A study on voltage issues caused by photovoltaic installations on the low voltage grid in New Zealand residential conditions

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ABSTRACT

This thesis discusses the opportunity of solar photovoltaic penetration in the New Zealand residential environment and the challenges it brings in terms of voltage quality i.e. voltage, imbalance sag and swell. It examines previous work conducted and extensions which should be investigated. The thesis analyses the voltage power quality guidelines proposed by the Electricity Authority and their validity in this new environment. The voltage issues that could be experienced in a low voltage residential network have been simulated dynamically with the use of a generic low voltage model. Solutions such as: reactive power control, batteries and a single phase micro-grid have been displayed. The validity of each solution has also been critically explored, through the use of a Strength Weakness Opportunity Threat (SWOT) analysis. The author has attempted to provide the perspective of both the customer and the distribution network operator.

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ATTESTATION OF AUTHORSHIP

I hereby declare that this submission is my own work and that, to the best of my knowledge and belief, it contains no material previously published or written by another person (except where explicitly defined in the acknowledgements), nor material which to a substantial extent has been submitted for the award of any other degree or diploma of a university or other institution of higher learning.

Signed: ________________________ Date: ___________________

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Last but not least, I would like to express my appreciation to my beloved family for their unconditional love and support throughout my entire life. This unbelievable support has provided me with the opportunity to complete a robust thesis while working full time.

CHAPTER 1. INTRODUCTION

1.1 BACKGROUND

The New Zealand government has set a target of 90% electricity generation coming from renewable energy sources by 2025. Currently, New Zealand is tracking at 79% renewable electricity production [1]. It is believed that distributed generation (DG) is currently playing an increasing role in electric power systems worldwide and will have a direct influence on New Zealand's electricity mix over the next 10 years [2]. There are multiple sources and sizes of DG systems available in the market today. The most common and readily available type of DG technology in New Zealand's residential environment, is a solar photovoltaic (PV) system.

As residential solar PV technology becomes more affordable and attractive, it raises awareness in the power industry with regards to a phenomenon known as the "death spiral", meaning a reduction in demand for power from electricity networks. This is as a result of customers continuously reducing energy consumption through the use of energy efficient products and/or private generation (i.e. solar PV systems). The reduction in electricity demand, will result in a high unit cost per kWh for electricity consumption (export). This is because most utilities have high fixed costs that are recovered by charging through kWh. As the tariffs increase, it will exacerbate the problem, encouraging customers to go off-grid and become self-sustainable, before the utility has a chance to make a return on the installed assets; hence resulting in a "death spiral" [3]. The fears of a "death spiral" are quickly becoming a reality, and therefore the lines companies are becoming more hesitant on spending lots of money on traditional solutions in their network i.e. larger cables/lines, bigger transformers, etc. They're instead encouraging customers to install solar PV systems to reduce demand and in doing so, maximise the efficiency of the existing network. But this can be dangerous, as the Hawaiian Distribution Network Operator (DNO) has experienced.

The Hawaiian DNO's interconnection nightmare is a case study that sheds light on the value of research before installing grid tied solar PV systems. In Hawaii more than 250MW of solar PV has been installed to grids with aggregate peak loads of 1500MW, penetration level of 16.7%. There was no pre-authorisation process or research performed prior to the crisis. Eventually the existing utility infrastructure was unable to deal with the growth and the Hawaiian Electric Company, had to stop approvals of grid tied PV installations and net metering. This left thousands of customers in "solar limbo" and caused lots of media attention [4]. These types of case studies tend to drive customers towards off-grid solutions. To avoid such media and public attention, robust research on connecting new technologies to the grid, must be done.

1.2 SOLAR PV SYSTEMS IN NEW ZEALAND

The PV market in New Zealand is largely built on off-grid sales, with a recent increase in grid connected units. Worldwide solar PV support is increasing from governments with high electricity "feed-in tariffs", tax benefits, etc. which all incentivise renewable energy production [5]. However, in New Zealand there is no governing policy for regulating the “buy back”, and no tax benefits. Currently electricity retailers import (feed-in) tariffs vary between $0.04 and $0.08 per kWh [6]. With an average electricity export tariff of $0.29 per kWh, split between generation cost of ~$0.08 per kWh and lines cost of ~$0.21. A rooftop solar PV unit could provide electricity as low as $0.26 per kWh (The Sustainable Energy Association of New Zealand) [7]. Making it more beneficial for the customer to use their own generated power, rather than import to the grid.

This has made solar PV systems an attractive solution for the residential consumer market. However, the reliability of solar PV systems is its major down fall. Most rooftop solar solutions only provide half the annual average household electricity consumption of 8000kWh, because solar PV systems only work when the sun is shining and the major demand for residential customers occurs during evening and morning periods which is before and after the peaks of optimum solar PV system’s output. This can be seen in Figure 1.

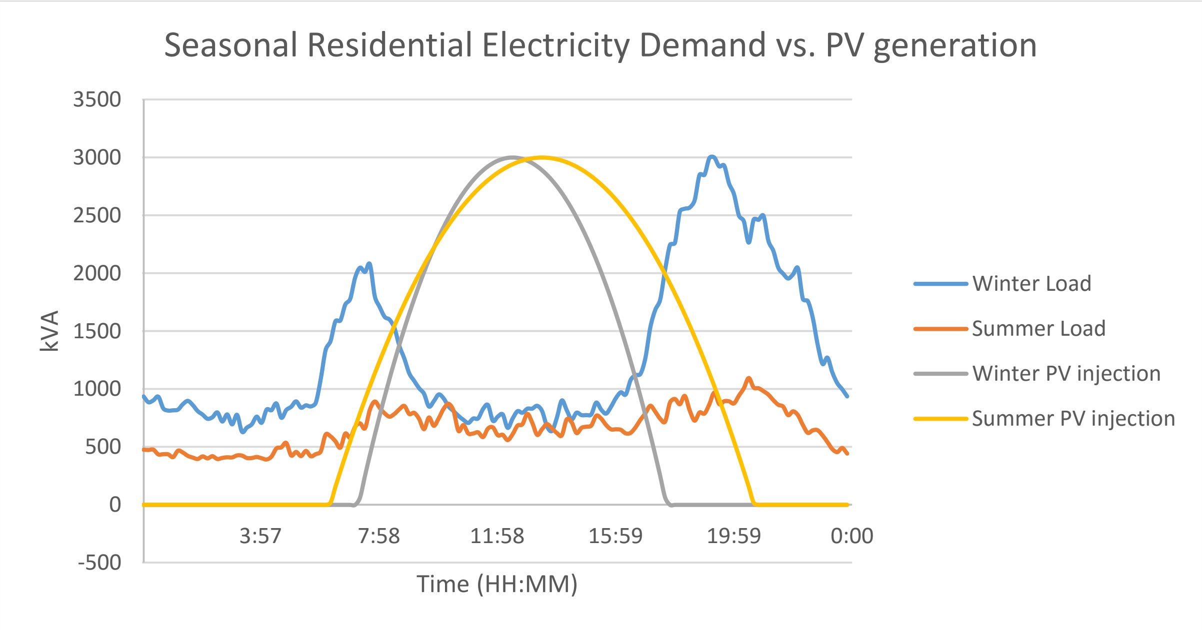


Figure 1: Seasonal residential electricity demand vs. PV assuming a 3kW solar PV unit and residential ADMD of 3kVA in ideal New Zealand conditions

This has led to a mass development of the energy storage market, in particular batteries. The cost of storage currently is still high, and pushes the affordability of solar PV systems into the unattractive region for the consumer. But it is only a matter of time until a breakthrough is made in storage [7].

The discussion above raises two questions:

- If solar PV systems were to become affordable, just how attractive a proposal is it for residential consumers?
- And when will solar PV systems start causing problems in the power industry?

Ipsos New Zealand is a company that looks into information about people, society and markets. It has recently performed a study that measures the favourability and familiarity of energy sources worldwide.

The consumer favours solar energy over any other source as shown in Figure 2. This tends to suggest that as reliability improves and price drops, the uptake in solar PV generation will generate a high consumer demand.

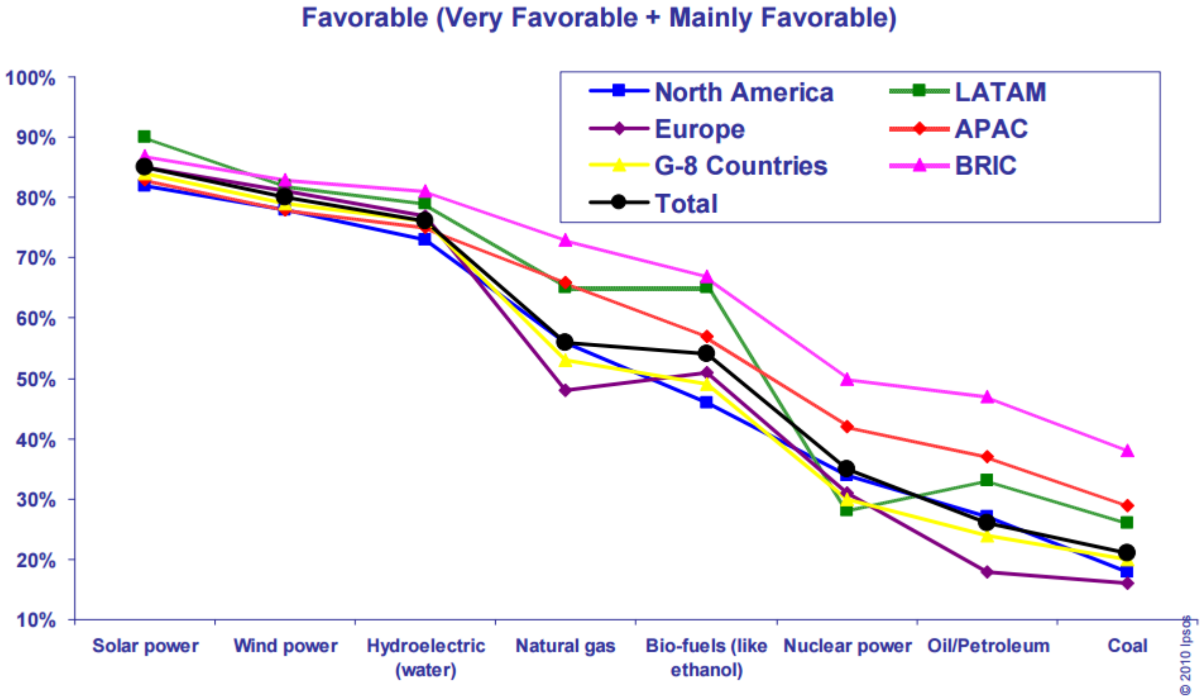


Figure 2: Ipsos New Zealand graph showing favourability of different energy sources worldwide

Vector Ltd, a DNO in Auckland, New Zealand, has published in its Asset Management Plan 2014, forecasts of solar PV system uptake, in Auckland, based on various different scenarios.

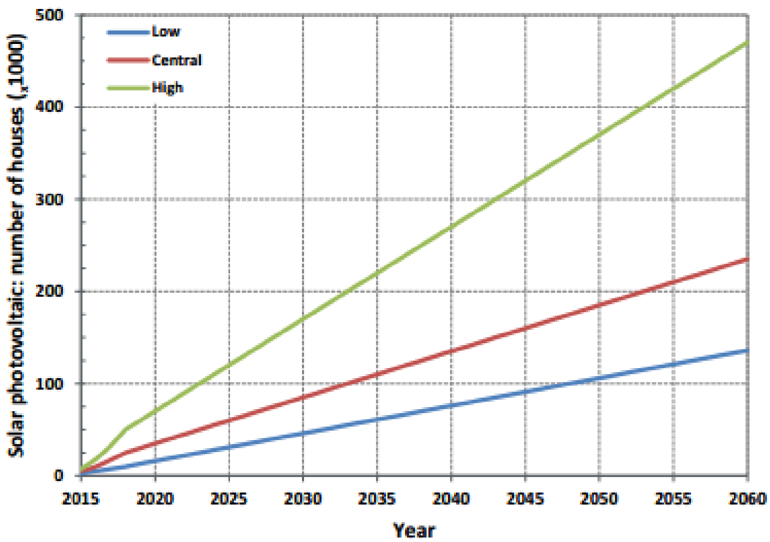


Figure 3: Solar uptake scenarios against housing stock (max ~540,000 connections)

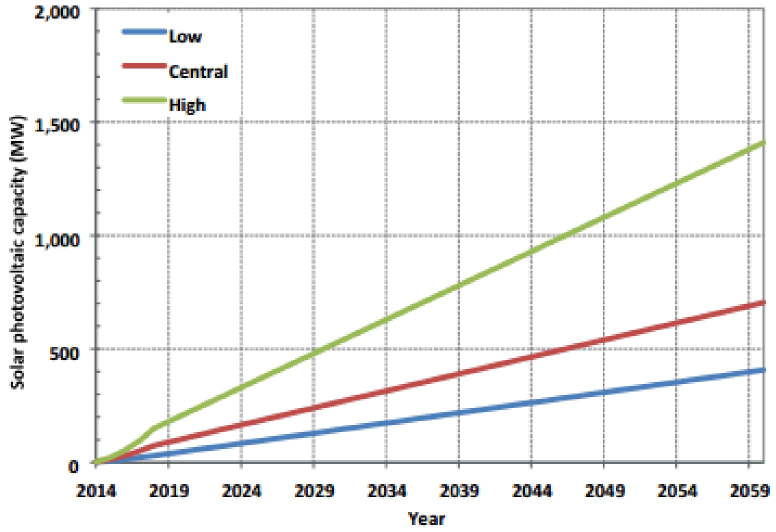


Figure 4: Solar uptake against capacity

By using the central trend shown in Figures 3 and 4 it can be concluded that the uptake in solar PV systems will be more gradual. The trends discussed above are in relation to penetration levels and maximum capacity data, these provide a perspective which assumes that the installed PV capacity will be evenly distributed along the DNO's network. However, this is not the reality. PV systems will probably develop in clusters on the low voltage (LV) network. Clustering of PV installations can cause a lot of issues for any DNO. Clustering can't be forecasted on the LV network and, therefore, could be problematic.

These factors introduce a lot of uncertainty for DNO's worldwide. This has meant more research and development opportunities have centred on clustering in an effort to keep customers happy with their existing inter-connection to the grid.

1.3 New Zealand Electricity Industry

In New Zealand the current electricity industry structure splits into four separate areas. A high level overview is shown in Figure 5.

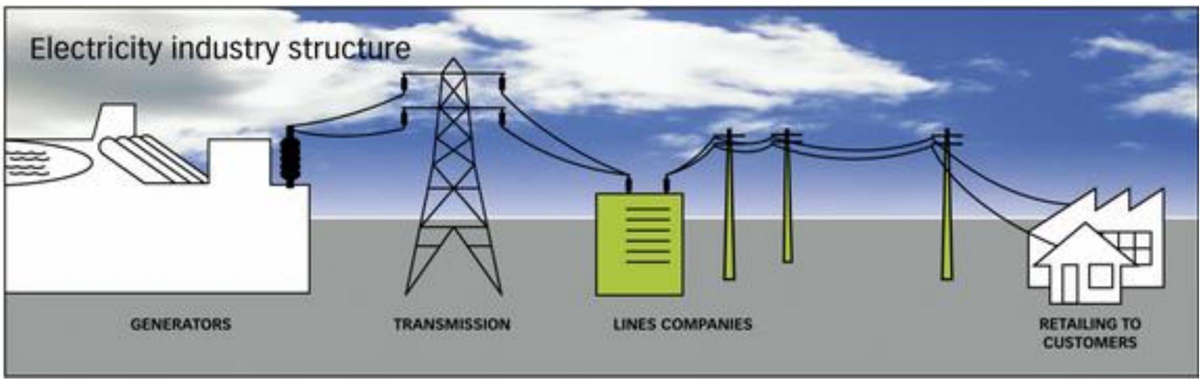


Figure 5: Structure of electricity industry in New Zealand (figure by Vector Ltd.)

Electrical power to be used in homes, businesses, commercial and industrial applications, is produced by the generation companies (Meridian, Mighty River Power, Genesis Power, etc.). The generated power is then transmitted to cities using the transmission company; in New Zealand's case, this is monopolised by the government organisation known as Transpower. Transpower in turn provides this electricity to DNO's. DNO's have restrictions imposed on them by: the customer, Transpower, generation companies and governing authorities (i.e. the Electricity Authority and Commerce Commission).

The traditional flow of power has always been from generation to consumer (unidirectional). The addition of DG introduces bidirectional power flows. Bidirectional power flows are problematic on a DNO's network. A further level of detail of the power industry and the role of consumer DG is shown in Figure 6. Voltage is stepped down using transformers at the grid exit point (GXP), zone substation and local substations. The various different voltage levels that exist on Vector's network are shown as an example. Ownership of the assets and network is dependent on the agreed demarcation points between the transmission company and the DNO. Normally, the point where ownership of assets changes is known as a GXP.

The area highlighted in Figure 6 has been chosen as the focal point of the research. This is because the effects of PV clustering would be noticed first at the 400V (3-phase) or 230V (1-phase) voltage level. Hence, residential DG must first become problematic at the local substation, before it can pose a threat to the rest of the grid.

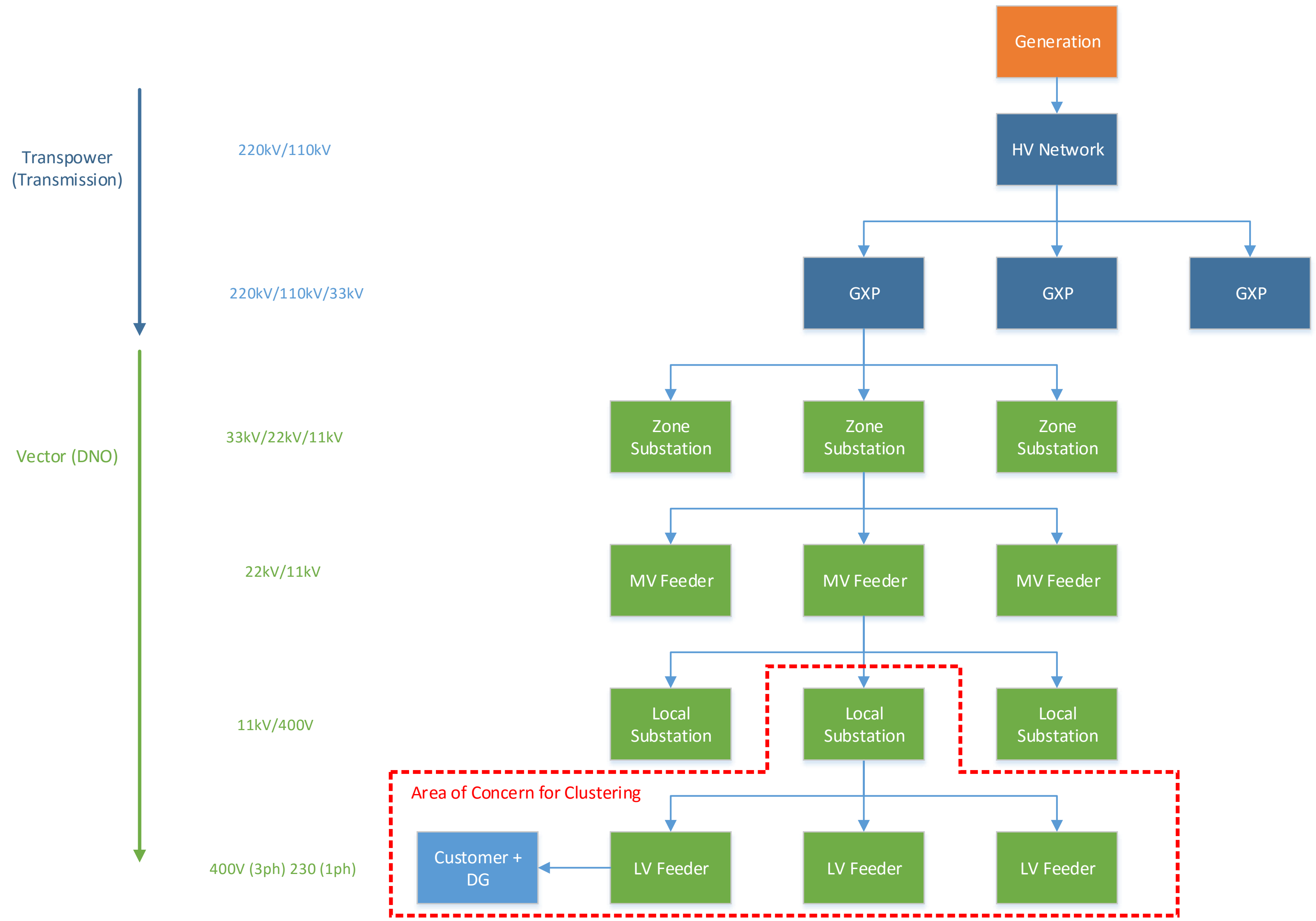


Figure 6: Power industry breakdown in New Zealand

1.4 AIMS AND OBJECTIVES

The aims of this thesis are:

- to analyse the severity of voltage issues caused by solar PV systems on the residential LV network
- and, to propose suitable, solutions for resolving voltage issues.

To achieve these aims the following milestones were deemed appropriate:

- construct a generic residential LV grid model with dynamic load profiling capability
- gather data relating to New Zealand relevant to:
  - residential electricity consumption
  - solar irradiation (in ideal conditions i.e. no cloud cover)
  - distribution equipment, i.e. sizes, ratings, etc.
- simulate and analyse voltage issues that arise as a result of PV penetration and clustering
- propose, simulate and analyse three potential solutions that could be used to solve the issues.

