure such as power line carriers.

6.5.3 Input data of the Model Predictive Controller

To demonstrate the effectiveness of the proposed controller, a 24-h time series power flow simulation is performed in this chapter. In terms of power, the required data for the controller includes the load data that needs to be supplied to the individual customers connected to the three-phase feeder and the generation from the individual rooftop PV units. As a 24-h
prediction horizon is being used for the simulations, the controller needed access to 48-h load and generation data to account for the prediction horizon. The relevant power data used for the case study presented is depicted in Figure 6-2. It was also assumed that the load and PV data replicated itself for the two consecutive 24 h segments. Although this may not be entirely replicating a real-life scenario, the main purpose of this study is to demonstrate how the controller performs under typical load and PV generation scenario and hence the load and PV data shape were not varied for the second 24 h required for the prediction horizon.

Figure 6-2 Net exchange of active power in LV feeder

Figure 6-3 shows the associated costs for the DNSP. According to the data provided in [82], the cost to use the CES yields 0.1076 $/kWh. This value being large compared to the feed-in tariff and spot pricing, causes the controller to not use the CES at all, as importing from the grid would be the more economical option. On the other hand, if the cost of the battery was taken to be zero, $P_{batt}^{CES}$ would be very fluctuating as the CES would be utilized in an unstable manner. Although the system constrains would still be still met, controlling $P_{batt}^{CES}$ in such a manner is not healthy for the lifetime of the ES system.

The cost of using the CES was selected to be 0.0175 $/kWh to ensure the ES device is not underutilized. Although small, this cost ensures the CES is not used in an unstable manner.
with sudden charging and discharging periods. The feed-in tariff that needs to be paid to the customer during reverse power flow period was 4.5 c/kWh. The spot price of electricity the DNSP must pay to import electricity had an average price of 0.015 $/kWh. The spot price was varied throughout the day, proportional to the load shape, to replicate a real-life scenario.

![Figure 6-3 Associated costs for the MPC controller](image)

6.5.4 Results and Discussions

6.5.4.1 CES Power with MPC

Figure 6-4 (a) shows $P_{batt}^{CES}$ in the three phases and Figure 6-4 (b) plots SoC variation throughout the 24 h simulation. As optimum calculations are performed throughout the prediction horizon, the voltage is monitored and if the voltage is expected to be outside the statutory limits of 216.2 V and 253 V, the voltage regulation mode is activated. To obtain the $P_{batt}^{CES}$ of the individual phases, the MPC algorithm was applied to each of the phase individually and the resultant optimal $P_{batt}^{CES}$ of the three-phase operation are given below. Although the $P_{batt}^{CES}$ in the individual phases followed a similar pattern, higher amount of energy from the CES was utilized in phase A. This is because phase A had a larger load and rooftop PV connected. The initial SoC at the start of the simulations was taken to be 15%. From the SoC plot the CES was optimally controlled to the maximum SoC limit (90%) until about 16:00 after which it started to discharge to support the peak evening load. It is to be noted that the presented case study is sensitive to the input parameters and any variation to the inputs such as the associated costs and initial SoC would change the obtained results.
Figure 6-4 Operation of the CES with the proposed MPC control (a) Three phase power CES (b) State of charge

6.5.4.2 Dual Mode Operation of the MPC Controller

For the proposed MPC controller, the CES is controlled in the economic mode of operation by default and the voltage regulation mode is only activated if an event is identified where the
voltage is expected to be outside the statutory limits. Figure 6-5 shows the values of k where a value of 1 corresponds to the voltage regulation mode being activated. For this case study, the voltage regulation mode needed to be activated during the daytime when there was maximum reverse power flow. Out of the 48-interval data for the 24 h simulation of the MPC, the voltage regulation mode was activated for 6 data intervals or 3 h as seen from the plot below.

It should be noted that the output of the MPC algorithm can never be predicted similar to rule-based algorithms and there could be a possibility during the daytime when the MPC may have signaled the CES to stop charging to minimize the costs. The use of a separate voltage control mode ensures this possibility does not occur and hence the results demonstrates that the dual mode operation works.

![Graph showing Dual mode operation of the proposed MPC controller]

6.5.4.3 Improvement of the Voltages Levels in the LV Feeder

Figure 6-6 depicts the time series variation of the LV feeder voltage with and without the CES MPC measured at the end of the feeder. It can be seen from Figure 6-6 (a) that without any control the voltages obtained are outside the limits during both the reverse power flow and the peak evening load for all the three phases. The voltage regulation capability of the proposed control algorithm is evident from Figure 6-6 (b), where the CES is optimally charged/discharged to ensure the voltages are maintained within the limits. The maximum voltage was reduced from 258 V to 248 V and the minimum voltage recorded in the feeder was increased from 212 V to 220.5 V. Figure 6-7 demonstrates the voltages of the three phases individually.
Figure 6-6 Time series 3-phase voltage variations (a) No control (b) With MPC
Figure 6-7 24-h Time series voltage improvement in the individual phases

6.5.4.4 Changes in Feeder Power and Line Losses

Figure 6-8 shows the total power in the MV/LV transformer throughout the 24 h simulation. Here a negative value, corresponds to when there is an overall energy export back to the MV network. The CES is successful in reducing the overall power in the feeder both for reverse power flow and the evening peak load. At Midday, the proposed algorithm reduced the power exported from the feeder from 157 kW to 102 kW and the total power from the evening peak
was reduced from 196 kW to 149 kW. This reduced power ensures that the conductor used does not exceed its ampacity, and a possibility of adding more houses to the network without overloading the LV feeder.

![Graph showing the comparison between feeder power with and without MPC](image)

Figure 6-8 Net exchange in active power from the MV/LV transformer

Figure 6-9 illustrates how the overall line losses vary throughout the day with and without the MPC based CES. During maximum reverse power flow at midday without any voltage regulation, the feeder must carry the excess power from the households to the upstream MV network and hence the line losses increase as seen from the blue plot. However, as seen from the orange plot the CES can be used to charge up the ES device during reverse power flow which reduces the line losses. This is similar for the evening peak load where the CES can be discharged to supply the LV loads locally. For the 24 h case study presented, the total energy lost from line losses without the proposed controller was 132.12 kWh which reduced to 86.42 kWh with the CES operating. In terms of distribution network performance, this reduction of 34.6% of the line losses is one of the key advantages of DNSPs will gain if they invest on a CES.
6.5.4.5 System Unbalance

To quantify the voltage unbalance in the system, the definition of the voltage unbalance factor (VUF) according to the IEC/TR 61000-3-13 [112], which has been already defined in equation (2.1) in Chapter 2. Figure 6-10 plots the variations in VUF measured at the end of the feeder, where the voltage difference between the phases was measured to be highest. The maximum VUF without any voltage regulation was measured to be 3% during the peak evening load. With the application of MPC, it was found that the VUF was overall lower for the 24 h simulation. However, there is an instance around 9:00 in the morning where the MPC increased the VUF to 3%. This is because at that time, the sudden discharging of the CES due to the economic operation increased the system unbalance as seen in Figure 6-4(a). In terms of the average VUF throughout the day, the MPC decreased the mean VUF from 1.64% to 1.28%.
Figure 6-10 Impact of MPC on VUF

Figure 6-11 shows the variation in the neutral-grounding potential at the 400 V bus-bar of the 11 kV/400 V transformer supplying the feeder with grounding resistance of 0.5 Ω. Overall, the N-G potential was reduced when the CES is utilized as seen from the orange plot. The average N-G voltage for the 24h was reduced 0.78 V to 0.41 V. The peak value of the N-G potential was decreased from 1.17 V to 0.87 V as a result of the MPC operation which resulted in a reduction of the neutral conductor current in the MEN LV feeder.

Figure 6-11 Variations of the N-G potential with MPC control
6.5.4.6 Impact of MPC based CES in LV on OLTC operation in the MV Network

In this section, the performance of MV network will be analyzed to investigate the impact of utilizing MPC based LV CES in the upstream MV distribution network OLTC operation. The MV network described in Section 3.5.2 has been used for the power flow simulations presented in this section. The 11 kV network replicating a practical MV network had a total length of 14.25 km, with 750 m between the buses. As seen from the MV network in Figure 3-7, there were 19 buses in total with an OLTC connected at the distribution substation to regulate the voltage. The 300 m LV feeder was connected to each bus of the network. This led to a total of 19 LV feeders connected to the MV network through a delta-star 11 kV/400 V step down transformer. A zone substation OLTC transformer was used for the analysis in this section and consists of 7x -1.5% taps and 14x +1.5% taps, with the remaining details as found in Section 3.5.2. As expected, due to the application of the CES, fewer taps were required to maintain the MV voltage levels as illustrated in Figure 6-12. This is because the CES overall decreased the amount of power imported and fed back to the MV network. The total number of tap changes for a 24 h simulation was reduced from 19 to 13.

![Figure 6-12 Changes in the HV/MV OLTC tap operation in presence of CES](image)

With the application of the CES, the OLTC was operating to mitigate the voltage rise in MV due to reverse power flow.
6.6 Chapter Summary

This chapter proposed an MPC based algorithm for the control of CES in an LV residential feeder with a dual objective to minimize total DNSP operational costs and provide voltage regulation. The dual objective function was implemented with a two level MPC algorithm where the higher-level controller selected the mode of operation and lower-level controller performed the required optimization.

The performance of the controller has been verified through a time series power flow simulation. Overall, the controller was successful in reducing operational costs and providing optimum voltage regulation, maintaining voltages within statutory limits. The optimum power regulating ability of the controller is demonstrated as the SoC was regulated depending on the load and PV generation predicted data. This demonstrates the key advantage of MPC based ES regulation compared to heuristic algorithms where the SoC can prematurely reach its limits.

The dual mode operation was successful in maintaining the voltages within the prescribed limits. For the 24 h simulation study presented, the maximum voltage was reduced from 258 V to 248 V at midday and the evening peak voltage was increased from 212 V to 220.5 V. The voltage regulation mode needed to be activated during the daytime when there was maximum reverse power flow. There was an overall reduction of 34.6% in line losses, improvement in the unbalance of the system.

