Customer-Side Voltage Regulation to Mitigate PV-induced Power Quality Problems in Radial Distribution Networks

Engineering Honours Thesis
Final Report

by

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Supervised by Dr Ali Arefi

A thesis submitted to Murdoch University to fulfil the requirements for the degree of Bachelor of Engineering (Hons.) in the discipline of Electrical Power Engineering and Industrial Computer Systems Engineering

Perth, Western Australia
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Author’s Declaration

I declare that this thesis is my own account of my research and contains as its main content, work which has not previously been submitted for a degree at any tertiary education institution.

X__________________________

Andrew Forbes
Abstract

The objective of this thesis is to illustrate the effectiveness of customer-side voltage regulation in unbalanced distribution networks, under increasing levels of distributed generation, with the overarching aim of reducing voltage magnitude and voltage imbalance violations. The voltage regulators will be installed between the point of common coupling and the customer point of access. This thesis focusses on a static time-series load flow study that has been developed using Python 3.6.

Load flow simulations have been carried out at PV penetrations levels from 30 to 100 per cent, utilising three different loads models—constant power, constant impedance and an equal impedance-power ratio. An algorithm has been developed for selecting the location of the voltage regulators, which uses the performance of the network in terms of voltage magnitude and voltage imbalance. The test network is based on a real four-wire multiple-earthed neutral distribution network in Perth, Western Australia. Real and reactive power readings from customer meters have been used. The voltage regulator model is constructed around an autotransformer regulator with 32 steps and an effective adjustment range of ±10%.

The proposed voltage regulation methodology in this thesis is effective in addressing the problems of voltage magnitude violations and to a lesser extent, voltage imbalance, in the presence of high PV penetration. However, the benefits this solution offers in terms of voltage violation reduction, loss reduction and autonomous operation, are not enough to overcome the current cost of these devices. The existing on-load tap changer solution modelled in this thesis for comparison, is shown to deliver better technical outcomes in terms of network performance, for less cost.
Acknowledgements

I would like to offer my sincerest thanks to my supervisor, Dr Ali Arefi, for his support and insight during this thesis project and acknowledge that, without his guidance to keep me on track, this journey would not have been possible.

To the entire Murdoch University teaching staff, the past 4.5 years have been some of the most challenging, enlightening and rewarding of my life, and I thank you all, for your part in my experience. Particular mention must go to Dr Gregory Crebbin and Dr Gareth Lee whose depth of knowledge, love of teaching, tolerance, professionalism and humility; has been, and will continue to be, an inspiration to me.
This thesis is dedicated to my parents whose support allowed me to exit the workforce and begin this degree. Throughout this journey, the positivity, love and support you have given me, has been unwavering and I will never be able to thank you enough.
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<td>IEC</td>
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<td>IEEE</td>
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<td>Internal rate of return</td>
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<td>KCL</td>
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<td>kWp</td>
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<td>Voltage adjustment mechanism</td>
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<td>Volt-ampere reactive</td>
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Chapter 1  Introduction

Climate science has been telling us of the need to reduce greenhouse gas emissions for many years now. One of the largest contributors to the problem of human-induced climate change, are the electrical networks that provide billions of people around the globe with electricity [1]. As a means of countering this problem, there has been a rapid uptake of renewable energy generation in recent years. Globally, the proportion of net new generating capacity that is renewable, has increased from 20 to over 60 per cent in the last decade (Fig. 1-1). This upward trend suggests a shift in the global energy generation balance away from more traditional generation sources, such as coal. In Australia, there has been a steady increase in the installation of photovoltaic (PV) systems [2], [3] since approximately July 2010 (Fig. 1-2). While this has primarily been driven by residential rooftop installations, more recently, commercial and utility solar installations have begun to increase their market share [4].

![Figure 1-1. Global new renewable power capacity as a percentage of net new power capacity.][5, Fig. 23]

![Figure 1-2. Total Australian PV installed capacity.][4]

Furthermore, predictions for growth in PV system installations over the next 10 years remain positive. This is primarily due to a combination of high energy costs, and the declining cost of new PV systems [6]. From a technical standpoint, the addition of

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[1] Net new capacity includes new installations, and generation coming offline. Renewable power does not include large hydroelectric facilities.
distributed generation (DG) sources into distribution networks, particularly intermittent sources such as photovoltaics, has presented power engineers with a new set of problems.

1.1 Problem Statement

Electrical networks are traditionally designed as unidirectional systems, with large generators providing energy supply to the transmission system. The high voltage (HV) transmission system is fed into the primary stage (medium voltage) of the distribution system before eventually being stepped-down to low voltage (LV) consumer levels in the secondary distribution system [7]. Integrating other energy generation sources into power systems introduces the potential for energy to flow in a direction that is counter to traditional system design.

The impacts of high PV penetration on LV distribution networks that are of greatest concern are voltage magnitude violations and voltage imbalance violations [8]. There are many published studies investigating voltage regulation in the distribution network using a range of different methods, where the most successful/promising of these are summarised in the following chapter. This thesis proposes a method which, unlike many of the solutions discussed in Chapter 2, does not require any form of computer-based measurement and control.
1.2 Objectives

This thesis is an investigation into a voltage regulation technique aimed at improving the power quality issues associated with distributed generation, with the over-arching goal of facilitating better integration of renewable energy technologies into LV distribution networks. The primary objective for this thesis is to test the effectiveness of series voltage regulators (VR) installed between the point of common coupling (PCC), and the customer point of access (PoA) in distribution networks with distributed PV generation (Fig. 1-3). This thesis is specifically concerned with radial distribution networks with varying levels of PV capacity. While considerable time has been spent in constructing a study case that is as realistic as possible, this thesis is a sensitivity analysis which will also make an economic assessment as to the viability of the series VRs in comparison with an on-load tap changer (OLTC) at the distribution transformer.

1.3 Thesis Outline

Chapter 1 defines the problem and objectives for this thesis while Chapter 2 discusses the areas of research surrounding the key concepts that readers should understand in order to evaluate this work. Specifically, Chapter 2 discusses the major impacts that distributed PV generators can have on LV networks along with some of the current methods for dealing with these impacts. Following this, is a description of the load flow analysis method used in this study and a brief discussion on load modelling techniques for static
load flow analyses. Chapter 2 finishes with a short account on the cost-benefit analysis process.

Chapter 3 presents the test network used for this study along with an analysis of the base case scenario. This is followed by a detailed description of the implementation methodology adopted for the VR location optimisation; and the addition of PV capacity and OLTC technology to the network configuration. The metrics used to assess the network performance under a range of scenarios complete Chapter 3.

Chapter 4 presents the load flow analysis results over a range of PV penetration, which focus primarily on the constant power load model but also compares this against a constant impedance load model and an equal impedance-power ratio load model.

Chapter 5 concludes this thesis with a discussion on the significance of the results, including how they might be applied to future studies. This chapter discusses the limitations of this study and any improvements that could be made for future development. Chapter 5 ends with the conclusion.
Chapter 2  Literature Review

This chapter presents a review of the literature relating to the most significant knowledge areas of this project. This chapter is divided into the following four areas of research:

1. Impact of dispersed generation on distribution networks
2. Methods of voltage regulation in distribution networks
3. Modelling of distribution networks
4. Cost-benefit assessment

2.1 Impact of Dispersed PV Generation on Distribution Networks

Distribution networks, most of which are radial, are typically fed by centralised power generation often emanating from a single substation, with downstream infrastructure designed for unidirectional power flow only [9, p. 1197]. Increases in distributed generation (DG) such as residential photovoltaic (PV) systems, results in power quality (PQ) issues that affect the stability and efficiency of the network. These can have wide-ranging consequences for network operators and users. A survey of the literature found that reverse power flow, which can result in voltage magnitude violations and phase voltage imbalance, are the most significant problems arising from increased PV penetration in radial distribution networks [8, p. 1], [9, p. 1196], [10, p. 967].

2.1.1 Reverse Power Flow and Voltage Violations

Australian standards dictate that LV distribution networks deliver a nominal 230/400 volts with a supply range of +10% to -6% [11, pp. 5–6]. Failure to meet these standards has potential economic and safety implications for network operators and users. Overvoltage conditions arise from a combination of two factors—reverse power flow and fixed voltage levels along the feeder. Reverse power flow will occur when PV current
output \((I_{\text{pv}})\) is greater than the load demand \((I_L)\). When current begins to flow back towards utility voltage regulation equipment that is designed to maintain a fixed voltage level, the feeder voltage profile undergoes a voltage rise [12, p. 1626]. Fig. 2-1 shows this scenario in a simplified single-line diagram (SLD) where the negative net current, which occurs when PV generation is greater than demand, forces the voltage profile (shown in red) to rise from the normal operating scenario (shown in blue).

![Fig. 2-1. Simple network under reverse power flow](image)

Overvoltage conditions are most acute during periods of optimal solar energy generation and low energy demand—the middle of the day when fewer people are at home. This is because during periods of high PV generation there is a greater likelihood that the PV current will be greater than the load current. Higher PV penetration levels in the network mean that the upper voltage limit is reached more easily [9, pp. 1196–1198]. This means that voltage rise has a limiting effect on the PV hosting capacity of LV feeders [12, p. 1626]. Additionally, overvoltage conditions can force existing voltage control devices into continual operation where they are constantly trying to reduce the voltage [13, p. 182].

Under-voltage conditions are most prominent at the terminating end of a distribution feeder because this is the longest distance from the substation—in general terms, voltage
drop is proportional to conductor length. Adding PV generators to a LV network complicates this issue. The PV supply intermittency caused by clouds can result in very fast changes in power flowing from the PV system. If, during a period of reverse power flow as discussed above, clouds were to suddenly reduce the power flowing back into the network, the voltage profile would experience rapid drop. This would initially be magnified by the substation voltage regulation equipment which, at the time, would have been trying to reduce the voltage.

2.1.2 Voltage Imbalance

Voltage imbalance is mathematically defined to be the ratio between the negative and positive sequence systems of symmetrical components of a three-phase network. Known as the voltage unbalance factor (VUF), this is shown in (1), where \(a = 1\angle120^\circ\) and \(V_{ij}\) corresponds to the relevant phase-to-phase voltage [14, p. 124], [15].

\[
VUF(\%) = \frac{V_{ab} + a^2 \cdot V_{bc} + a \cdot V_{ca}}{V_{ab} + a \cdot V_{bc} + a^2 \cdot V_{ca}} \times 100
\] (1)

More practically, voltage imbalance is where there exists a difference between the phase voltage magnitudes or, the difference between the phase angles is greater than the nominal 120\(^\circ\) [16]. The effects of voltage imbalance can be drastic for three-phase motors, particularly induction motors, where a VUF value greater than acceptable AS/NZS limits of 2\% [17, p. 9] can result in destructive temperature rise [14, pp. 124–125]. Voltage imbalance is also known to adversely affect distribution transformers and can result in incorrect operation of voltage regulation hardware and protection relays [16]. While voltage imbalance in LV networks is unavoidable due to the asymmetric nature of network infrastructure and customer energy usage [18, p. 782], its effects can be magnified by an increase in randomly dispersed PV generators in the network [19]. The sensitivity analysis presented in [16] shows that the location of PV systems can influence
the voltage imbalance along the LV feeder that is hosting PV systems, as well as adjacent feeders without PV.

2.2 Methods of Regulating Voltage in Distribution Networks

The adjustment of voltage levels in electrical networks can be achieved by one of four methods—changing the impedance, changing the current, reactive power compensation or by directly manipulating the voltage in series. Changing the line impedance is very costly and changing the current by load reduction or demand response has direct implications for the end user. The remaining two options are commonly employed by network operators and power engineers in a variety of ways.

Traditional methods for voltage regulation (VR) in distribution networks can be separated into either series or shunt-connected devices. Series VR devices directly adjust voltage levels to fit within acceptable limits, whereas shunt-connected (parallel) devices indirectly control the voltage level via the injection/absorption of reactive power. Variations and combinations of both these methods have been utilised with varying levels of success in the presence of high PV penetration. A discussion of the literature relating to commonly used methods, as well as some emerging methods, follows.

2.2.1 On-load Tap Changer (OLTC)

On-load tap changers (OLTCs) refer to componentry that provides voltage regulation by the adjustment of transformer tap ratios while under load. Also known as ULTCs [20], these series devices are typically installed on three phases at the supply end of a low voltage feeder as a means of ensuring adequate voltage levels along the entire distribution line. While the mechanical switching OLTC is considered too slow to be effective in dealing with rapid voltage variations arising from cloud-induced transient events [20], [21], OLTCs that utilise electronic switches have much faster response times. In addition to this advantage, solid-state OLTCs are known to correct voltage swell and flicker
problems [9, p. 1200]. Major problems with solid-state OLTCs are the limits on the number of switches and discontinuous power flow [9, p. 1200], [22, p. 499]. Development on the electronic OLTC aimed at delivering fast and continuous voltage regulation is presented in [22]. Described as an on-load voltage regulator based on electronic power transformer (OLVR-EPT), this device seems likely to see widespread uptake once the cost of solid-state transformers can be reduced [9, p. 1200], [23, p. 20].

2.2.2 Dynamic Voltage Restorer (DVR)

A dynamic voltage restorer (DVR) is a series voltage compensator which can be installed on MV\(^1\) or LV networks [25, p. 750] or further down the feeder, and is best suited to large (>10%), short (0.5 cycles to 1 min) voltage dips [24]. A common configuration for a DVR (see Fig. 2-2) consists of an in-line injection transformer (one for each phase) fed by a dc supplied voltage source converter (VSC) which provides compensation voltage at the required magnitude, phase and frequency [24, p. 139], [26, p. 1033]. The VSC generated harmonics are filtered by an LC circuit [24]. A method presented in [27] shows that a DVR can be used to supply a non-linear, unbalanced load while maintaining a constant voltage magnitude. Instead of using a dc source to supply the DVR, a voltage across a dc supply capacitor is maintained by a PI\(^2\) control algorithm. [26] also makes a strong case for the DVR as a means of dealing with unbalanced phases. A single-phase DVR

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1 Medium voltage
2 Proportional integral
utilising an ac-ac converter is presented in [28]. This configuration does not require a dc link, is easily extendable to three phases and is shown to effectively deal with voltage sags, swells, harmonics and flicker, independent of phase imbalance. Similar ac-ac configurations without a dc-link are presented in [29], [30].