1.5 SIGNIFICANCE OF RESEARCH

From the background research done above, it can be seen that residential PV systems pose a real and ominous threat to DNO's worldwide. The purpose of the research is to gain an understanding of voltage issues caused by residential solar PV systems and to trial some solutions. The problems, solutions and discussions provided by this research provide a foundation to address voltage-related issues and pave a path for future research and development as well as practical trials.

1.6 STRUCTURE OF THESIS

The thesis in split into six chapters. The aims, objectives, justification and structure for the research are provided by chapter 1.

Chapter 2 provides details on literature reviews carried out prior to beginning research in the field. It provides a foundation upon which the research is performed. It contains summaries that relate to previous studies on modelling and simulation of LV networks, voltage issues relating to PV installations, PV clustering and solutions for voltage issues introduced by PV.

Chapter 3 discusses the methodology used for development of the models and scenarios that were simulated. It discusses the justifications of the scenarios, the derivation of a generic LV network and data gathered and used. The foundation of the trialled solutions are also discussed in this chapter.

Chapter 4 provides relevant results to the scenarios proposed in the previous chapter. The outcome of each result is investigated and analysed in-depth. This is to create an advanced understanding of both the depth of the voltage issues as well as the effectiveness of the solutions that were trialled.

Chapter 5 provides discussion points about the conducted research. It provides a strength, weaknesses, opportunities and threats (SWOT) analysis of the solutions, as well as the applicability of current PQ guidelines.

The final chapter concludes the thesis and consists of a self-reflection, potential improvements and future avenues for further research.

CHAPTER 2. LITERATURE REVIEW

In this chapter, existing work performed in this area of research is discussed. This chapter is broken up into three sub-sections. The chapter starts with an investigation into the effects of DG systems on the properties of voltage and builds on the effects of PV clustering. Next, proposed solutions to voltage issues in the low voltage network are investigated and a summary is provided. The content covered in this chapter provides a basis for further research. The avenues of further research, explored by this thesis, are provided at the end of each sub-section. These factors aid in the development of a robust methodology, which is then discussed in chapter 3.

2.1 VOLTAGE ISSUES OF DG ON THE LV NETWORK

There are three undesirable properties of voltage on the grid. DNO's are required to control these three properties at the point of common coupling (PCC). These are:

- overvoltage
- voltage sag
- imbalance.

Regulation in New Zealand dictates the following voltage limits on DNO's:

- A maximum root mean square (RMS) voltage deviation of +/- 6% from the nominal voltage at PCC.
- A maximum voltage imbalance of 1% for permanent connections and a maximum of 2% temporarily at PCC. However, a maximum imbalance of 3% may occur in areas where there are predominantly single phase loads (i.e. residential).

This means voltage experienced at PCC, must be within the bounds of 243.8V_{RMS} and 216.2V_{RMS} and the maximum and minimum voltages across all phases must be of magnitudes that don't exceed the 3% imbalance threshold [8]. There are two ways to measure voltage imbalance: either using sequence voltages or through the measurement of maximum RMS deviation across all phases. The latter has been used in this thesis. The formula is presented by equation (1) as follows:

$$\%\, voltage\ imbalance\ =\ Maximum\ deviation\ from\ the\ average\ \div\ average\ \times\ 100 \qquad (1)$$

The breach of these set limits may result in equipment damage (e.g. overheating or explosion of three phase motors, transformers, lines, etc.), protection mal-operation (e.g. fuses, circuit breakers, etc.). Both will impact on safety for the general public and employees working on a DNO's network.

The research on effects of DG, in particular PV, on the LV networks with reference to voltage properties has been investigated and is summarised below.

2.1.1 Overvoltage and Under-Voltage Caused by PV Injection on the LV Network

Voltage performance, under high PV generation is reported on by [9]. The research considers dynamic demand of industrial and residential loading under a high saturation of PV. The PV profile injected into the grid is also noted to be of the dynamic nature. The four studies that the literature performs analysis on are on constant insolation and voltage profile study, industrial load profiles, residential load profiles and simultaneous residential and industrial loads. All under consideration of the Sydney sun irritation profile. For the standard insolation and voltage profile study, it is noted that a base voltage rises between 3% - 6% was experienced depending on the node of concern. It was seen that the further the node was away from the regulated bus the greater the voltage rise experienced. In the industrial and residential scenarios, it was observed that a maximum voltage deviation of +12.5% and +11.5% appropriately. This is seen to be concerning as limits in NZ are +/- 6%. The study does not consider variable PV penetration and makes no considerations for NZ conditions. These avenues have been investigated as part of this thesis.

In [10] authors attempt to determine the maximum amount of DG that secondary distribution networks can withstand without exhibiting over and under voltage issues. The analysis performed in this paper focuses on maximum DG output during lightly loaded conditions. They recognise this as the worst case scenario and this does hold true for overvoltage situations when PV installations are in a residential environment. The LV network topology that is focused on in this paper is of a meshed nature, which is consistent with the methodology used in the Vector LV network. The placement of DG and the selection of size has been done based on Gibbs sampler algorithm discussed in detail in [10]. The paper concluded that placement of DG played a more vital role than the magnitude of injection to dictate the overvoltage and under-voltage parameters.

Many DNO's attempt to keep their voltage range within the permitted limits through the use of automatic voltage regulators (AVRs), load tap changing (LTC) transformers and shunt compensators [11]. Under normal circumstances (i.e. no DG), the equipment listed above, is used to control the voltage sag on a DNO's network.

The most common equipment used to control the voltage sag are LTC transformers. The methodology for determining the tap setting on LTC's is discussed in [11] and [12]. Tap setting is determined through the use of load drop compensators (LDCs). "LDCs are simple RL circuits that can be adjusted to predict voltage drop at a remote point in a distribution system" [12]. Equations for the tap setting are derived based on a DNO's requirements. Normally the tap on an LTC is set so that:

- Voltage at the furthest node in a distribution system doesn't experience a sag.
- Voltage at the closest node to the transformer doesn't experience overvoltage (i.e. $243.8<R_{esidence\ 1,\ 2\ldots\ N}<216.2$).

But there are limits to the equations derived in [12]. As explained in [13], when a large DG is installed close to a substation, it fools the LTC into setting a lower voltage than what is required to maintain voltage levels at the end of the feeder. Hence under voltages are experienced at the end of feeders. It can, therefore, be concluded that the equations discussed in [12] only hold true for networks where power flow is unidirectional.

A solution was suggested in [13] to use LTC and place DG at the end of feeders where they improve voltage regulation and don't influence the LTC. It fails to consider, however, that the loads furthest from the local transformer are the most susceptible to overvoltage and that the location of customer PV penetration can't be controlled.

The studies presented in [11] and [12] are conducted for static loads and fixed DG. Results in [12] show a maximum overvoltage of ~5% and minimum sag of ~2%, with an automatic tap changing transformer. This would be deemed as acceptable, but in most utilities the local distribution transformer supplying residential customers is of the fixed tap nature as seen in [14]. The taps are set to avoid voltage sags on the furthest node on the LV network. Also the DG size, injection location and injection profile is not consistent with a clustered PV system on an LV network. Therefore, further investigations were conducted to provide a more realistic perspective.

In [15] a realistic approach is taken, where the tap of the local transformer is fixed and the loads for houses and DG (in this case PV) follow a realistic daily profile. The dynamic approach taken in [15], sets residential loads and solar PV peaks of the same peak power, but occurring at different times during the day. By using a fixed tap, an assumption was made by the author that voltage sag was not likely to occur. Therefore, the investigation solely focuses on the overvoltage property. This is seen to be an improvement to the studies carried out by [11] and [12].

The results from [15] show a voltage swell of up to ~7%. A similar study is conducted by [14] with a voltage swell of ~12%. The results are concerning because they breach the set regulations and the DNO will be forced to reinforce an area with decreasing demand. Even more concerning is the fact that the load profiles used in [14] and [15] seem to be during peak residential demand with peak PV generation. This might be true for some parts of the world, but in New Zealand the maximum amount of sunlight is available during the summer season, when the electricity load is at its lightest.

It is still felt that the true realistic worst case for overvoltage and voltage sag has not been derived for New Zealand conditions and requires further research. Article [11] justifies this by arguing, that a true representation of a realistic worst case in a distribution system requires the consideration of:

- location of local distribution transformer on the MV feeder (primary voltage variations)
- location(s) of DG placement and/or clustering on the LV network
- consideration of seasonal dynamic loads.

It is recommended that consideration of the above is important and is researched as part of this thesis. Once these factors are considered, the result derived will be a true worst case for voltage magnitude experienced on a DNO's network.

2.1.2 Voltage Imbalances Caused by PV Injection on the LV Network

Under conventional circumstances (i.e. no DG), DNOs design their LV networks where loads are evenly distributed across the three phases. Single phase customers don't impose equal current flows into the LV network like three phase customers [16]. In a residential network, with multiple single phase connections, the voltage is inherently imbalanced due to the loading variations that occur throughout a day, on each phase [17].

In [16] authors explored a method of control for single phase DG with the aim of reducing voltage imbalance in the distribution network. They begin by defining that there are two states of imbalance which could be experienced on the network which are temporary (during faults) and permanent (installed loads are unbalanced). The network under study had a permanent imbalance between 1-10% depending on the time of day. In relation PV (without storage) the induced imbalance could be seen as a combination of both. This is because it is a permanently installed load which causes imbalance but only during periods when the sun is shining. The control is defined next as a device which can select the best phase for interconnection of single-phase DG based on calculated imbalance parameters per phase. Three scenarios were simulated; without DG, with DG but no control, with DG and control. A dynamic response for the load was used, but with static value is used for the DG output. It was observed that the voltage imbalance improved when an online control mechanism was used. But it was seen that the scenario with DG and no control was still seen as an improvement, which may not be true for the solar PV condition. The improvement in imbalance varied between 1-5% depending on the time of day. In a residential environment where most connections are of a single phase nature, switching DG between phases to improve imbalance would not be possible. A DNO requesting a three phase connection for every DG installed may be an unreasonable request for the customer especially if their peak demand has been lowered/remains the same.

In [17], the authors attempt to analyse the extent of imbalance that could occur under various scenarios. The experiment is set up where a static 2500W load is assigned to each phase of a distribution system. The PV penetration is then ramped up on one phase. It is observed that 850W of PV generation, during a peak loading on 2500W on all phases, will result in the breach of the 1% imbalance limit. If the PV and a single residential load peak is assumed to be the same, then it can be summarised that a ratio of 1:3 (1 PV system per 3 loads), with PV generation on only one phase, is deemed necessary for voltage imbalance to not breach set thresholds. A more practical study on imbalance is carried out in [14], and it shows that the imbalance varies between ~1.3%- ~1.7% for balanced and unbalanced PV penetration.

It is understood that the worst case for voltage imbalance is when one phase has a PV cluster. It is felt that the PV clustering effect of two phase still needs to be considered and requires further research. Also, the relationship between distance from the PV cluster and the imbalance magnitude was not investigated.

PV installations can't be pre-determined and customers that want to connect their PV systems to the DNO's network can't be turned away, simply to uphold a clustering ratio. Therefore, it falls on the DNO to take reinforcement action when this scenario arises. It was deemed that further investigation and analysis was needed to determine the effect of clustering on system imbalance. Further research conducted as part of this thesis includes:

- single phase, two phase and three phase penetration with a variation of injection distances, relative to local distribution transformer
- The effect of seasonal loading on voltage imbalance.

2.2 VOLTAGE SOLUTIONS

This section examines the range of the most popular solutions that have been investigated by previous researchers, for voltage issues relating to PV. The list of solutions, summaries and the comments are provided in Table 1. Following the table is the interrogation of the three solutions that were deemed to be the most viable. This is in an attempt to gauge the shortfalls of existing research and build upon an existing foundation.

Table 1: Summary table of potential solutions for voltage issues

Suggested Solution	**Summary**
Reactive power control	Involves the injection and consumption of reactive power through the smart inverter of the solar PV system. Reactive power can control voltage regulation. By improving regulation, it inherently improves imbalance. The reactive power injection or consumption without/with storage can change the amount of losses on a DNO's network. The ability to control losses and voltage makes reactive power a viable solution for voltage issues.
New methodology for OLTC	Requires the setting of taps by considering the penetration of potential PV penetration. Most local distribution transformers have a fixed tap to address the sag issue. If focus is changed to addressing the swell, voltage sag will be compromised [18]. This doesn't address the base problem of voltage regulation. Regulation will only get worse as more clusters are introduced. Could be convoluted exercise, when other solutions are simpler to introduce.
Batteries	Involves consumption of excess active power from the solar PV system to be stored and used at a later period. In time of use (TOU) pricing schemes, it provides a mechanism to lower demand during high price periods. This means the owner doesn't need to change his/her routine to adapt to the TOU pricing to achieve a lower bill. Reactive power control can also be added if used in conjunction with a smart inverter. Has the capability to improve voltage regulation and imbalance on a LV network through the use of set charge and discharge profiles. The hardware for the technology is costly and is currently unattractive. But efforts on further research are being made to improve capacity and reduce size, which may eventually lead to affordable pricing. Controls that mutually benefit the customer and the DNO are yet to be developed. Further investigations on various controls and ideal storage size for New Zealand conditions is required, making it a target for further research opportunities.
Generation curtailment	Disconnecting PV units from the grid when a voltage swell breaches a threshold. Cutting LV generation, is effectively increasing the load on and helps to suppress the LV voltage during peak PV injection periods. Islanding for long periods is hard to achieve for PV systems without storage or other means. This solution will make customers unhappy, because they will not be able to make the most out of their investment. In an industry that is actively trying to be more customer focused, this action will not sit well. This will drive demand for more off-grid solutions. Therefore deemed to be not a suitable solution for further investigation.

Reducing line resistance	Involves increasing the cable or line size which results in a reduction of resistance. The lower the resistance of a line the lower the voltage drop/swell on the line. Very expensive exercise and cost inefficient for a DNO. Therefore practically not a suitable solution and was not investigated further.
Single Phase Micro-grids (an original idea)	Traditionally, micro-grid involves the interfacing of multiple DG and storage equipment to make the use of the energy within an isolated three phase LV network. A customised, non-traditional solution was examined. It refers to the use of a temporary single phase micro-grid in conjunction with batteries. The methodology is having a unit that is capable of interconnecting all the phases of an LV network while operating disconnected from the grid. This means the LV network is of a single phase temporarily. This increases the efficiency of the storage and will help maintain voltage regulation. Traditional micro-grids help with voltage regulation but do little for imbalance that could be introduced by clustering. This solution has the possibility to provide a better utilisation of assets in areas where there are no three phase machines/connections. It can improve reliability and provides assured power quality. Further investigation was conducted due to the numerous unknowns presented by this solution.

2.2.1 Reactive Power Injection and Consumption

Reactive power control in LV distribution networks has the capability to control the voltage regulation and imbalance. Reactive power consumption and injection have the effect of sagging and swelling voltage.

Devices such as dynamic VAr compensators (DVARs) and active filters (i.e. capacitor banks and inductor banks) are used to control reactive power on distribution networks. These are normally associated with medium voltage (MV) feeders (i.e. 22kV or 11kV distribution). The use of these reactive power compensation devices on the LV network with DG penetration is introduced by [12], where there is a DG unit which injected real power and a reactive power compensation device to regulate voltage. The LV network is supplied by an on-load tap changing (OLTC) transformer. An algorithm is used in [12] to calculate the exact amount of reactive power required to achieve the following two objectives:

- to reduce the swell of voltage
- to avoid the OLTC transformer from tapping, because if it taps up it will produce a sag on the furthest node of the LV network, and if it taps down it will exasperate the problem on the nodes closest to the transformer.

The algorithm was seen to work successfully and achieved both objectives. But the shortfall is that, in reality the DNO must install an additional component on its network to achieve the required reactive compensation. The reactive component comes in a fixed size and is not variable, it is either switched on or off which makes it difficult to control voltage when loads in the LV network are dynamic. Another downfall is as penetration of DG increases (e.g. more installations of PV on the feeder), a larger reactive control component might be required. A further consideration is the physical space available to the DNO for these types of installation. Due to these shortcomings, it is therefore ascertained that the traditional reactive power control solutions may not be suitable to address voltage issues caused by DG.

An untraditional methodology is the use of smart inverters in solar PV systems. Smart inverters control reactive power by applying a phase shift between the reference current and grid voltage [19]. This shift can result in both inductive and capacitive reactive compensation. To mitigate overvoltage caused by solar PV, inductive reactive power must be injected into the grid. To inject inductive reactive power, a sacrifice on the active (real) power is needed. The sacrifice of active power ensures that the inverter is kept within its specified nameplate VoltAmp (VA) rating. This is explained by figure 7. The circle describes the VA rating of the inverter, and any point on this circle can be selected by the inverter to inject complex power into the grid.

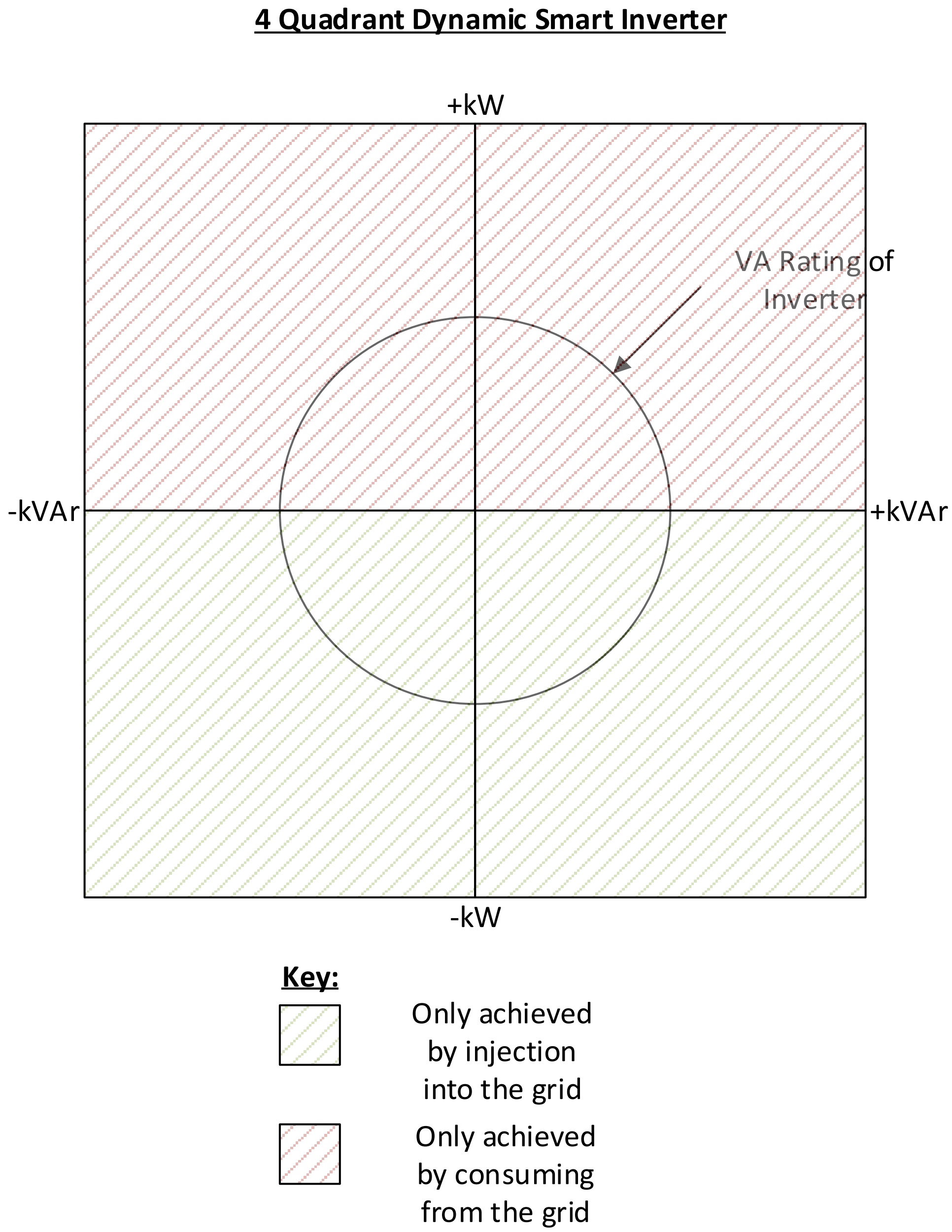


Figure 7: 4 Quadrant dynamic smart inverter

In [19] investigations are conducted on using reactive power to support voltage during the evening peaks where there is little/no PV injection available. The proposed solution involves the transformation of active power to capacitive reactive power, i.e. like a capacitor. This has the potential to reduce the voltage sag experienced during heavy load conditions, only if the load that is being supplied is heavily inductive or there are high line inductive losses. It is essentially like having distributed variable capacitor banks on the network which improve the power quality. But, in New Zealand, the residential peak demand occurs during winter evenings and real power makes up the majority of the demand. Hence it was felt that this solution for voltage sag may not be appropriate for residential scenarios in this thesis.

An approach for the operation of multiple DG on a LV network, without breaching voltage swell regulation and imbalance limits, is explored in [20]. The network that is analysed has a PV penetration of 29%. The conditions provided in [20] are, peak residential load, simultaneous peak PV injection, and storage. The loads in the model are static and don't vary with respect to time or seasonal demands. The results show that when each unit provides reactive power support with active power injection, it results in the best response for voltage imbalance and voltage regulation. The optimal reactive power will vary depending on the location of the PV penetration. But it is felt a more in-depth investigation is required using a more dynamic methodology for loading, PV injection and without the use of storage.