Due to the operation of the CES the total power imported/fed into the upstream network there was a drop in the MV OLTC tap operation from 19 to 13.
Chapter 7

Comparative Study of Voltage Regulation Techniques in PV Rich Distribution Networks

7.1 Chapter Overview

This chapter provides a comparative study between the distribution network voltage regulation techniques investigated in this thesis (LV-STATCOM and Model Predictive Control of LV Community Energy Storage) and some comparative techniques implemented by DNSPs in recent times. The modern voltage regulation techniques to be used as a comparative benchmark include smart inverter functions (Volt-VAr, Volt-Watt) and rule based controlled (RBC) CES. Modern inverters have built-in Volt-VAr and Volt-Watt functions to be readily used and RBC was chosen for the Energy Storage (ES) control as it is often implemented in off the shelf residential storage devices. The aim of this chapter is to provide a more detailed network performance study to allow better understanding of the efficacy of the different voltage regulation techniques in terms of their voltage management performance and utilization of feeder capacity. To normalize the network performance parameters two indices are introduced; maximum voltage deviation (MVD) and feeder reserve capacity (FRC) to analyze voltage and hosting capacity of the feeder respectively. The distribution network defined in Section 3.5 is re-utilized for the case study analysis.

The remainder of the chapter is divided into five sections. Section 7.2 defines the voltage regulation techniques to be used as a performance benchmark. The Volt-VAr and Volt-Watt functionality as prescribed in Australian Standard AS 4777.2:2015 [14] has been selected for
this purpose. Section 7.3 introduces the distribution network performance indices which are used to analyze the performance of the aforementioned voltage regulation techniques. In Section 7.4 a comparative study is performed in order to investigate distribution network performance and the advantages and disadvantages of the individual voltage regulation techniques is discussed in detail. Section 7.5 summarizes the chapter with concluding remarks.

7.2 Modern Voltage Regulation Techniques

As discussed in Chapter 3, rooftop PV systems that generate DC electricity are connected to the AC distribution network by means of a power electronic inverter. In the past, PV inverters were typically configured to operate at unity power factor and thus the total reactive power from the PV system was zero. Modern inverters are equipped with voltage response modes which allow regulation of the active and reactive power of the PV systems as a function of the voltage measured at the PCC. In Australia, standard AS 4777.2:2015 defines the settings at which the inverters should be set to operate [14]. Similarly for ES systems, the battery unit is connected to the grid via a bidirectional AC/DC converter where the power flow can be regulated. In this section, the two smart inverter voltage regulation techniques (Volt-Watt and Volt-VAr) and a rule-based control technique for CES systems will be presented. Each of the voltage regulation techniques has been split up into two subsections where both the operational characteristic and their performance in LV feeders are presented. While the simulation results presented in the earlier chapters of the thesis make use of the OpenDSS COM interface to control the devices at every time step via MATLAB, the simulation model for the Volt-Watt and Volt-VAr control techniques is developed utilizing the built-in time series function of OpenDSS. This method has been implemented in order to utilize the capabilities of OpenDSS to handle multiple inverters at each time step, and in these techniques with multiple devices involved the interaction between each device is of key importance. The parameters for the LV feeder can found in Section 3.5.

7.2.1 Volt-Watt

7.2.1.1 Operational Characteristics

In the Volt-Watt mode, the inverter regulates the output active power from the PV system in response to the voltage at its connection terminal. Figure 7-1 shows the characteristic curve for Volt-Watt mode according to the AS 4777.2:2015 standard [14]. It can be seen from the
red voltage response curve that, in this mode, the inverter reduces the active power output linearly when the voltage magnitude is higher than $V_1$. The power output is curtailed to 20\% of its rated peak value when the voltage reaches $V_2$. For Australia, the default value of $V_1$ is 250 V and $V_2$ is 265 V. In the simulation study presented in this chapter these default values of $V_1$ and $V_2$ have been used. For voltages higher than $V_2$ the inverter overvoltage protection operates to disconnect the inverter in order to protect the system and equipment connected thereto from sustained overvoltage. For the 5 kW rooftop LV PV system used in this thesis, based on the Volt-Watt characteristic curve, the output power would be reduced to 1 kW if 265 V was measured at the inverter terminals.

![Inverter response curve for Volt-Watt mode](image)

7.2.1.2 Performance in LV Feeder

In this section, the impact of implementing Volt-Watt mode on LV feeder voltage magnitudes will be demonstrated by activating Volt-Watt function in the PV inverters. The 300 m LV feeder described in Section 3.5.1 has been utilized. Figure 7-2 shows the time series voltage at the end of the LV feeder for phase A. In this figure the blue plot shows the voltage magnitude without any voltage regulation and the orange plot shows the feeder voltage magnitude when Volt-Watt is activated. For the Volt-Watt response, it is seen that the curtailment of active power due during afternoon PV generation peak was not sufficient to
maintain voltage magnitudes (i.e., mitigate rise) to within the threshold limit of 253 V. However, it was very close to achieving this outcome. The maximum voltage magnitude detected for this case study was reduced from 258.1 V to 253.4 V. This is because Volt-Watt is applied locally at each inverter in the feeder and power curtailment is only applied in the PV systems towards the end of the radial LV feeder where higher voltages than 250 V are recorded. This highlights one of the key disadvantages of the application of the Volt-Watt technique; inequity among customers at different points in the network can be introduced. For example, a customer closer to the distribution transformer may have higher financial gain from feed-in rates when compared to a customer connected at the end of the feeder as the network impedance seen by the customer closer to the transformer is lower and as such voltage rise is less when compared to the customer at the end of the feeder. Since voltage regulation is only applied when the voltage is more than 250 V, there is no difference in the voltage reading in the rest of the 24 h period and this voltage regulation technique cannot mitigate any undervoltage issues experienced during the evening peak load.

![Figure 7-2 Impact of Volt-Watt on LV feeder voltage magnitude (at end of feeder)](image)

Figure 7-3 depicts the time series active power flow in the three-phase LV network with and without the Volt-Watt mode activated in the feeder. As would be expected based on the premise of Volt-Watt operation, active power curtailment is observed when the voltage
magnitude of the feeder was greater than 250 V. This is observed between 11:00 and 15:00 in the 24 h simulation when the generation from the PV units was elevated towards its peak rating. As demonstrated by the difference in the blue and orange plots, the maximum reverse power flow in the feeder was reduced from 156.2 kW to 142.4 kW. Although this 8.8% decrease is beneficial for the DNSP, this reduction is achieved through the curtailment of renewable energy which may be in conflict with the modern policies of depending more on renewable energy. If this is applied on a wider scale, there will be a significant reduction in energy generated by PV. However, Volt-Watt provides a simple and economical solution to mitigate voltage rise in distribution networks.

![Figure 7-3 Change in feeder active power due to Volt-Watt operation](image)

### 7.2.2 Volt-VAr

#### 7.2.2.1 Operational Characteristics

In Volt-VAr mode, the inverter regulates the reactive power output from the PV system as a function of the voltage magnitude measured at the inverter terminals. Figure 7-4 depicts the Volt-VAr response curve according to AS 4777.2:2015, where the default values for the voltages $V_1$, $V_2$, $V_3$ and $V_4$ for Australia are 207 V, 220 V, 250 V and 265 V respectively [14]. In the simulation study described in this chapter, the default values for $V_1$, $V_2$, $V_3$ and $V_4$ have been used. In terms of the percentage of reactive power, the highest value from the recommended range of 0% to 60% was utilized to provide the greatest voltage regulation.
While some traditional inverters used in rooftop systems may not have the capability to regulate reactive power at night, it is assumed that all the inverters in this case study are fitted with the appropriate technology to utilize this feature.

The Volt-VAr mode responds to undervoltage conditions by supplying reactive power (capacitive) and absorbing reactive power (inductive) during overvoltage scenarios in order to reduce the network voltage. When the voltage is within the range of 220 V and 250 V the reactive power is set to zero. It also must be noted that for the reactive power to be generated often the active power needs to be curtailed to ensure the operation is within the inverter ratings. For example, if the voltage magnitude is 265 V the inverter is required to absorb reactive power equal to 60% of its rating (3 kVAR for a 5 kVA system). To maintain a fixed rating, the active power output needs to be curtailed by 20% to 4 kW (i.e. $P = \sqrt{5kVA^2 - 3kVAR^2}$) even if there is maximum irradiance.

Figure 7-4 Inverter response curve for Volt-VAr mode

7.2.2.2 Volt-VAr Performance in LV Feeder

The impact of the performance of the LV feeder when Volt-Var response is activated is demonstrated in this section. Figure 7-5 shows the 24 h end node feeder voltage for phase A, with and without the application of Volt-VAr in the rooftop PV inverters. It can be seen that the Volt-VAr voltage regulation was unable to completely mitigate the overvoltage and
undervoltage detected during midday and evening as shown by the orange voltage profile. For the application of Volt-VAr, reactive power was absorbed by the inverter to reduce the voltage during reverse power flow and the maximum feeder voltage was reduced from 258.1 V to 255.2 V. While this corresponds to a voltage rise reduction by 1.12%, the high R/X ratio in LV feeders meant the total reactive power absorbed in the inverters towards the end of the feeder was not sufficient for voltage management in this case study. Compared to Volt-VAr, the reactive power-based solution through use of a LV-STATCOM device proposed in Chapter 5 was successful in maintaining voltage magnitudes to within the prescribed range. This is because the droop curve design according to the line specifications allows the feeder voltage sensitivity to be considered to ensure the STATCOM can be sized properly. Compared to Volt-VAr mode, for STATCOM based voltage regulation, the voltage rise was reduced by 2.98%. If the Volt-VAr curve (Figure 7-5) is analyzed, it is seen that voltage regulation is only activated if the voltage magnitude is above 250 V or below than 220 V. This demonstrates the need to revisit the default values of $V_2$ and $V_3$ as prescribed in AS 4777.2:2015. Further investigation is required to determine if the idle period (220 V to 250 V) needs to be reduced to improve the feeder voltage regulation capabilities with Volt-VAr response. Similar to the overvoltage situation at midday, the reactive power injected through Volt-VAr operation was unable to mitigate the undervoltage issue during evening peak load which is observed during the peak load at approximately 21:00.
Figure 7-5 Impact of Volt-VAr response on LV feeder voltage magnitude

Figure 7-6 shows how the total reactive power in the LV feeder varies for a 24 h time series simulation. According to the Volt-VAr curve, the inverter will only implement reactive power regulation when the measured voltage magnitudes are outside the range of 220 V to 250 V. Hence, there is only a difference in the feeder Q during high generation of PV and during peak loads. During periods of reverse power flow, the inverters with voltages magnitudes higher than 250 V at their terminals absorb reactive power and operates with a lagging power factor. As the loads in this study were 0.95 lagging this increases the total reactive power flow in the network. At midday, the peak reactive power supplied by the distribution transformer was increased from 48.1 kVAR to 70.1 kVAR. If the feeder is already operating close to its peak power, this 24.9% increase in reactive power has the potential to overload the feeder. In contrast, during the evening peak there was a reduction in the total reactive power in the network from 66.9 kVAR to 53.1 kVAR. There is an overall reduction in the feeder reactive power as the 13.8 kVAR total reactive power injected during Volt-VAr operation can be used to supply the leading pf loads.