2.2.3 Distribution Static Compensator (D-STATCOM)

Functionally the same as their HV counterparts, and typically connected to the PCC, distribution static compensators (D-STATCOM) are widely used to mitigate voltage dips caused by heavy industries [31, p. 1561]. A typical D-STATCOM consists of a bi-directional VSC, a dc source capacitor, a transformer, a ripple filter and an ac inductor [32, pp. 532–533]. The VSC transfers power from the dc bus capacitor via pulse width modulated controlled electronic switches. Real power flow is controlled by varying the phase angle between the ac supply and the inverter, while the reactive power is influenced by the difference in voltage magnitudes between the supply and the converter [33, p. 331]. A 2012 study [31] presents a process to economically optimise the PV penetration in a distribution network by the implementation of D-STATCOM to control voltage excursions outside nominal limits. The authors make the point that choosing a D-STATCOM with a VSC, as opposed to a current source converter (CSC), will result in less power loss. This study showed positive gains in PV penetration could be achieved from the utilisation of D-STATCOMs in distribution networks. [34] shows that the location of PV generators and D-STATCOMs can have a significant influence on losses, voltage profile and voltage imbalance.

2.2.4 Inverter-based VAR Compensation

Numerous studies have looked at inverter-based reactive power compensation (RPC) [10], [20], [21], [35] and recent changes to the AS/NZS 4777.2:2015 standard [36, p. 16] suggest this method will see widespread application in the future. A 2012 study [21]
presents an adaptive control algorithm designed to balance voltage regulation requirements with loss minimisation. Designed around the capability of PV inverters to supply reactive power when needed, the algorithm is simulated on sparsely-loaded rural distribution network with high PV penetration and allows for an adjustable priority to be applied to voltage regulation and loss minimisation. Numerous studies indicate a need for larger inverter capacity before any meaningful results can be realised by inverter-based RPC [13, p. 183], [21, p. 1660].

2.2.5 Switched Capacitor VAR Compensation

Divan et al. propose VAR injection at the secondary side of the distribution transformer by the high-speed switching of capacitors managed by an onboard controller [23]. This utility-based solution presented here involves a swarm (20-100) of ENG0-V 10 pole-mounted devices [37] connected in shunt at numerous locations along a feeder, all operating from a broadcast voltage setpoint. The major drawback to VAR compensation in LV networks is related to the high R/X ratios found in distribution systems as compared to HV transmission networks. This factor means that the same amount of reactive power is less effective in regulating voltage in distribution networks.

2.2.6 Autotransformer Voltage Regulators

A survey of the literature suggests that the use of voltage regulators for mitigation of power quality problems in distribution networks appears to be largely confined to utility-based solutions. One such strategy for autonomously controlling overvoltage situations by coordinated reactive power control of PV inverters and voltage regulators (VR) is presented in [13]. The VR model used is a typical autotransformer-type line drop compensator. The goal of this study was to prevent voltage control hardware such as OLTCs and VRs from operating in continuous, ‘runaway’ scenarios that can arise when PV inverters operate near their limit at unity power factor. Effective voltage control is
achieved in simulations by design of OLTC and PV setpoints that are derived from network specific constraints such as voltage limits, branch current and PV generation limits.

2.2.7 AC-AC Converters

An electronic voltage regulator from a 2017 study [38] proposes a three-phase solution that delivers continuous voltage magnitude and phase control. The design consists of a hybrid transformer with two output windings that are joined by an array of nine bi-directional switches that form the matrix converter. One advantage of this device is the lack of a dc supply element (as found in most DVR and D-STATCOM devices) which often results in larger, heavier and more costly designs [39, p. 195]. This advantage means that the system requires a minimum network voltage to operate and therefore may not operate correctly under deep sags or fault conditions. The hybrid transformer with matrix converter cleanly compensates for overvoltage and, with the implementation of a more complex switch modulation scheme, phase imbalance. A multi-level AC-AC converter proposed in [40] for high power applications is capable of bi-directional power flow and offers zero voltage switching for over half of the required semiconductors. This converter achieves higher efficiency for less cost than comparable converters.

2.2.8 AC-DC-AC Converters

While not typically utilised in distribution networks for voltage control, AC-DC-AC converters such as those found in wind turbines, are designed to convert an ac voltage of variable magnitude and frequency to a stable output voltage. The simplest version of this type of converter consists of a diode rectifier (AC-DC), linked to a DC-DC converter which supplies a VSC (DC-AC) as shown in Fig. 2-3 [41, p. 690]. A corrected output voltage is achieved by monitoring and adjusting either the dc link voltage or the inverter output. A limitation on this type of converter is that it is unidirectional.
AC-DC-AC converters used in various motor and generator applications as discussed in [42, pp. 253–274] present a potential solution that is bidirectional. This type of converter, as utilised in [43] for wind energy conversion, which offers active and reactive power control, consists of two tri-phase inverters that sit either side a dc link capacitor. A similar configuration for use in electric vehicles is presented in [44].

2.3 Modelling of Distribution Networks

Power systems are some of the most complex and non-linear systems on earth and the ability to accurately model these systems can have economic impacts that affect us all. Static load flow modelling is vital for effective network planning as it allows power engineers to understand the behaviour of the network under a range of possible scenarios. The following two sections will discuss a load flow modelling technique specific to distribution networks and the ZIP load model often used to approximate the non-linear load characteristics of end users.

2.3.1 Load Flow Analysis

Popular load flow modelling techniques such as the Newton-Raphson and the Gauss-Seidel techniques, typically employed for transmission network modelling, have been shown to be inadequate when it comes to modelling unbalanced distribution networks [45, p. 882], [46, pp. 6–11]. Distribution networks are more problematic to model because they are unbalanced between phases; usually, have a radial or weakly meshed topology with a large number of elements; and have less uniform R/X ratios [45, p. 882]. Assuming a distribution network to be balanced is likely to underestimate energy losses, voltage excursions outside the nominal range and neutral currents [47, pp. 31–33]. These
factors have led to the development of several load modelling techniques which attempt to produce accurate results while minimising computation time and maximising algorithm robustness.

A load flow analysis method for radial or weakly meshed, unbalanced, three-phase networks presented by Teng [45] in 2003 and duplicated in [48], effectively deals with the aforementioned problems. Direct load flow solutions are obtained via matrix multiplication of two developed matrices—the bus-injection to branch-current matrix (BIBC); and the branch-current to bus-voltage matrix (BCBV). This method converts the real and reactive bus loads into equivalent bus current injections. After establishing the branch currents from the application of Kirchoff’s Current Law (KCL), bus voltages can be calculated using the known line impedance. This process is streamlined by the use of matrix algebra and is computed iteratively until a solution is found. This method is discussed in more detail in 0.

2.3.2 Load Modelling

Accurate mathematical representation of load characteristics for power system modelling is important for effective planning and management of electrical networks. Overestimation of network loads might lead to expensive, unwarranted network capacity, while under-estimating network load requirements, could result in system-wide voltage collapse [49]. Numerous studies have demonstrated that significant benefits can be realised where more accurate load models are utilized [49, p. 475]. Modelling of network loads is a topic which has received less attention than other network components such as generators, transmission lines and sub-station hardware in the past [50]. A diversity of load characteristics; difficulties in collection of accurate load component data; and variation in load composition due to factors such as weather, customer habits, time of
day, the day of week and season; are some of the major factors which make accurate load modelling a challenging task [49].

A load model is a mathematical representation of the power to voltage sensitivity of an electrical component [49]. When considering steady-state (static) modelling applications, there are numerous techniques that can be used to model an electrical load [49]. A popular polynomial model known as the ZIP coefficient model is a static composition of impedance \( Z \), current \( I \) and power \( P \) with respect to voltage. The expressions for the active \( P \) and reactive \( Q \) power at operating voltage \( V_i \) are shown in (2) & (3);

where \( P_0 \) and \( Q_0 \) are the active and reactive power, respectively, at rated voltage \( V_0 \); and \( Z_{p/q} \), \( I_{p/q} \) and \( P_{p/q} \) are the ZIP coefficients (impedance, current, power) for the active and reactive power equations [51]. Alternative higher-order expressions might be used for devices that exhibit a greater degree of non-linearity with respect to change in voltage. (2) & (3) are second-order examples of this [52, p. 3], [46, pp. 6–6], where \( Z_p + I_p + P_p = Z_q + I_q + P_q = 1 \).

\[
P = P_0 \left[ Z_p \left( \frac{V_i}{V_0} \right)^2 + I_p \frac{V_i}{V_0} + P_p \right] \tag{2}
\]

\[
Q = Q_0 \left[ Z_q \left( \frac{V_i}{V_0} \right)^2 + I_q \frac{V_i}{V_0} + P_q \right] \tag{3}
\]

Due to the small frequency variance usually found in power systems, it is acceptable to neglect the effects of frequency when formulating static load model equations [53]. Further discussion regarding the derivation and application of load models can be found in Appendix D.1.

2.4 Cost-Benefit Analysis

For an organisation to invest in a project, there must be some sort of formal evaluation of the economic implications that the project or investment would have for key stakeholders.
A cost-benefit analysis (CBA) is a methodical way to evaluate the economic viability of a project, with the net present value (NPV) being the metric most commonly used [54–59]. NPV can be defined as the present value of future cash flow minus the initial investment cost [60]. NPV accounts for the time value of money, by normalising all future costs and benefits to present-day value. The formula for calculating the NPV is shown in (4) [61]—where $t$ represents the period, usually calculated annually; $d$ is the nominal discount rate; and $F_t = \text{Benefits}_t - \text{Costs}_t$. The concept of the NPV is often presented as the net present cost (NPC) where the costs and benefits are simply assigned positive and negative values respectively—this is opposite to the NPV.

$$NPV = \frac{F_0}{(1 + d)^0} + \frac{F_1}{(1 + d)^1} + \cdots + \frac{F_t}{(1 + d)^t} = \sum_{t=0}^{T} \frac{F_t}{(1 + d)^t}$$  \hspace{1cm} (4)

The discount rate, often used interchangeably with the weighted average cost of capital (WACC) [62, p. 7], can be thought of as the interest rate charged if the capital costs were borrowed. The real discount rate ($d_{\text{Real}}$), shown in (5), accounts for inflation ($f$) and is substituted for $d$ in (4) [63].

$$d_{\text{Real}} = \frac{d - f}{1 + f}$$  \hspace{1cm} (5)

Internal Rate of Return (IRR), another commonly used method for investment evaluation, is simply the discount rate which results in an NPV equal to zero [64, p. 244]. Both the NPV and IRR can be used to compare competing investments and are calculated based on a common set of assumptions regarding the economic lifespan of the project; likely costs and benefits that will impact the project; discount rate; and the perspective the CBA is being analysed from (ie government, utilities or consumers). While IRR can be a useful evaluation tool, NPV is the preferred option as IRR calculations can yield multiple solutions or no solution under some circumstances [59, p. 31]. Further detail relating to
the CBA process, determination of the discount rate and project life cycle can be found in 0.

2.5 Summary of Literature Review

Research shows that distributed generation negatively affects the number of voltage magnitude and VUF violations in radial distribution networks. This chapter compared a wide range of voltage regulation techniques aimed at minimising these violations and it was found that there is no previous research relating to series voltage regulation at the customer premises. Established load flow analysis and load modelling techniques suitable for static time-series modelling were discussed. Finally, the NPV/NPC was found to be a more reliable metric for economic evaluation than the IRR.
Chapter 3  Analysis and Testing Methodology

This chapter begins with a presentation and brief load flow analysis of the low voltage test network used for this study. Following this is a discussion of the analysis methods that have been employed to achieve the thesis objectives.

3.1 Test Network: Australian 23 Bus LV Network

The test network used for this study is based upon a distribution feeder located in Perth, Western Australia. This network was part of the Western Australian government funded, Perth Solar City research program and has been used in numerous studies [8], [65]–[68]. The Pavetta 1 LV distribution network is a 23-pole, 3-phase, 4-wire, unbalanced network that is fed by a 200 kVA, 22 kV/415 V transformer. It has a PV penetration\(^1\) of approximately 30%, with an average PV system capacity of 1.88 kWp.

The network contains two overhead line types where the series impedance matrices have been derived using the Carson equations [69]. This method accounts for the physical configuration of the cables; and the self and mutual inductance between the three phases, the neutral wire and the multiple ground points. The resultant 4x4 matrix is reduced to a 3x3 matrix via the Kron reduction method [70]. The unbalanced series conductor models for each line type are represented in Fig. 3-1 and Fig. 3-2, while Table B-1 and Table B-2 in Appendix B shows the adopted impedance matrices. Fig. 3-3 conceptually shows the resulting network configuration with the consumer mains impedance and PV generators included.

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\(^1\) This is the ratio of total PV capacity to transformer/network capacity
Series Impedance Matrix: Moon ($Z_1$)

Fig. 3-1. Series impedance matrix representation for Moon ($Z_1$) conductor type

Series Impedance Matrix: Mars ($Z_2$)

Fig. 3-2. Series impedance matrix representation for Mars ($Z_2$) conductor type
The load profiles used for this study consists of real (P) and reactive (Q) power values for each phase and all poles/buses, at discrete 30-minute intervals over a discontinuous period of approximately 2 years. This data originated from power meters installed throughout the network and six nodes (6A, 6C, 11B, 11C, 14A and 14B) showed no recorded data. P & Q values for each of these non-PV nodes were created by averaging the load data from three other randomly chosen nodes on the same phase resulting in load data for all 69 nodes in the network. A start time of 01:30 AM on October 7, 2011 has been assumed so that the time of maximum demand matches the time (18:45 on January 25, 2012) specified in [66, p. 3]. Historical temperature data for the closest weather station (Perth Airport) indicates that this day of peak demand was the second day of a five-day hot spell in the summer of 2012, where the temperature reached 40 °C [71]—a time when air conditioner use would have been extremely high. Fig. 3-4 shows the real power load profiles for each bus and phase on January 25th.
The load data, obtained from a previous study [65], has been modified to increase the network voltage imbalance. The average real and reactive power distribution per phase for the complete dataset is shown in Fig. 3-5.