A reactive control methodology was explored in [21], where a power conditioning system (inverter) controls the injected reactive and active power into the grid. Dynamic seasonal loads and PV generation profiles, under German conditions, are used to display the effects of the control on LV system voltage. A low voltage networks was formulated by the authors for the purposes of the study. The model consisted PV penetration at every load. Simulations showed that it was possible to have PV penetration at every node and still be able to regulate the voltage below the standard PQ guidelines. During lightly loaded conditions and when PV generation was at its peak, reverse real power injection was experienced and reactive power was drawn from the grid to stabilise the voltage. It should be noted that results are shown for a node which is in the middle of the LV network, effects on voltage at the end and beginning of the LV network are not shown. This was seen to be an avenue for further exploration.

An approach to improve inherent imbalance in low voltage network through the use of reactive power control is discussed in [22]. The paper introduces a network which has an inherent imbalance of ~0.5% at the furthest node. With the unbalanced introduction of single phase PV, the imbalance on the network rises as penetration is further away from the point of regulation (i.e. distribution transformer). The magnitude of imbalance also rises to ~1.3%. The reactive power solution reduces the imbalance to be seen as negligible. The amount of reactive power to be injected by each PV unit is based on voltage magnitude on the adjacent phases. Therefore, access to voltages on adjacent phases is required for this solution to work, which is hard in a practical environment, where residential connections are single phase.

Avenues for further research were identified by the literature review. The points below have been examined further as part of the methodology section:

- incorporation of dynamic seasonal loads with coincidental PV generation profiles in New Zealand conditions
- reactive power compensation required at different generic locations of a LV network to keep voltage imbalance and voltage regulation within the specified limits of the LV network.

2.2.2 Battery Storage

Battery storage is used in conjunction with various forms of DG because of its ability to store excess energy, which provides voltage stability in networks. PV systems with batteries have the ability to consume excess power produced by PVs during lightly loaded conditions [23]. They can then use this stored energy to off-set future load.

The formulas discussed in [23] and [24] describe how batteries are used to regulate the swell in voltage. For the equation (2) shown below, R, X, P, P_S, P_L, Q and V_G represent: cable resistance, cable reactance, real power at the node, real power drawn by the battery, real power drawn by the load, reactive power at the node and grid voltage. When no battery exists, P_S component is ignored.

$$\Delta U = \frac{(R.P^{*} + X.Q)}{V_G} \; ; P^{*} = P_{PV} - P_L - P_S \qquad (2)$$

The value for P_S is determined by the customer or DNO's setting, which ensures a swell in voltage is not experienced at PCC. The control of active power storage is seen as an effective method for influencing voltage sag, swell and the imbalance of a network. In [24] the investigation for the battery solution was split into centralised storage, distributed storage and combined storage. Studies in [23] explore reactive and active power variation provided by the distributed storage approach only. It is seen that [24] offers a more thorough investigation into solving voltage regulation issues, because it explores the opportunity of centralised storage which may come to fruition if communities or a group of residences decide that a centralised battery storage system is a more cost-effective solution.

There are two methods of interconnection of batteries with PV systems discussed in [23]. First, the connection of the battery to a DC bus, which interconnects with an inverter and the PV array module. Second, an inverter for the PV array module and a separate inverter and control for the battery system. The first method is seen as the most common and is also used in simulations conducted in [24]. The second method is thought to be a double up of components, which will not be a cost-effective solution, but it might be easier to retrofit for existing solar PV systems that were installed without batteries.

In [24], a six-day dynamic profile for PV and residential loading is used to simulate results. The scenarios simulated are: centralised storage at various distances from the local transformer, distributed storage at locations of PV injection and reactive power injection in combination with centralised and distributed storage. The results of the simulations are categorised based on the maximum discharge/charge rate (kW) and maximum energy storage (kWh) required to minimise the effects on voltage regulation. It is seen that distributed storage with power injection at P.F. 0.95 requires the smallest battery size and lowest charge/discharge rate. Therefore, a derivative of this distributed storage solution has been trialled on the generic LV model in the sections below.

The operational modes of the battery when in use with PV injection has been described by four modes. These modes are discussed in [23], which are listed in Table 2:

Table 2: Four modes of operation for a battery system

Mode	**Description**
1	Battery is charged when PV generation exceeds demand of the residence. Battery is discharged when PV generation is lower than demand of residence.
2	If state of charge of the battery is less than 100%; charge battery when grid voltage reaches the set upper voltage limit, don't feed load.
3	If state of charge of battery is 100%;

	use inverter to consume reactive power when grid voltage reaches the set upper limit.
4	If state of charge of battery is 100% and inverter is unable to lower grid voltage; reduce reactive power output of the system.

Another method for regulating overvoltage through the batteries is explored in [25]. The idea explored was to have a centralised decision making controller at each distribution substation, which would collect data on the distributed PV systems and batteries that are connected downstream from it (i.e. decentralised systems with centralised control). The controller would actively run load flows to calculate the voltage at each node downstream and issue commands to each individual system. The method was trailed on a test network with dynamic loading and PV profiles. The loading seen was not seasonal. The results showed a marked improvement in both sag (improvement by 4%) and overvoltage (reduction by 6%). However, shortfalls of such a system are that every distribution transformer must know its downstream LV connectivity, and in a practical environment this will be hard achieve as open points in LV networks are changed based on faults and planned work. Also running dynamic load flows for every time interval could be onerous on an aggregated control mechanism. It was felt that a better method might be a control is one that is disaggregated (i.e. having a control mechanism at every load/PV/battery connection to the LV network).

Centralised, decentralised and distributed control for battery storage were studied [26]. Where centralised control is a method similar to explored in [25], decentralised was seen as a control mechanism which is independent of any subsystems and distributed control is seen to be a compromise between the two systems, where limited information exchange occurs between subsystem which is mediated by a central entity but control is located at each battery. A summary of each control mechanisms advantages and disadvantages are discussed by the table below.

Table 3: Advantages and disadvantages of battery control mechanisms

Control Mechanism	**Advantage**	**Disadvantage**
Centralised	Easier to achieve the goal of any aggregated variation in energy and/or demand.	Large communications overhead. Complex computation requirements. Full knowledge of LV network.
Decentralised	Small communications overheads. Limited knowledge of network. Simpler computation requirements.	Requires forecasting ability. Requires assumptions to be made. Hard to achieve optimal network-wide conditions.
Distributed	Reasonable co-operation between residential energy management systems. Optimisation of centralised and decentralised schemes.	Can be seen as a doubling up of components and decision-making therefore costlier. Hard to practically execute due to its complexity

The investigated results only related to energy consumption and not voltage deviation. Therefore, scope for further investigation was observed here. Distributed control and its effects on voltage in particular has been investigated further by this thesis.

The research investigated above does contain gaps. Further research points have been incorporated into the methodology of this thesis, these points are:

- maximum available charge produced by PV system during different seasons (winter/summer)
- required charge and discharge profiles during different seasons
- an extension of the four modes of operation to account for the seasonal changes in loading and discharging the battery (discussed in table 2).
- Effect of distributed control on voltage profiles

2.2.3 Single Phase Micro-Grids

In the electricity distribution industry, building a micro-grid is normally a customer-initiated action. The reasoning for constructing micro-grids by the customer, can be narrowed down to reliability improvement and/or financial gain. Prior research in the area of micro-grids entails interfacing multiple sources or a single source of distributed generation with a storage medium, normally batteries seen in [27] and [28] . All research leads to trying to improve the efficiency of a micro-grid, i.e. all energy that is generated by DGs within the micro-grid must be used by the loads within the micro-grid. Constructing micro-grids involves consideration of multiple DG sources, storage, grid connection/disconnection and power quality control.

An example methodology for controlling distributed energy in the micro-grid is presented in [27]. It is based on using a centralised processing unit and controller that communicates to generation sources within the micro-grid. It makes decisions on:

- controlling the active and reactive power from the local DG sources and batteries during:
  - grid connected mode
  - islanded mode.

The decisions are based on the generated active and reactive power, forecasting max/min available generation at particular times, forecasting the max/min local absorption of generation at that time and inverter rating and overload capabilities. The result of these decisions, controls the power quality and in turn the voltage regulation and stability of the micro-grid network.

The micro-grid methodology investigated in [29] is a three phase disconnection and reconnection of a local LV network from the grid and while disconnected from the grid, the three phases remain separate. The author's original idea was applied in a different manner. The thesis investigates the validity of a temporary grid islanded micro-grid, where the LV network is converted into a single phase during the islanded state and converted back to the three phase state when a reconnection to the grid is required. It involves the use of two circuit breakers simultaneously. The first breaker interconnects the normally three individual phases, followed by a breaker that disconnects the grid temporarily.

Grid disconnection and phase interconnection are performed when there is sufficient DG or storage on an LV network for it to be self-sustainable. Excess power can be stored in either centralised or disaggregated batteries. The benefit that this method provides is flexibility, the flexibility to use storage or DG across all phases.

Converting a three phase LV network to a single phase LV network has been suggested, because in most residential zones loading was seen to be single phase. The only reason the electrical industry has three phase networks is to drive big three phase industrial motors, pumps and machines. Having a single phase electrical network in combination with PV, allows the use of scattered and clustered PV generation across any phase to support total load on adjacent phases on a LV without causing swells in voltage on any particular phase. It also provides the opportunity to reduce battery size and peak current draw (inrush).

Therefore, unlike traditional scenarios where micro-grids are requested by customers, this solution could be initiated by the DNO to mitigate voltage issues on a DNO's MV network. It makes use of the maximum PV penetration available and distributes the generation to all customers connected to the local LV network. It will improve the efficiency of storage and has the capability to drive down the size of storage required. These concepts are investigated and discussed as part of this thesis. However, stability analysis of the single-phase micro-grid solution is deemed out of scope.

CHAPTER 3. METHODOLOGY

The methodology section of this thesis is split into three separate parts: scenarios to be simulated, assumptions made and model constructed. Each section provides the direction and structure for simulations conducted and the results gathered are detailed in Chapter 4. Figure 8 depicts a breakdown of the methodology taken when conducting research for this thesis.

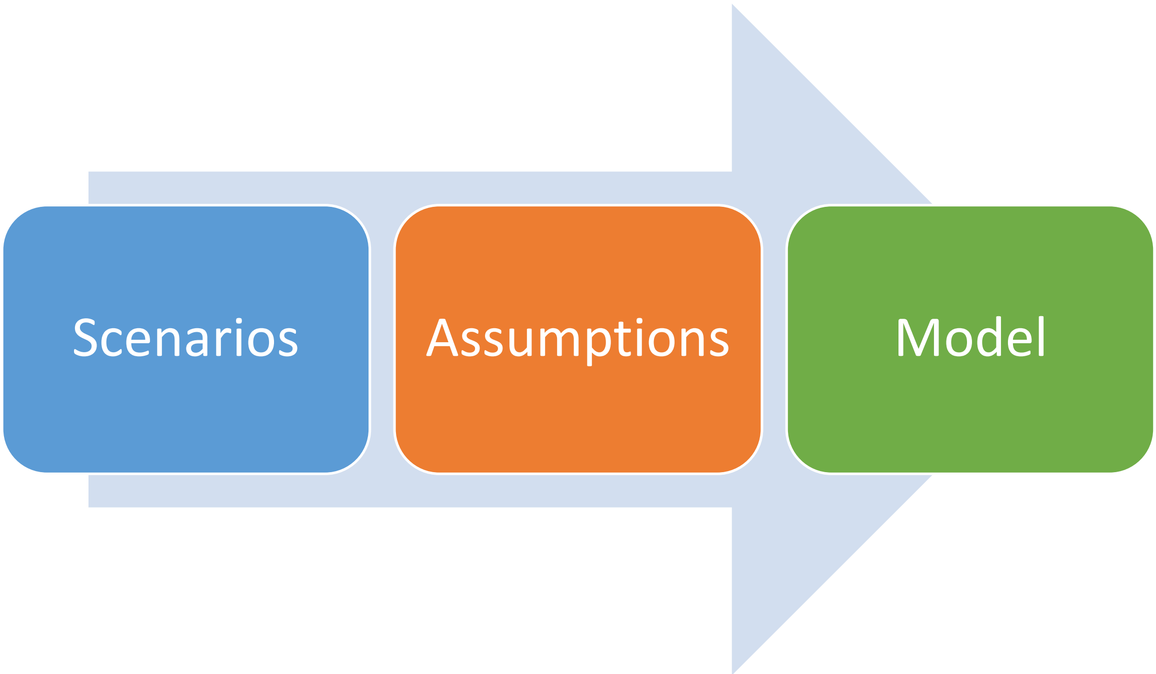


Figure 8: Methodology structure

The first component of the methodology was to decide on the scenarios to be simulated. These scenarios were designed to build upon the existing research reviewed in chapter 2. The next section discusses the “assumptions” made to make the model generic to New Zealand conditions. Finally, the “model” construction phase describes the:

- components of a generic residential LV model
- residential PV system
- smart inverter (i.e. reactive power solution)
- battery system
- temporary single phase micro-grid.

3.1 SOFTWARE USED

The software used to perform simulation for this thesis was Matlab. This product is well known in the industry and has been used for many research and development type projects. Matlab was readily available in AUT and the author was familiar with its use and that is why it was the preferred modelling tool.

3.2 SCENARIOS

The intention of the scenarios was to demonstrate:

- the realistic worst case, in terms of voltage regulation (sag and overvoltage) and imbalance in LV networks, whilst the LV network was under the influence of PV penetration
- the effectiveness of trialled solutions which address voltage regulation and imbalance issues.

The derivation process for the scenarios for each point is detailed in the sub-sections below. Each scenario was formulated based on an extension of the examined prior research. Each scenario encompasses multiple simulation results.

3.2.1 Scenarios for Worst Case

From the discussions presented in the previous chapter, it was realised that there are multiple factors that influence the worst case in a LV network. This makes it difficult to define a single scenario which exhibits the worst case. Hence, a variation of parameters was required to comprehend and simulate a true worst case. The chosen parameters for this thesis are: seasons, PV clustering, MV/LV transformer size, location of PV injection, number of PV modules and the location of LV network on MV grid. Figure 9 shows the precise variations of each parameter as they are applied in this thesis.

Figure 9: Worst case parameter variations

3.2.2 Scenarios for Solutions

Solution scenarios were formulated as an extension of the different solutions discussed in the previous chapter. These are as follows.

- Reactive power solution, which controls the amount of injected complex power at the point of PV installation.

- Battery solution, which controls the amount of injected power into the grid during both sunlight and non-sunlight hours and the system was located at the point of PV installation.
- Single phase micro-grid solution, which consists of a double breaker and a battery unit, which controls grid islanding into a single phase during high PV injection or while storage is available on the LV network.

The application of each solution to the LV network results in its own scenario.

3.3 ASSUMPTIONS

The purpose of assumptions for this thesis was to simplify and justify the steps taken to produce meaningful results. This section explains the assumptions made to derive a generic residential LV model and leads to describing the assumptions made for each of the parameters that make up the generic residential LV model.

3.3.1 Definition of Generic Residential LV Model

The first challenge and assumption was to decide on a generic residential LV model, which would be applicable to a majority of cases seen in New Zealand. Through the use of Vector's resources, it was observed that LV networks consisted of:

- MV network (path for generation to the LV network)
- Local MV/LV transformer
- LV lines
- LV loads.

The planning of the LV network occurred in a manner, where voltages during peak loading for:

- customers closest to the MV/LV transformer would experience a nominal voltage of 240V
- customers close to the mid-point of a LV feeder would experience a nominal voltage of ≥ 230V
- customers furthest from the MV/LV transformer would experience a nominal voltage ≥ 220V.

Therefore, to reduce complexity, the LV feeder would be constructed in a way that reflected the criteria specified above. There would only be nine LV loads (customers); one load at each voltage step node and three loads on each phase. A single line diagram (SLD) of the generic model can be seen in Figure 10.

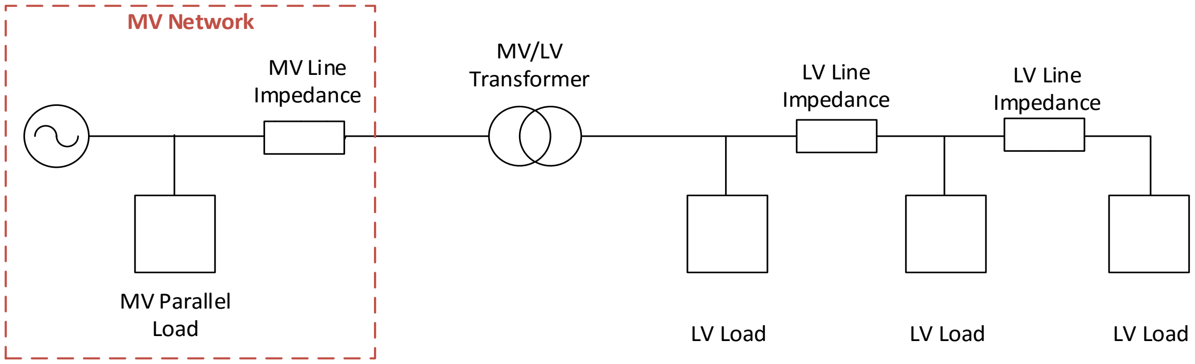


Figure 10: SLD of generic residential LV model

3.3.2 MV Grid

Most residential distribution networks have a radial topology. In a radial distribution network residential customers are normally fed by a local distribution transformer. This local distribution transformer belongs to a MV feeder. The MV network consists of a feeder from a zone substation. The MV network for this thesis consisted of generation, a parallel load and a line drop constant (series resistance).

The parallel load and line drop constant define any adjacent LV networks spawning from the MV feeder. The parallel load and line drop was varied based on the scenario to be simulated. It was assumed that the parallel loads on the MV network would have exactly the same dynamic load profile to that of an individual residential load point on the LV network, except they would be scaled up. Demand diversity was not accounted for in these simulations, because it was assumed that the MV feeder only supplied residential load and all the customers had identical demand profiles.

A single generator was used as a power source for the model. The MV load and line drop values would vary depending on the selected scenario, but the generation would be constant. This was an attempt to show the limits of the MV network. The capacity of MV feeders on Vector's network is normally 5MVA for an urban residential area. This same assumption was used to define the limits of the generator; 5MVA supply, 11kV, 3-phase, with a short circuit impedance of 5%. No variations to the supply were required to satisfy the scenarios stated above.

3.3.3 Transformers

Distribution transformers vary in size and impedance and are dependent on multiple factors, i.e. manufacturer construction methodology, utility/customer requirements, materials used. This makes it difficult to choose a specific transformer size and impedance ratio to accurately satisfy the scenarios. Therefore, a standardised table for transformer size and impedance ratio, which has been developed by Vector, was used as a guide (see Table 3).

Table 4: Vector's transformer size to impedance rating for distribution transformers MV/LV

Transformer Size	**Impedance %**
<100kVA	3%
100k – 500kVA	4%
750k – 1000kVA	5%

Distribution transformers in Vector’s network are also operated as a fixed tap. The tap position is determined by the peak LV load on the network. The effect of voltage during peak HV load conditions is not considered. The vector group used to step down from MV to LV is Dyn1. This is where the primary winding of the transformer is connected in the delta format and the secondary in the wye. There is also a -30° phase shift that is induced to the injected primary waveform. The voltage rating for the transformer will be assumed as 11kV/415V 3-phase. This was to achieve the 240V single phase for the customers closest to the MV/LV transformer during lightly loaded conditions.

3.3.4 LV and MV Line Losses

Lines have impedance and this is modelled as a combination of three parameters: resistance, inductance and capacitance. Resistance in lines is the major cause of losses through heat. As higher voltages are experienced through the same size conductor, the current draw reduces and a drop in losses is experienced. However, the resistance of the line will continue to remain constant. For long transmission circuits at high voltages, the length of the line dictates inductive losses and the proximity of other lines dictates the capacitive losses. The effect of capacitive losses is assumed seen to be negligible if the line length is less than 60km.

In Vector’s network the average length of a residential MV feeder is approximately 5km. The LV network has an average length of ~0.5km. This meant that capacitive losses were not considered as part of this, as they were considered to be negligible. Therefore, the major cause of line losses can be narrowed down to two properties, i.e. resistance and inductance.

3.3.5 LV and MV Loads

In New Zealand, residential appliances are a mix of linear and non-linear loads. Linear loads have the characteristic of a constant impedance and are normally modelled as resistors. Non-linear loads have the characteristic of a constant power and are modelled as a combination of resistors, capacitors and inductors. This means for non-linear loads, the impedance of the load changes to adapt to the voltage sag or swell to deliver a constant power.

In the case of the generic LV model, an assumption of 3kVA after diversity maximum demand (ADMD) was made. It is difficult to simulate a mixture of linear and non-linear loading of a residence; but, it is known that the magnitude of power consumed by linear loads is much greater than that of non-linear loads. This can be seen from Tables 4 and 5.

Table 5: Linear residential appliances peak power

Linear Residential Appliances	kW rating
Hot water cylinders	3
Heaters	2.4
Washing machines	2
Dryers	1
Electric stove top ovens	3

Fridge	1
Toaster	0.4
Kettle	2.2

Table 6: Non-Linear residential appliances peak power

Non-linear Residential Appliances	kW rating
Computer(s)	0.2
TV	0.2
Mobile phone chargers	0.01

Therefore, an assumption was made that the profile of the residential load would be of a linear nature and would comprise of a resistor and inductor in series. The inductor has been added to compensate for the inductive losses which occur within the residence, i.e. through wiring and appliance demand. It was also assumed that all residential loads had a coincidental peak, therefore, no diversity factor was applied.