Figure 7-6 Impact of Volt-VAr response on LV feeder reactive power
Figure 7-7 shows the total active power flow in the LV feeder both with and without the activation of the Volt-VAr response. It is seen that there is no noticeable change in the feeder active power flow, and approximately a 2 kW curtailment of PV power was observed during the maximum reverse power flow period (zoomed in section of Figure 7-7). This is because, the reactive power regulation is only activated in the rooftop PV systems towards the end of the feeder where voltage magnitudes of higher than 250 V are observed. Since, in this simulation study the voltages magnitudes do not exceed 258.1 V, the maximum inverter capacity of none of the inverters were utilized which could have induced higher P curtailment. These results reiterate the findings in [41], where the authors concluded that activation of both Volt-VAr and Volt-Watt response modes only contributes to maximum 2% curtailment of PV active power. During the evening load, since there was no PV generation, the inverters could generate the required reactive power to boost the voltage without any change in the active power flow in the LV feeder.

![Graph showing total active power flow in LV feeder](image)

Figure 7-7 Impact of Volt-VAr response on LV feeder active power

7.2.3 Rule Based Control of CES
7.2.3.1 Operational Characteristics

To provide a benchmark with which to compare the performance of the proposed MPC strategy, a simple RBC will be defined which will be applied to the CES connected to the LV feeder. In RBC, a series of conditional if/else statements are utilized to control the charging and discharging rate of the CES. For the RBC technique applied in this chapter, the primary objective of the controller is to ensure that the net consumption of the LV feeder from the upstream MV network is equal to 0 kW. Pseudocode for the charging and discharging conditions is given below in Table 7-1. In simple terms, the CES is charged whenever the PV production in the LV feeder is greater than the total load of the feeder. It is assumed that the CES control system is fitted with the sophisticated smart metering infrastructure required to obtain the total feeder PV generation and load values. The RBC does not take in the account the price of electricity or its current SoC when determining the output power of the CES.

Table 7-1 Pseudocode for RBC control of CES

```matlab
% Rule based control of CES
% Discharging Scenario
if feeder_load(k) > feeder_pv(k)
    % Check if the feeder is fully discharged
    if(SoC_CES(k)>SoC_min)
        CES(k)=feeder_load(k)-feeder_pv(k)
    else if(SoC_CES(k) <= SoC_min)
        CES(k)=0
    end
end

% Charging Scenario
if feeder_load(k) < feeder_pv(k)
    % Check if the feeder is fully charged
    if(SoC_CES(k)<SoC_max)
        CES(k)=feeder_pv(k)-feeder_load(k)
    else if(SoC_CES(k) >= SoC_max)
        CES(k)=0
    end
end
```

7.2.3.2 Performance in LV Feeder

In this section, the performance of the case study LV feeder when operated with a CES controlled by a heuristic RBC technique (defined above) is presented. The size, placement, and other parameters of the CES are identical to the configuration for the MPC techniques as presented in Section 6.5.1. In summary, the CES had a total capacity of 450 kW (operational
between SoC of 10% and 90%), peak charging/discharging power of the individual phases was limited to 20 kW, and the storage device was placed at the end of the feeder as the voltage sensitivity to active power is highest at the node (in radial feeders) furthermore from the distribution transformer.

Figure 7-8 depicts the 24 h LV feeder voltage for phase A with and without the application of CES. It can be seen from the orange plot, which shows voltage magnitude with the CES implemented, that the voltage at the start of the simulation is significantly higher than the voltage without any voltage regulation applied. This is because the initial SoC was selected to be 15% (75 kWh) and without any PV generation at the start of the simulation, the CES discharged until the minimum SoC is reached to support the load according to the RBC algorithm. After that, the CES remained idle until the PV generation in the feeder exceeds the feeder load at approximately 9:00 in the morning. The CES then starts to charge according to the RBC algorithm until the CES is fully charged.

![Figure 7-8 Impact of RBC CES on LV feeder voltage](image)

It is seen that the feeder voltage exceeds the mandated upper limit of 253 V at this time. While this problem can easily be solved by increasing the overall capacity of the CES, this highlights the main downside of the RBC algorithm as the system states are not considered to decide the storage device power. In comparison, the MPC based algorithm, described in
Section 6.4, successfully controlled the voltage for the whole 24 h as optimal calculations were performed based on the sliding window technique where the future states of the feeder are considered at every time step. This highlights the main advantage of MPC even though it requires higher computational capabilities and a centralized communication structure.

Figure 7-9 demonstrates the performance the CES when controlled by the RBC algorithm in terms of both the variation of the CES SoC and three-phase power for the 24 h simulation as the load and PV generation varies throughout the day. It must be noted that due to the different scaling of the CES SoC and power axis, both sides of the y axis has been utilized and have been differentiated using blue and orange text. As demonstrated from the description of the feeder voltage, initially the CES discharges until the SoC of the device reaches its minimum threshold of 50 kWh (10%). The CES is then idle for a significant period of time until the total rooftop PV generation exceeds the feeder loading after which the CES starts to charge using the excess PV power and reducing the amount of reverse power flow to the upstream MV network. The CES continues to charge at its maximum rating (20 kW per phase) until it is fully charged. The CES then stays idle for the rest of the day (with PV generation) and in the evening the stored energy in the CES is utilized to support the load reducing the energy required to be drawn from the upstream network.
7.3 Indices for Performance Analysis

The contribution of rooftop PV generation units in LV feeders on the network behavior depends on a lot of factors including line impedance, loading, and level of PV penetration. So far in this thesis, numerical values of the various network aspect such as voltage, power flow etc. which were specific to the case study network parameters have been analyzed. In this section, two numerical indices will be defined to normalize the voltage deviation and feeder utilization. The indices to be used in this chapter were proposed by the authors in [113] and have been modified to analyze the impact in LV feeders. The two indices to be used in this are described in detail below:

7.3.1 Maximum Voltage Deviation

To quantify the voltage deviation in future distribution networks, the index MVD will be utilized. MVD is defined as the percentage of maximum voltage deviation observed with respect to the nominal voltage ($V_{nom}$) at a time instant ($k$), as shown in (7.1). For Australia, $V_{nom}$ is equal to 230 V according to AS 61000.3.100 [105]. In (7.1), $V_{max}(k)$ refers to the maximum amount of voltage deviation detected in the LV feeder at the $k$th time instant.
\[ MVD(k) = \frac{V_{\text{max}}(k) - V_{\text{nom}}}{V_{\text{nom}}} \times 100\% \] (7.1)

It should be noted that MVD needs to be calculated for each of the phases separately. MVD values can also have a negative or a positive value. Without rooftop PV, \( V_{\text{max}} \) is typically measured to be lower than the nominal voltage and MVD hence will be negative, demonstrating a drop in the voltage as power flows downstream. However, as PV induces voltage rise in the LV network, the numerator in (7.1) will be positive and hence a positive value of MVD indicates the feeder is experiencing voltage rise. According to AS 61000.3.100, DNSPs are required to maintain the voltage limits within -6% and 10% of the nominal value. The magnitude of MVD directly corresponds to the voltage variations in the LV feeder.

### 7.3.2 Feeder Reserve Capacity

As the power from the PV generators can be used to serve the loads in the feeder locally, the power drawn from the upstream network decreases which leads to a lesser utilization of the feeder assets including the distribution transformer and feeder conductor. However, when the PV generation exceeds the loads by a significant amount the high reverse power flow in the network may also lead to the network assets being utilized to near to or over their rated capacities. To numerically analyze the use of the feeder assets, the Feeder Reserve Capacity (FRC) will be utilized. FRC is defined below.

\[ FRC(k) = \left(1 - \frac{|S_a(k) + S_b(k) + S_c(k)|}{S_{\text{Feeder}}} \right) \times 100\% \] (7.3)

In (7.3), \( S_a \), \( S_b \) and \( S_c \) corresponds to the total complex power flow in the three-phase LV feeder distribution transformer, and \( S_{\text{Feeder}} \) is the total rated capacity of the LV distribution transformer. A FRC value of 100% means the feeder capacity is fully available whereas a value of 0% means the feeder assets are fully utilized. When the operating point of the feeder is higher than its rated capacity, the value of FRC obtained may be negative. This would indicate that the feeder is operating at a value higher than its rated capacity at a particular given time. In this chapter FRC will be used to investigate the impact of various voltage regulation techniques on utilization of feeder assets.
7.4 Comparative Analysis

In this section, a comparative study of the different voltage regulation techniques will be presented. For the purposes of simulation modelling, the earlier defined 300 m MEN 4-wire LV feeder will be used. The details of the model parameters for this feeder can be found in Section 3.5.1. As discussed previously, the feeder is supplied from an 11 kV/400 V delta/star grounded transformer and the voltage at the transformer busbar was assumed to be 240 V. The distribution transformer is rated at 220 kVA. The loads, rooftop PV units and unbalance of the system have been modelled identically to the approach described in Section 4.2.3.1, where network unbalance is induced by increasing the load and PV size in phase A by 10% and decreased by 10% in phase C. The CES unit for the RBC control was also connected to the end of the feeder identical to the MPC study described in Chapter 6. The CES has a total capacity of 450 kWh, where the minimum and maximum SoC of the CES was assumed to be 45 kWh and 405 kWh, respectively. The efficiency of the CES converter unit was assumed to be 90%.