Due to inconsistencies/unknowns in network topology and stated feeder PV penetration (29-32%) found in the literature [8], [65]–[68], the PV-connected nodes were determined by cross-checking nodes that exhibit negative real power values, with the network diagram in [66, Fig. 2]. This process revealed nodes 13B and 15B as real power
generators even though they were not listed as having a connected PV system [66]. Furthermore, nodes 4C, 13C, 16B and 16C were designated PV nodes but did not supply any power to the network over the entire dataset. Buses 13B and 15B were added to the list of PV-connected nodes—see Table B-3 in 0—while 4C, 13C, 16B and 16C remained on the list due to the possibility that power consumption remained higher than generation. Fig. 3-6 shows the network topology with bus and phase allocation for each grid-connected PV system, noting that the term ‘bus’ is used interchangeably with the term ‘pole’ in this document. For this network, a bus/pole represents a group of three independent nodes—one for each phase—which can each have multiple customer connections.

Fig. 3-6. Australian 23-pole LV network diagram with PV by phase
3.1.1 Baseline Case Analysis

The Baseline case study to be presented in this section is a load flow analysis without any customer voltage regulation (VR) devices present in the network. A fixed transformer (slack bus) phase voltage of 250 V (1.04375 p.u.) was determined by minimising voltage and VUF limit violations (Fig. 3-7) with the per unit set-point constrained to even multiples of a typical transformer tap increment (0.00625 pu) [72, p. 1], [73, p. 2], [74, p. 2].

![Transformer Voltage Setpoint](image)

**Fig. 3-7. Transformer voltage set-point by voltage and VUF violations**

This case study consists of approximately two years of discrete 30 minute time intervals, with all loads modelled as constant power loads (i.e. ZIP coefficients are $P_C = P_D = 1$). Western Power limits for the steady-state voltage magnitude of ±6% have been adopted [75, p. 7]. Fig. 3-8 shows the number of bus voltages violations aggregated by both bus and phase; and over- and under-voltage violations, noting that buses 1–10 have been omitted for clarity as these buses saw no violations. Fig. 3-8 clearly shows the under-voltage breaches on phase C to be the biggest contributor to the total numbers of voltage violations for the year, while Fig. 3-9 shows the voltage violations aggregated by month,
with the summer months producing the most violations as expected. The total number of voltage magnitude violations for the year came to 1048, where 329 were above the upper 1.06 p.u. limit and 719 were below the lower 0.94 p.u. limit.

![Graph showing voltage magnitude violations aggregated by bus & phase](image1)

**Fig. 3-8. Base case: voltage magnitude violations aggregated by bus & phase**

![Graph showing voltage magnitude violations aggregated by month](image2)

**Fig. 3-9. Base case: voltage magnitude violations aggregated by month**

Given the obvious disparity between the heavier loading on phase B (Fig. 3-5), and the voltage violations of phase C (Fig. 3-8), further investigation of the transformer currents during January, the month showing the most voltage violations (Fig. 3-9), was undertaken. Fig. 3-10 shows transformer current loading for the nine days in January 2012 which recorded the highest number of voltage magnitude violations. Each of these
days show a peak demand period (evening) where phase C is carrying more current than phase B, yet for the non-peak times, phase B was generally more heavily loaded. Also, the P and Q ratios per phase for January remained almost unchanged from Fig. 3-5.

Voltage imbalance violations where the VUF is greater than 2%, occurred on 68 occasions while there were 540 events where the VUF was greater than 1.5%. VUF duration curves—see Section 3.3.2 for explanation of duration curves—for each bus for the entire dataset are shown in Fig. 3-11. This figure indicates that the VUF across the whole network was less than 1% for over 95% of the time and less than 0.5% for close to 75% of the time. The inset (Fig. 3-11) shows the 68 VUF violations all occurring on the 6 busses (18-23) that are located the greatest distance away from the distribution transformer (see Fig. 3-6).
3.2 Sensitivity Analysis

As previously discussed, the main objectives of this thesis are to explore measures to reduce the number of voltage magnitude violations and to improve the voltage imbalance via the installation of series VRs installed at the PCC. The experimental method for this study is a sensitivity analysis that assesses the performance of the distribution network under different scenarios. Load flow analysis is undertaken using three different load models (constant power, constant impedance and an equal impedance-power ratio), increased PV penetration (30–100%) and three different voltage regulation solutions. The experimental methodology that has been used to achieve these goals is described in Sections 3.2.1–0.

3.2.1 Software Implementation

The load flow (LF) analysis methodology is key to this thesis, with the development of an efficient and robust simulation program being a critical milestone for the project. The decision to use a text-based programming environment was made in part, because of the
convergence issues associated with the commonly utilised LF algorithms when applied to radial networks [76, p. 419], [77, p. 1229]; but also to allow for voltage regulator model customisation. Additionally, a customised text-based approach allowed the utilisation of conductor series impedance matrices which, at the time, was not possible using Power Factory. The open-source, multi-platform, Python 3.6, was the language chosen, with simulations being run on both Mac OS (10.13.3–6) and Windows 7.

3.2.2 Load Flow Algorithm with Voltage Regulation

The load flow algorithm, known as the direct load flow (DLF) method, has been briefly discussed in Section 2.3.1 and in more detail in 0. This method is ideally suited to radial networks and Fig. 3-12 shows the flow chart for the LF algorithm with the addition of the voltage regulator at the PCC. The load flow algorithm is iterative with node voltages being compared to previous values for each iteration. A mathematically valid solution is where the maximum difference between this comparison, is less than the allowable calculation error of 0.0001. An invalid solution is where the number of iterations reaches a threshold limit of 100, before solution convergence is achieved. The steps shown in Fig. 3-12 are applied to each time event and the key steps in this process are summarised in Table 3-1.
Chapter 3: Analysis and Testing Methodology

1.1) The $P_{ZIP}$ and $Q_{ZIP}$ coefficients are essentially scaling factors applied to each constant $P/Q$ value where each coefficient is calculated by (2) and (3) in Section 2.3.2—making both $P$ and $Q$ a function of voltage.

1.2) Calculation of the equivalent current injected by each load. The first iteration assumes a node voltage value (e.g. $V_k = 1\angle0^\circ$).

1.3) The BIBC and BCBV matrices are used to find the node voltages throughout the network.

1.4) The result of 1.3) is compared against the previous iteration. VR adjustment will not occur until the maximum error between successive iterations is within acceptable limits.

2.1) After convergence has been reached in 1.4), the load-side of each VR is checked and adjusted where necessary. Note that the source-side voltage is used to compute the LF on each iteration.

2.2) The VR adjustment co-efficient, $a_r$, is used to adjust the current drawn by the load. This value is initially set equal to 1 but will change ($a_r = 1 \mp 0.00625$) depending on the load-side voltage of the VR nodes. This value will only be adjusted after initial LF convergence has been reached.

2.3) Re-calculate node voltages and check for convergence.

2.4) The $a_r$ values and tap positions for each VR are updated as required where the tap positions and VR voltage levels are used as the algorithm exit condition.

---

**Fig. 3-12. Load flow algorithm with VR**

**Table 3-1. Summary of LF algorithm with VR**

<table>
<thead>
<tr>
<th>Step</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.1)</td>
<td>The $P_{ZIP}$ and $Q_{ZIP}$ coefficients are essentially scaling factors applied to each constant $P/Q$ value where each coefficient is calculated by (2) and (3) in Section 2.3.2—making both $P$ and $Q$ a function of voltage.</td>
</tr>
<tr>
<td>1.2)</td>
<td>Calculation of the equivalent current injected by each load. The first iteration assumes a node voltage value (e.g. $V_k = 1\angle0^\circ$).</td>
</tr>
<tr>
<td>1.3)</td>
<td>The BIBC and BCBV matrices are used to find the node voltages throughout the network.</td>
</tr>
<tr>
<td>1.4)</td>
<td>The result of 1.3) is compared against the previous iteration. VR adjustment will not occur until the maximum error between successive iterations is within acceptable limits.</td>
</tr>
<tr>
<td>2.1)</td>
<td>After convergence has been reached in 1.4), the load-side of each VR is checked and adjusted where necessary. Note that the source-side voltage is used to compute the LF on each iteration.</td>
</tr>
<tr>
<td>2.2)</td>
<td>The $a_r$ values and tap positions for each VR are updated as required where the tap positions and VR voltage levels are used as the algorithm exit condition.</td>
</tr>
</tbody>
</table>
The voltage regulator (VR) model adopted for the load flow analysis component of this thesis is an autotransformer type regulator such as a step voltage regulator (SVR) or line-drop compensator (LDC) as described in Section 2.2.6. Fig. 3-13 is a simplified circuit diagram [73] where the supply \( V_S \) would typically be connected to the series and shunt windings. The control transformers are configured to activate a series of relays (not shown) connected to the autotransformer which adjusts the turns-ratio of the series transformer when the load-side voltage falls out of tolerance.

The VR algorithm used has 32 steps which covers a range ±10% of the nominal voltage. This results in a step size of 0.00625 p.u. Calculation of load voltage \( V_L \) is shown in (6), where \( a_R = 1 \mp 0.00625 \) is the regulator adjustment coefficient and \( N_T \) is the number of tap steps required.

\[
V_L = \frac{1}{a_R N_T} V_S \tag{6}
\]

Both the resistance and inductance of the VR is negligible relative to the network and is therefore ignored for the load flow analysis.

The choice of this type of VR is somewhat academic given this study is a static (steady-state) time-series load flow analysis which does not consider the dynamic behaviour of the voltage regulator. Simply put, the means in which the voltage is regulated has almost no bearing on the results of the load flow analysis and therefore alternative methods for...
voltage regulation, such as the ac-ac converter discussed in Chapter 2, could be utilised with comparable results.

Placement of the voltage regulator in the LV network is between the LV feeder at the point of common coupling (PCC), and the customer point-of-access (PoA). It is likely that the most feasible scenario would be to install the VR at the feeder-end of the consumer mains, noting that the impedance of the consumer mains has been neglected for this load flow analysis—Fig. 3-14 shows this configuration. The VR is assumed to have an automatic bypass functionality which allows for unadjusted current flow in the event that the device fails. This functionality is found in both devices used in the economic assessment [78], [79] which is discussed in Section 3.3.5.1. The significance of this assumption means that the addition of the VRs to the network will not affect the system reliability.

![Fig. 3-14. Voltage regulator placement in network](image)

### 3.2.2.2 VR Placement Algorithm

The base case LF analysis presented in Section 3.1.1 resulted in 27 of the 69 nodes in the network having at least one voltage violation—either magnitude or VUF. Adding a
voltage regulator at each of these nodes and testing every possible combination was
computationally too expensive and thus required the development of a methodical process
for optimising the location of VRs in the network.

A simple method that accounted for both the number of voltage and VUF violations, as
well as the magnitude of the violation was implemented. In the case of the voltage
violations, the absolute voltage deviation from the voltage range limits \(0.94 < V_k < 1.06\) is calculated for each violation. The results are then summed for each node \(V_k\) and
ranked in descending order, where the ranking defines the preference for VR
placement. This same process is then applied to the VUF violations for each bus \(VUF_n\) except that in this case, the VUF does not require normalisation. The process is
summarised in (7), where \(V_{\text{Rank}}\) and \(VUF_{\text{Rank}}\) are the resultant ranked list of node and
bus numbers respectively.

\[
\sum |V_{\text{Limit}} \pm V_k| \rightarrow V_{\text{Rank}}
\]

\[
\sum VUF_n > 2\% \rightarrow VUF_{\text{Rank}}
\]

The next step is to combine the voltage violation and VUF violation rankings into a single
list of nodes prioritised for VR placement. A VUF weight is calculated by cross-checking
the two lists, and any node in the voltage violation list, whose corresponding bus also
appears in the VUF violation list, is multiplied by a weighting \(W_{VUF}\) as computed in (8).
The weighting has a definable ceiling value \(1 + W_{Max}\) and decays exponentially across
the ranked VUF bus list with a minimum weighting equal to \(1 + W_{max}/VUF_{\text{Rank,n}}\),
where \(VUF_{\text{Rank,n}}\) is the rank of the last bus in the VUF violation list.

\[
W_{VUF} = 1 + \frac{W_{Max}}{VUF_{\text{Rank}}}
\]
Determination of the weighted ranking \( (VR_{\text{Rank}}) \) is shown in (9), where any nodes whose corresponding bus does not appear in the VUF violation list, are given a weighting equal to one.

\[
\sum |V_{Limit \pm} - V_k| \times W_{VUF,k} \rightarrow VR_{\text{Rank}}
\]

Furthermore, \( W_{Max} \) can be scaled depending on the importance of VUF violation mitigation for any given case study. For example, a feeder known to have a high three-phase/single-phase connection ratio would likely require a larger \( W_{Max} \) in order to minimise customer damage costs related to three-phase induction motors.

The process of prioritising VR placement of nodes/buses by a cumulative sum of violations offers a simple and methodical approach that can be easily applied to any network. The top 13 results of the VR placement ranking for the base case, with \( W_{Max} = 0.5 \), are shown in Table 3-2, where the \( VR_{\text{Rank}} \) is the weighted node ranking. Note that in this case, node 23C was promoted up the ranking because of the VUF ranking of bus 23.