3.3.6 Solar PV System Injection and Irradiation Profile

The solar PV system was modelled as a current injection source. This was because the current injection of a PV system is directly proportional to the amount of irradiation available from the sun at a moment in time. An assumption of an ideal irradiation profile was made, because it helps provide the worst scenario for injection from a DNO’s perspective. Basically, this means that there would be no cloud cover to obstruct the PV panel from solar irradiation. Another assumption relates to the physical positioning of the PV panel; it is thought that the panel would be positioned in a way that maximises the duration of sunlight experienced. Therefore, all the available irradiation was converted into injected current. The last assumption was that the peak output from the solar panel will be 3kW. This was to match the peak ADMD of residential demand.

3.3.7 Reactive Power Control

Reactive power control was achieved through the shifting of injected current from the PV with reference to the grid voltage. It is assumed that in a residential system with little reactive power demand, the voltage and current supplied by the grid was in-phase with each other. By injecting the produced PV system current at a phase shift, the voltage swell would be minimised. An assumption was made that the inverter rating was limited to a peak complex power of 3kVA.

3.3.8 Batteries

Batteries were first calculated into the model with the assumption that there are no capacity or peak current restrictions. This is so that an ideal battery can be sized as a result of the simulations conducted. The results were then compared to a battery with the latest available technology. At the time of the thesis, the latest in battery technology was the Tesla Powerwall. The specifications for this battery can be found in Table 6.

Table 7: Tesla Powerwall design specifications

Efficiency (Roundtrip)	92%
Continuous power	2kWh
Peak power	3kWh
Voltage range	350-450Vdc
Continuous current	5.8A (2.0kW)
Peak current	8.6A (3.0kW)

It was later seen that the restrictions proposed by this battery were sufficient for the purpose of this model.

3.3.9 Single Phase Micro-Grid

The single phase micro-grid consists of two breakers and a battery storage system. The interconnecting breakers were assumed to be ideal switches for the purpose of the simulation and will disconnect and re-connect together without any time lag. The current injection from the PV will adjust simultaneously to synchronise to this single phase system and vice versa.

The battery was to be used to store any excess current produced by the PV system, in addition to the local demand of the LV network. Like the previous section, the battery used would not have any capacity or discharge/charge current limitations.

3.4 MODEL

This section describes the derivation and construction of each component of the generic residential LV model. It discusses the components, formulas and ideologies used to construct an accurate dynamic time domain model. The purpose of the model was to show the voltage at multiple nodes dynamically over a 24-hour period with varying seasonal loading, PV injection and adoption of solutions.

3.4.1 Construction of MV Grid

The MV grid for this thesis was seen as the condensation of generation, the transmission network and the MV feeder distribution network parallel loading, up to the point of the MV/LV local distribution transformer. The interconnection methodology of the MV grid with the local distribution transformer, was varied based on the scenario that was simulated.

From Section 3.2.1, Figure 9, it can be seen that three variations were constructed. Each variation had a set of line resistance and parallel dynamic MV feeder load.

The “beginning of MV feeder” had the requirement of representing a local distribution transformer right at the beginning of a MV feeder. This was achieved by directly connecting the generation block to the local distribution transformer, without any series line resistance and parallel load. This would theoretically produce the highest possible voltage injected into the MV terminals of the MV/LV transformer.

The “mid-point of MV feeder” requirement was to represent a local distribution transformer positioned mid-way along a MV feeder (see Figure 11). This meant a line resistance and a dynamic parallel load was added. The parallel load would be dynamic with a peak load of 2.5MVA. The series line resistance was sized to simulate a voltage drop of 3% during peak loaded conditions. Equation (3) is used to determine the size of the three phase series resistance.

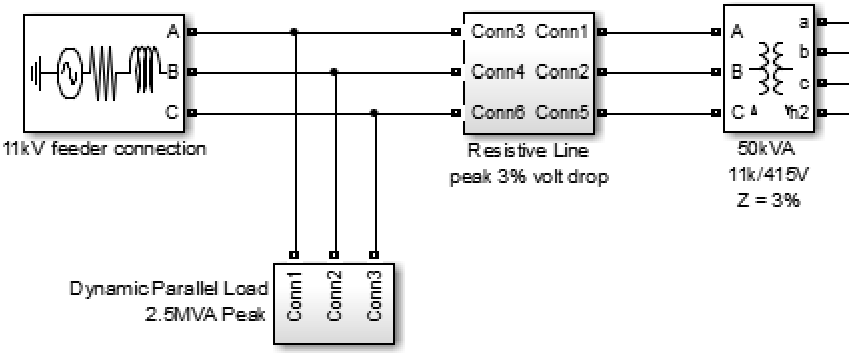


Figure 11: Schematic representation of a mid-feeder scenario

$$Required\ Series\ Resistance = \frac{11k - 11k \times 0.97}{(\frac{3kVA \times 9}{11k})} = 134.44\Omega \quad (3)$$

The final requirement for “end of MV feeder” was constructed similarly to the mid-feeder. The size of the series resistance was increased, so that a 6% volt drop at peak load was experienced at the primary terminals of the local distribution transformer (see Figure 12). The parallel load was uprated to a peak of 5MVA with the same dynamic load profile. This would theoretically simulate a full loaded MV feeder.

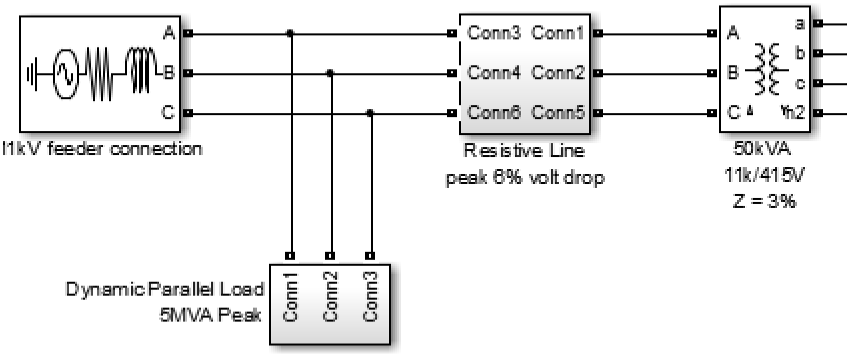


Figure 12: Schematic representation of an end-feeder scenario

$$Required\ Series\ Resistance = \frac{11k - 11k \times 0.94}{(\frac{3kVA \times 9}{11k})} = 268.89\Omega \quad (4)$$

3.4.2 Construction of LV Lines

The LV lines were simulated as purely resistive. A simulation test was carried out to observe the effects on voltage, if the equivalent inductive component was added. This was not included as part of Figure 9, because it resulted in a negligible effect.

Three electrical nodes were created through the use of these lines. These were to satisfy the scenario requirements, “beginning of LV feeder”, “mid-point of LV feeder” and “end of LV feeder”. These three points were electrically 240V, 230V, and 220V during peak residential loading state (see Figure 13). Therefore, the construction of the lines occurred in a manner to satisfy the volt drops of 0V, 10V and 20V. For the purpose of calculating the resistance of each line component, an ideal voltage source of 240V from the local distribution transformer was assumed.

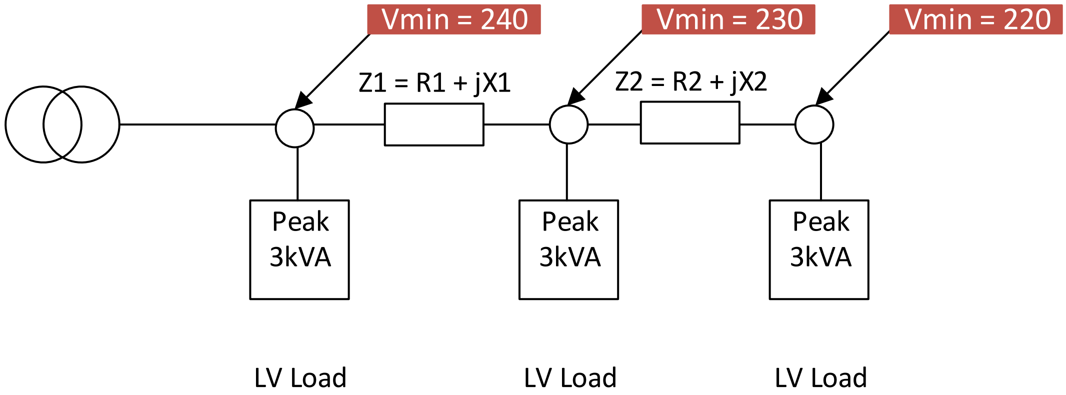


Figure 13: Single line equivalent of model used to work out impedance requirements

Where;

Z1 and Z2 = dynamic complex residential loads

R1 = Line resistance required to reduce the voltage to 230V during a 3kVA residential peak

R2 = Line resistance required to reduce the voltage to 220V during a 3kVA residential peak

The impedance parameters can only be calculated at a point where loads are known, hence they have been calculated using the residential peak load. The calculation for the line resistance is described by equations (5) and (6)

$$R2 = \frac{230-220}{Peak\ Load} = \frac{230-220}{(\frac{3\times 10^3}{220})} = 0.733\Omega \quad (5)$$

$$R1 = \frac{240-230}{Peak\ Load} = \frac{240-230}{(\frac{3\times 10^3}{220}+\frac{3\times 10^3}{230})} = 0.375\Omega \quad (6)$$

The inductive component of lines was calculated by assuming a LV line conductor which was a 1c 16mm^2 Al, XLPE/PVC. AS/NZS 3008.2 was used to calculate the distance of the line for given resistance. The inductive component of the line is shown below.

AS/NZS 3008 .2 states maximum current in a 1c 16mm^2 Al, XLPE/PVC = 114A

Rc = 1.47 ohms/km (cable); Xc = 0.122 ohms/km (cable) ← Values from AS/NZS 3008.2

$$LV\ Line\ length = \frac{0.733}{1.47} = 255m;\ Line\ 2\ length\frac{0.375}{1.47} = 500m \quad (7)$$

$$X1 = 0.255 \times 0.122 = j0.031\Omega \text{ ; } X2 = 0.500 \times 0.122 = j0.061\Omega \tag{8}$$

$$Inductor1 \ = \frac{0.031}{2 \times \pi \times 50} = 0.099mH \text{ ; } Inductor2 = \frac{0.061}{2 \times \pi \times 50} = 0.194mH \tag{9}$$

3.4.3 Construction of Residential Loads

The residential load profile was created by utilising data provided by Vector regarding a residential distribution transformer on their network. A year's worth of apparent (kVA), reactive (kVAr) and real (kW) power data at 10min intervals was made available to the author. The date range was between 01/01/2012 till 01/01/2013. It was observed that the highest load occurs during the June to August months or the winter season. A plot of the profile is shown in Figure 14.

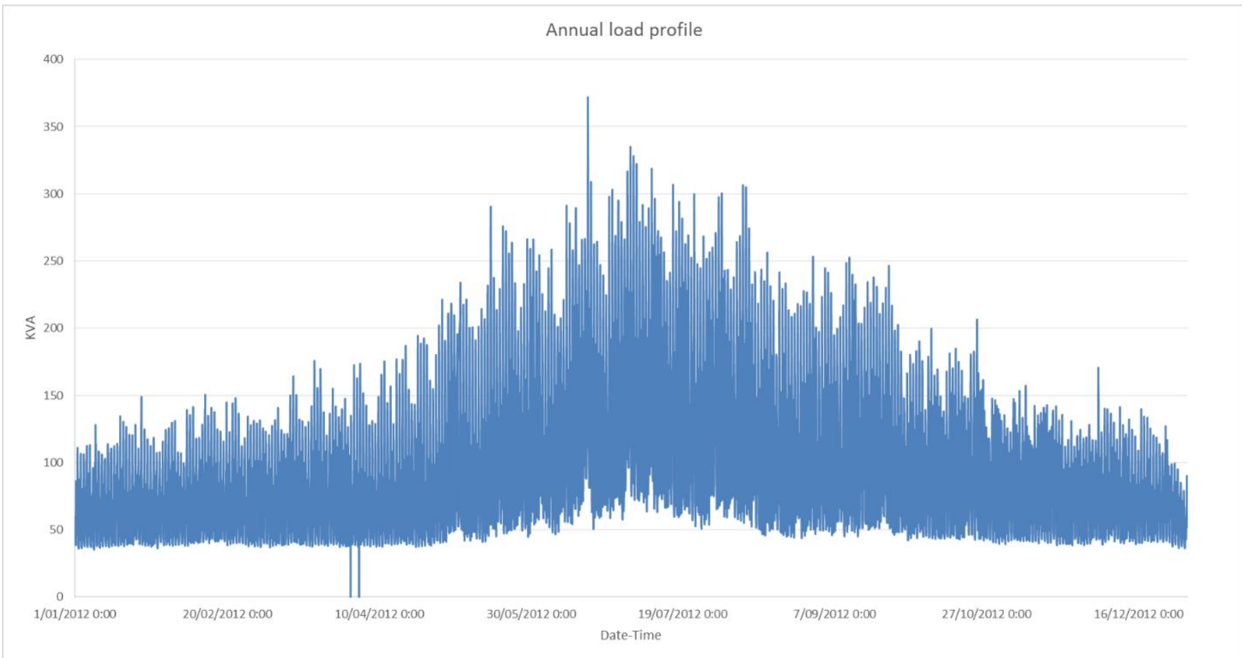


Figure 14: Load profile of year 2012 for residential local distribution transformer on Vector's network

The load profile that occurs on two dates was selected based on the solar criteria discussed in the next sub-section. The dates occurred during the summer and winter. The selected winter date was 30/07/2012 and the summer date was 21/01/2012. All 10min kVA values for both dates from the original local distribution transformer profile, have been divided by a factor so that the normalised winter peak is at 3kVA. The load profile for the dates is shown in Figure 15.

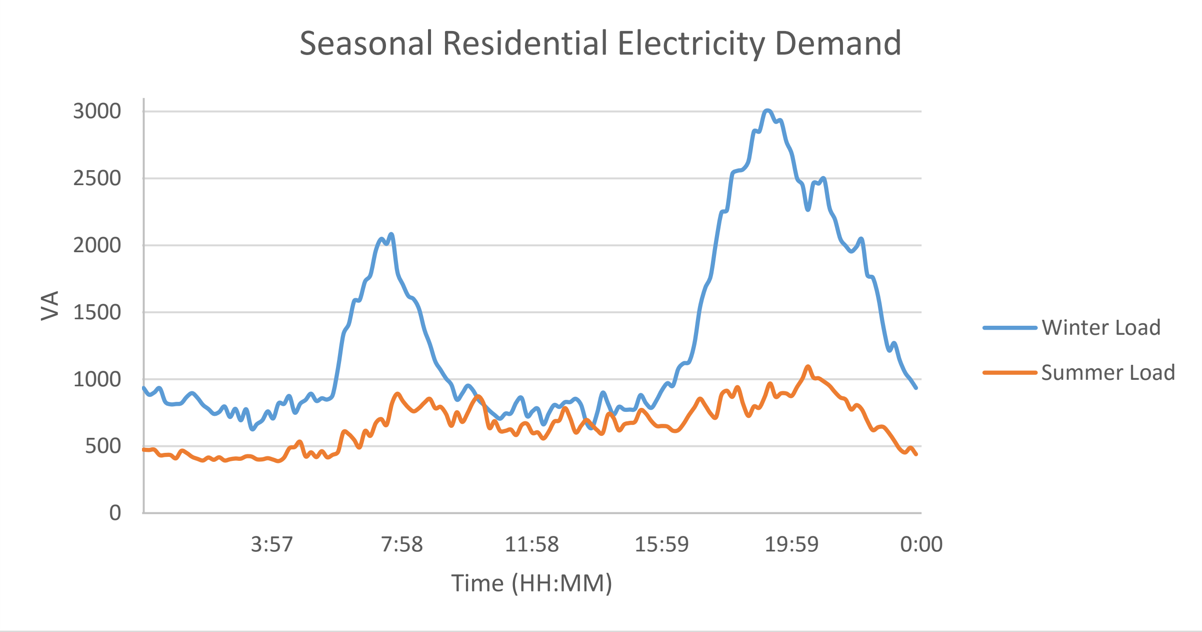


Figure 15: Used seasonal demand for simulation for thesis

The power factor was calculated by the author. This was to determine the varying resistive and inductive components used to describe the linear load. The power factor profile for the two days is shown in Figure 16.

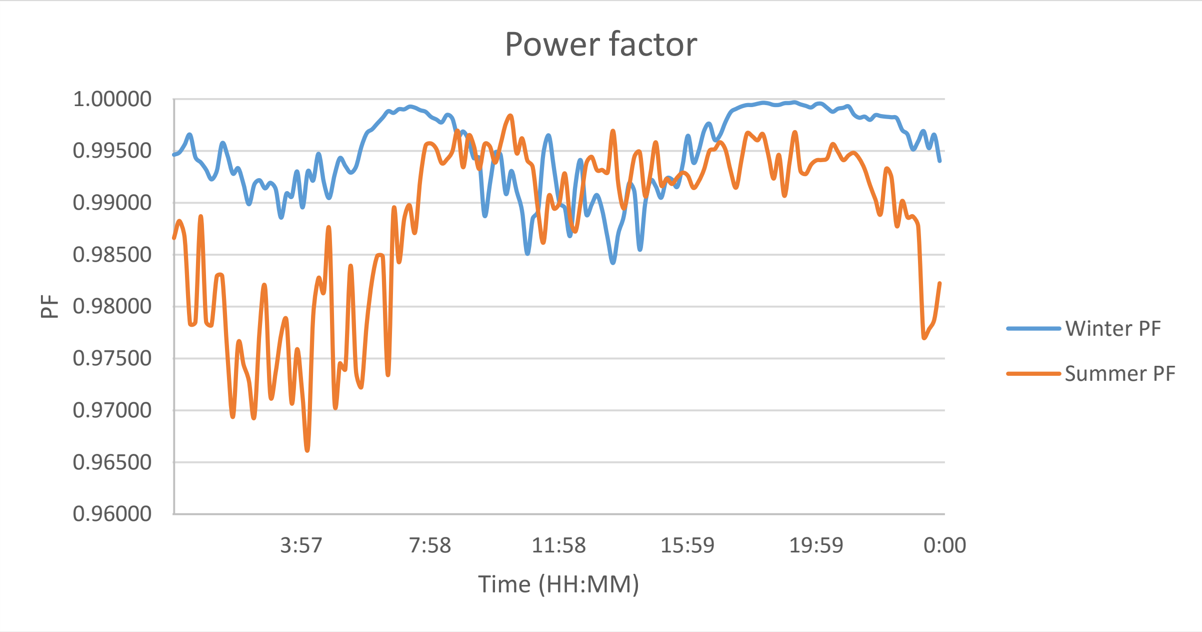


Figure 16: Dynamic power factor for seasonal demands

The resistive and inductive components were calculated assuming a voltage rating of 230V. Resistors and inductors dynamic values were calculated for each 10min interval and fed into equivalent programmable components in Matlab.

A total of nine loads were required based on the scenarios to be simulated and the generic model. A diagram portraying the electrical schematic is shown in Figure 17.

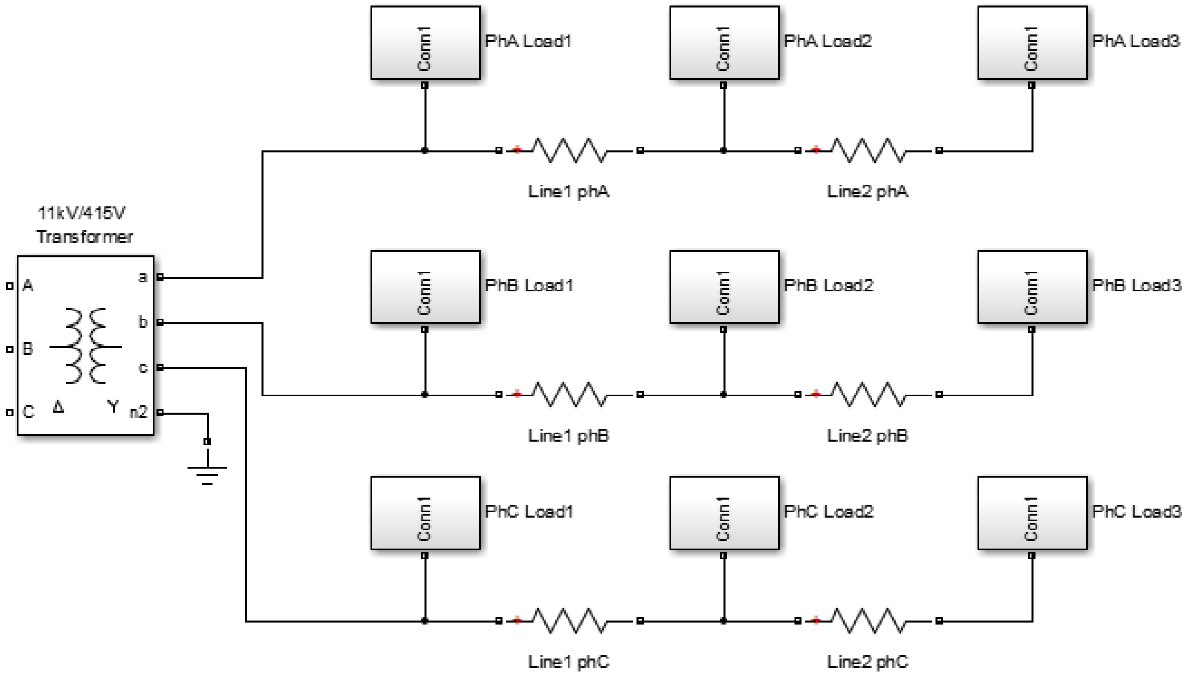


Figure 17: 3ph electrical schematic of LV network

3.4.4 Solar PV Injection Profiles

The injection profile for solar PV systems was calculated using equation (10). The values for sunrise time and sunset time were determined by using data obtained from the Royal Astrological Association in New Zealand. To simulate the best injection, the average longest day in summer was selected (see Table 7). To measure the injection during peak winter loading, the average shortest day in winter was selected (see Table 8).