7.4.1 Voltage Management

In this section, MVD is used to compare how the voltage deviation in the feeder varies when subject to different voltage regulation techniques. As demonstrated in the simulation results previously, phase a will experience both maximum voltage rise and voltage drop compared to the other two phases and hence the MVD values of phase A are analyzed here. Figure 7-10 plots the MVD values of the LV feeder, where the blue, orange, yellow, purple, green and grey plots correspond to the implementation of no voltage regulation, Volt-Watt, Volt-VAr, LV-STATCOM, MPC based CES and RBC CES respectively. Since AS 61000.3.100 requires the voltage at the consumer point of supply to be within -6% and +10% of the 230 V, the region outside these limits with the corresponding MVD values have been shaded in red to highlight that the voltage is outside the allowable range. The maximum MVD value obtained was 12.3% which corresponds to a voltage rise of 12.3%, whereas the minimum value of -7.01% demonstrates undervoltage condition in the feeder during high loads as the voltage is lower than the 216.2 V allowed according to AS 61000.3.100 [6].
Table 7-2 summarizes the key MVD values of the LV feeder when subject to the different voltage regulation techniques. Since overvoltage and undervoltage is observed for a brief period for some voltage regulation techniques, both the 5th and 95th percentile values of MVD will be utilized for better understanding of their voltage regulation performances. With the activation of Volt-Watt, it is seen that the maximum voltage rise is reduced from 12.3% to 10.4%; an improvement of 2%. Since Volt-Watt only operates to mitigate voltage rise, there was no change in the minimum and 5th percentile values of MVD compared to the results obtained without any regulation. In the case of Volt-VAr, however, the 5th percentile value of MVD increased from -6.3% to -5.6% and the 95th percentile value decreased from 11.7% to 10.8% demonstrating the capability of this technique to mitigate both overvoltage and undervoltage issues. However, as Volt-VAr is only activated in rooftop PV systems towards the end of the feeder, the reactive power regulation provided was not enough to maintain the feeder voltages as both the 95th percentile and maximum values are greater than the 10% allowable voltage rise. Since LV feeders are constructed with conductors with a high R/X...
ratio, the 95th percentile values demonstrate superior performance of Volt-Watt compared to Volt-VAr in terms of voltage rise mitigation. For RBC based CES voltage regulation, the 5th and 95th percentile values of MVD obtained were -3.4% and 8.2% respectively. While this demonstrates that the feeder voltages are within the 216.2 V to 253 V range for more than 90% of the simulation period, the maximum value of 11.3% demonstrates that there are relatively short periods during which voltage rise greater than the 10% voltage rise allowed in AS 61000.3.100. This was observed when the CES was prematurely fully charged, and the feeder experienced significant reverse power flow for a short period of time in the afternoon. In comparison, both the voltage regulation techniques proposed in this thesis, LV STATCOM and MPC based CES, were successful in maintaining the voltages within the prescribed limits for the full 24 h period. For the LV STATCOM, the 5th percentile MVD value decreased to -4.9% and the 95th percentile value decreased to 7.8%. This demonstrates significant improvement in voltage regulation of the LV feeder as the total bandwidth (difference between minimum and maximum) of the voltage deviation reduced from 19.4% to 14%. With the application of MPC based CES, the 5th and 95th percentile obtained were -3.7% and 5.7% respectively. The MPC based solution provided the best voltage regulation performance out of all the other techniques discussed in this chapter, where the bandwidth of the voltage deviation was obtained to be 12.7%.

Table 7-2 Breakdown of MVD to demonstrate voltage improvement

<table>
<thead>
<tr>
<th>Method</th>
<th>Minimum (%)</th>
<th>5th Percentile (%)</th>
<th>95th Percentile (%)</th>
<th>Maximum (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Voltage Regulation</td>
<td>-7.1</td>
<td>-6.3</td>
<td>11.7</td>
<td>12.3</td>
</tr>
<tr>
<td>Volt-Watt</td>
<td>-7.1</td>
<td>-6.3</td>
<td>10.3</td>
<td>10.4</td>
</tr>
<tr>
<td>Volt-VAr</td>
<td>-6.1</td>
<td>-5.6</td>
<td>10.8</td>
<td>11.1</td>
</tr>
<tr>
<td>RBC CES</td>
<td>-4.1</td>
<td>-3.4</td>
<td>8.2</td>
<td>11.3</td>
</tr>
<tr>
<td>LV STATCOM</td>
<td>-5.7</td>
<td>-4.9</td>
<td>7.8</td>
<td>8.3</td>
</tr>
<tr>
<td>MPC CES</td>
<td>-4.7</td>
<td>-3.7</td>
<td>5.7</td>
<td>7.8</td>
</tr>
</tbody>
</table>

Figure 7-11 presents a stacked bar graph to summarize the performance of each of the voltage regulation techniques in terms of voltage management. The region shaded in red represents the voltages that are outside the allowable limit of +10/-6%, prescribed in AS 61000.3.100. While the yellow region represents the voltage deviation bandwidth for 90% of the time of the 24 h simulation. Only the LV-STATCOM and MPC based CES voltage regulation was successful in maintaining the voltage magnitudes within the prescribed range for the whole
24 h period. While Volt-Watt and Volt-VAr were unsuccessful in maintaining voltage magnitudes to within the prescribed range for the entire 24 h simulation, it is evident from Figure 7-11 that RBC maintained the voltage magnitudes within range the majority of the simulation period and the maximum voltage rise exceeded the limit only for a brief period (when the CES was fully charged).

Figure 7-11 Graphical presentation of the maximum voltage deviation for the various voltage regulation techniques

If the results obtained for LV-STATCOM and MPC based CES are compared, quantitatively it is evident that the MPC techniques provides better regulation. While it can be concluded that MPC outperforms the LV STATCOM, the economic and practical implementation of both the systems should also be considered [114]. While the lower voltage deviation bandwidth provided by MPC is beneficial for DNSPs, it comes at the cost of sophisticated centralized communication infrastructure, high initial set up cost of CES and a requirement for modern forecasting techniques to be embedded in the control system [115]. In comparison, LV STATCOMs are a cost friendly device and only require the voltage to be measured at the location where it is connected in the LV network. Hence, it can be concluded
that while the MPC is a long-term futuristic solution to voltage regulation issues, LV STATCOMs are a more realistic solution to address the voltage regulation issues in feeders that may experience high voltage rise in the short term.

7.4.2 Utilization of LV Feeder

In this section, FRC will be used to analyze how the individual voltage regulation techniques utilize the LV feeder capacity as they operate. The FRC value provides the remaining capacity of the feeder at a particular time instant as a percentage of the feeder rating. A value of 100% of FRC means the feeder capacity is fully available whereas a value of 0% means the feeder assets are fully utilized. As distribution networks integrate new emerging technologies such as EVs that increases the peak load of modern households, it is very important to analyze the impact of the discussed voltage regulation techniques on the hosting capacity of a feeder.

Figure 7-12 shows how the FRC values vary for the 24 h case study simulation when subject to the different voltage regulation techniques. It is seen that greatest feeder utilization feeder occurs during the evening peak load, where the minimum value of FRC was measured to be 6.9% without the activation of any voltage regulation modes. This implies that the feeder is operating at 93.1% of its rated capacity during that period. In general, since the CES operates by storing the excess PV generation and discharging the excess power in the evening, both the RBC and MPC based CES solutions increase the hosting capacity of the feeder significantly as less power is drawn from or fed back to the upstream network. For both the Volt-VAr and LV STATCOM options, the FRC values are lower during the high PV generation periods indicating higher utilization of the feeder as they draw additional reactive power from the upstream network to mitigate voltage rise.
Feeder capacity significantly increased as storage devices are used to store the power generated from the PV units.

Feeder capacity reduced in Volt-Var and STATCOM due to the increase of Q in the line.

Figure 7-12 Impact of various voltage regulation technique on FRC

Table 7-3 shows the breakdown of the FRC values for the LV feeder model with the application of the different voltage regulation techniques. This includes the minimum value which corresponds to the peak usage of the feeder, the 5th percentile which highlights the highest feeder usage for 95% of the 24 h simulation period, and the average to demonstrate the overall impact on the feeder utilization for the full 24 h simulation. Figure 7-13 presents a stacked bar graph to summarize the performance of each of the voltage regulation techniques in terms of FRC.
Table 7-3 Breakdown of FRC values to analyze the feeder usage

<table>
<thead>
<tr>
<th></th>
<th>Minimum (%)</th>
<th>5th Percentile (%)</th>
<th>Average (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Voltage Regulation</td>
<td>6.9</td>
<td>13.1</td>
<td>44.3</td>
</tr>
<tr>
<td>Volt-Watt</td>
<td>6.9</td>
<td>13.2</td>
<td>44.4</td>
</tr>
<tr>
<td>Volt-Var</td>
<td>8.6</td>
<td>14.3</td>
<td>41.8</td>
</tr>
<tr>
<td>RBC CES</td>
<td>34.5</td>
<td>39.1</td>
<td>55.0</td>
</tr>
<tr>
<td>LV STATCOM</td>
<td>13.7</td>
<td>20.1</td>
<td>47.0</td>
</tr>
<tr>
<td>MPC CES</td>
<td>27.7</td>
<td>36.1</td>
<td>51.1</td>
</tr>
</tbody>
</table>

In terms of the peak operating point of the feeder, the minimum value of FRC was 8.6%, 34.5%, 13.7% and 27.7% for Volt-Var, RBC CES, LV STATCOM and MPC CES respectively. Since Volt-Watt does not operate during the evening peak, the minimum FRC value was unchanged at 6.9%. The results demonstrate the excellent capability of CES to increase the hosting capacity of the feeder as the peak usage is reduced from 93.1% to 65.5% and 72.3% for RCB CES and MPC CES respectively. For Volt-Var and STATCOM, the total line current decreases during peak load as reactive power is injected (consumed by the
lagging loads) to boost the voltage. In terms of the 5\textsuperscript{th} percentile values, significant improvements are observed for the CES based voltage regulation as FRC increases from 13.1\% to 39.1\% and 36.1\% for RBC and MPC respectively. For the LV STATCOM, the 5\textsuperscript{th} percentile FRC was 20.1\%, corresponding to the feeder operating at lower than 79.9\% of its rated capacity for more than 95\% of the simulation period. In terms of the average usage of the feeder for the whole simulation period, it was found that all the voltage regulation techniques operated within the range of 48.9\% and 55.6\% of its total capacity.

7.5 Chapter Summary

This chapter presents a comparative study of the distribution network voltage regulation techniques investigated in this thesis including some modern techniques implemented by DNSPs in recent times.

In terms of the proposed voltage regulation techniques, the LV-STATCOM provides a non-centralized economical voltage regulation solution that requires minimal communication infrastructure, while the MPC based CES solution provides a centralized futuristic solution that requires sophisticated communication and will be expensive to implement in real life.

The modern voltage regulation techniques used as comparison included smart inverter functions (Volt-VAr and Volt-Watt) and rule based controlled (RBC) CES. To normalize the network performance parameters two indices are introduced; maximum voltage deviation (MVD), and feeder reserve capacity (FRC). These indices are used to analyze voltage magnitude performance and hosting capacity of the feeder respectively.