<table>
<thead>
<tr>
<th>( VR_{\text{Rank}} )</th>
<th>( VUF_{\text{Rank}} )</th>
<th>( VR_{\text{Rank}} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>20C</td>
<td>20</td>
<td>20C</td>
</tr>
<tr>
<td>19C</td>
<td>19</td>
<td>19C</td>
</tr>
<tr>
<td><strong>18C</strong></td>
<td><strong>23</strong></td>
<td><strong>23C</strong></td>
</tr>
<tr>
<td>23C</td>
<td>22</td>
<td>18C</td>
</tr>
<tr>
<td>22C</td>
<td>18</td>
<td>22C</td>
</tr>
<tr>
<td>21C</td>
<td>21</td>
<td>21C</td>
</tr>
<tr>
<td>17C</td>
<td>17C</td>
<td></td>
</tr>
<tr>
<td>20A</td>
<td>20A</td>
<td></td>
</tr>
<tr>
<td>19A</td>
<td>19A</td>
<td></td>
</tr>
<tr>
<td>23A</td>
<td>23A</td>
<td></td>
</tr>
<tr>
<td>22A</td>
<td>22A</td>
<td></td>
</tr>
<tr>
<td>16C</td>
<td>20B</td>
<td></td>
</tr>
<tr>
<td>20B</td>
<td>16C</td>
<td></td>
</tr>
</tbody>
</table>
3.2.3 Additional PV Capacity

The original load data consisted of real and reactive power values for each node and time event. This data is known to be discontinuous and has been modified during previous studies to increase power quality violations. These facts have three implications for this study:

1. It is not possible to construct PV generation curves from historical irradiance data as there is no way to synchronise the load data against time.

2. The average PV system rating of 1.88 kWp [65, p. 75] is no longer valid and must therefore be derived from existing load data.

3. The stated PV penetration of approximately 30% is no longer valid however this is assumed to be correct for this study as any modifications to the load data would have likely been scalar in nature. A potential scenario where this assumption would be incorrect, is if the load data had been scaled differently across the three phases, where each phase has a different number of PV loads.

As discussed in Section 3.1, the customers with and without PV systems were known. This information was used to construct PV generations curves which were then added to the real load profiles in order to increase the overall PV capacity in the network. The following two sections discuss the method adopted for achieving this incremental increase in PV penetration.

3.2.3.1 Creating PV Generation Profiles

The underlying assumption behind this methodology is that customers who have similar power usage patterns in non-daylight hours, will continue to have similar usage patterns during daylight hours. Using this assumption, the method discussed below matches non-PV nodes/customers, with PV nodes which exhibit similar power usage patterns during non-daylight hours where the difference between these two real power load profiles
during daylight hours, is assumed to be the PV generation profile. The summarised steps adopted for creating new PV generation profiles from the original load data are as follows:

1. All non-daylight time events where real power generation does not occur were identified.

2. All combinations of PV and non-PV real load profiles were compared and evaluated for correlation during the non-daylight times established in the previous step.

3. Node combinations that exhibit high Pearson correlation coefficients, as shown in Table 3-3, imply similar power usage patterns.

4. For each of the ten most closely correlated node combinations in Table 3-3, the non-PV real load profile (for all time events) was subtracted from the corresponding PV profile as shown in (10). This produced an array of ten PV generation profiles.

\[ P_{PV,GEN} = P_{PV} - P_{Non-PV} \]  

(10)

5. All non-daylight time events in the PV generation profiles were set equal to zero and any remaining positive values were scaled by -0.1 to ensure all non-zero values are negative (i.e. power is being supplied to the node/network).

<table>
<thead>
<tr>
<th>Non-PV Node</th>
<th>PV Node</th>
<th>Correlation Coefficient[^2]</th>
</tr>
</thead>
<tbody>
<tr>
<td>31</td>
<td>2</td>
<td>0.8534</td>
</tr>
<tr>
<td>31</td>
<td>35</td>
<td>0.8499</td>
</tr>
<tr>
<td>31</td>
<td>23</td>
<td>0.8478</td>
</tr>
<tr>
<td>31</td>
<td>56</td>
<td>0.8413</td>
</tr>
<tr>
<td>10</td>
<td>23</td>
<td>0.8341</td>
</tr>
<tr>
<td>31</td>
<td>43</td>
<td>0.8282</td>
</tr>
<tr>
<td>16</td>
<td>23</td>
<td>0.8220</td>
</tr>
<tr>
<td>10</td>
<td>35</td>
<td>0.8167</td>
</tr>
<tr>
<td>10</td>
<td>2</td>
<td>0.8163</td>
</tr>
<tr>
<td>10</td>
<td>56</td>
<td>0.8161</td>
</tr>
</tbody>
</table>

\[^2\] Pearson correlation co-efficient
The sequence of steps above result in a set of ten PV generation profiles/curves which are approximately synchronised to the original load data. A brief discussion regarding the process for adding these generation curves to the original load data follows.

3.2.3.2 Adding PV Generation to Load Profiles

To test the effectiveness of the series VR under increasing levels of PV capacity, it was necessary to incrementally increase the PV penetration in the network. The uncertainty in the PV penetration and average PV system rating as discussed above, meant that some assumptions had to be made before the PV generation profiles could be appropriately scaled. The following four steps describe the assumptions and procedures undertaken:

1. A new average PV rating/capacity was calculated from the derived PV generation profiles where the maximum value from each profile was assumed to be 95% of the system capacity.
2. Multiplying the calculated average PV rating by the number of known PV nodes, was used to determine the total PV capacity of the system.
3. Assuming the PV penetration of 30% to be correct, allowed derivation of a value that represents the percentage increase \( (PV_{\%INC}) \) in PV capacity for the system. Equation (11) has been used to incrementally increase the derived PV generation profiles \( (P_{PV,GEN}) \) where \( P_{PV,GEN,Max} \) is the maximum generation value for each profile, \( PV_{p,Orig\%} \) is the assumed PV penetration of 30% and \( PV_{p,New\%} \) is the increased penetration level to be modelled.

\[
P_{PV,GEN,New} = \frac{P_{PV,GEN}}{P_{PV,GEN,Max}} \times PV_{\%INC} \times \frac{PV_{p,New\%} - PV_{p,Orig\%}}{\#\ New\ PV\ nodes} \tag{11}
\]

4. (11) was calculated for 20 nodes and the resulting PV generation profiles added to the real power load profiles of 20 randomly selected nodes, noting that each of the ten PV generation profiles was used twice to cover all 20 nodes. The resulting load profiles
for each node and each PV penetration level (PVp 40–100%) is shown for the day of peak loading in Fig. 3-15.

Fig. 3-15. Load profiles with incrementally increasing PV capacity for day of peak loading

Shows the 20 randomly selected nodes used for increasing the network PV penetration (PVp)
3.2.4 Adding an OLTC to the Network

An on-load tap changer (OLTC) installed in the network at the distribution transformer was selected as a means of comparing the performance of the VRs to an established solution. Independent adjustment of each phase of the transformer is reliant on a SCADA\(^3\) system to provide communications between voltage measurement devices on each phase and the distribution transformer OLTC. The location of each voltage measurement device is determined by the V-VUF ranking of the base case LF analysis as detailed in Table 3-2.

3.3 Network Performance Metrics

The following sections discuss the metrics which have been used to assess the performance of the network for each load flow analysis.

3.3.1 Voltage Magnitude Limits

Australian Standards [11, pp. 5–6] specify distribution network voltage levels should remain between 0.94–1.1 per unit however Western Power limits of 0.94–1.06 p.u. [75, p. 7] for customer utilisation voltage levels have been adopted for this study. This equates to a phase-to-ground range of 225.6–254.4 \(V_{RMS}\) for a nominal 240 \(V_{RMS}\) network. Unless specified otherwise, all ac voltage and current values in this thesis, are given as root-mean squared (RMS) quantities.

The maximum voltage deviation index (MVDI) is a measure of the voltage deviation from the nominal level and is calculated in (12), where \(V_i\) is the bus voltage [80, p. 5]. This index can be applied to phases, buses or an entire network.

\[
MVDI(\%) = \frac{|V_{nominal} - V_i|}{V_{nominal}} \times 100 \tag{12}
\]
3.3.2 Voltage Imbalance Limits

The Australian standard AS/NZS 61000.2.2:2003 (R2013) defines the VUF limit to be 2% noting that this is to be considered over a duration of greater than 10 minutes [17, pp. 8–9]. While there exists some differences in the definition of the VUF between the various standards organisations (IEC, NEMA, CIGRE and IEEE)\(^4\) [65, p. 8]; this study will consider only the ratio of the magnitudes of the sequence components shown in (1) in Section 2.1.2. (13) is the modified equation which neglects the complex angle.

\[
VUF(\%) = \frac{|V_{ab} + a^2 \cdot V_{bc} + a \cdot V_{ca}|}{|V_{ab} + a \cdot V_{bc} + a^2 \cdot V_{ca}|} \times 100
\]

(13)

Given that VUF is assessed over a period of time, the concept of duration curves is used to illustrate the performance of the network in terms of voltage imbalance. VUF duration curves show the exceedance time for a VUF condition occurring over a given time period and are constructed by graphing the entire VUF dataset in descending order on the y-axis, with the x-axis showing time ascending as a percentage of the total time. If we make the assumption that the VUF dataset is wholly representative of the network behaviour over a large time period, then the exceedance time can be thought of as probability. The exceedance time of a given VUF duration curve value is simply the percentage of time where the network VUF is greater than the given VUF value. VUF duration curves for the baseline case are shown in Fig. 3-11.

3.3.3 Current Limits

Electrical cables have current carrying capacity (CCC) limits that are defined by the manufacturer for a variety of environmental conditions, and exceeding these thermal limits can result in the physical breakdown of the cable. Similar to the MVDI, the maximum current capacity index (MCCI) shown in (14), is a measure of the maximum

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line loading where $CCC_k$ is the maximum allowable line current, and $I_k$ is the measured current in line $k$.

$$MCCI(\%) = \frac{CCC_k - I_k}{CCC_k} \times 100$$  \hspace{1cm} (14)

The average feeder loading index (AFLI) [80, p. 5] is an average of the line current relative to line capacity across the entire network or feeder, which is weighted according to conductor length ($l_k$). $L_f$ from (15), is the total feeder length, $CCC_k$ is the maximum allowable line current, $I_k$ is the measured current in line $k$, and $n$ is the number of branches.

$$AFLI(\%) = \sum_{k=1}^{n} \left( \frac{l_k}{L_f} \cdot \frac{I_k}{CCC_k} \right)$$  \hspace{1cm} (15)

### 3.3.4 Losses

Loss minimisation is critical for the efficient operation and effective utilisation of network assets. Reducing network losses allows the network to serve more customers and can have direct influence on network operator profits. The feeder loss to load ratio (FLLR) [80, p. 5], shown in (16), can be used to measure the changes in feeder losses relative to a baseline case.

$$FLLR = \frac{\sum P_{loss}}{\sum P_{load}}$$  \hspace{1cm} (16)

Losses arising from the switching of voltage regulators is assumed to be proportional to the number of switching operations and transformer losses have been neglected for this study.

### 3.3.5 Net Present Cost

The economic costs considered in this study can be grouped according to investment costs; operational and maintenance (OM) costs; reliability costs and penalty costs. An
asset life of 25 years for the voltage regulators and the OLTC, has been assumed for each scenario with network performance related costs (3.3.5.3) assumed to be uniform over the asset life. A discount rate of 6.53% has been adopted from [56, p. 22] and an inflation rate of 2% has been assumed. This results in a real discount rate of 4.44%.

3.3.5.1 Investment Costs

Investment costs are simply the cost of purchase plus the installation of the VR asset. Asset purchase price functions, shown in Fig. 3-16, has been derived from market research\(^5\) of suitable single-phase VRs [78], [79]. Both of these devices utilise a buck-boost transformer and power electronic converter. Due to the disparity in price between the two options, an assumed cost function was adopted as shown in Fig. 3-16. The cost of the asset installation is assumed to be a fixed cost of $1500 which was estimated from consultation with numerous industry participants.

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\(^5\) Email correspondence with Nam Paik (Sales VP) from www.TSiPower.com
The size of each installed VR is individually calculated to be 120% of the maximum apparent power at the point of installation as determined by the V-VUF ranking algorithm discussed in Section 3.2.2.2.

The cost of the OLTC and SCADA system are assumed to be $10,000 each with a $1,500 installation cost for both items. Table B-4 in the appendixes summarises the project costs.

3.3.5.2 Operational and Maintenance Costs

Operational and maintenance (O&M) costs relating to VR operation considered for this thesis, can be classified under three different types as shown in (17). Firstly, fixed O&M costs \( C_{FixedO&M} \) account for the ongoing maintenance of the VR asset and have been assumed to be 5% of the investment cost—a figure adopted from a similar study [8, p. 5]. The remaining O&M costs are variable costs which are influenced by network losses and are comprised of an energy component, and a capacity component. The peak power loss \( P_{Loss} \) is used to calculate the cost of additional network capacity while the total energy loss \( E_{Loss} \) is used to determine the variable generation costs [8], [81].

\[
C_{O&M} = C_{FixedO&M} + c_{PL}P_{Loss} + c_{EL}E_{Loss}
\]  

(17)

\( c_{PL} \) is the incremental cost of peak power loss and is assigned a value of $235 per kW-year. \( c_{EL} \) is equal to $0.04 per kWh and is representative of the centralised generation costs. Both of these values are have been assumed from [82, p. 1655].

3.3.5.3 Cost of Reliability

As energy costs continue to rise in Australia, there exists a renewed focus on the need for network operators to balance reliability with affordability, ensuring that over-investment in network infrastructure is minimised. The cost of reliability \( C_{Reliability} \) has been calculated under the assumption that the addition of VRs to the network has no effect on the overall system reliability as discussed in Section 3.2.2.1. Instead of calculating system
reliability dynamically, reliability index values have been adopted from Western Power’s 2016 Service Standard Performance Report. Table 3-4 shows the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) for urban distribution networks averaged over the reported years 2012–2016 [83, p. 17].