Table 8: Sunset and sunrise times for summer in New Zealand

Date	Rise	Set	Time of Sunlight	Selected?
Jan-01	6:05	20:43	14:38	N
Jan-11	6:13	20:43	14:30	N
Jan-21	6:24	20:40	14:16	Y
Jan-31	6:35	20:33	13:58	N
Feb-10	6:46	20:24	13:38	N
Feb-20	6:56	20:12	13:16	N
Mar-02	7:06	19:59	12:53	N
Mar-12	7:16	19:45	12:29	N
Mar-22	7:25	19:30	12:05	N
Apr-01	7:34	19:15	11:41	N

Table 9: Sunset and sunrise times for winter in New Zealand

Date	Rise	Set	Time of Sunlight	Selected?
Jun-10	7:30	17:11	9:41	N
Jun-20	7:33	17:11	9:38	N
Jun-30	7:35	17:14	9:39	N
Jul-10	7:33	17:19	9:46	N
Jul-20	7:29	17:26	9:57	N
Jul-30	7:22	17:33	10:11	Y
Aug-09	7:12	17:41	10:29	N
Aug-19	7:00	17:50	10:50	N
Aug-29	6:47	17:58	11:11	N

The standard solar irradiation and PV current injection profile follow an inverse bell curve dictated by the equation described below. When there is no sunlight the current output is held at 0.

$$y = a\,(x - h)^2 + k \tag{10}$$

Where;

y = Current injection

a = Dictates the width of the bell curve i.e. the amount of time that the sun is up. This will vary depending on season simulated.

h = the time at which max current injection is at its peak, i.e. sun irradiation is at its peak. This will change depending on the season simulated.

k = Peak of the inverse bell allowed, i.e. peak current injected by the solar panel into the system. This will be held constant regardless of seasonal changes.

The following equations were used to derive current injection profiles for summer and winter seasons. The resultant profiles are shown in Figure 18.

$y = 0.0095\,(x - (13{:}30))^2 + (3 \times \sqrt{2})$; y = 0 before 06:20 and after 20:40 (11)

$y = 0.018\,(x - (12{:}30))^2 + (3 \times \sqrt{2})$; y = 0 before 07:20 and after 17:20 (12)

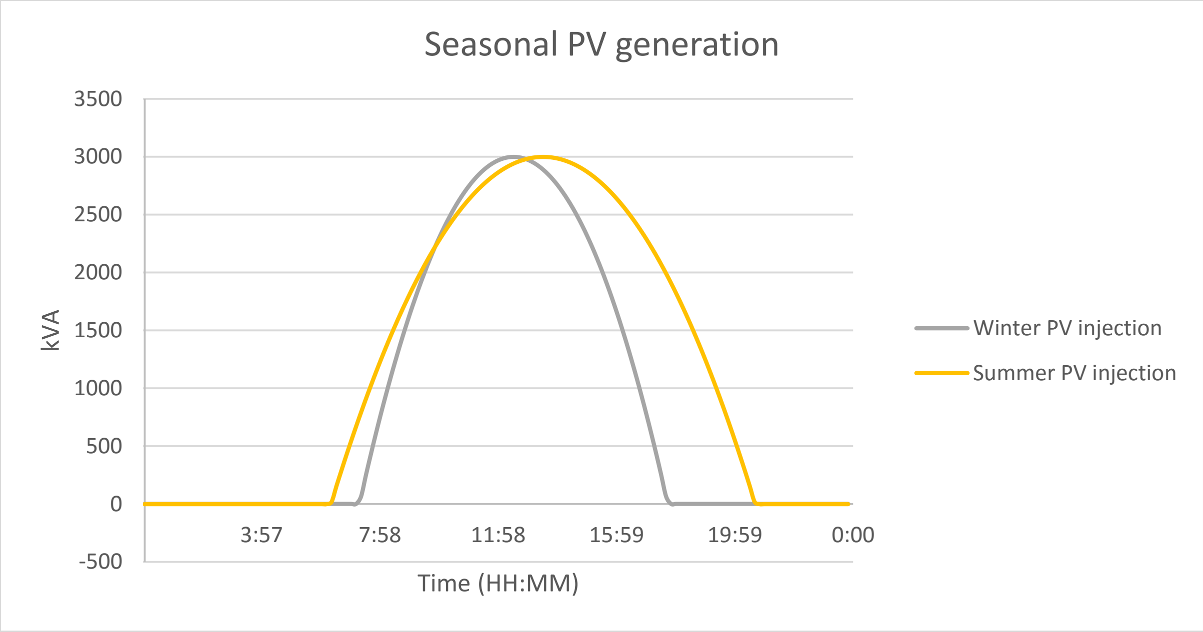


Figure 18: Seasonal PV injection profiles

Solar PV injection was added to the generic model by using a programmable AC current injection source that varies with respect to time. The value for injection was calculated at each 10min time interval.

3.4.5 Reactive Power Control

The phase shift required to compensate for voltage swell caused by PV injection was calculated at 10min intervals. The phase shift requirements were directly fed into the AC current source based PV injection module. This is because an inverter was not simulated. The inverter added complexity to the model, which drastically slowed down simulations and produced the same results seen in section 4.

Reactive power was injected only if the injected PV real power exceeded the local real power demand. The phase shift was varied depending on the difference between the local demand for real power and generated PV power. The methodology for calculating phase shift for each 10min interval is shown by the equations (13), (14) and (15).

$$I = W\angle Z^\circ = x + jy \qquad (13)$$

$$y = I_{PV} - I_R;\, x = I_R; \qquad (14)$$

$$Z^\circ = tan^{-1}\left(\frac{y}{x}\right) \qquad (15)$$

Where;

I_{PV} = Real PV injected current

I_R = Real residential demand

Z° = required phase shift of PV for regulating voltage at injection node.

The reactive power control profiles were varied and were dependent on the seasonal loading changes. The resultant plots for each season can be seen in Figures 19 and 20.

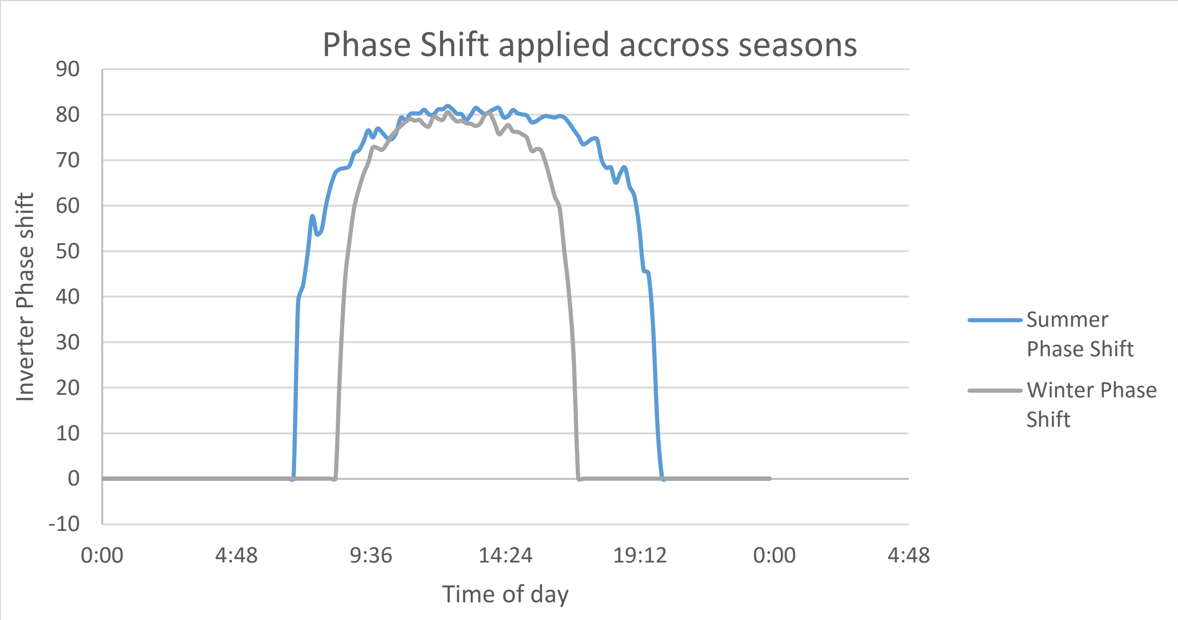


Figure 19: Phase shift plots for summer and winter

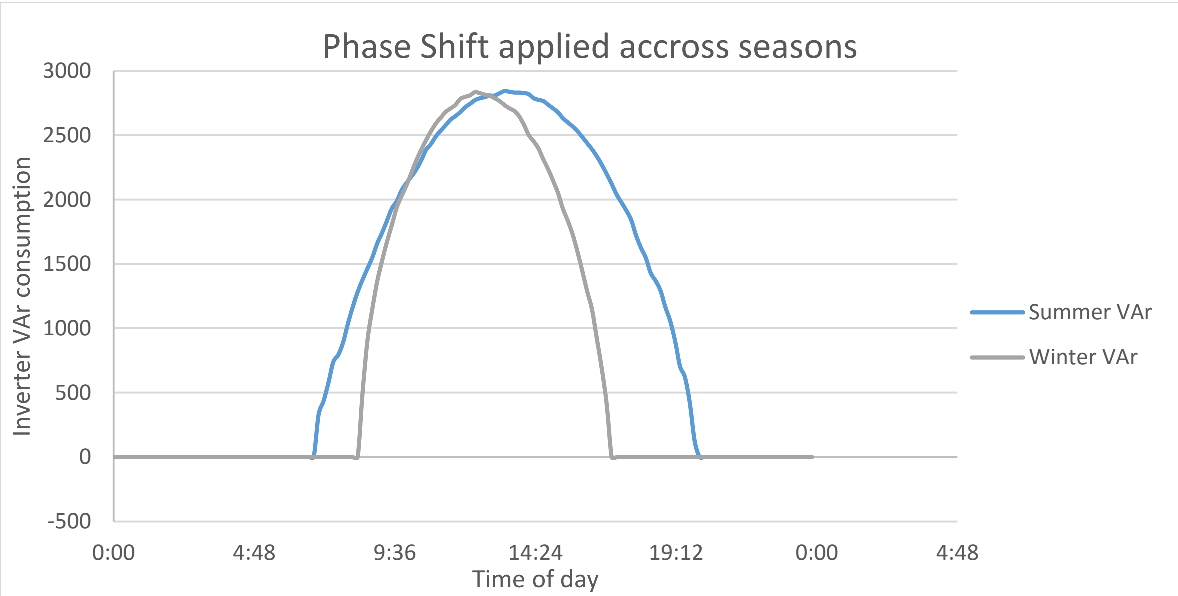


Figure 20: VAr consumption by inverter

3.4.6 Battery Storage System

The battery storage system was modelled as a current injection and consumption source. The electrical location of the battery system was at the same place as the injection of PV. The consumption and injection profiles of the battery were dependant on the season. The methodology used for battery control is shown in Tables 9 to 12. The conditions specified in the table were followed regardless of seasonal changes.

Table 10: Relationship between power source for the load and condition during no battery restrictions

	Condition #				
Power source:	[1]	[2]	[3]	[4]	[5]
Grid	√				
PV			√		
Batt					√
Grid + PV		√			
PV + Batt				√	

Table 11: Explanation of conditions during a no restriction on battery environment

Condition #	**Explanation**
[1]	Time between the start of the simulation (00:00 hours) and sunrise; Or When the battery doesn't have any charge and there is no PV injection
[2]	Time between sunrise and while PV generation is less than residential demand
[3]	When PV generation and residential demand are equal
[4]	When PV generation is greater than residential demand (charge is consumed by battery) Or When PV generation is less than residential demand and there is charge in the battery (battery discharges the difference in demand)
[5]	Battery has enough charge to support the load fully and there is no PV generation available

Table 12: Relationship between power source for the load and condition using Tesla Powerwall restrictions

	Condition #						
Power source:	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Grid	√						
PV			√				
Batt						√	
Grid + PV		√					
PV + Batt				√			
PV + Grid + Batt					√		
Grid + Batt							√

Table 13: Explanation of conditions using Tesla Powerwall restrictions

Condition #	**Explanation**
[1]	Time between the start of the simulation (00:00 hours) and sunrise <u>Or</u> When the battery doesn't have any charge and there is no PV injection
[2]	Time between sunrise and while PV generation is less than residential demand
[3]	When PV generation and residential demand are equal
[4]	When PV generation is greater than residential demand (charge is consumed by battery) <u>Or</u> When PV generation is less than residential demand and there is charge in the battery (battery discharges the difference in demand)
[5]	Battery doesn't have the ability to store all of the excess charge produced by PV generation <u>Or</u> PV generation and peak battery output is not enough to support the residential load and requires the grid to do so
[6]	Battery has enough charge to support the load fully and there is no PV generation available
[7]	Battery doesn't have enough charge to support the load fully and requires partial support from the grid

Tables 9 and 10 are applicable to a battery which is not constrained by either capacity or maximum current ratings. Whereas Tables 11 and 12 are applicable where restrictions are imposed.

Equations (13) – (16) are used to calculate the battery profile discharge and charge characteristics for each 10min interval. Separate equations are used to calculate the profile for a battery with and without any restrictions. Equations (14) and (16) describe periods where restrictions are imposed.

$$I_{charge} = I_{PV} - I_{Residenance} \qquad (13)$$

Only if charge capacity is less than 100%

$$I = I_{PV} - I_{Residenance};\ If\ I > 8.6A\ then\ I_{charge} = 8.6\ A;\ otherwise\ I_{charge} = I \qquad (14)$$

$$I_{discharge} = I_{Residenance} \qquad (15)$$

Only if charge capacity is greater than 0%

$$If\ I_{Residenance} > 8.6A\ then\ I_{discharge} = I_{Residenance};otherwise\ I_{discharge} = 8.6A \qquad (16)$$

Once the battery profile was calculated (based on the forecasted loading) for each 10min interval, it was found that the maximum current requirements didn't exceed the maximum restrictions imposed by the Tesla specifications. However, the capacity of the Tesla unit would be breached during the summer season (see Figures 21 and 22).

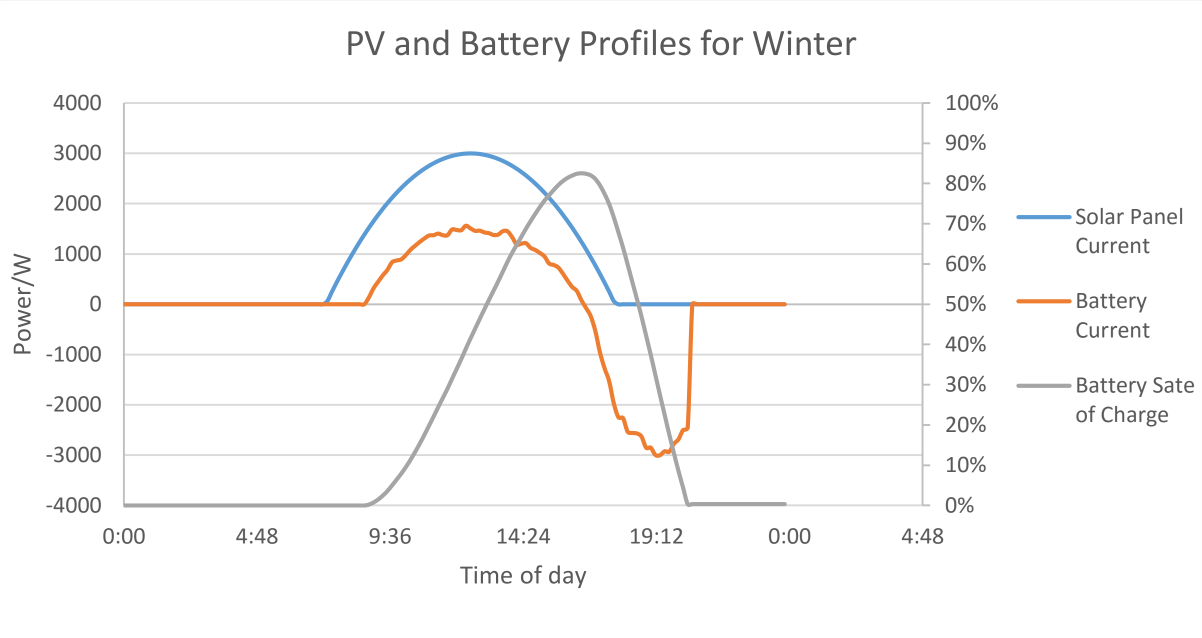


Figure 21: Winter charge and discharge profile with State of Charge throughout the day for battery

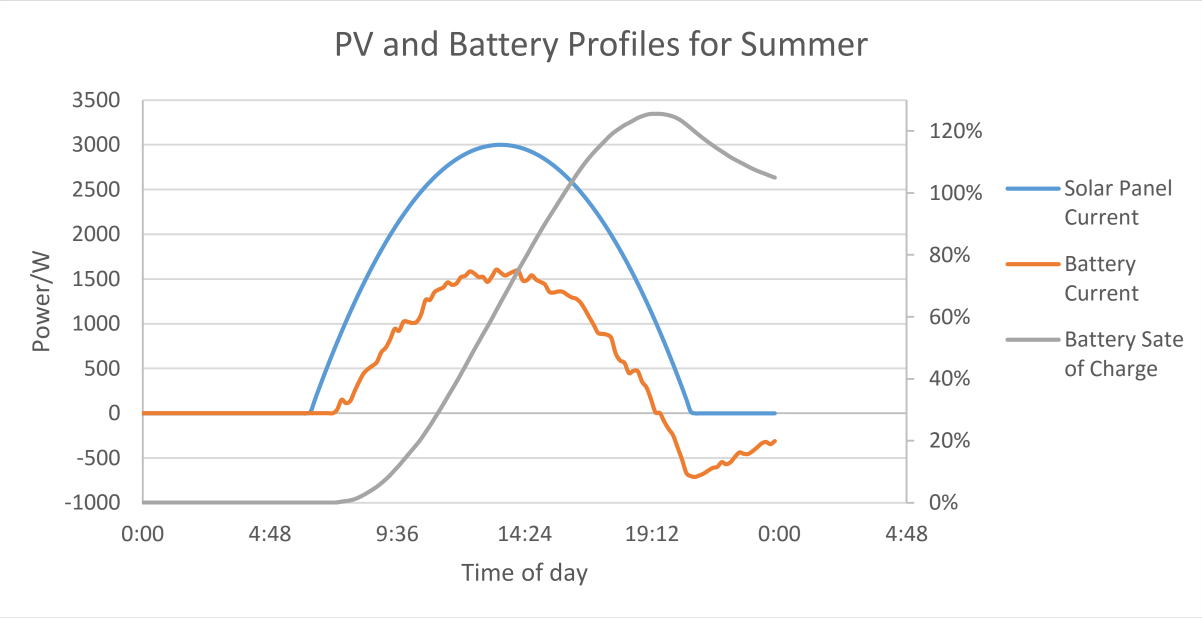


Figure 22: Summer charge and discharge profile with State of Charge throughout the day for battery

3.4.7 Single Phase Micro-Grid

The single phase micro-grid consists of two LV interconnecting breakers and one battery. Both breakers were located on the terminals on the LV side of the MV/LV transformer. One breaker disconnected the MV grid and then other interconnected all three phases, forming a single phase for the LV network.

The size and absorption/discharge profiles of the battery bank and switching timings of the breakers is provided by Figures 23 and 24. The breaker switching is denoted as 1s and 0s. The 1s describe when the system is connected to the grid in three phase mode, and the 0s describe the change to single phase micro-grid mode. The philosophy adopted for calculating the times of breaker switching and storage requirements were calculated based on the following methodology:

- The breakers were cycled between single phase mode and back to grid mode only once daily.
- Switching between the modes would occur when:
    - Grid connected → Grid Isolated: When Tx'fer LV terminal current <= 0A
    - Grid isolated → Grid connected: When voltage PV or battery or a combination of both can no longer support the load of the LV network.

The positioning and number of phases of the battery bank was not fixed, unlike in Section 3.4.6. This was because in a community type environment, it is not necessary to place the battery bank at the point of PV injection, seeing as the battery is not owned by a single customer.