The case study demonstrated that both inverter function-based voltage regulation strategies, namely Volt-Watt and Volt-VAr were not successful in maintaining the voltages within the mandated limits of 216.2 V and 253 V at all times. It was also found that if the CES is regulated by a heuristic rule-based control the ES is prematurely fully charged (i.e. capacity reached before the optimum time) a short period of overvoltage condition results. This demonstrated the advantage of implementing a MPC controller which can adjust the CES charging/discharging in accordance with the forecast future load and PV generation. Overall, the MPC based CES solution outperformed the LV-STATCOM both in terms of voltage management, utilization of the feeder and other technical benefits. However, since LV-STATCOMs would be much easier and cheaper to implement, in practice it makes it an
economically viable solution for the DNSPs to utilize until the price of CES drops and the proper communication infrastructure and other infrastructure required to implement MPC, at a competitive price point, is available in distribution networks.
Chapter 8

Conclusion and Recommendations for Future Work

This thesis aimed to contribute new knowledge and understanding to the field of power distribution network voltage regulation. This included investigation and analysis of different approaches to voltage regulation in power distribution networks in the literature, and to propose new methods and improvements to existing methods.

A detailed analysis of the literature was carried out to understand the problems related to high integration of renewables can bring to the network. A time series analysis tool has been developed using OpenDSS, where data obtained from Australian DNSPs was utilized to model a realistic 4-wire LV feeder (400 V LL). A realistic MV network model was also used to analyze the impact on the tap operation of the HV/MV substation transformer. Two main solutions are proposed, where the first solution is based on STATCOMs and later is based on utilization of MPC based CES in LV feeders. The STATCOM based voltage regulation is an economic solution which requires no sophisticated communication infrastructure and the CES based solution explores a modern optimal objective-based solution requiring centralized control. The proposed voltage regulation techniques are validated through 24-h power flow simulations capable of capturing the long-term performance of the distribution networks including change in the overall line losses, network unbalance and feeder utilization. The developed analysis tool was utilized to appropriate model the modern regulation techniques used by DNSPs such as Volt-Watt, Volt-VA and rule-based CES to provide a benchmark for comparison of the proposed voltage regulation methods.

8.1 Summary of Key Findings

A summary of the key findings in each chapter is given below-
Chapter 2 provides a detailed literature review related to voltage regulation in PV-rich distribution networks. The primary goal was to review both traditional and novel voltage regulation technologies available in the literature. The main contributing factors that cause voltage regulation issues are introduced, along the importance of detailed 4-wire modelling of LV feeder. The limitations of utilizing existing voltage regulation techniques and implementation challenges are discussed. The main voltage regulation techniques discussed included smart inverter control, utilizing energy storage devices and FACTs devices, and other modern advanced voltage regulation techniques requiring advanced communication infrastructure and optimization methods. While the literature review demonstrated a significant progress in terms of regulating the distributing network voltage, most solutions were found to concentrate on the application of voltage management devices in MV and HV networks. Most of the modern voltage regulation techniques was also to not consider the limitations of practical distribution networks (for example communication) and the relevant standards for DNSPs, which will be addressed in this thesis.

Chapter 3 presented the modelling three phase power flow analysis to assess the distribution network performance with a high penetration of single-phase PV units integrated. The detailed 4-wire modelling implemented for the LV feeder is capable to capture the impact on the neutral conductor during high unbalance in the system. The MV network has also been modelled to model how the issues in LV can propagate through distribution systems. Detailed three-phase mathematical models of all the major components in the grid including lines, transformers, PV, STATCOM and ES devices are formulated for use in the three-phase power flow equations. Realistic feeder design and cable data from an Australian DNSP was used for the developing the case study parameters for this thesis. The purpose of this chapter was to provide a comprehensive approach to modeling the distribution network, taking into account both steady-state and dynamic effects. The models developed in this chapter is utilized throughout the thesis to analyze the performance of various voltage regulation techniques introduced in this thesis.

Chapter 4 presented simulation results designed to investigate voltage regulation issues in future PV rich distribution networks. In the first half of the chapter, the impact of small-scale rooftop PV on the performance of LV feeders was investigated. In terms of line losses, it was observed that there was reduction of 35% for the scenario of high penetration of distributed solar PV generation. While it was found that PV production decreased VUF measurements in
the daytime however the high neutral currents induced during reverse power flow periods may increase the N-G potential if the grounding resistance is high in the MEN 4 wire system. It was found that PV has the potential to significantly increase the number of tap changes and the simulation study demonstrated that without mitigation, PV units in LV feeders will cause both overvoltage and undervoltage conditions. The outcomes of this chapter highlight the importance of voltage regulation in distribution networks, that are proposed in the latter chapters of this thesis.

Chapter 5 investigated the feasibility of application of STATCOM based reactive power regulation to maintain the steady-state voltage levels within prescribed limits in radial 4-wire LV feeders. An exact lumped load model has been utilized to provide a guideline for approximate sizing of the STATCOM required for a general LV radial feeder to control the steady state voltage levels such that they are within the range specified by the relevant Australian standard. The simulation results demonstrated that the STATCOM was successful in maintaining voltage levels within the prescribed range during reverse power flow and peak evening load. It was observed N-G voltage increased during PV generation. In terms of impact on the changer operations at the nearest HV/MV transformer, the total number of tap changes was reduced from 19 to 13. This chapter demonstrates that LV-STATCOM provides a non-centralized economical voltage regulation solution with minimal communication infrastructure.

Chapter 6 proposed an MPC based algorithm for the control of CES in a LV residential feeder with a dual objective to minimize total DNSP operational costs and provide voltage regulation. The dual objective function was implemented with a two level MPC algorithm where the higher-level controller selected the mode of operation and lower-level controller performed the required optimization. The performance of the controller has been verified through a time series power flow simulation. Overall, the controller was successful in reducing operational costs and providing optimum voltage regulation, maintaining voltages within statutory limits. The optimum power regulating ability of the controller is demonstrated as the SoC was regulated depending on the load and PV generation predicted data. This demonstrates the key advantage of MPC based ES regulation compared to heuristic algorithms where the SoC can prematurely reach its limits.

Chapter 7 presented a comparative study between distribution network voltage regulation techniques covered in this thesis and some modern techniques implemented by DNSPs in
recent times. The case study demonstrated that both inverter function-based voltage regulation of Volt-Watt and Volt-VAr was not successful in maintaining the voltages within the mandated limits of 216.2 V and 253 V. It was also found that if the CES is regulated by a heuristic rule-based control the ES is prematurely fully charged for a short period of time resulting in an overvoltage condition. This demonstrated the power capability of implementing a MPC controller which can adjust the CES power in accordance with the future loads and generation of the PV units. Overall, the MPC based CES solution outperformed the LV-STATCOM both in terms of voltage management and utilization of the feeder. However, since LV-STATCOMs would be much easier and cheaper to implement, it makes them a economically viable solution for the DNSPs to utilize until the price of CES drops and the proper communication infrastructure is available in distribution networks.

8.2 Direction for Future Research

Directions for future work related to this thesis are provided below-

- EVs, in future distribution networks, will impose an additional burden as these new emerging technologies have the potential to increase the peak load. EVs also have the capability to reduce the reverse power flow in the system if a significant proportion of the PV generation can be utilized to charge the EV at daytime. Future work involving EVs includes performing a detailed investigation of the combined effect of EVs and rooftop PV in distribution networks to develop voltage regulation solutions utilizing the energy storing capabilities of EVs through V2G.

- While the distribution network analysis tool developed in this thesis is capable of modelling various types of distribution networks, the case studies provided only consider a homogenous MV/LV network with uniform loading and a fixed length feeder. An extension of the work may involve, doing a sensitivity study of distribution network with variations in feeder length, non-uniform loading, and consideration of other relevant power quality issues.

- In this thesis, voltage sensitivity was the only factor considered to find the placement of the STATCOM and CES. Hence for a radial feeder, the devices were placed at the end of the feeder to provide maximum voltage control. In a future work, other network attributes such as line losses could also be included in finding the optimum placement of these
voltage regulation devices. The work to be carried out would also consider the sensitivity study variations mentioned above.

- The MPC algorithm developed to regulate the CES power in this thesis, considered the operational costs of the DNSP and voltage regulation for the objective function. While the developed algorithm demonstrated excellent voltage regulation performances, a future project on this topic may include including other parameters such as voltage unbalance, line losses, and total feeder into the objective function. Future work to be carried out can also aim to utilize the reactive power capabilities of CES systems and consider other CES topologies (for example utilizing the CES in two segments for the same feeder) to aim for better performance.

- The simulations results in this thesis demonstrated that the application of Volt-VAr and Volt-Watt according to the standard AS 4777 introduces an inequity issue as the inverters of customers at different locations in the network are not utilized in the same manner. This demonstrated that more work needs to be done in order to develop proper financial structures of Volt-Watt/Volt-VAr and also adjustment to the standards to mitigate this issue. While this thesis concentrated on the technical performance of various voltage regulation techniques, financial justification studies also need to be carried out to quantify the economic benefits of them.

- Simulation based studies provide a great platform to investigate the performance of voltage regulation techniques in distribution networks. As a future project, it will be interesting to investigate how the proposed voltage management solutions perform in practical networks for better understanding of their feasibility in real life.