<table>
<thead>
<tr>
<th>Reliability index</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>SAIDI (minutes per interruption)</td>
<td>101.1</td>
</tr>
<tr>
<td>SAIFI (interruptions per year)</td>
<td>1.0725</td>
</tr>
</tbody>
</table>

Multiplying SAIDI and SAIFI together yields the total average minutes of interruptions per year for this type of network—this is the amount of time that customers are not receiving reliable energy supply. Converting this figure to a ratio means it can be used to calculate the amount of energy not supplied. To assign a cost to this amount of energy not supplied, a value for the cost of customer reliability (VCR) of $25.95 per kWh has been adopted from a 2014 reliability review conducted by the Australian Energy Market Operator (AEMO) [84, p. 2]. This VCR figure represents the amount that a typical residential participant in the National Energy Market (NEM) is willing to pay for reliable energy. This process is summarised in (18).

\[ C_{Reliability} = \frac{SAIDI \times SAIFI}{\text{Min. per year}} \times \sum \text{Energy} \times VCR \]  

(18)

3.3.5.4 Penalty Costs

Penalty factors are applied to the voltage magnitude and VUF violations. It is inherently difficult to assign accurate costs to these violations [85] so values have been assumed purely to allow the key performance metrics to be simplified down to a single dollar value. Assumed penalty factors, to be multiplied by the number of violations, for under-voltage,
over-voltage and VUF violations are $5, $8 and $12 respectively (Table B-4). Over-voltage is assigned a higher value than under-voltage violations as these are more likely to result in damage to customer equipment [85]. Similarly, VUF violations can result in damage to 3-phase induction motors commonly used in air-conditioners and pumps. Combining the penalty costs ($C_{penalty} = C_{V^-} + C_{V^+} + C_{VUF}$) with (17) and (18) gives the total cost (19).

$$C_{Total} = C_{O&M} + C_{Reliability} + C_{penalty}$$ (19)
Chapter 4  Results

The load flow simulation results have been grouped according to the load type, with simulations carried out using the ZIP model coefficients as shown in Table 4-1.

Table 4-1. Simulation Case summary

<table>
<thead>
<tr>
<th>Case</th>
<th>Case name</th>
<th>Abbr.</th>
<th>Z&lt;sub&gt;ZIP&lt;/sub&gt;</th>
<th>I&lt;sub&gt;ZIP&lt;/sub&gt;</th>
<th>P&lt;sub&gt;ZIP&lt;/sub&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Constant Power</td>
<td>P&lt;sub&gt;ZIP&lt;/sub&gt;</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>2</td>
<td>Constant Impedance</td>
<td>Z&lt;sub&gt;ZIP&lt;/sub&gt;</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>3</td>
<td>Equal Impedance-Power Ratio</td>
<td>ZP&lt;sub&gt;ZIP&lt;/sub&gt;</td>
<td>0.5</td>
<td>0</td>
<td>0.5</td>
</tr>
</tbody>
</table>

Each of the three cases—constant power, constant impedance and an equal impedance-power ratio—have been analysed at discrete 10% increments of PV penetration (PV<sub>p</sub>) starting at the Base Case<sup>1</sup> level of 30%, up to 100% PV<sub>p</sub>. Furthermore, load flow analyses are undertaken for each of these 24 network configurations utilising three different voltage adjustment technologies as follows:

1. Series voltage regulators (VR) at the point of common coupling—discussed in Section 3.2.2.1–3.2.2.2;
2. An on-load tap changer (OLTC) at the distribution transformer—discussed in Section 3.2.4; and
3. A hybrid VR-OLTC combination of the above two options.

A standardised naming convention used to identify the sub-cases is comprised of the voltage adjustment mechanism (VR/OLTC/VR-OLTC) and the ZIP load model abbreviation (P<sub>ZIP</sub>/Z<sub>ZIP</sub>/ZP<sub>ZIP</sub>).

<sup>1</sup> PV penetration of 30% is assumed to be the Base Case for each of the different ZIP load models. For example, Base Case: corresponds to the constant power case.
4.1 Voltage Magnitude Violations

The number of voltage magnitude violations is shown to decrease with the addition of voltage regulation devices (VR/OLTC) across all cases, voltage adjustment mechanisms (VAMs) and for PV penetration levels 30–70%, with both of the OLTC options performing better than the VR-only solution. Under- and over-voltage violations for the real power scenario (Case 1) are shown in Fig. 4-1–Fig. 4-6. The number of magnitude violations (±6% of $V_{\text{NOMINAL}}$) are shown on the y-axis as a percentage of the total potential violations (no. of time events multiplied by the no. of nodes). The number of voltage regulators included in the network for each load flow analysis is shown on the x-axis noting that the order of the VR installation differs between cases and VAMs. The lack of uniformity is because the order of VR installation is governed by the V-VUF ranking algorithm (Section 3.2.2.2). Line graphs showing the same data for Case 2 and 3 can be found in Appendix A.1 (Fig. A-1–Fig. A-12).

![Fig. 4-1. Case 1: Under-voltage violations [VR-PZIP]](image1)

![Fig. 4-2. Case 1: Over-voltage violations [VR-PZIP]](image2)
Both OLTC solutions show an immediate and sharp decrease in the number of violations. This decrease is more significant than the case where a single VR is added to the network because the OLTC adjustment affects every node ‘downstream’ from the transformer. This is clearly demonstrated in the node voltage plots for the over-voltage event in Appendix A.7.1 which show the Base Case, VR and OLTC solutions (shown in Fig. A-36, Fig. A-38 and Fig. A-40 respectively). Similar behaviour is evident for Cases 2 and 3. For contrast, the time-event which produced the most under-voltage violations, is shown in parallel with the over-voltage event.

When considering PVp of 50–100%, the under-voltage violations for the VR-only solution, show a knee-point (Fig. 4-1) where the violation percentage starts to decrease.
This knee-point corresponds closely with the asymptotic point on the over-voltage graph (Fig. 4-2) where the rate of reduction in violations starts to decrease as more VRs are added to the network. This relationship, also evident in Case 2 and 3 (see Appendix A.1), is a result of the VR placement algorithm prioritising nodes with the most violations, and the fact that high PVp scenarios result in more over-voltage violations. This means these nodes are allocated VRs prior to nodes displaying under-voltage violations.

All of the OLTC-only solutions show that there is some PVp limitation (60–70%, 40–50% and 50–60% for Case 1, 2 and 3 respectively) beyond which these options become ineffective in reducing under-voltage violations. The cause of this is related to the prevalence of the elevated voltage levels associated with high PVp. Under these conditions the OLTC will set the target voltage low in order to mitigate over-voltages. However this results in more under-voltage violations when cloud transients quickly reduce the power output from the PV generators.

To summarise the relationship between the three cases: Case 1 produces more under-voltage but less over-voltage violations than Case 2, while the number of violations for Case 3 sits between Case 1 and 2 for both under- and over-voltage violations.

4.1.1 Maximum Voltage Deviation Index (MVDI)

The mean of the MVDI is grouped according to the VAM with PVp on the x-axis while the shaded areas represent the range between the maximum and minimum values for each PVp level. The VR-only solution for Case 1 shown in Fig. 4-7 displays very little deviation from the mean MVDI, with the largest difference between the maximum and minimum values (ie the most effective voltage reduction) equal to 0.723% for the PVp100% scenario. This small change in the MVDI is due to the limited range and location at the end of the feeder of the VRs, where the location means that the VR is opposing the maximum effective fault level of the network. In contrast, both OLTC
options provide reductions of 7.959% and 9.393% for the OLTC and VR-OLTC solutions respectively (Table 4-2), where the range is equal to the MVDI of the final solution less the MVDI of the Base Case.

![Mean Maximum Voltage Deviation Index [P_{ZIP}]](image)

*Fig. 4-7. Case 1: Mean maximum voltage deviation index [P_{ZIP}]*

<table>
<thead>
<tr>
<th>VAM²</th>
<th>Metric</th>
<th>PVp30%</th>
<th>PVp40%</th>
<th>PVp50%</th>
<th>PVp60%</th>
<th>PVp70%</th>
<th>PVp80%</th>
<th>PVp90%</th>
<th>PVp100%</th>
</tr>
</thead>
<tbody>
<tr>
<td>VR</td>
<td>No. of VR Range (%)</td>
<td>27</td>
<td>40</td>
<td>50</td>
<td>58</td>
<td>62</td>
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<td>66</td>
</tr>
<tr>
<td></td>
<td></td>
<td>-0.679</td>
<td>-0.678</td>
<td>-0.685</td>
<td>-0.661</td>
<td>-0.693</td>
<td>+0.699</td>
<td>-0.707</td>
<td>+0.723</td>
</tr>
<tr>
<td>OLTC</td>
<td>No. of VR Range (%)</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>VR-OLTC</td>
<td>No. of VR Range (%)</td>
<td>18</td>
<td>28</td>
<td>40</td>
<td>50</td>
<td>49</td>
<td>52</td>
<td>55</td>
<td>60</td>
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<td></td>
<td></td>
<td>-4.709</td>
<td>-4.583</td>
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<td>-3.240</td>
<td>-5.338</td>
<td>-8.386</td>
<td>-9.393</td>
</tr>
</tbody>
</table>

When considering the different ZIP load models, Case 2 and 3 display qualitatively similar curves (Fig. A-13 and Fig. A-14) over the PVp range, although both cases show a much greater range in reduction when comparing the different PVp levels for the OLTC

² Voltage adjustment mechanism
solutions (Table A-1 and Table A-2). It is important to highlight that the range specified in Table 4-2 does not necessarily indicate that the level of improvement between the base case and the final solution. While this is true for both of the OLTC cases as shown in Fig. 4-9 and Fig. 4-10, Fig. 4-8 shows the MVDI step back up for PVp levels of 80% and 100%. Case 2 and 3 exhibit similar behaviour.

![Graph](attachment:image1.png)

**Fig. 4-8. Case 1: MVDI [VR-PZP]**

![Graph](attachment:image2.png)

**Fig. 4-9. Case 1: MVDI [OLTC-PZP]**

![Graph](attachment:image3.png)

**Fig. 4-10. Case 1: MVDI [VR-OLTC-PZP]**

4.2 VUF Violations

Voltage imbalance violations (VUF > 2%) for the real power scenario (Case 1) are shown in Fig. 4-11–Fig. 4-13 where the number of violations are shown as a percentage of the total potential violations (no. of time events multiplied by no. of buses). A line graph for each VAM is presented with PVp levels represented by unique series. The number of
voltage regulators included in the network for each load flow analysis is shown on the x-axis. Case 2 and 3 display qualitatively similar values for all VAMs and can be found in Appendix A.3. All cases show a reduction in VUF violations across all the PVp levels for the VR-only solution, with Case 1 displaying a prominent plateau, followed by a knee-point for PVp greater than 40%. This knee-point is less severe, but still evident in Case 3 (Fig. A-18) but not in Case 2, and displays similar behaviour to the under-voltage violations discussed in Section 4.1. Both of the OLTC solutions reduce the VUF violations to zero for all PVp levels up to 50%, for all cases. For PVp levels greater than 50%, the OLTC solutions start to increase the number of VUF violations.

![Fig. 4-11. Case 1: VUF violations [VR-PZIP]](image1)

![Fig. 4-12. Case 1: VUF violations [OLTC-PZIP]](image2)

![Fig. 4-13. Case 1: VUF violations [VR-OLTC-PZIP]](image3)
4.3 Branch Current

The minimum and maximum values for both the maximum current capacity index (MCCI) and the maximum average feeder loading index (AFLI) are grouped according to the VAM with PVp on the x-axis and the shaded areas representing the range of the maximum/average current in the network between the Base Case, and the final solution for each network configuration. The constant power (Case 1) results graphed in Fig. 4-14 and Fig.4-15 show the VR solution with only minimal change in the maximum and average network current over all PVp levels. The sign of the range values in Table 4-3 are an indication of the trend (+/-) as VRs are added to the network, with the largest increase of 0.472% for the 100% PVp. The range of the maximum AFLI for Case 1 follows what is qualitatively the same curve as the MCCI.

Both OLTC options show a 4% reduction in the MCCI from 30% to 60% PVp which then transitions to an increase between the PVp range of 60–80%, ending with an increase in the MCCI of 6.489% and 14.213% at 100% PVp for the OLTC and VR-OLTC solutions respectively (Table 4-3). This initial reduction in MCCI can be attributed to more local utilisation of PV generated power, where the increase is a result of excessive reverse power flow.
The major difference between the ZIP load models is that both Case 2 and 3 show a much narrower range in the MCCI and the maximum AFLI for the two OTLC options from 30–70% (see Fig. A-21–Fig. A-24).

4.4 Energy Loss & Peak Power Loss

The energy loss and the peak power loss have been presented in the same format with the mean of both loss quantities shown as a percentage difference to the relevant Base Case on the y-axis, and are grouped according to the VAM, with PVp on the x-axis. This representation, as shown in Fig. 4-16 for Case 1, was chosen because many of the PVp series show very little variance with the addition of VRs to the network, whereas there are obvious differences across the PVp range. To give an indication of the change in loss over each of the PVp series (i.e. as VRs are added to the network), the difference between the minimum and maximum loss values (expressed as the ‘range’) and the number of network configurations over which these values are determined, is shown in accompanying tables. The range is assigned a polarity (+/-) that is calculated by subtracting the first peak/trough, from the second, giving a negative value, for example, if a PVp series shows a reduction in energy/power between these two network

\[\text{Range} = \text{Minimum} - \text{Maximum} \]

---

\(3\) PV penetration of 30% is assumed to be the Base Case for each of the different ZIP load models. For example, Base Case 1 corresponds to the constant power case.
configurations. In most instances, the range is the difference between the Base Case and the final solution.