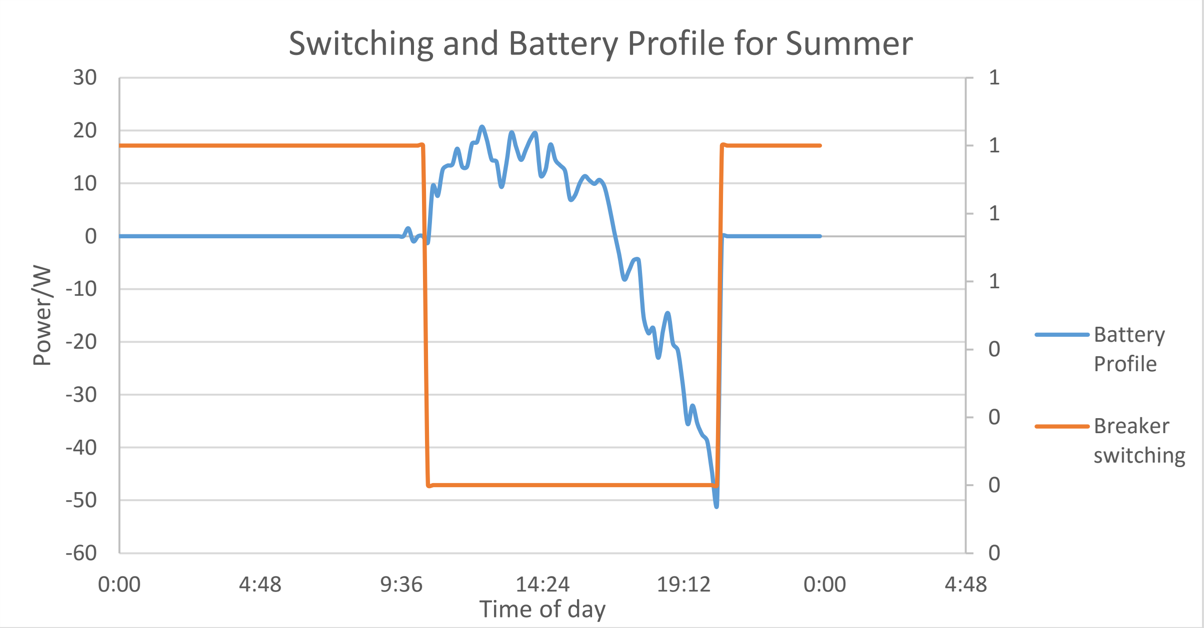


Figure 23: Dynamic battery profile and switching timings for a single phase micro-grid during summer

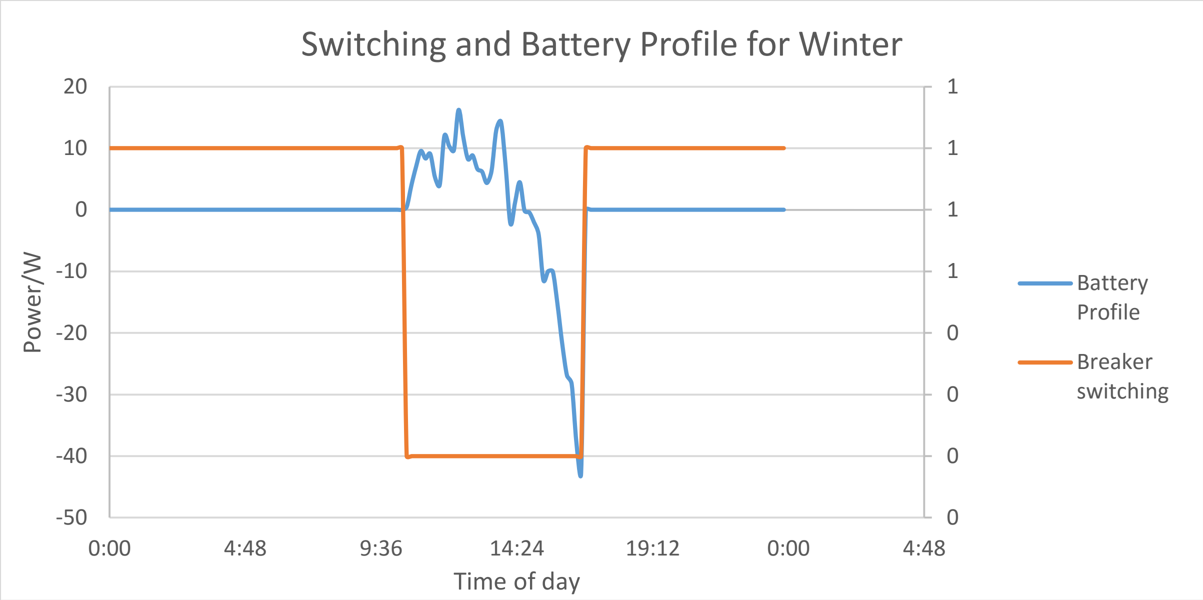


Figure 24: Dynamic battery profile and switching timings for a single phase micro-grid during winter

3.4.8 Voltage & Current Measurements

Voltages were measured at each electrical node on the network. This was to measure the magnitude of overvoltage and voltage sag with reference to distance from the local distribution transformer. Voltage imbalance was calculated using the same methodology discussed in section 2.1. The imbalance was calculated in real-time at each node on the LV network. Measurements of injected and consumed current at each electrical node were also captured. This was done to observe the relationship between current, voltage imbalance, overvoltage and sag.

For both voltage and current measurements, only the RMS values have been plotted.

CHAPTER 4: RESULTS AND FINDINGS

The results section of this thesis are split into four major sub-sections. The first sub-section aims to describe the depth of voltage imbalance, overvoltage and voltage sag that could possibly occur on the generic LV network. Figure 9 is used as a reference; it shows the different types of parameter variations that were implemented to produce certain results.

The following sub-sections plan to mitigate the issues through the additions of the prescribed solutions, i.e. reactive power control, addition of battery and single-phase micro-grids.

Each scenario is structured in the following style:

1. Introduced with schematics that were produced in Matlab Simulink package.
2. Simulations of the dynamic voltage profile and/or imbalance results.
3. Brief summary of observations per simulation.

The purpose of this structure is to provide a standardisation of results for easy comparison across all of the simulated scenarios.

4.1 VOLTAGE ISSUES IN LV GENERIC MODEL

The first simulation conducted was to assess voltage without PV injection. Each component seen in the schematics below has been justified in section 3. The parameter selections made are shown in Figure 26. The SLD is provided below.

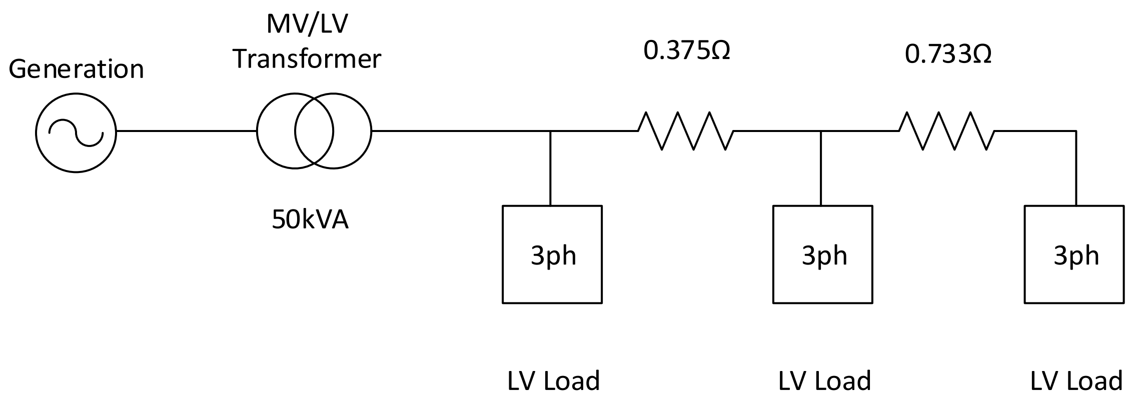


Figure 25: SLD for the base-line simulations

It can be observed that there is no PV unit shown above (see Figure 25), therefore no PV injection is being connected to the grid at this time. It is also observed that the MV grid simulated is under the assumption that the MV/LV transformer is located at the beginning of the MV feeder and the size of the transformer is 50kVA.

The voltage and current plots at each node of the LV network, and for each season, are shown on Tables 13 and 14. A summary table of the results is shown by Tables 15 and 16. In future simulations on the summary tables (i.e. method used for tables 15 and 16) are provided, full plots can be observed in the attached appendices. The table headings CN, MN and FN stand for: closest node, middle node and furthest node from the local distribution transformer.

Figure 26: Baseline simulations selection

Table 14: Winter plots for generic model

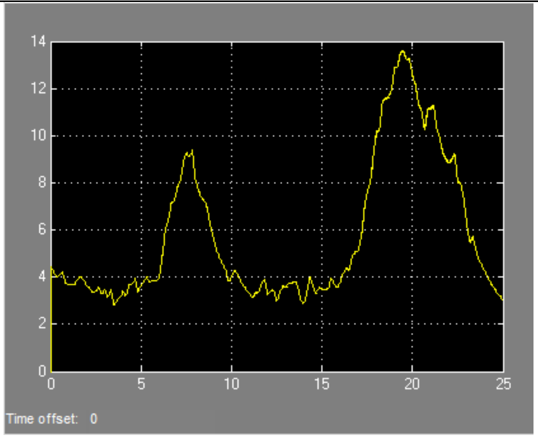
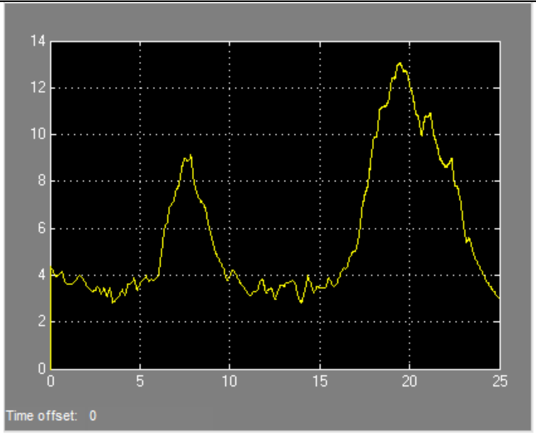
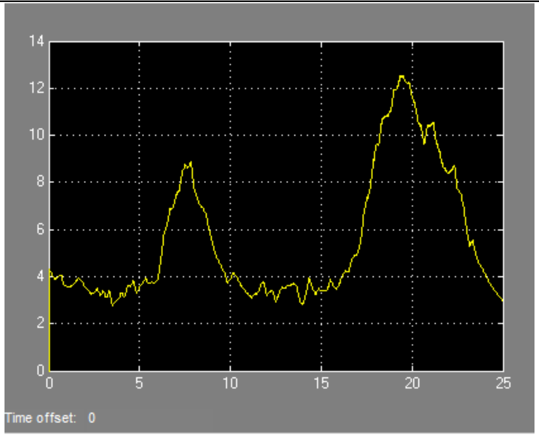
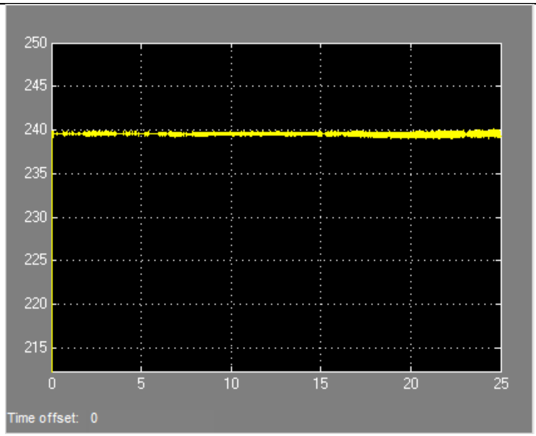
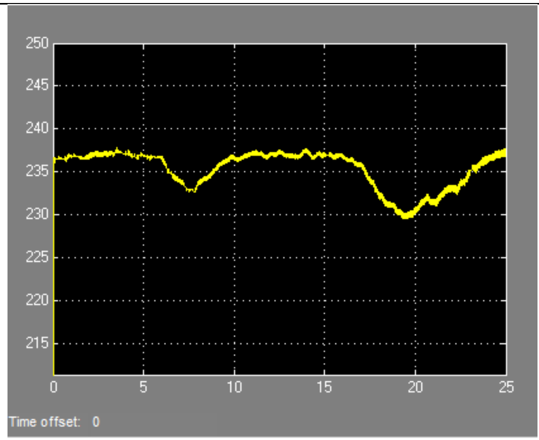
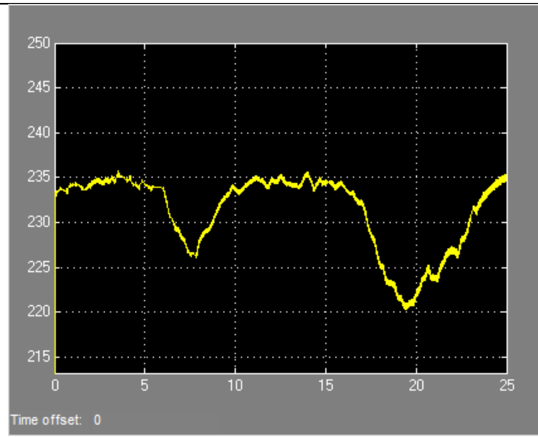
Winter	CN	MN	FN
Load (A)			
Volt (V)			

Table 15: Summer plots for generic model

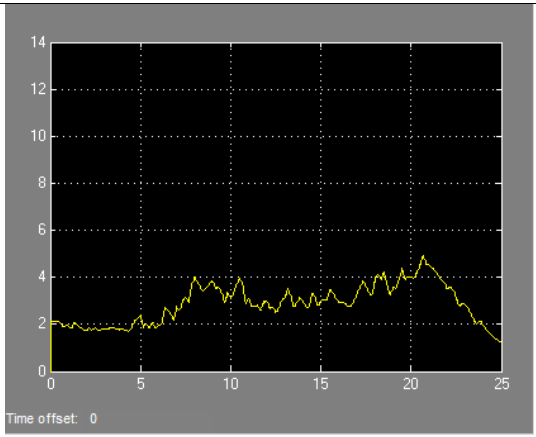
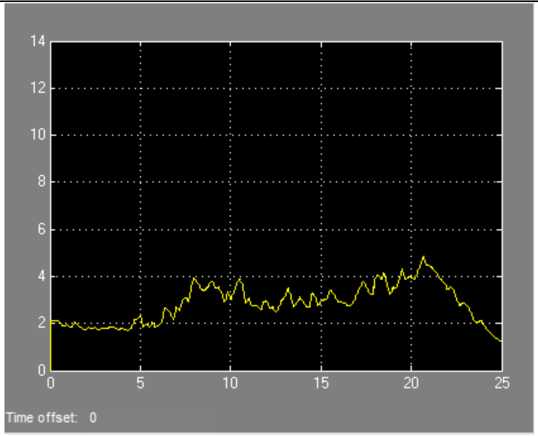
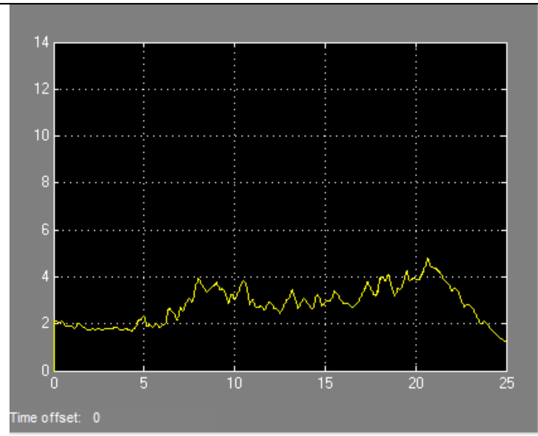
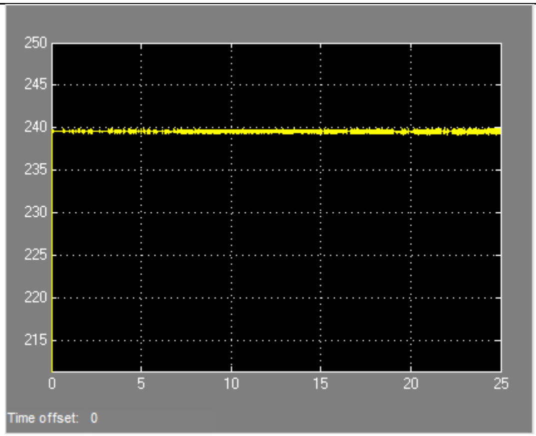
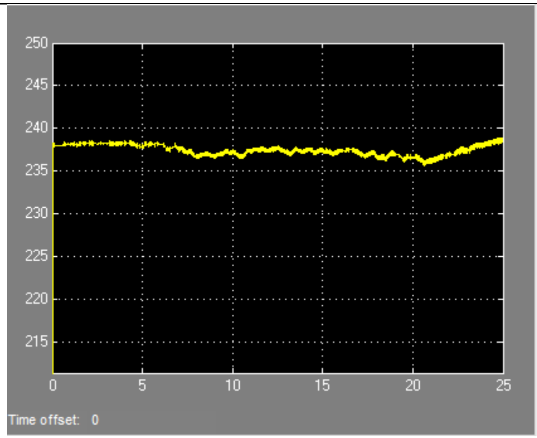
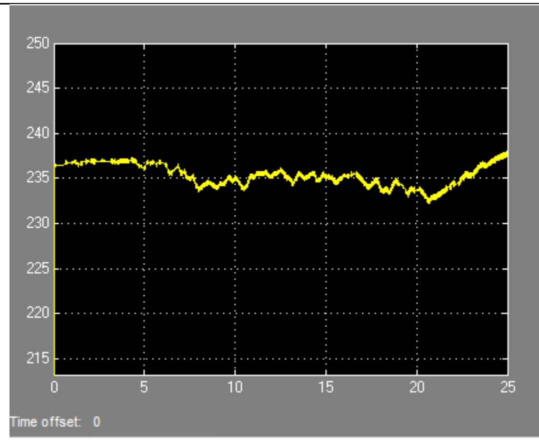
<table>
<tr><th>Summer</th><th>CN</th><th>MN</th><th>FN</th></tr>
<tr><td>Load (A)</td><td></td><td></td><td></td></tr>
<tr><td>Volt (V)</td><td></td><td></td><td></td></tr>
</table>

Table 16: Winter summary results for generic model

Winter	**No PV / V**
CN Voltages	Max: 240
	Min: 239
MN Voltages	Max: 237
	Min: 230
FN Voltages	Max: 235
	Min: 220

Table 17: Summer summary results for generic model

Summer	**No PV / V**
CN Voltages	Max: 240
	Min: 240
MN Voltages	Max: 238
	Min: 236
FN Voltages	Max: 237
	Min: 233

The above plots and summary tables show a difference in voltage and current consumed at each electrical location on the generic LV network. It can be seen that the lowest voltages are experienced at the furthest point from the MV/LV transformer, along with the greatest voltage deviation. A maximum deviation of 15V is noticed in the winter, compared to 4V deviation in the summer. It is also observed that the voltage is well regulated during the summer loading cycle and when loads are located close to the MV/LV transformer.

No imbalance profiles have been provided, because all three phases experience exactly the same voltage and current profiles.

4.1.1 Overvoltage and Voltage Sag Scenarios

This section of scenarios focuses on simulations specific to overvoltage and voltage sag. It was an attempt to derive the worst case for voltage regulation, through progressively adding complexity in the form of varying MV loads, reactive components and impedances on the generic LV network. Each conducted scenario and their simulations are provided below.

4.1.1.1 Scenario 1 – Adding PV injection

Scenario 1 introduces the addition of PV injection into the base case simulated above. The schematics and SLD are shown by Figures 27 and 28. Tables 17 and 18 display the summarised results. The red dots (and dashed lines in Figure 27) in the schematic symbolise the different connection points as the PV injection module is moved for the different simulations performed. The structure of the tables has also changed to display the plots in a matrix format. It now shows the voltage profiles at each location as the PV injection location is changed.