- A detailed cost-effectiveness analysis of the proposed voltage regulation techniques was outside the scope of this thesis. A future work on this topic may include an investigation into the economic feasibility of voltage regulation in distribution networks.
References


University of Wollongong. Power Quality Compliance Audit


Appendix

A.1 Formation of LV Feeder in OpenDSS

!Creating example LV circuit with the basic components
!Clearing everything before the actual code
!Setting the Default Base Frequency
Set DefaultBaseFrequency=50

!Giving the circuit name and setting up the basic parameters for the source bus
new circuit.Test_LV basekV=11 pu=1.05 angle=30 frequency=50 phases=3 mvasc3=200000

!Giving the transformer connection and
new transformer.LVSS windings=2 buses=(Sourcebus, x) conns=(delta, star) kvs=(11, 0.4) kvas=(220, 220)
%loadloss=0 xhl=2.5

!Giving the line parameters
new linecode.B nphases=4 rmatrix=[0.6313 | 0.0493 0.6313 | 0.0493 0.0493 0.6313 | 0.0493 0.0493 0.0493 0.6313] xmatrix=[0.7823 | 0.4321 0.7823 | 0.3991 0.4543 0.7823 | 0.4543 0.3991 0.3773 0.7823] units=km

!forming the network
new line.busbar-1 bus1=x bus2=1 length=0.002 phases=4 units=km linecode=B
new line.busbar-2 bus1=1 bus2=2 length=0.015 phases=4 units=km linecode=B
new line/busbar-3 bus1=2 bus2=3 length=0.015 phases=4 units=km linecode=B
new line/busbar-4 bus1=3 bus2=4 length=0.015 phases=4 units=km linecode=B
new line/busbar-5 bus1=4 bus2=5 length=0.015 phases=4 units=km linecode=B
new line/busbar-6 bus1=5 bus2=6 length=0.015 phases=4 units=km linecode=B
new line/busbar-7 bus1=6 bus2=7 length=0.015 phases=4 units=km linecode=B
new line/busbar-8 bus1=7 bus2=8 length=0.015 phases=4 units=km linecode=B
new line/busbar-9 bus1=8 bus2=9 length=0.015 phases=4 units=km linecode=B
new line/busbar-10 bus1=9 bus2=10 length=0.015 phases=4 units=km linecode=B
new line/busbar-11 bus1=10 bus2=11 length=0.015 phases=4 units=km linecode=B
new line/busbar-12 bus1=11 bus2=12 length=0.015 phases=4 units=km linecode=B
new line/busbar-13 bus1=12 bus2=13 length=0.015 phases=4 units=km linecode=B
new line/busbar-14 bus1=13 bus2=14 length=0.015 phases=4 units=km linecode=B
new line/busbar-15 bus1=14 bus2=15 length=0.015 phases=4 units=km linecode=B
new line/busbar-16 bus1=15 bus2=16 length=0.015 phases=4 units=km linecode=B
new line/busbar-17 bus1=16 bus2=17 length=0.015 phases=4 units=km linecode=B
new line/busbar-18 bus1=17 bus2=18 length=0.015 phases=4 units=km linecode=B
new line/busbar-19 bus1=18 bus2=19 length=0.015 phases=4 units=km linecode=B
new line/busbar-20 bus1=19 bus2=20 length=0.015 phases=4 units=km linecode=B

new reactor.reactor1 phases=1 bus1=1.4 R=0.5 X=0
new reactor.reactor2 phases=1 bus1=2.4 R=0.5 X=0
new reactor.reactor3 phases=1 bus1=3.4 R=0.5 X=0
new reactor.reactor4 phases=1 bus1=4.4 R=0.5 X=0
new reactor.reactor5 phases=1 bus1=5.4 R=0.5 X=0
new reactor.reactor6 phases=1 bus1=6.4 R=0.5 X=0
new reactor.reactor7 phases=1 bus1=7.4 R=0.5 X=0
new reactor.reactor8 phases=1 bus1=8.4 R=0.5 X=0
new reactor.reactor9 phases=1 bus1=9.4 R=0.5 X=0
new reactor.reactor10 phases=1 bus1=10.4 R=0.5 X=0
new reactor.reactor11 phases=1 bus1=11.4 R=0.5 X=0
new reactor.reactor12 phases=1 bus1=12.4 R=0.5 X=0
new reactor.reactor13 phases=1 bus1=13.4 R=0.5 X=0
new reactor.reactor14 phases=1 bus1=14.4 R=0.5 X=0
new reactor.reactor15 phases=1 bus1=15.4 R=0.5 X=0
new reactor.reactor16 phases=1 bus1=16.4 R=0.5 X=0
new reactor.reactor17 phases=1 bus1=17.4 R=0.5 X=0
new reactor.reactor18 phases=1 bus1=18.4 R=0.5 X=0
new reactor.reactor19 phases=1 bus1=19.4 R=0.5 X=0
new reactor.reactor20 phases=1 bus1=20.4 R=0.5 X=0
adding single phase loads in each bus. Keeping it constant and uniform for initial testing.

Bus 1
new load.1a bus1=1.1.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 vmaxpu=2 conn=star
new load.1b bus1=1.2.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 vmaxpu=2 conn=star
new load.1c bus1=1.3.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2

Bus 2
new load.2a bus1=2.1.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.2b bus1=2.2.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.2c bus1=2.3.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2

Bus 3
new load.3a bus1=3.1.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.3b bus1=3.2.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.3c bus1=3.3.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2

Bus 4
new load.4a bus1=4.1.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.4b bus1=4.2.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.4c bus1=4.3.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2

Bus 5
new load.5a bus1=5.1.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.5b bus1=5.2.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.5c bus1=5.3.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2

Bus 6
new load.6a bus1=6.1.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.6b bus1=6.2.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.6c bus1=6.3.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2

Bus 7
new load.7a bus1=7.1.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.7b bus1=7.2.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.7c bus1=7.3.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2

Bus 8
new load.8a bus1=8.1.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.8b bus1=8.2.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.8c bus1=8.3.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2

Bus 9
new load.9a bus1=9.1.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.9b bus1=9.2.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.9c bus1=9.3.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2

Bus 10
new load.10a bus1=10.1.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.10b bus1=10.2.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.10c bus1=10.3.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2

Bus 11
new load.11a bus1=11.1.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.11b bus1=11.2.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.11c bus1=11.3.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2

Bus 12
new load.12a bus1=12.1.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.12b bus1=12.2.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.12c bus1=12.3.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2

Bus 13
new load.13a bus1=13.1.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.13b bus1=13.2.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.13c bus1=13.3.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2

Bus 14
new load.14a bus1=14.1.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.14b bus1=14.2.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.14c bus1=14.3.4 phases=1 kV=(0.23) kW=2 pf=0.95 model=1 conn=star vmaxpu=2

Bus 15
new load.15a bus1=15.1.4 phases=1 kV=(0.23) kw=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.15b bus1=15.2.4 phases=1 kV=(0.23) kw=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.15c bus1=15.3.4 phases=1 kV=(0.23) kw=2 pf=0.95 model=1 conn=star vmaxpu=2

!Bus 16
new load.16a bus1=16.1.4 phases=1 kV=(0.23) kw=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.16b bus1=16.2.4 phases=1 kV=(0.23) kw=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.16c bus1=16.3.4 phases=1 kV=(0.23) kw=2 pf=0.95 model=1 conn=star vmaxpu=2

!Bus 17
new load.17a bus1=17.1.4 phases=1 kV=(0.23) kw=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.17b bus1=17.2.4 phases=1 kV=(0.23) kw=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.17c bus1=17.3.4 phases=1 kV=(0.23) kw=2 pf=0.95 model=1 conn=star vmaxpu=2

!Bus 18
new load.18a bus1=18.1.4 phases=1 kV=(0.23) kw=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.18b bus1=18.2.4 phases=1 kV=(0.23) kw=2 pf=0.95 model=1 conn=star vmaxpu=2
new load.18c bus1=18.3.4 phases=1 kV=(0.23) kw=2 pf=0.95 model=1 conn=star vmaxpu=2

!Bus 19
new load.19a bus1=19.1.4 phases=1 kV=(0.23) kw=2 pf=0.95 model=1 conn=star vmaxpu=2
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new load.19c bus1=19.3.4 phases=1 kV=(0.23) kw=2 pf=0.95 model=1 conn=star vmaxpu=2

!Bus 20
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new load.20b bus1=20.2.4 phases=1 kV=(0.23) kw=2 pf=0.95 model=1 conn=star vmaxpu=2
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new generator.PV17c bus1=17.3.4 phases=1 kV=0.23 kW=0 pf=1 model=1 vmaxpu=1.5 vminpu=0.5
new generator.PV18a bus1=18.1.4 phases=1 kV=0.23 kW=0 pf=1 model=1 vmaxpu=1.5 vminpu=0.5
new generator.PV18b bus1=18.2.4 phases=1 kV=0.23 kW=0 pf=1 model=1 vmaxpu=1.5 vminpu=0.5
new generator.PV18c bus1=18.3.4 phases=1 kV=0.23 kW=0 pf=1 model=1 vmaxpu=1.5 vminpu=0.5
new generator.PV19a bus1=19.1.4 phases=1 kV=0.23 kW=0 pf=1 model=1 vmaxpu=1.5 vminpu=0.5
new generator.PV19b bus1=19.2.4 phases=1 kV=0.23 kW=0 pf=1 model=1 vmaxpu=1.5 vminpu=0.5
new generator.PV19c bus1=19.3.4 phases=1 kV=0.23 kW=0 pf=1 model=1 vmaxpu=1.5 vminpu=0.5
new generator.PV20a bus1=20.1.4 phases=1 kV=0.23 kW=0 pf=1 model=1 vmaxpu=1.5 vminpu=0.5
new generator.PV20b bus1=20.2.4 phases=1 kV=0.23 kW=0 pf=1 model=1 vmaxpu=1.5 vminpu=0.5
new generator.PV20c bus1=20.3.4 phases=1 kV=0.23 kW=0 pf=1 model=1 vmaxpu=1.5 vminpu=0.5
!set maxiterations=35 maxcontroliter=35
set controlmode=static
set mode=snapshot
calcvoltagebases
!Set Algorithm=Newton
!solve
A.2 Formation of MV Feeder in OpenDSS

!Creating MV circuit

!Clearing everything before the actual code clear

!Setting the Default Base Frequency
Set DefaultBaseFrequency=50

!Giving the circuit name and setting up the basic parameters for the source bus
new circuit.Test_LV basekV=33 pu=1 angle=30 frequency=50 phases=3 mvasc3=200000

!Giving the transformer connection and
new transformer.MVSS windings=2 buses=(Sourcebus, x) conns=(star,star) kvs=(33,11) kvas=(30000,30000) %loadloss=0 xhl=12.5 maxtap=1.21 mintap=0.895 NumTaps=21

New RegControl.Reg1 Transformer=MVSS Winding=2 Vreg=100 ptratio=63.51 band=2.8 bus=6.1 enabled=yes

!Giving the line parameters MV
new linecode.A nphases=3 rmatrix=[0 0.7773 |0.0493 0.7773 |0.0493 0.0493 0.7773] xmatrix=[0.7892|0.4328 0.7892|0.3991 0.4543 0.7892] units=km