![Mean Energy Loss (P_{ZIP})](image)

\textit{Fig. 4-16. Case 1: Mean percentage difference in energy loss [P_{ZIP}]}

The percentage difference in mean energy loss for Case 1 shows very little difference between the VAMs across the entire PVp range, with the greatest deviation equal to 4% between the VR and the VR-OLTC solution at 100% PVp. The PVp range of 30–70% shows a reduction in the mean energy loss which peaks at 14.14% for the 50% PVp level. Cases 2 and 3 are display similar reductions of 13.9% and 14% respectively for all VAMs at a PVp of 50% (see Fig. A-25 and Fig. A-26). All cases start to see an increase in the mean energy loss above 70% PVp.

For PVp levels greater than 60% for Case 1, the positive range values for all VAMs indicate an increase in energy loss with the addition of VRs/OLTC to the network (Table 4-4). For 60% PVp, the percentage deviation from the mean is only 0.028%, 0.101% and 0.106% for the VR, OLTC and VR-OLTC solutions, respectively. However, it increases to 0.443%, 4.396% and 4.636% at 100% PVp. This pattern is consistent for both of the
VR-only solutions in Cases 2 and 3 (Table A-3 and Table A-3), however the corresponding OLTC solutions show that this pattern is reversed.

<table>
<thead>
<tr>
<th>VR</th>
<th>No. of VR</th>
<th>Metric</th>
<th>PVp30%</th>
<th>PVp40%</th>
<th>PVp50%</th>
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<tr>
<td></td>
<td></td>
<td>Mean (%)</td>
<td>-0.013</td>
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<td></td>
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<td>-0.015</td>
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<table>
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<tr>
<th>OLTC</th>
<th>No. of VR</th>
<th>Metric</th>
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<th>PVp40%</th>
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<tr>
<td></td>
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<td>Mean (%)</td>
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<td>-14.100</td>
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<td></td>
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<td>Range (%)</td>
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<th>PVp100%</th>
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<tbody>
<tr>
<td></td>
<td></td>
<td>Mean (%)</td>
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<td>-10.436</td>
<td>-14.139</td>
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<tr>
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<td></td>
<td>Range (%)</td>
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<td>+0.796</td>
<td>+1.786</td>
<td>+3.108</td>
<td>+4.636</td>
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</tbody>
</table>

Mean (%)—the percentage difference to Base Case; Range(%)—the first peak/trough subtracted from the second, as a percentage of the mean energy loss

The mean peak power loss for Case 1, shown as the percentage difference from Base Case1, is almost unchanged from 30 to 60% PVp for all VAMs, with the VR-OLTC solution producing the peak power in this range (Fig. 4-17). All VAMs display a sharp rise in the mean peak power loss between 70 and 80% PVp, with VR-OLTC solution producing the highest values for PVp levels above 70%.
Fig. 4.17. Case 1: Percentage difference in peak power loss [P_{ZIP}]

Table 4-5. Case 1: Peak power loss (mean & range) [P_{ZIP}]

<table>
<thead>
<tr>
<th>VR Type</th>
<th>Metric</th>
<th>PVp30%</th>
<th>PVp40%</th>
<th>PVp50%</th>
<th>PVp60%</th>
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<th>PVp80%</th>
<th>PVp90%</th>
<th>PVp100%</th>
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<tr>
<td>VR</td>
<td>No. of VR</td>
<td>27</td>
<td>40</td>
<td>50</td>
<td>58</td>
<td>62</td>
<td>62</td>
<td>64</td>
<td>66</td>
</tr>
<tr>
<td></td>
<td>Mean (%)</td>
<td>-0.788</td>
<td>-0.813</td>
<td>-0.586</td>
<td>-0.435</td>
<td>-0.368</td>
<td>-0.317</td>
<td>+44.406</td>
<td>+97.345</td>
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<td>Range (%)</td>
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<td>-0.887</td>
<td>-0.885</td>
<td>-0.884</td>
<td>-0.883</td>
<td>-0.883</td>
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<tr>
<td>OLTC</td>
<td>No. of VR</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Mean (%)</td>
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<td>-4.832</td>
<td>-4.832</td>
<td>-4.832</td>
<td>0.000</td>
<td>+6.062</td>
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<td>+110.072</td>
</tr>
<tr>
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<td>49</td>
<td>52</td>
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<td>Range (%)</td>
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<td>-0.886</td>
<td>+15.253</td>
<td>+20.285</td>
<td>+23.376</td>
</tr>
</tbody>
</table>

Mean (%)—the percentage difference to Base Case; Range(%)—the first peak/trough subtracted from the second, as a percentage of the mean energy loss.

Cases 2 and 3 shows very little separation between each VAM for 30–70% PVp and this continues through to 100% PVp for Case 3 (Fig. A-28). For Case 2, the VR solution produces the highest mean peak loss for 60–100% PVp (Fig. A-27). Table 4-5 shows that both the OLTC options produce the best peak power reduction—10.155% and 10.674%.
for the OLTC and VR-OLTC solutions respectively—for 30–60% PVp but then display the highest as PVp increases to 100%.

### 4.5 Economic Evaluation

The results of the objective function (19) (i.e. the total net present costs) for Case 1 are shown in Fig. 4-18–Fig. 4-20. The number of voltage regulators included in the network for each load flow analysis is shown on the x-axis and each series represents a PVp level. The VR solution shows the NPC increasing at a constant rate for 30–50% PVp (Fig. 4-18). This behaviour is due to purchase price of the VRs being too high to outweigh the benefits they deliver in terms of loss reduction and voltage penalty costs. For a PVp of 60–100%, there exists a saddle-point before which the VR solution is shown to deliver better economic outcomes than the cost of doing nothing. However after this saddle-point, the cost of the VRs again begins to outweigh the financial benefits they deliver.

The OLTC solution delivers a reduced NPC for all PVp levels for Case 1 and shows excellent results for the higher PVp levels. The VR-OLTC shows an initial drop in NPC but then begins to rise as the cost of the VRs begins to increase. Cases 2 and 3 yield similar NPC curves for all VAMs.

![Fig. 4-18. Case 1: Net present cost [VR-P20]](image1)

![Fig. 4-19. Case 1: Net present cost [OLTC-P20]](image2)
Fig. 4-20. Case 1: Net present cost [VR-OLTC-P_{20y}]
Chapter 5      Discussion

The installation of series voltage regulation devices between the point of common coupling and the customer point of access improves power quality issues associated with distributed generation. In particular, this method of regulating network voltage is shown to improve voltage magnitude levels and voltage imbalance. However contrasting the performance of this method against an established voltage regulation technique (OLTC) has shown the proposed method to be sub-optimal when assessed on many of the metrics utilised in this study.

Voltage magnitude violations were reduced by the VR solution in all scenarios however the both of the OLTC solutions were shown to be more effective. In particular, the VR solution was ineffective in reducing the larger violations that occur with high PVp. The reason for the better performance by the OLTC is related to the location of the VRs. By adjusting the voltage at the distribution transformer, the OLTC effects the whole network whereas the VR is effecting only a single node. Installing the VR at the end of the line means that it can operate autonomously but this benefit is outweighed by its effectiveness.

Voltage imbalance violations were also shown to be reduced with the application of the series VR but again the OLTC solutions were more effective up to PVp levels of 50–70%. After this level, the OLTC solutions were shown to increase the VUF violations but further investigation as to the cause of this is required. Changes in the maximum branch current and average feeder loading index were shown to be minimal for the VR solution whereas the more effective voltage regulation achieved by the OLTC solutions results in greater change in both current metrics.

The observed energy losses showed very small reductions for the VR solution and only marginal improvements from both OLTC options. The reduction in energy loss for all
cases between 30 and 70% PVp can be attributed to increased local utilisation of PV generated energy, whereas the rise in energy losses from 70–100% PVp is a reflection of over-supply of PV generated energy resulting in excessive reverse power flow. These facts suggest that any future work using this data and with similar goals, should focus on PVp levels above 60–70%.

Economically the VR solution is shown to be non-viable. The reasons for this are that the hardware costs are too high, and the financial benefits that they provide in terms of loss reduction are too low. The improved NPC observed between 30 and 50% PVp can be attributed to the loss reduction associated with better use of PV energy as discussed above. While it is admitted that there are significant margins of error in the economic model, specifically the penalty factors, the cost that is contributing most heavily to the overall cost of the VR solution, is the VR itself.

One of the key strengths of this study is the utilisation of real load data and conductor impedance models to establish a realistic base model. Considering the weaknesses of this study, modelling the network transformer as an infinite bus is unrealistic and consideration of the system fault level and source impedance would provide a more realistic model. Conducting analysis on three different load models—constant power, constant impedance and an equal impedance-power ratio—has provided a depth to the results in that the range between the cases is representative of the likely range of metrics that could be expected in a real network.

5.1 Conclusion

The voltage regulation methodology proposed in this thesis has been shown to be effective in addressing the problems of voltage magnitude violations and to a lesser extent, voltage imbalance, in the presence of high PV penetration. However the benefits this solution offers in terms of voltage violation reduction, loss reduction and autonomous
operation, is not enough to overcome the present cost of these devices. The existing OLTC solution modelled in this thesis for comparison, is shown to deliver better technical outcomes in terms of network performance, for less cost.

5.2 Future Work

In terms of experiment design, this study is somewhat deterministic and further work should aim to look at this problem in a more probabilistic manner. The existence of the ‘knee-point’ in the VR under-voltage violations results (discussed in Section 4.1) is evidence of this. Conducting a similar study using Monte Carlo analysis methodology as opposed to a sensitivity analysis, would improve the robustness of the results. Specifically, the placement of both the voltage regulators and the new PV generators could be randomised and simulated many times.

Future improvements in battery storage technology and reduction in purchase costs are likely to result in increased usage in coming years similar to the growth that PV installations have already undergone (Fig. 1-2). This trend is likely to be closely followed by increased popularity in electrical vehicles. The addition of both of these elements to the test network would provide useful insight into the long term performance of series voltage regulation at the customer premises.
Bibliography


[57] Infrastructure Australia 2017, Assessment Framework: For initiatives and projects to be included in the Infrastructure Priority List. Australia: Infrastructure Australia, 2017.


Appendix A   Supplementary Results

A.1  Voltage Magnitude Violations

A.1.1  Case 2: Voltage Violations

Fig. A.1. Case 2: Under-voltage violations [VR-Z_{2\theta}]

Fig. A.2. Case 2: Over-voltage violations [VR-Z_{2\theta}]

Fig. A.3. Case 2: Under-voltage violations [OLTC-Z_{2\theta}]

Fig. A.4. Case 2: Over-voltage violations [OLTC-Z_{2\theta}]

Fig. A.5. Case 2: Under-voltage violations [VR-OLTC-Z_{2\theta}]

Fig. A.6. Case 2: Over-voltage violations [VR-OLTC-Z_{2\theta}]
A.1.2 Case 3: Voltage Violations

Fig. A-7. Case 3: Under-voltage violations [VR-ZPZP]

Fig. A-8. Case 3: Over-voltage violations [VR-ZPZP]

Fig. A-9. Case 3: Under-voltage violations [OLTC-ZPZP]

Fig. A-10. Case 3: Over-voltage violations [OLTC-ZPZP]

Fig. A-11. Case 3: Under-voltage violations [VR-OLTC-ZPZP]

Fig. A-12. Case 3: Over-voltage violations [VR-OLTC-ZPZP]
Appendix A: Supplementary Results

A.2 Maximum Voltage Deviation Index

![Graph showing mean maximum voltage deviation index for Case 2 and Case 3](image)

Fig. A-13. Case 2: Mean maximum voltage deviation index \([Z_{ZIP}]\)

Fig. A-14. Case 3: Mean maximum voltage deviation index \([ZP_{ZIP}]\)

### Table A-1. Case 2: Range of max. voltage deviation index \([Z_{ZIP}]\)

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<th>PVp40%</th>
<th>PVp50%</th>
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<tbody>
<tr>
<td>VR</td>
<td>No. of VR</td>
<td>25</td>
<td>39</td>
<td>53</td>
<td>62</td>
<td>62</td>
<td>64</td>
<td>66</td>
<td>68</td>
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<tr>
<td></td>
<td>Range (%)</td>
<td>0.650</td>
<td>0.650</td>
<td>0.668</td>
<td>0.686</td>
<td>0.686</td>
<td>0.707</td>
<td>0.706</td>
<td>0.731</td>
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<tr>
<td>OLTC</td>
<td>No. of VR</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<tr>
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<td>Range (%)</td>
<td>2.068</td>
<td>1.988</td>
<td>2.426</td>
<td>5.144</td>
<td>7.772</td>
<td>11.051</td>
<td>11.507</td>
<td>11.990</td>
</tr>
<tr>
<td>VR-OLTC</td>
<td>No. of VR</td>
<td>13</td>
<td>19</td>
<td>35</td>
<td>45</td>
<td>49</td>
<td>55</td>
<td>59</td>
<td>62</td>
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<tr>
<td></td>
<td>Range (%)</td>
<td>2.734</td>
<td>2.522</td>
<td>3.076</td>
<td>5.805</td>
<td>8.415</td>
<td>11.756</td>
<td>15.039</td>
<td>18.627</td>
</tr>
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</table>

### Table A-2. Case 3: Range of max. voltage deviation index \([ZP_{ZIP}]\)

<table>
<thead>
<tr>
<th>VR Type</th>
<th>Metric</th>
<th>PVp30%</th>
<th>PVp40%</th>
<th>PVp50%</th>
<th>PVp60%</th>
<th>PVp70%</th>
<th>PVp80%</th>
<th>PVp90%</th>
<th>PVp100%</th>
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<tr>
<td>VR</td>
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<td>27</td>
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<td>62</td>
<td>63</td>
<td>66</td>
<td>66</td>
</tr>
<tr>
<td></td>
<td>Range (%)</td>
<td>0.660</td>
<td>0.659</td>
<td>0.660</td>
<td>0.685</td>
<td>0.691</td>
<td>0.703</td>
<td>0.718</td>
<td>0.725</td>
</tr>
<tr>
<td>OLTC</td>
<td>No. of VR</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Range (%)</td>
<td>2.760</td>
<td>2.665</td>
<td>3.100</td>
<td>2.923</td>
<td>5.778</td>
<td>8.875</td>
<td>9.592</td>
<td>9.675</td>
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<tr>
<td>VR-OLTC</td>
<td>No. of VR</td>
<td>18</td>
<td>27</td>
<td>38</td>
<td>44</td>
<td>49</td>
<td>54</td>
<td>58</td>
<td>59</td>
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A.3 Voltage Imbalance Violations