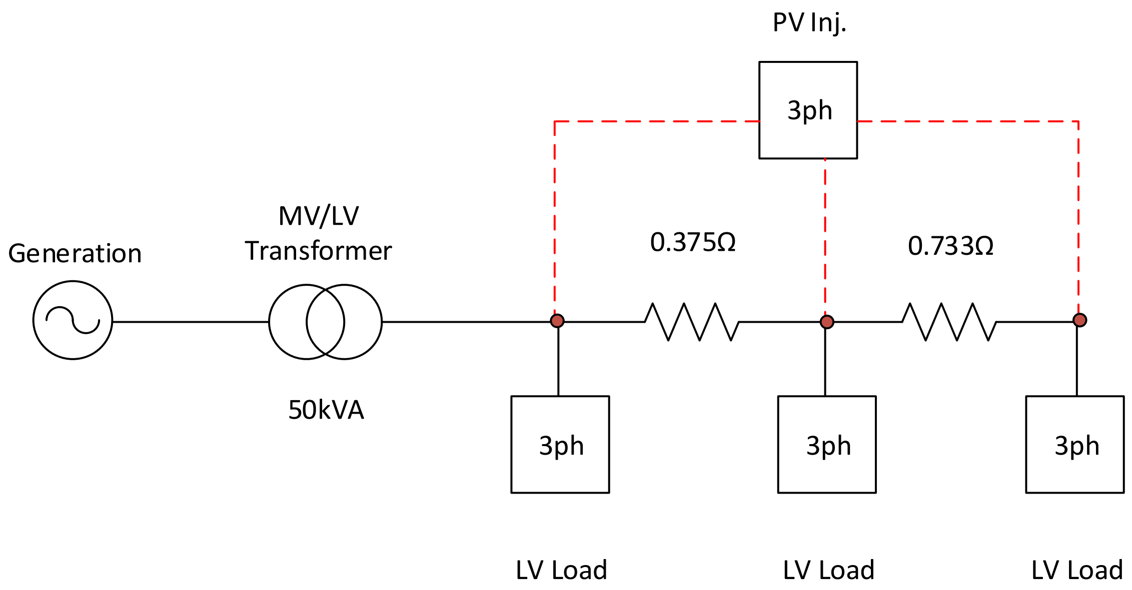


Figure 27: SLD of 3ph PV cluster connected at the same voltage node

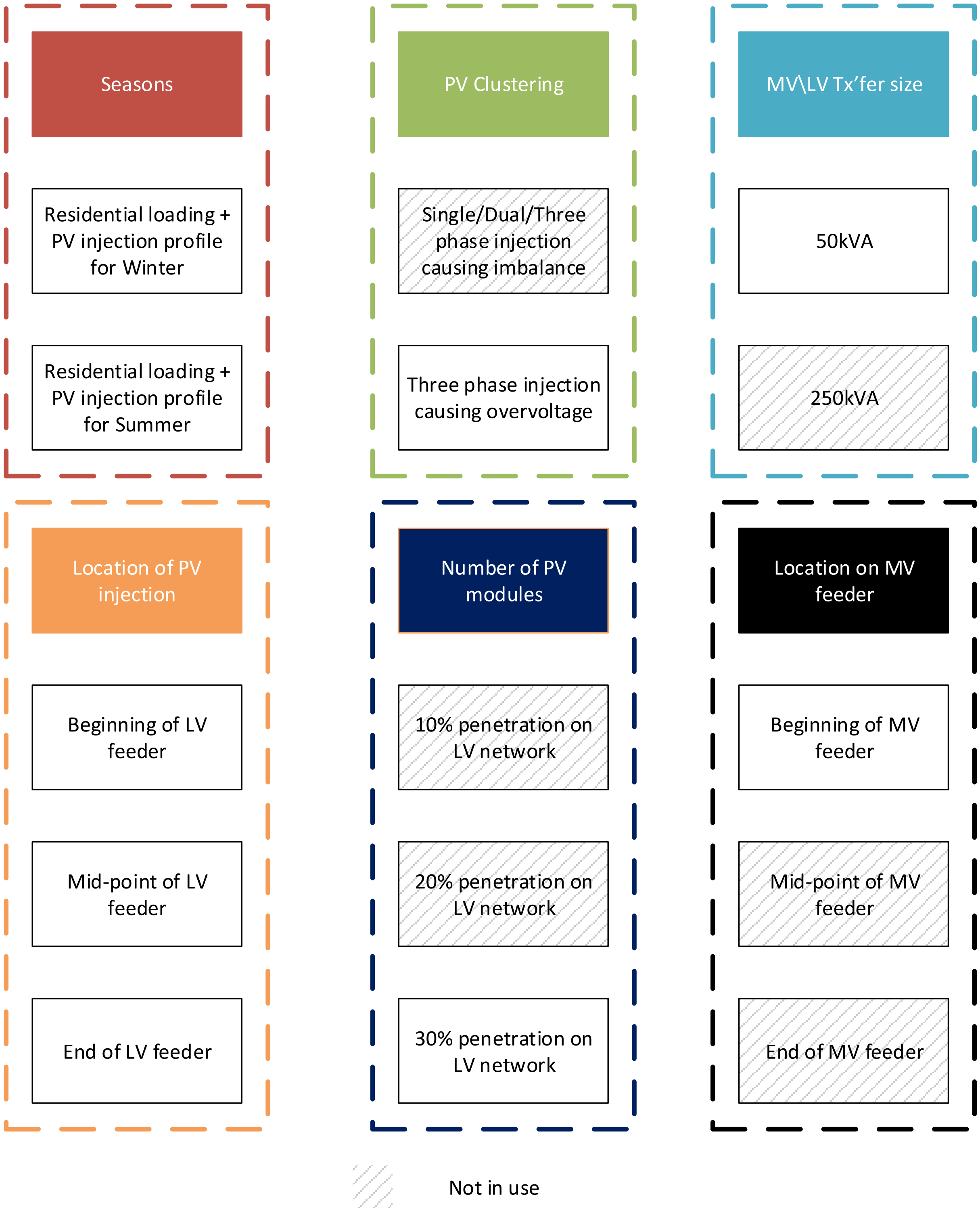


Figure 28: Addition of three phase PV cluster connected at the same voltage node

Table 18: Winter results for added PV injection

Winter	PV at CN / V	PV at MN / V	PV at FN / V
CN Voltages	Max: 240	Max: 240	Max: 240
	Min: 239	Min: 239	Min: 239
MN Voltages	Max: 237	Max: 242	Max: 242
	Min: 230	Min: 230	Min: 230
FN Voltages	Max: 235	Max: 240	Max: 249
	Min: 220	Min: 220	Min: 220

Table 19: Summer results for added PV injection

Summer	PV at CN / V	PV at MN / V	PV at FN / V
CN Voltages	Max: 240	Max: 240	Max: 240
	Min: 240	Min: 240	Min: 240
MN Voltages	Max: 238	Max: 243	Max: 243
	Min: 236	Min: 236	Min: 236
FN Voltages	Max: 237	Max: 241	Max: 250
	Min: 233	Min: 233	Min: 233

The influence of PV injection was examined and compared against the base case of the generic LV network in a dynamic environment. It was seen that the magnitude of overvoltage rose up to 250V. The duration of overvoltage was also seen to be influenced by the seasonal loading of both the LV network and PV injection. The duration of overvoltage was larger during the summer simulation. Lastly, it was noticed that when PV injection was added on the FN, the greatest overvoltage was experienced. PV injection on the CN had little to no effect at all the nodes on the LV network.

4.1.1.2 Scenario 2 – Changing MV/LV transformer size to 250kVA

The next simulation focuses the effect on voltage as transformer size and impedance was increased. The purpose of this simulation was to gain an understanding regarding the regulation effects of a transformer with a larger capacity. The schematic and results for the simulated case are shown in Figures 29, 30 and Tables 19 and 20 respectively.

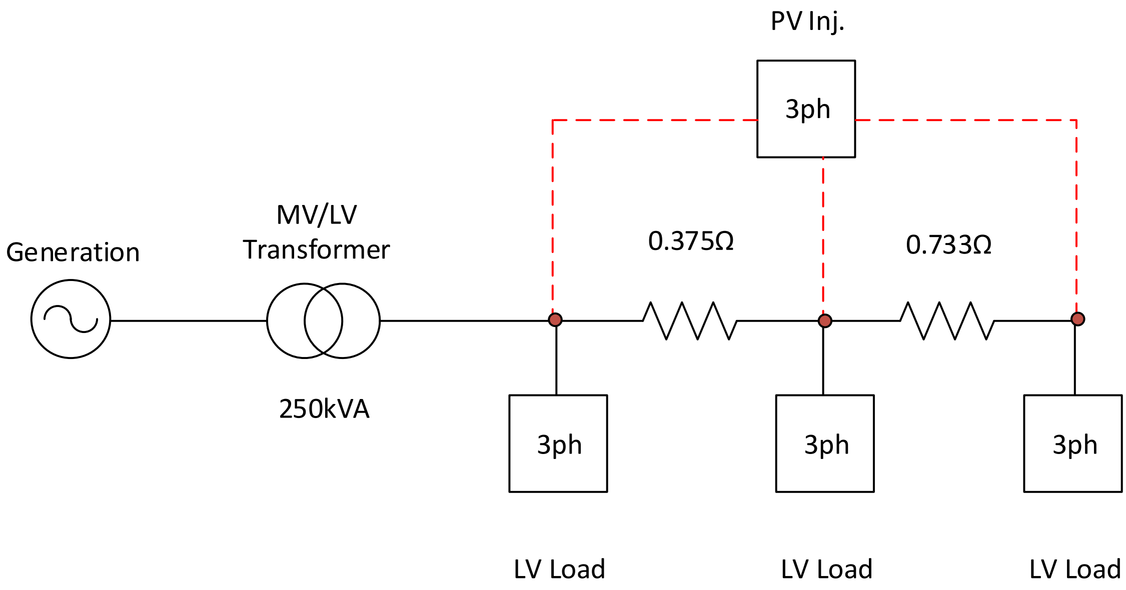


Figure 29: SLD of larger transformer scenario

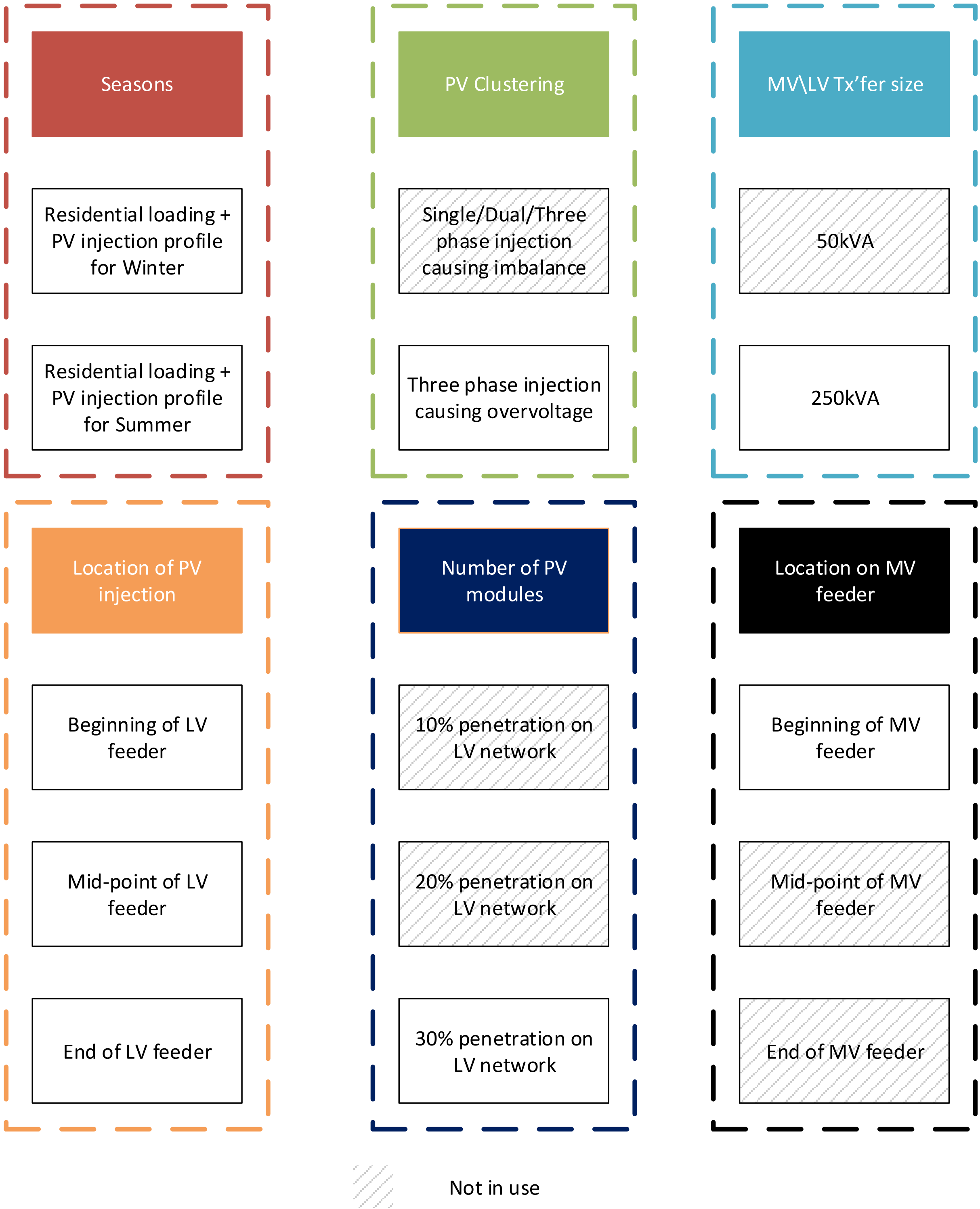


Figure 30: Parameter selection of changing transformer capacity

Table 20: Winter results for 250kVA transformer

Winter	PV at CN / V	PV at MN / V	PV at FN / V
CN Voltages	Max: 240	Max: 240	Max: 240
	Min: 239	Min: 239	Min: 239
MN Voltages	Max: 237	Max: 242	Max: 242
	Min: 230	Min: 230	Min: 230
FN Voltages	Max: 235	Max: 240	Max: 249
	Min: 220	Min: 220	Min: 220

Table 21: Summer results for 250kVA transformer

Summer	PV at CN / V	PV at MN / V	PV at FN / V
CN Voltages	Max: 240	Max: 240	Max: 240
	Min: 240	Min: 240	Min: 240
MN Voltages	Max: 238	Max: 243	Max: 243
	Min: 236	Min: 236	Min: 236
FN Voltages	Max: 237	Max: 241	Max: 250
	Min: 233	Min: 233	Min: 233

Little to no difference was observed relating to voltage profiles. Therefore, it was concluded that transformer capacity had no effect on the voltage profile of the LV network.

4.1.1.3 Scenario 3 – Adding LV line inductance

The previous two simulations were conducted under the assumption that the LV line reactive components were negligible. To understand if this was true, a scenario was simulated with the added proportional line reactance values. The SLD is shown by Figures 31. Tables 21 and 22 provide the results.

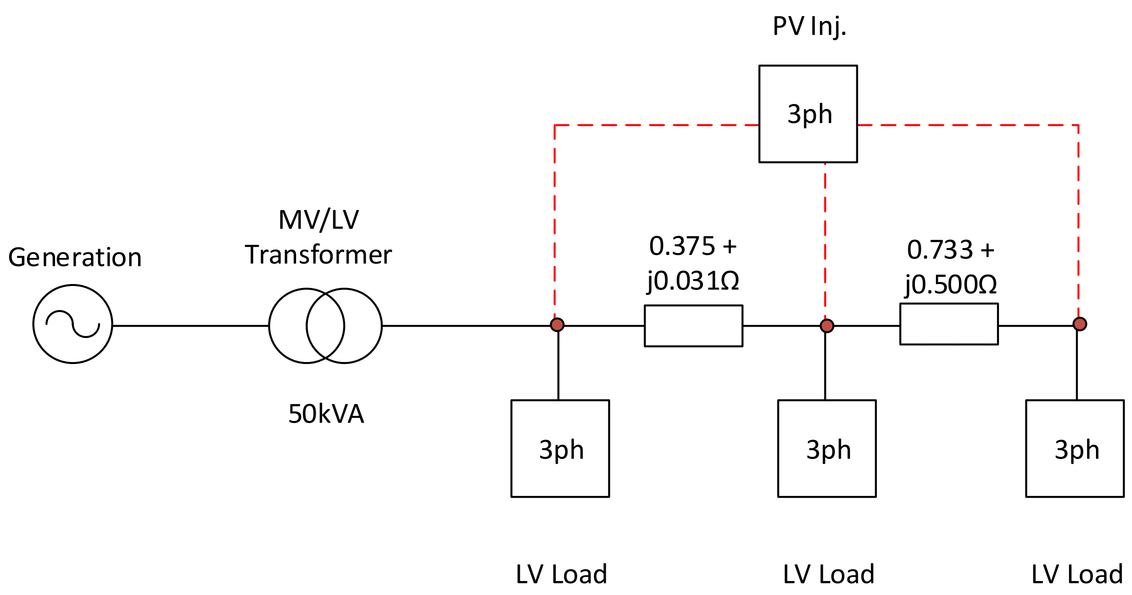


Figure 31: SLD for the change in LV line resistance to LV line impedance

Table 22: Winter results for LV line reactance

Winter	PV at CN / V	PV at MN / V	PV at FN / V
CN Voltages	Max: 240	Max: 240	Max: 240
	Min: 239	Min: 239	Min: 239
MN Voltages	Max: 237	Max: 242	Max: 242
	Min: 230	Min: 230	Min: 230
FN Voltages	Max: 235	Max: 240	Max: 249
	Min: 220	Min: 220	Min: 220

Table 23: Summer results for LV line reactance

Summer	PV at CN / V	PV at MN / V	PV at FN / V
CN Voltages	Max: 240	Max: 240	Max: 240
	Min: 240	Min: 240	Min: 240
MN Voltages	Max: 238	Max: 243	Max: 243
	Min: 236	Min: 236	Min: 236
FN Voltages	Max: 237	Max: 241	Max: 250
	Min: 233	Min: 233	Min: 233

Again, a negligible difference was seen. Therefore, the proceeding scenarios were simulated without the consideration of reactance and with a fixed transformer rating of 50kVA.

4.1.1.4 Scenario 4 – Changing the MV network to mid-point of MV feeder

The next scenario aids in gauging the magnitude of sag that is permissible on a network given a parallel load along with MV line impedances. The simulation conducted in this scenario describes the voltage profiles on the LV network, if the LV network was located mid-way along a MV feeder (see Figures 32, and 33).

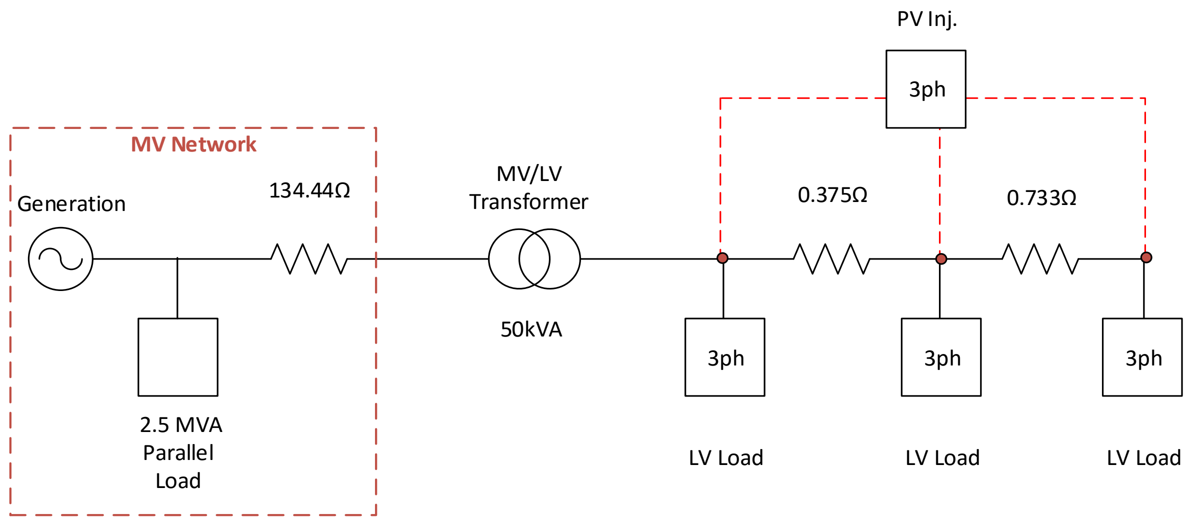


Figure 32: SLD for LV network located at the mid-point of MV feeder scenario

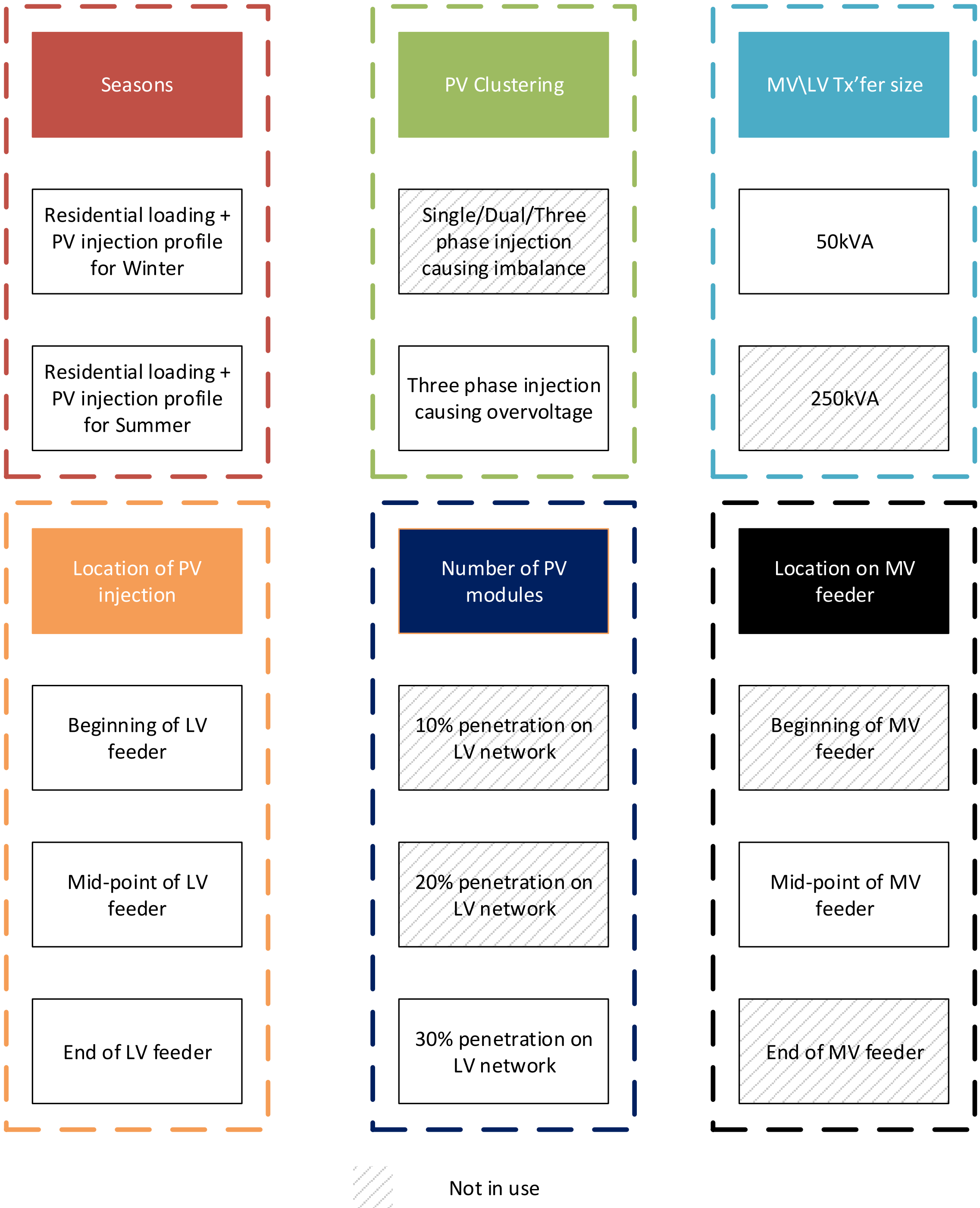


Figure 33: Parameter selection for simulation of MV feeder mid-point

Table 24: Winter results for MV feeder mid-point

Winter	**PV at CN / V**	**PV at MN / V**	**PV at FN / V**
CN Voltages	Max: 240	Max: 240	Max: 240
	Min: 228	Min: 228	Min: 228
MN Voltages	Max: 237	Max: 242	Max: 242
	Min: 220	Min: 220	Min: 220
FN Voltages	Max: 235	Max: 240	Max: 249
	Min: 209	Min: 209	Min: 209

Table 25: Summer results for MV feeder mid-point

Summer	**PV at CN / V**	**PV at MN / V**	**PV at FN / V**
CN Voltages	Max: 240	Max: 240	Max: 240
	Min: 235	Min: 235	Min: 235
MN Voltages	Max: 238	Max: 243	Max: 243
	Min: 233	Min: 233	Min: 233
FN Voltages	Max: 237	Max: 241	Max: 250
	Min: 228	Min: 228	Min: 228

From the results captured above (see Tables 23 and 24), it can be seen that the voltage sag observed for both seasons have drastically deteriorated. With a peak voltage of 250V and a sag of 209V. The 209V is experienced during the peak winter load, however, this can't be seen on the graph due to the scaling. Fluctuations in voltage were also now more prominent at the CN, which were not evident in prior simulations.