!forming the network MV
new line.busbar-1 bus1=x bus2=1 length=0.75 phases=3 units=km linecode=A
new line.busbar-2 bus1=1 bus2=2 length=0.75 phases=3 units=km linecode=A
new line.busbar-3 bus1=2 bus2=3 length=0.75 phases=3 units=km linecode=A
new line.busbar-4 bus1=3 bus2=4 length=0.75 phases=3 units=km linecode=A
new line.busbar-5 bus1=4 bus2=5 length=0.75 phases=3 units=km linecode=A
new line.busbar-6 bus1=5 bus2=6 length=0.75 phases=3 units=km linecode=A
new line.busbar-7 bus1=6 bus2=7 length=0.75 phases=3 units=km linecode=A
new line.busbar-8 bus1=7 bus2=8 length=0.75 phases=3 units=km linecode=A
new line.busbar-9 bus1=8 bus2=9 length=0.75 phases=3 units=km linecode=A

!Branch 1
new line.busbar-10 bus1=2 bus2=10 length=0.75 phases=3 units=km linecode=A
new line.busbar-11 bus1=10 bus2=11 length=0.75 phases=3 units=km linecode=A
new line.busbar-12 bus1=11 bus2=12 length=0.75 phases=3 units=km linecode=A

!Branch 2
new line.busbar-13 bus1=5 bus2=13 length=0.75 phases=3 units=km linecode=A
new line.busbar-14 bus1=13 bus2=14 length=0.75 phases=3 units=km linecode=A
new line.busbar-15 bus1=14 bus2=15 length=0.75 phases=3 units=km linecode=A
new line.busbar-16 bus1=15 bus2=16 length=0.75 phases=3 units=km linecode=A

!Branch 3
new line.busbar-17 bus1=7 bus2=17 length=0.75 phases=3 units=km linecode=A
new line.busbar-18 bus1=17 bus2=18 length=0.75 phases=3 units=km linecode=A
new line.busbar-19 bus1=18 bus2=19 length=0.75 phases=3 units=km linecode=A

!Adding single phase loads in each bus. Keeping it constant and uniform for initial testing
new load.1 bus1=1 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
new load.2 bus1=2 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
new load.3 bus1=3 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
new load.4 bus1=4 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
new load.5 bus1=5 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
new load.6 bus1=6 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
new load.7 bus1=7 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
new load.8 bus1=8 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
new load.9 bus1=9 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
new load.10 bus1=10 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
new load.11 bus1=11 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
new load.12 bus1=12 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
new load.13 bus1=13 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
new load.14 bus1=14 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
new load.15 bus1=15 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
new load.16 bus1=16 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
new load.17 bus1=17 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
new load.18 bus1=18 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
new load.19 bus1=19 phases=3 kW=11 kw=2 kvar=1 model=1 vmaxpu=2 conn=star
set controlmode=static
set mode=snapshot
set voltagebases=[33, 11]
calcvoltagebases
!Set Algorithm=Newton

Solve
B.1 Simulation of Time Series Load Flow for LV Feeder via MATLAB

clear;
load('pv.mat');
load('load.mat');
DSSObj=actxserver('OpenDSSEngine.DSS');
if ~DSSObj.Start(0)
    disp('Unable to Start the OpenDSS Engine')
    return
end
DSSText=DSSObj.Text;
DSSCircuit=DSSObj.ActiveCircuit;
% Change the directory depending on which computer is being used
% University
% C:\Users\or994\OneDrive - University of Wollongong\Obaidur PhD\Simulation\Droop Control\debug.dss
% Home computer
% C:\Users\User\OneDrive - University of Wollongong\Obaidur PhD\Simulation\Droop Control\debug.dss

% Loads are name 1a,1b,1c, 2a, 2b......... and hence creating a string to
% change them in a loop
busname=[1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20];
phase=['a' 'b' 'c'];
% changing the peak size of PV and load as a multiplier
peak_load=3;
pv_size=5;
% creating unbalancing in the loads
A=1.1;
B=1.0;
C=0.9;
DSSText.Command='Compile (C:\Users\obura\OneDrive - University of Wollongong\Obaidur PhD\Simulation\Chapter 3 Simulations\debug 2.dss)';

% Running the simulation in a loop with 5 min interval and giving total of
% 288 points
for t=1:1440
    % calling for the open dss fine
    % changing each of the 20 loads in each phase
    for k=1:20
        DSSCircuit.Loads.Name=strcat(num2str(busname(k)),num2str('a'));
        DSSCircuit.Loads.kW=A*(peak_load.*load(t));
        DSSCircuit.Loads.kvar=A*sqrt(((load(t)*peak_load)/0.95)^2-(load(t)*peak_load)^2);
        DSSCircuit.Loads.Name=strcat(num2str(busname(k)),num2str('b'));
        DSSCircuit.Loads.kW=B*(peak_load.*load(t));
        DSSCircuit.Loads.kvar=B*sqrt(((load(t)*peak_load)/0.95)^2-(load(t)*peak_load)^2);
        DSSCircuit.Loads.Name=strcat(num2str(busname(k)),num2str('c'));
        DSSCircuit.Loads.kW=C*(peak_load.*load(t));
        DSSCircuit.Loads.kvar=C*sqrt(((load(t)*peak_load)/0.95)^2-(load(t)*peak_load)^2);
    end
    % changing each of the 20 PV generation at each step in each phase
    % changing the max iterations due to the convergence problems faced
    DSSText.Command='solve';
    for i=1:20
        DSSCircuit.SetActiveBus(num2str(busname(i)));
        DSSBus = DSSCircuit.ActiveBus;
        void(1,t,1) = DSSBus.Vmag(1);
        void(1,t,2) = DSSBus.Vmag(3);
        void(1,t,3) = DSSBus.Vmag(5);
        void(1,t,4) = DSSBus.Vmag(7);
    end
    % checking the power
    pold(t)=DSSCircuit.TotalPower(1);
    qold(t)=DSSCircuit.TotalPower(2);
    plossold(t)=DSSCircuit.Losses(1);
    qlossold(t)=DSSCircuit.Losses(2);
end

DSSText.Command='Compile (C:\Users\obura\OneDrive - University of Wollongong\Obaidur PhD\Simulation\Chapter 3 Simulations\debug 2.dss)';
% Repeating the simulations with PV Units
for t=1:1440
    for k=1:20
        DSSCircuit.Loads.Name=strcat(num2str(busname(k)),num2str('a'));
        DSSCircuit.Loads.kW=A*(peak_load*load(t));
        DSSCircuit.Loads.kvar=A*sqrt(((load(t)*peak_load/0.95)^2-(load(t)*peak_load)^2);
        DSSCircuit.Loads.Name=strcat(num2str(busname(k)),num2str('b'));
        DSSCircuit.Loads.kW=B*(peak_load*load(t));
        DSSCircuit.Loads.kvar=B*sqrt(((load(t)*peak_load/0.95)^2-(load(t)*peak_load)^2);
        DSSCircuit.Loads.Name=strcat(num2str(busname(k)),num2str('c'));
        DSSCircuit.Loads.kW=B*(peak_load*load(t));
        DSSCircuit.Loads.kvar=B*sqrt(((load(t)*peak_load/0.95)^2-(load(t)*peak_load)^2);
    end
    for k=1:20
        DSSCircuit.Generators.Name=strcat('PV',num2str(busname(k)),num2str('a'));
        DSSCircuit.Generators.kW=A*pv_size.*pv(t);
        DSSCircuit.Generators.kvar=0;
        DSSCircuit.Generators.Name=strcat('PV',num2str(busname(k)),num2str('b'));
        DSSCircuit.Generators.kW=B*pv_size.*pv(t);
        DSSCircuit.Generators.kvar=0;
        DSSCircuit.Generators.Name=strcat('PV',num2str(busname(k)),num2str('c'));
        DSSCircuit.Generators.kW=C*pv_size.*pv(t);
        DSSCircuit.Generators.kvar=0;
    end
end
DSSText.Command='solve';
DSSBus = DSSCircuit.ActiveBus;
for i =1:20
    DSSCircuit.SetActiveBus(num2str(busname(i)));
    vnew(i,t,1) = DSSBus.Vmag(1);
    vnew(i,t,2) = DSSBus.Vmag(3);
    vnew(i,t,3) = DSSBus.Vmag(5);
    vnew(i,t,4) = DSSBus.Vmag(7);
end
pnew(t)=DSSCircuit.TotalPower(1);
qnew(t)=DSSCircuit.TotalPower(2);
plossnew(t)=DSSCircuit.Losses(1);
qlossnew(t)=DSSCircuit.Losses(2);
end

%Observing three phase just to save the results
for t=1:1440
    va1(t)=vold(20,t,1);
    va2(t)=vold(20,t,2);
    va3(t)=vold(20,t,3);
    va4(t)=vold(20,t,4);
    vb1(t)=vnew(20,t,1);
    vb2(t)=vnew(20,t,2);
    vb3(t)=vnew(20,t,3);
    vb4(t)=vnew(20,t,4);
end
B.2 Simulation of Time Series Load Flow for MV Feeder

clear;
load('pnew.mat');
load('real.mat');
load('react.mat');
load('VWP.mat');
load('VVP.mat');
load('-react_new.mat');
load('pv.mat');
load('load.mat');

DSSObj=actxserver('OpenDSSEngine.DSS');
if ~DSSObj.Start(0)
disp('Unable to Start the OpenDSS Engine')
return
end
DSSText=DSSObj.Text;
DSSCircuit=DSSObj.ActiveCircuit;

% Loads are name 1a,1b,1c, 2a, 2b........ and hence creating a string to
% change them in a loop
busname=[1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19];

for t=1:1440
    DSSText.Command='Compile (C:\Users\obura\OneDrive - University of Wollongong\Obaidur PhD\Simulation\OLTC\openDSS.dss)';
    for k=1:19
        DSSCircuit.Loads.Name=num2str(busname(k));
        %Assigning the loads for no PV
        DSSCircuit.Loads.kW=60*3*load(t);
        DSSCircuit.Loads.kvar=1*sqrt((60*3*load(t)/0.95)^2-(60*3*load(t))^2);

        %Assigning the loads for MPC
        DSSCircuit.Loads.kW=-0.8*pnew(t);
        DSSCircuit.Loads.kvar=1*sqrt((60*3*load(t)/0.95)^2-(60*3*load(t))^2);

        %Assigning the loads for PV
        DSSCircuit.Loads.kW=60*3*load(t)-60*5*pv(t);
        DSSCircuit.Loads.kvar=1*sqrt((60*3*load(t)/0.95)^2-(60*3*load(t))^2);

        %Assigning the loads for STATCOM
        DSSCircuit.Loads.kW=-pnew(t);
        DSSCircuit.Loads.kvar=-qnew(t);

        %Assigning the loads for Volt-Watt
        DSSCircuit.Loads.kW=VWP(t);
        DSSCircuit.Loads.kvar=VWQ(t);