A.3.1 Case 2: Voltage Imbalance Violations

Fig. A-15. Case 2: VUF violations [VR-Zp]

Fig. A-16. Case 2: VUF violations [OLTC-Zp]

Fig. A-17. Case 2: VUF violations [VR-OLTC-Zp]
Appendix A: Supplementary Results

A.3.2 Case 3: Voltage Imbalance Violations

Fig. A-18. Case 3: VUF violations [VR-ZP\textsubscript{20}]

Fig. A-19. Case 3: VUF violations [OLTC-ZP\textsubscript{20}]

Fig. A-20. Case 3: VUF violations [VR-OLTC-ZP\textsubscript{20}]
A.4 Branch Current

A.4.1 Case 2: Branch Current

![Image of MCCI and AFLI for Case 2](image1)

Fig. A-21. Case 2: Range of MCCI $[Z_{20}]$

Fig. A-22. Case 2: Range of maximum AFLI $[Z_{20}]$

A.4.2 Case 2: Branch Current

![Image of MCCI and AFLI for Case 3](image2)

Fig. A-23. Case 3: Range of MCCI $[PZ_{20}]$

Fig. A-24. Case 3: Range of maximum AFLI $[PZ_{20}]$
### A.5 Power & Energy Loss

#### A.5.1 Case 2: Energy Loss

**Fig. A-25.** Case 2: Mean percentage difference in energy loss $[Z_{20}]$

**Table A-3.** Case 2: Energy loss (mean % difference to Base Case 2 & range as % of mean) $[Z_{20}]$

<table>
<thead>
<tr>
<th>VAM$^1$</th>
<th>Metric</th>
<th>PVP30%</th>
<th>PVP40%</th>
<th>PVP50%</th>
<th>PVP60%</th>
<th>PVP70%</th>
<th>PVP80%</th>
<th>PVP90%</th>
<th>PVP100%</th>
</tr>
</thead>
<tbody>
<tr>
<td>VR</td>
<td>No. of VR</td>
<td>25</td>
<td>39</td>
<td>53</td>
<td>62</td>
<td>62</td>
<td>64</td>
<td>66</td>
<td>68</td>
</tr>
<tr>
<td></td>
<td>Mean (%)</td>
<td>-0.002</td>
<td>-10.506</td>
<td>-13.892</td>
<td>-9.833</td>
<td>+2.023</td>
<td>+22.036</td>
<td>+50.597</td>
<td>+88.103</td>
</tr>
<tr>
<td></td>
<td>Range (%)</td>
<td>-0.003</td>
<td>-0.003</td>
<td>+0.007</td>
<td>+0.051</td>
<td>+0.163</td>
<td>+0.306</td>
<td>+0.460</td>
<td>+0.595</td>
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<tr>
<td>OLTC</td>
<td>No. of VR</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Mean (%)</td>
<td>+0.012</td>
<td>-10.493</td>
<td>-13.914</td>
<td>-10.024</td>
<td>+1.317</td>
<td>+20.279</td>
<td>+47.012</td>
<td>+81.868</td>
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<tr>
<td></td>
<td>Range (%)</td>
<td>+0.024</td>
<td>+0.026</td>
<td>-0.041</td>
<td>-0.338</td>
<td>-1.138</td>
<td>-2.442</td>
<td>-4.155</td>
<td>-5.916</td>
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<tr>
<td>VR-OLTC</td>
<td>No. of VR</td>
<td>13</td>
<td>19</td>
<td>35</td>
<td>45</td>
<td>49</td>
<td>55</td>
<td>59</td>
<td>62</td>
</tr>
<tr>
<td></td>
<td>Mean (%)</td>
<td>+0.022</td>
<td>-10.483</td>
<td>-13.933</td>
<td>-10.169</td>
<td>+0.768</td>
<td>+18.845</td>
<td>+43.836</td>
<td>+75.769</td>
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<tr>
<td></td>
<td>Range (%)</td>
<td>+0.023</td>
<td>+0.025</td>
<td>-0.044</td>
<td>-0.339</td>
<td>-1.144</td>
<td>-2.508</td>
<td>-4.424</td>
<td>-6.665</td>
</tr>
</tbody>
</table>

Mean (%)—the percentage difference to Base Case 2; Range(%)—the first peak/trough subtracted from the second, as a percentage of the mean energy loss

---

$^1$ Voltage adjustment mechanism
A.5.2 Case 3: Energy Loss

![Mean Energy Loss Graph](image)

**Fig. A-26. Case 3: Mean percentage difference in energy loss [ZP2k]**

<table>
<thead>
<tr>
<th>VAM</th>
<th>Metric</th>
<th>PVP30%</th>
<th>PVP40%</th>
<th>PVP50%</th>
<th>PVP60%</th>
<th>PVP70%</th>
<th>PVP80%</th>
<th>PVP90%</th>
<th>PVP100%</th>
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<tr>
<td></td>
<td>No. of VR</td>
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<td>62</td>
<td>63</td>
<td>66</td>
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<tr>
<td>VR</td>
<td>Mean (%)</td>
<td>-0.006</td>
<td>-10.435</td>
<td>-13.995</td>
<td>-10.656</td>
<td>-0.378</td>
<td>+16.870</td>
<td>+41.121</td>
<td>+72.399</td>
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<tr>
<td></td>
<td>Range (%)</td>
<td>-0.006</td>
<td>-0.007</td>
<td>-0.006</td>
<td>+0.039</td>
<td>+0.132</td>
<td>+0.258</td>
<td>+0.390</td>
<td>+0.515</td>
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<tr>
<td></td>
<td>No. of VR</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>OLTC</td>
<td>Mean (%)</td>
<td>-0.001</td>
<td>-10.431</td>
<td>-13.997</td>
<td>-10.691</td>
<td>-0.506</td>
<td>+16.568</td>
<td>+40.547</td>
<td>+71.450</td>
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<tr>
<td></td>
<td>Range (%)</td>
<td>+0.002</td>
<td>+0.002</td>
<td>-0.004</td>
<td>-0.015</td>
<td>-0.054</td>
<td>-0.123</td>
<td>-0.219</td>
<td>-0.332</td>
</tr>
<tr>
<td></td>
<td>No. of VR</td>
<td>18</td>
<td>27</td>
<td>38</td>
<td>44</td>
<td>49</td>
<td>54</td>
<td>58</td>
<td>59</td>
</tr>
<tr>
<td>VR-OLTC</td>
<td>Mean (%)</td>
<td>-0.002</td>
<td>-10.432</td>
<td>-13.998</td>
<td>-10.700</td>
<td>-0.529</td>
<td>+16.511</td>
<td>+40.422</td>
<td>+71.203</td>
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<tr>
<td></td>
<td>Range (%)</td>
<td>-0.002</td>
<td>-0.002</td>
<td>-0.004</td>
<td>-0.020</td>
<td>-0.054</td>
<td>-0.123</td>
<td>-0.219</td>
<td>-0.333</td>
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</table>

Mean (%)—the percentage difference to Base Case; Range(%)—the first peak/trough subtracted from the second, as a percentage of the mean energy loss.
### Case 2: Peak Power Loss

![Graph: Mean Peak Loss [Z_{IP}]](image)

**Fig. A-27. Case 2: Mean percentage difference in peak power loss [Z_{IP}]**

**Table A-5. Case 2: Peak power loss (mean & range) [Z_{IP}]**

<table>
<thead>
<tr>
<th>VAM&lt;sup&gt;2&lt;/sup&gt;</th>
<th>Metric</th>
<th>PVp30%</th>
<th>PVp40%</th>
<th>PVp50%</th>
<th>PVp60%</th>
<th>PVp70%</th>
<th>PVp80%</th>
<th>PVp90%</th>
<th>PVp100%</th>
</tr>
</thead>
<tbody>
<tr>
<td>VR</td>
<td>Mean (%)</td>
<td>-0.193</td>
<td>-0.197</td>
<td>-0.131</td>
<td>-0.117</td>
<td>+13.551</td>
<td>+96.649</td>
<td>+208.013</td>
<td>+351.629</td>
</tr>
<tr>
<td></td>
<td>Range (%)</td>
<td>-0.205</td>
<td>-0.205</td>
<td>-0.204</td>
<td>-0.204</td>
<td>+1.187</td>
<td>+1.228</td>
<td>+1.268</td>
<td>+1.311</td>
</tr>
<tr>
<td>OLTC</td>
<td>Mean (%)</td>
<td>+2.227</td>
<td>+2.227</td>
<td>+0.000</td>
<td>+0.000</td>
<td>+6.273</td>
<td>+80.178</td>
<td>+181.549</td>
<td>+311.645</td>
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<tr>
<td></td>
<td>Range (%)</td>
<td>-4.357</td>
<td>-4.357</td>
<td>+0.000</td>
<td>+0.000</td>
<td>+11.806</td>
<td>+16.247</td>
<td>+16.639</td>
<td>+17.169</td>
</tr>
<tr>
<td>VR-OLTC</td>
<td>Mean (%)</td>
<td>+4.150</td>
<td>+4.239</td>
<td>-0.190</td>
<td>-0.180</td>
<td>+0.094</td>
<td>+54.833</td>
<td>+128.120</td>
<td>+212.920</td>
</tr>
<tr>
<td></td>
<td>Range (%)</td>
<td>-4.294</td>
<td>-4.291</td>
<td>+0.205</td>
<td>+0.205</td>
<td>+12.739</td>
<td>+26.431</td>
<td>+34.509</td>
<td>+43.980</td>
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</table>

*Mean (%)—the percentage difference to Base Case; Range(%)—the first peak/trough subtracted from the second, as a percentage of the mean energy loss*

<sup>2</sup> Voltage adjustment mechanism
### A.5.4 Case 3: Peak Power Loss

**Fig. A-28. Case 3: Mean percentage difference in peak power loss \([Z_{P,0}]\)**

**Table A-6. Case 3: Peak power loss (mean & range) \([Z_{P,0}]\)**

<table>
<thead>
<tr>
<th>VAM</th>
<th>Metric</th>
<th>PVp30%</th>
<th>PVp40%</th>
<th>PVp50%</th>
<th>PVp60%</th>
<th>PVp70%</th>
<th>PVp80%</th>
<th>PVp90%</th>
<th>PVp100%</th>
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</thead>
<tbody>
<tr>
<td>VR</td>
<td>No. of VR</td>
<td>27</td>
<td>39</td>
<td>51</td>
<td>60</td>
<td>62</td>
<td>63</td>
<td>66</td>
<td>66</td>
</tr>
<tr>
<td></td>
<td>Mean (%)</td>
<td>-0.591</td>
<td>-0.597</td>
<td>-0.410</td>
<td>-0.306</td>
<td>-0.249</td>
<td>+41.698</td>
<td>+113.522</td>
<td>+200.274</td>
</tr>
<tr>
<td></td>
<td>Range (%)</td>
<td>-0.664</td>
<td>-0.664</td>
<td>-0.662</td>
<td>-0.662</td>
<td>-0.661</td>
<td>+1.113</td>
<td>+1.206</td>
<td>+1.213</td>
</tr>
<tr>
<td>OLTC</td>
<td>No. of VR</td>
<td>18</td>
<td>27</td>
<td>38</td>
<td>44</td>
<td>49</td>
<td>54</td>
<td>58</td>
<td>59</td>
</tr>
<tr>
<td></td>
<td>Mean (%)</td>
<td>-0.307</td>
<td>-0.312</td>
<td>-0.319</td>
<td>-0.476</td>
<td>-0.411</td>
<td>+38.710</td>
<td>+107.967</td>
<td>+191.268</td>
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<tr>
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<td>Range (%)</td>
<td>-0.335</td>
<td>-0.335</td>
<td>-0.336</td>
<td>-0.663</td>
<td>-0.662</td>
<td>-1.337</td>
<td>-1.812</td>
<td>-2.395</td>
</tr>
</tbody>
</table>

Mean (%)—the percentage difference to Base Case; Range(%)—the first peak/trough subtracted from the second, as a percentage of the mean energy loss.
Appendix A: Supplementary Results

A.6 Economic Evaluation

A.6.1 Case 2: Net Present Cost

Fig. A-29. Case 2: Net present cost [VR-Z2p]

Fig. A-30. Case 2: Net present cost [OLTC-Z2p]

Fig. A-31. Case 2: Net present cost [VR-OLTC-Z2p]
A.6.2 Case 3: Net Present Cost

**Fig. A-32. Case 3: Net present cost [VR-ZP]**

**Fig. A-33. Case 3: Net present cost [OLTC-ZP]**

**Fig. A-34. Case 3: Net present cost [VR-OLTC]**
A.7 Node Voltage Plots

A.7.1 Case 1: Node Voltage Plots

Fig. A-35. Case 1: Under-voltage event [Base Case 1]

Fig. A-36. Case 1: Over-voltage event [Base Case 1]

Fig. A-37. Case 1: Under-voltage event [VR-P29]

Fig. A-38. Case 1: Over-voltage event [VR-P29]

Fig. A-39. Case 1: Under-voltage event [OLTC-P29]

Fig. A-40. Case 1: Over-voltage event [OLTC-P29]
A.7.2 Case 2: Node Voltage Plots
Fig. A-47. Case 2: Under-voltage event [OLTC-ZIP]

Fig. A-48. Case 2: Over-voltage event [OLTC-ZIP]

Fig. A-49. Case 2: Over-voltage event [VR-OLTC-ZIP]

Fig. A-50. Case 2: Over-voltage event [VR-OLTC-ZIP]

A.7.3 Case 3: Node Voltage Plots

Fig. A-51. Case 3: Under-voltage event [Base Case3]

Fig. A-52. Case 3: Over-voltage event [Base Case3]
Fig. A-53. Case 3: Under-voltage event [VR-ZP]  

Fig. A-54. Case 3: Over-voltage event [VR-ZP]

Fig. A-55. Case 3: Under-voltage event [OLTC-ZP]  

Fig. A-56. Case 3: Over-voltage event [OLTC-ZP]

Fig. A-57. Case 3: Over-voltage event [VR-OLTC-ZP]  

Fig. A-58. Case 3: Over-voltage event [VR-OLTC-ZP]
Appendix B  Test Network Specifications

B.1  Conductor Impedance Models

Table B-1. Series impedance [Ω/km] matrix for Z1 (Moon)

<table>
<thead>
<tr>
<th></th>
<th>Z_a</th>
<th>Z_b</th>
<th>Z_c</th>
</tr>
</thead>
<tbody>
<tr>
<td>Z_a</td>
<td>0.5595 + 0.0329j</td>
<td>0.2550 + 0.1965j</td>
<td>0.2909 + 0.0974j</td>
</tr>
<tr>
<td>Z_b</td>
<td>0.2550 + 0.1965j</td>
<td>0.5832 + 0.0085j</td>
<td>0.3051 + 0.1126j</td>
</tr>
<tr>
<td>Z_c</td>
<td>0.2909 + 0.0974j</td>
<td>0.3051 + 0.1126j</td>
<td>0.6654 - 0.0742j</td>
</tr>
</tbody>
</table>

Table B-2. Series impedance [Ω/km] matrix for Z2 (Mars)

<table>
<thead>
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<th></th>
<th>Z_a</th>
<th>Z_b</th>
<th>Z_c</th>
</tr>
</thead>
<tbody>
<tr>
<td>Z_a</td>
<td>0.6808 + 0.1214j</td>
<td>0.2391 + 0.2743j</td>
<td>0.2711 + 0.1865j</td>
</tr>
<tr>
<td>Z_b</td>
<td>0.2391 + 0.2743j</td>
<td>0.7020 + 0.1045j</td>
<td>0.2838 + 0.2061j</td>
</tr>
<tr>
<td>Z_c</td>
<td>0.2711 + 0.1865j</td>
<td>0.2838 + 0.2061j</td>
<td>0.7752 + 0.0474j</td>
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</table>

B.2  Network Load Allocation

Table B-3. Network load allocation

<table>
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<th>Bus/Pole</th>
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<th>1ϕ Load + DG</th>
<th>3ϕ Load</th>
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<td>A</td>
<td>1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>B</td>
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<tr>
<td>1</td>
<td>C</td>
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<td>B</td>
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<td>1/3</td>
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<td>3</td>
<td>C</td>
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Appendix B: Test Network Specifications

### Table B-4. Summary of costs

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<th>Item</th>
<th>Rate/Cost</th>
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<td>Discount rate</td>
<td>6.53%</td>
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<tr>
<td>Inflation rate</td>
<td>2%</td>
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<tr>
<td>Peak loss ($/kW-year)</td>
<td>$235</td>
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<tr>
<td>Energy loss ($/kWH)</td>
<td>$0.04</td>
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<tr>
<td>OLTC purchase</td>
<td>$10,000</td>
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<tr>
<td>SCADA purchase</td>
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</tr>
<tr>
<td>VR installation</td>
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</tr>
<tr>
<td>OLTC installation</td>
<td>$1,500</td>
</tr>
<tr>
<td>SCADA installation</td>
<td>$1,500</td>
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#### B.3 Summary of Costs

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<th>Bus/Pole</th>
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<th>1ϕ Load</th>
<th>1ϕ Load + DG</th>
<th>3ϕ Load</th>
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Appendix C  Direct Load Flow Methodology

Understanding this methodology is best facilitated by an explanation of the algorithm assuming a single-phase radial system. Expanding this to an unbalanced three-phased system is relatively trivial after the initial methodology is understood. Consider the simple distribution system reproduced from [45], in Fig. C-1, and note the bus loads expressed as *equivalent current injections* (ECI).

![Diagram of 5-bus example network](image)

*Fig. C-1. 5-bus example network [45]*

The equivalent current injected by each bus can be obtained by converting the real and reactive loads for each bus to the corresponding ECI, shown in (20), where the ECI \( I_i \) is a function of bus voltage \( V_i \) for the \( i \)-th bus [45, p. 883], [86, p. 484].

\[
S_i = V_i I_i^* = P_i + j Q_i \quad \Rightarrow \quad I_i = \left( \frac{P_i + j Q_i}{V_i} \right)^* \tag{20}
\]

Using Kirchoff’s Current Law (KCL), it can be shown that the branch currents are equal to the sum of all the ‘downstream’ injection currents. For example, the current in Branch 2 \( (B_2) \) is shown in (21).

\[
B_2 = I_3 + I_4 + I_5 + I_6 \tag{21}
\]

Expressing this relationship for the entire network in Fig. C-1, leads to the matrix in (22). The upper triangle matrix in this expression is known as the BIBC matrix—*bus-injection matrix*.
to branch-current—and contains only 1s and 0s. This is expressed in a general form in (23).

\[
\begin{bmatrix}
B_1 \\
B_2 \\
B_3 \\
B_4 \\
B_5
\end{bmatrix} =
\begin{bmatrix}
1 & 1 & 1 & 1 & 1 \\
0 & 1 & 1 & 1 & 1 \\
0 & 0 & 1 & 1 & 0 \\
0 & 0 & 0 & 1 & 0 \\
0 & 0 & 0 & 0 & 1
\end{bmatrix}
\begin{bmatrix}
I_2 \\
I_3 \\
I_4 \\
I_5 \\
I_6
\end{bmatrix}
\]

(22)

The relationship between the branch currents obtained from the (23), and the bus voltages, is governed by Ohm’s Law. When expressed as a difference in voltage relative to Bus 1, it is simply the sum of all the voltage changes between Bus 1 and Bus \(i\). As an example, this relationship is expressed for Bus 5 (Fig. C-1) in (24), noting that \(\Delta V = ZB\).

\[
V_5 = V_1 - Z_{12}B_1 - Z_{23}B_2 - Z_{34}B_3 - Z_{45}B_4
\]

\[
\Delta V = V_1 - V_5 = Z_{12}B_1 + Z_{23}B_2 + Z_{34}B_3 + Z_{45}B_4
\]

(24)

The same relationship is expressed in matrix form in (25) for the entire network (Fig. C-1), where the lower triangle matrix is known as the \emph{branch-current to branch-voltage} matrix (BCBV) and in general form in (26) [45, p. 884].

\[
\begin{bmatrix}
V_1 - V_2 \\
V_1 - V_3 \\
V_1 - V_4 \\
V_1 - V_5 \\
V_1 - V_6
\end{bmatrix}
= 
\begin{bmatrix}
Z_{12} & 0 & 0 & 0 & 0 \\
Z_{12} & Z_{23} & 0 & 0 & 0 \\
Z_{12} & Z_{23} & Z_{34} & 0 & 0 \\
Z_{12} & Z_{23} & Z_{34} & Z_{45} & 0 \\
Z_{12} & Z_{23} & 0 & 0 & Z_{36}
\end{bmatrix}
\begin{bmatrix}
B_1 \\
B_2 \\
B_3 \\
B_4 \\
B_5
\end{bmatrix}
\]

(25)

\[
[\Delta V] = [BCBV][B]
\]

(26)

Combining (23) & (26), gives the general equation (27) for bus voltage variations relative to the equivalent current injections across the entire network.

\[
[\Delta V] = [BCBV][BIBC][I]
\]

\[
[\Delta V] = [DLF][I]
\]

(27)

The non-linear nature of \emph{distribution load flow} analyses requires an iterative approach that is based around an assumed bus voltage and known real and reactive load at each
bus. This approach is summarised in (28) & (29), where \( k \) and \( i \) are the iteration and bus indexes respectively [45, p. 884].

\[
I_i^k = \left( \frac{P_i + jQ_i}{V_i^k} \right)^* (28)
\]

\[
[V^{k+1}] = [V^0] + [DLF][I^k] = [V^0] + [\Delta V^{k+1}] (29)
\]

Expanding the *distribution load flow* analyses described above, to an unbalanced three-phase system requires the following modifications to the process [45, p. 884]:

1. Each branch current term \((B_i)\) will be expanded to a \(3x1\) vector and all non-zero terms in the BIBC matrix will be \(3x3\) identity matrix.
2. Each impedance term \((Z_{ij})\) in the BCBV matrix is comprised of a \(3x3\) impedance matrix as shown in (30). Derivation of the three-phase impedance model can be found in [45, pp. 882–883].

\[
[Z_{abc}] = \begin{bmatrix}
Z_{aa-n} & Z_{ab-n} & Z_{ac-n} \\
Z_{ba-n} & Z_{bb-n} & Z_{bc-n} \\
Z_{ca-n} & Z_{cb-n} & Z_{cc-n}
\end{bmatrix} (30)
\]

Extending this methodology for load flow analyses of meshed networks can be found in [45].
Appendix D  Supplementary Notes

D.1  Load Modelling

Two techniques are commonly adopted in the development of load models—these are measurement-based, and component-based [46], [49]–[52]. As the name suggests, the measurement-based technique involves physically measuring the power to voltage and frequency sensitivities of demonstrative nodes in the network, from which an appropriate level of load characteristic detail can be inferred [52, p. 1]. The amount of data acquisition is entirely dependent on the granularity required by the study. One of the main advantages of the measurement-based approach is that the data is taken directly from the system under investigation—this often results in a more accurate model. This can however, be a disadvantage due to the difficulties associated with compensating for changes in load behaviour brought about by variable weather and demand. Another disadvantage of this method is that is usually impractical, if not impossible, to obtain voltage or frequency measurements over a sufficient range without causing major disruptions to the network [52, p. 1]. The measurement-based approach is a ‘top-down’ methodology. This is in direct contrast to the component-based method, which establishes the load models from the ‘bottom-up’ [46, pp. 6–3].

The component-based approach involves the aggregation of individual component models that are either theoretically derived, or established from laboratory measurements [52, p. 1]. As with the measurement-based approach, the accuracy required by the study will dictate the detail of the constituent components to be combined into a single aggregated model. The obvious advantage with this approach is that field measurements are not required. This means that load models can be applied across entire systems with only minimal adjustments according to load classification [52, p. 1]. Classifying network loads according to electrical characteristics is widely used to aid in power system
modelling. Industrial, commercial and residential are the three macro-level classes most commonly used in load flow studies. Each of these classes may then be divided further into sub-classes or strataums according to electrical characteristics and/or demand [51]. Load windows are a tool used to compile a load profile from individual models. This method apportions load contributions from individual components according to usage to produce a single composite load model.

D.2 Cost-Benefit Analysis

Understanding NPV is best achieved by rearranging a simple principle (P) and interest formula, and swapping the interest rate (i) with a discount rate (d)—see Eq. 31 [64, p. 242]—where \( F \) represents future earnings.

\[
F = P(1 + i)^n \Rightarrow P = \frac{F}{(1 + d)^n}
\]  

(31)

An alternative formula to (4) (Section 2.4) for calculating the NPV—normalised cash flow less initial capital costs (\( C_0 \))—is shown in (32) [61]. Where \( t \) represents the time period, usually calculated annually; and \( F_t = Benefits_t - Costs_t \).

\[
NPV = \frac{F_1}{1 + d} + \frac{F_2}{(1 + d)^2} + \cdots + \frac{F_t}{(1 + d)^t} - C_0 = \sum_{t=1}^{T} \frac{F_t}{(1 + d)^t} - C_0
\]  

(32)

Establishing a realistic forecast of the future cost and benefits for a project, from which to calculate a NPV, is a critical step in the CBA process. The impacting factors are often grouped according to the type of project. For example, the European Investment Bank define four potential benefits for electrical network infrastructure projects. These are [54]:

1. Capacity expansion or refurbishment
2. Reliability
3. Integration of renewable generation
4. Loss reduction
Capacity, reliability and loss reduction are used as CBA impacts in [55, pp. 1730–1731].

The discount rate also has a significant effect on the outcome of the CBA. As an indication of current industry rates, 2017 Infrastructure Australia guidelines specify a real discount rate of 7%p.a., with sensitivity analysis rates of 4% and 10%p.a [57]. This agrees closely with a 6.53% discount rate adopted by Western Power for a 2016 capacity expansion project report [56, p. 22]. The final component of a CBA that should be discussed here for completeness, is the project life-cycle.

The economic life of a project/investment is the period over which the investment is discounted—this is usually the period where the investment is expected to be generating revenue. Also known as the project life-cycle, time horizon or appraisal/evaluation period, it is an important factor because it can have a significant effect on the outcome of a CBA. Typical appraisal periods for electrical network infrastructure is 20-25 years [54], [55].

The process of a conducting a cost-benefit analysis can be summarised as per the following sequence of steps [59, p. 41], [87, p. 6]:

1. Define the baseline and all credible alternatives to be analysed. The baseline might be the business-as-usual case, or if change is unavoidable, then it might be the cheapest or easiest to implement option. This is a decision that is specific to the project.
2. Define the perspective of the CBA. Different stakeholders may place significantly different values on the factors impacting the project. A common example of this is difference in value placed on the reduction of CO₂ emissions by society, government or the utilities [58, p. 9].
3. Identify CBA impacts and associated metrics. These might be parts, installation, operation and maintenance, loss reduction, deferred network expansion or emissions reduction.
4. Determine dollar value of all impacts.
5. Define discount rate and life of project
6. Calculate and compare NPV/IRR values
7. Conduct sensitivity analysis
8. Make recommendations