        %Assigning the loads for Volt-Var
        DSSCircuit.Loads.kW=VVP(t);
        DSSCircuit.Loads.kvar=VVQ(t);
    end
    DSSText.Command='solve';
    pold(t)=DSSCircuit.TotalPower(1);
    qold(t)=DSSCircuit.TotalPower(2);
    DSSBus = DSSCircuit.ActiveBus('19');
    MV(t) = DSSBus.Vmag(1);
    MV(t)= MV(t)*sqrt(3);
    Tap(t)=DSSCircuit.Transformers.Name='MVSS';
    Tap(t)=DSSCircuit.Transformers.Tap;
    Tap(t)=(Tap(t)-1)/0.015;
end

plotting
C. Implementation of STATCOM Droop Control

```matlab
% Applying droop control for the statcom
% Droop with 20kvar and limits of 200-260
for t=1:1440
    for i=1:3
        Q(i,t)=(2/3)*vold(i,t) - (460/3);
        if Q(i,t)<=-20;
            Q(i,t)=-20;
            end
        if Q(i,t)>=20;
            Q(i,t)=20;
            end
    end
end

DSSText.Command = 'Compile (C:\Users\obura\OneDrive - University of Wollongong\Obaidur PhD\Simulation\Drop Control\debug.dss)';
DSSText.Command = 'new load.statcom_a bus1=20.1 phases=1 kV=0.23 kw=0.01 kvar=0 model=1 vmaxpu=1.5 vminpu=0.5';
DSSText.Command = 'new load.statcom_b bus1=20.2 phases=1 kV=0.23 kw=0.01 kvar=0 model=1 vmaxpu=1.5 vminpu=0.5';
DSSText.Command = 'new load.statcom_c bus1=20.3 phases=1 kV=0.23 kw=0.01 kvar=0 model=1 vmaxpu=1.5 vminpu=0.5';
% Repeating the simulations with a statcom
for t=1:1440
    for k=1:20
        DSSCircuit.Loads.Name=strcat(num2str(busname(k)),num2str('a'));
        DSSCircuit.Loads.kW=A*(peak_load*load(t));
        DSSCircuit.Loads.kvar=A*sqrt((((load(t)*peak_load)/0.95)^2-(load(t)*peak_load)^2));
        DSSCircuit.Loads.Name=strcat(num2str(busname(k)),num2str('b'));
        DSSCircuit.Loads.kW=B*(peak_load*load(t));
        DSSCircuit.Loads.kvar=B*sqrt((((load(t)*peak_load)/0.95)^2-(load(t)*peak_load)^2));
        DSSCircuit.Loads.Name=strcat(num2str(busname(k)),num2str('c'));
        DSSCircuit.Loads.kW=C*(peak_load*load(t));
        DSSCircuit.Loads.kvar=C*sqrt((((load(t)*peak_load)/0.95)^2-(load(t)*peak_load)^2));
    end
    for k=1:20
        DSSCircuit.Generators.Name=strcat('PV',num2str(busname(k)),num2str('a'));
        DSSCircuit.Generators.kW=A*pv_size.*pv(t);
        DSSCircuit.Generators.kvar=0;
        DSSCircuit.Generators.Name=strcat('PV',num2str(busname(k)),num2str('b'));
        DSSCircuit.Generators.kW=B*pv_size.*pv(t);
        DSSCircuit.Generators.kvar=0;
        DSSCircuit.Generators.Name=strcat('PV',num2str(busname(k)),num2str('c'));
        DSSCircuit.Generators.kW=C*pv_size.*pv(t);
        DSSCircuit.Generators.kvar=0;
    end
    DSSCircuit.Loads.Name='statcom_a';
    DSSCircuit.Loads.kvar=Q(1,t);
    DSSCircuit.Loads.Name='statcom_b';
    DSSCircuit.Loads.kvar=Q(2,t);
    DSSCircuit.Loads.Name='statcom_c';
    DSSCircuit.Loads.kvar=Q(3,t);
    DSSText.Command='set maxiterations=3000';
    DSSText.Command='solve';
    DSSCircuit.SetActiveBus('20');
    DSSTBus = DSSCircuit.ActiveBus;
    vnew(1,t) = DSSTBus.Vmag(1);
    vnew(2,t) = DSSTBus.Vmag(3);
    vnew(3,t) = DSSTBus.Vmag(5);
    pnew(t)=DSSCircuit.TotalPower(1);
    qnew(t)=DSSCircuit.TotalPower(2);
    plossnew(t)=DSSCircuit.Losses(1);
    qlossnew(t)=DSSCircuit.Losses(2);
end
```
D. Implementation of MPC in MATLAB

% Loading the available data for the simulation
% This includes cost of electricity, feed in tariff, battery cost, load data
% and PV data
clear;
% Cost of using the battery
load('cost_bat.mat')
% Cost to sell the electricity
load('feed_in.mat')
% Time of use tariff data
load('tou.mat')
% Using PV and load shapes normalized to a factor of 1
load('load_data.mat')
load('pv_data.mat')
% Initializing for speed of simulation
for t=1:48
    Pch1(t)=0;
    Pdis1(t)=0;
    Pch(t)=0;
    Pdis(t)=0;
    Pim(t)=0;
    Pex(t)=0;
    SoC(t)=0;
end
% Initializing the initial SoC of the Battery and creating one extra to
% implement the initial condition and satisfy the loop
SoC(1)=20;
% Initializing the mode selector and starting with the EMPC activated
for i=1:48
    phi1(i)=1;phi2(i)=0;
end
% Creating the loop to implement rolling horizon optimization
for t=1:48
    % Open loop MPC with mode 1 activated
    [Pch1,Pdis1]=myempc(cost_bat,feed_in,tou,load_data,pv_data,t,SoC(t),phi1,phi2);
    % Perform Power flow to obtain the voltage
    [volt]=opendss(Pch1,Pdis1,t,load_data,pv_data);
    for i=1:48
        for j=1:3
            if(volt(j,i)>253 || volt(j,i)<216.2)
                phi1(i)=0;phi2(i)=1;
            end
        end
    end
    [Pch(t),Pdis(t),Pim(t),Pex(t),costbat,feedin,TOU]=myempc2(cost_bat, feed_in, tou, load_data,
    pv_data, t, SoC(t),phi1,phi2);
    SoC(t+1)=SoC(t)-Pch(t)*1/2*0.9-Pdis(t)*(1/2)/0.9;
    Bat_SoC(t)=SoC(t);
t
end
[voltage,pfeeder,qfeeder,ploss,load,pv]=opendss2(Pch,Pdis,load_data,pv_data);
for t=1:48
    va1(t)=voltage(1,t);
end
function [Pchv,Pdisv,Pimv,Pexv,costbat,feedin,TOU]=myempc(cost_bat, feed_in, tou, load_data, pv_data,
    t, EbatI,phi1,phi2)
% Taking a peak load of 4 kW and PV size of 5 kW
% Creating new variables to include the rolling horizon
for i=1:48
    load(i)=3.*load_data(i+t).*20;
    pv(i)=5.*pv_data(i+t).*20;
    costbat(i)=cost_bat(i+t);
    feedin(i)=feed_in(i+t);
    TOU(i)=tou(i+t).*0.2;
    ref(i)=0;
end
prob = optimproblem;
% Real time parameter
Pim = optimvar('Pim',48,'LowerBound',0,'UpperBound',inf);
Pex = optimvar('Pex',48,'LowerBound',-inf,'UpperBound',0);
Pch = optimvar('Pch',48,'LowerBound',-20,'UpperBound',0);
Pdis = optimvar('Pdis',48,'LowerBound',0,'UpperBound',20);
EbattV = optimvar('EbattV',45,'LowerBound',0,'UpperBound',405);
% Create binary variables to stop charging and discharging at the same time
Z_X = optimvar('Z_X',48,'Type','integer','LowerBound',0,'UpperBound',1);
% Charging binary variable array
Z_Y = optimvar('Z_Y',48,'Type','integer','LowerBound',0,'UpperBound',1);
% Discharging binary variable array
prob.Constraints.Ch_on = Pch >= -20*Z_X;
prob.Constraints.Dis_on = Pdis <= 20*Z_Y;
prob.Constraints.notPositive = Z_X + Z_Y <= 1;
% Stopping charging and discharging at the same time
% Defining the constraints for the power balance and energy balance for maintaining the SoC of the battery
prob.Constraints.energyBalance = optimconstr(48);
prob.Constraints.energyBalance(1) = EbattV(1) == EbatI;
prob.Constraints.energyBalance(2:48) = EbattV(2:48) == EbattV(1:47) - Pch(1:47)*1/2*0.9 - Pdis(1:47)*(1/2)/0.9;
prob.Constraints.powerbalance = pv' + Pim + Pex + Pch + Pdis == load';
prob.ObjectiveSense = 'minimize';
obj = sum(phi1(t).*((TOU*Pim + feedin*Pex + costbat*Pch + costbat*Pdis) + phi2(t)).*((Pim-Pex) - ref));
prob.Objective = obj;
options = optimoptions('intlinprog','Display','off');
[values,~,exitflag] = solve(prob,'Options',options);
% If there is a zero load all zeros
if exitflag <= 0
    Pimv = zeros(288,1);
Pexv = zeros(288,1);
Pchv = zeros(288,1);
Pdisv = zeros(288,1);
else
    % Else save the values for plotting in arrays
    Pimv = values.Pim(1);
Pexv = values.Pex(1);
Pchv = values.Pch(1);
Pdisv = values.Pdis(1);
end
E. Implementation of RBC in MATLAB

% Algorithm used for Rule based implementation
% Repeating for all the time steps
for t=1:1440
% Splitting up the phases for the rbc implementation
for x=1:3
% Condition for CES Charging
if(Pload(t,x)>Ppv(t,x))
  if(SoC(t)>50)
    bat(t,x)=20;
  else
    bat(t,x)=Pload(t,x)-Ppv(t,x);
  endif
elseif(SoC(t)<=50)
  bat(t,x)=0;
end
% Condition for CES discharging
if(Pload(t,x)<Ppv(t,x))
  if(SoC(t)<400)
    if(Ppv(t,x)-Pload(t,x)>20)
      bat(t,x)=-20;
    else
      bat(t,x)=Pload(t,x)-Ppv(t,x);
    endif
  elseif(SoC(t)>=400)
    bat(t,x)=0;
  end
end
end
SoC(t+1)=SoC(t)-(bat(t,1)+bat(t,2)+bat(t,3))*(1/60)/0.9;