4.1.1.5 Scenario 5 – Changing the MV network to end-point of MV feeder

This scenario acts as an extension of the previous. It shows the resultant voltage sag seen on the LV network as a result of it being located at the end of a MV feeder (see Figures 34, and 35). This scenario describes the 11kV limits set by the EA (Electricity Authority) in their *Power Quality Guidelines* document (2012).

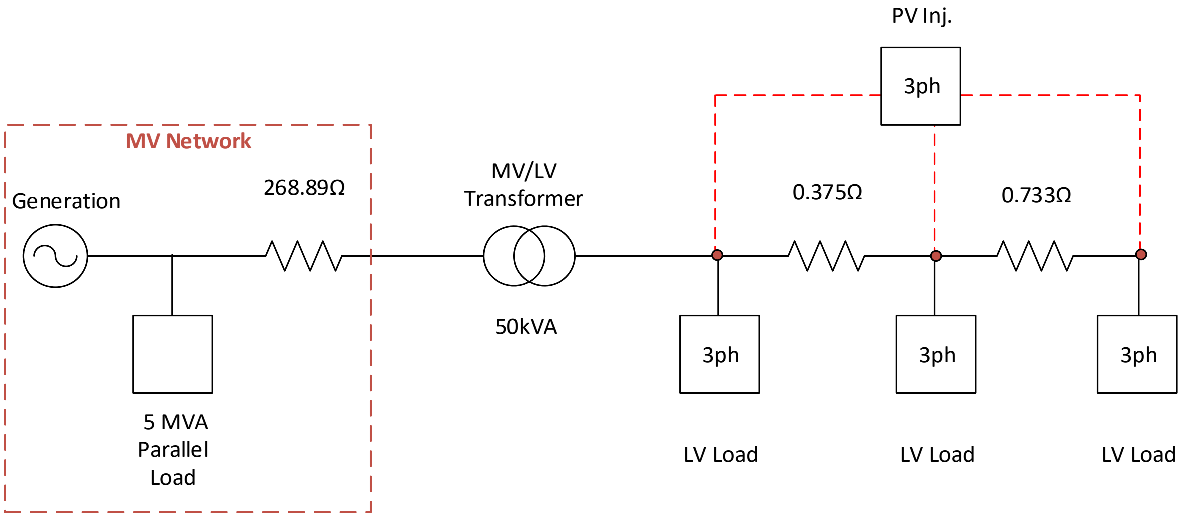


Figure 34: LV network located at the end of MV feeder scenario

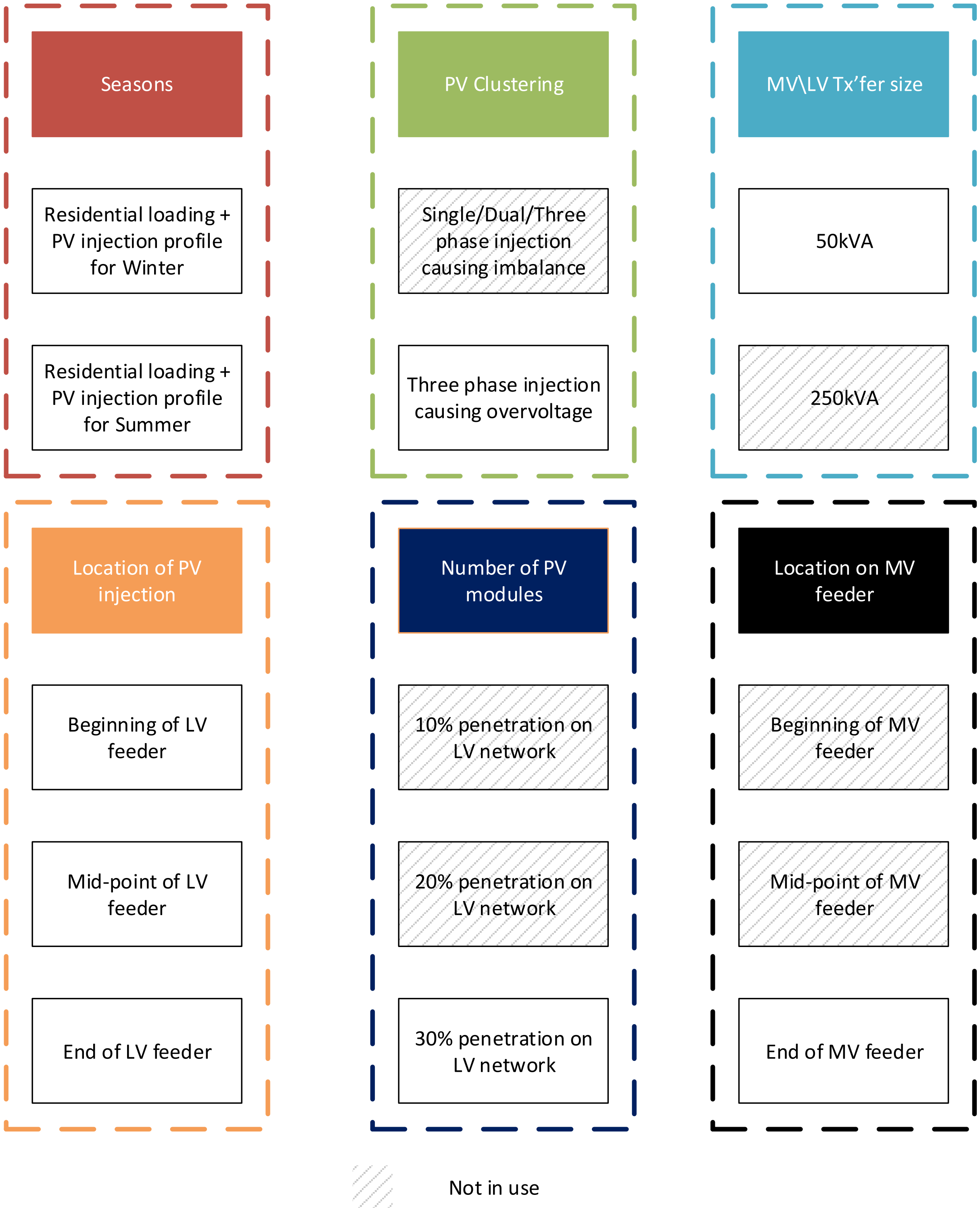


Figure 35: Parameter selection for simulation MV feeder mid-point

Table 26: Winter results for MV feeder end-point

Winter	PV at CN / V	PV at MN / V	PV at FN / V
CN Voltages	Max: 240	Max: 240	Max: 240
	Min: 218	Min: 218	Min: 218
MN Voltages	Max: 237	Max: 242	Max: 242
	Min: 209	Min: 209	Min: 203
FN Voltages	Max: 235	Max: 240	Max: 249
	Min: 200	Min: 200	Min: 200

Table 27: Summer results for MV feeder end-point

Summer	PV at CN / V	PV at MN / V	PV at FN / V
CN Voltages	Max: 240	Max: 240	Max: 240
	Min: 232	Min: 232	Min: 232
MN Voltages	Max: 238	Max: 243	Max: 243
	Min: 228	Min: 228	Min: 228
FN Voltages	Max: 237	Max: 241	Max: 250
	Min: 225	Min: 225	Min: 225

It was hypothesised from the previous scenario, that the voltage sag would become worse. The sag of the MP during winter is now 209V and sag at the FN is 200V (see Tables 25 and 26). It can, therefore, be surmised, that according to the EA guidelines, it is very difficult to achieve voltage regulation within +/- 6% LV network threshold, if the absolute maximum feeder lengths are applied for the MV network.

4.1.2 Imbalance

The focal point for the selection of scenarios covered in this section was voltage imbalance. In the following scenarios, complexity was added through the means of varying the number of connected PV units and the different electrical nodes that they connect to on the LV network.

4.1.2.1 Scenario 6 – Effect of PV cluster on a single phase

The first imbalance scenario introduced a one, single phase, PV unit and varies its electrical injection point. The purpose of this was to evaluate the effect on imbalance if only one house uses a PV unit. The influence of distance of the MV grid was ignored, because a voltage deviation in the MV grid would result in a balanced voltage deviation on the LV grid resulting in no imbalance.

Unlike the previous simulations, the plots provided below express the phase to phase difference in voltage as a percentage, rather than a voltage profile. This is because the type of injection now resulted in a RMS voltage offset on one or more phases which resulted in imbalance. The value of 1 on the y-axis means all voltages across all phases were the same; the value 1.1 means that there was an imbalance of 10%. The MV/LV transformer current and voltage wave forms are also provided, for added discussion. Summary tables have also been constructed to provide a simplistic viewpoint and are used henceforth to describe imbalance magnitudes.

The SLDs, schematics and scenario built are shown by Figures 36 and 37. Results are shown in Tables 27 - 32.

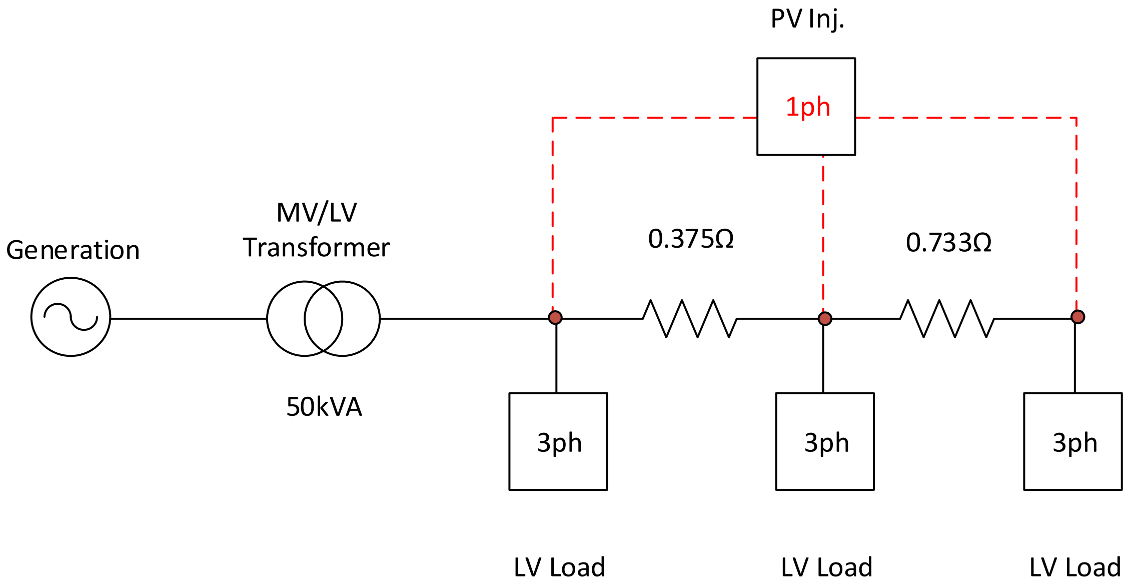


Figure 36: SLD of single phase cluster of PV on generic LV network

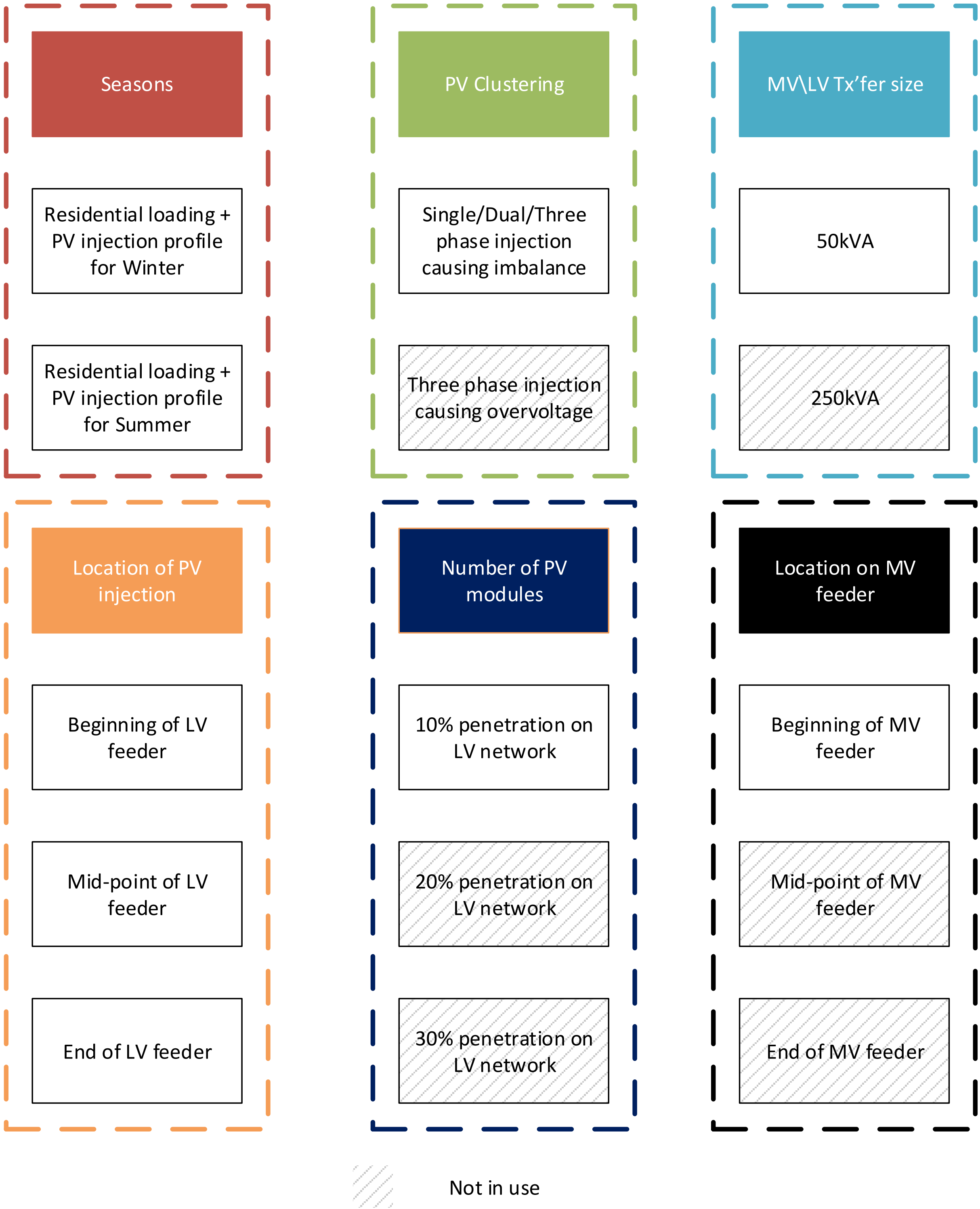


Figure 37: Parameters selected for simulation of single phase PV injection

Table 28: Winter plots imbalance plots for single phase PV injection

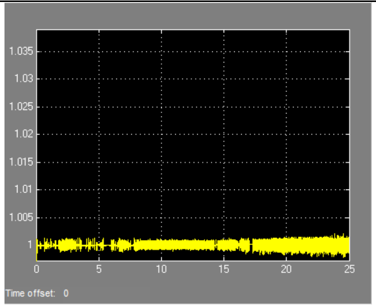
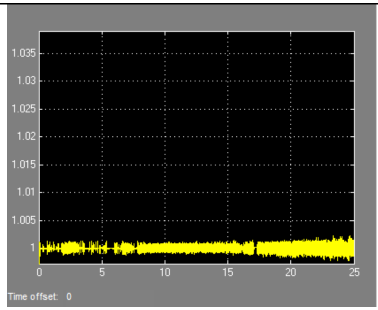
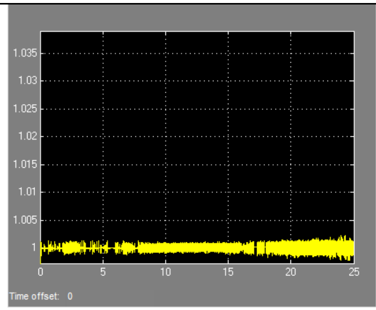
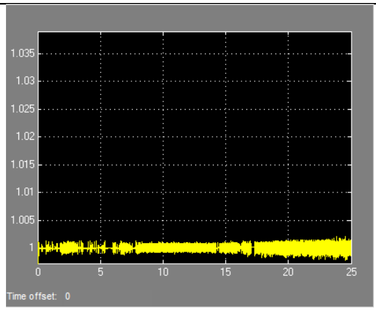
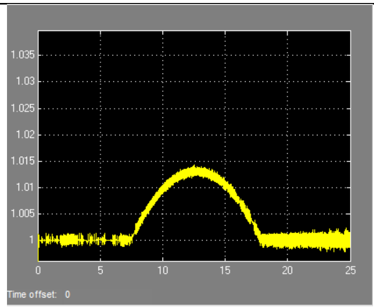
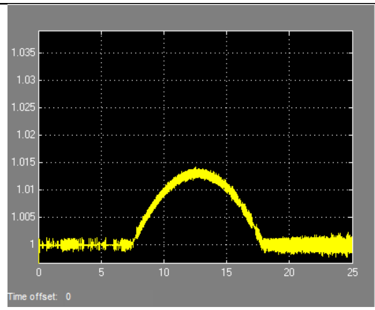
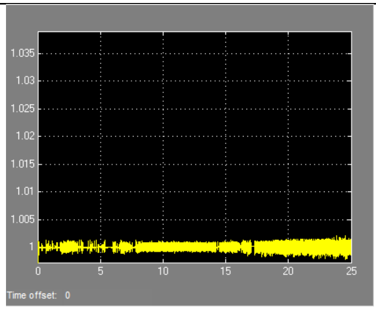
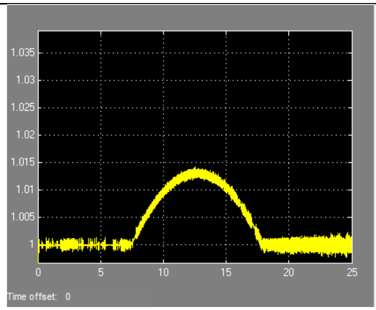
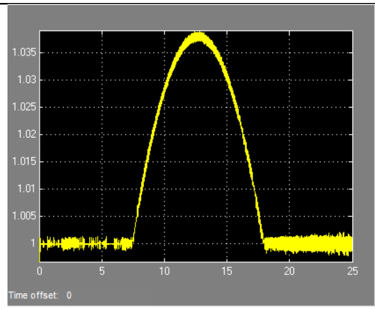
Winter	PV at CP	PV at MP	PV at FP
CP voltage profile			
MP voltage profile			
FP voltage profile			

Table 29: Summer plots imbalance plots for single phase PV injection

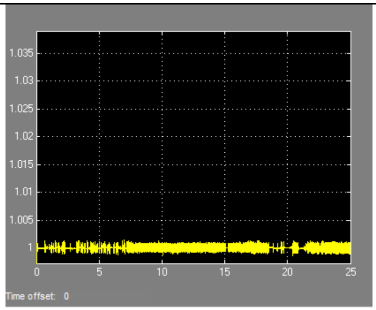
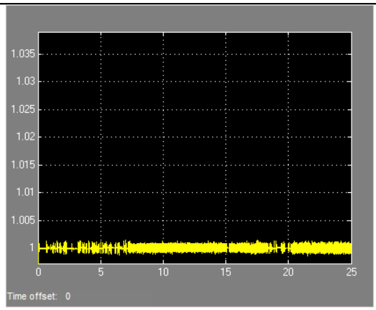
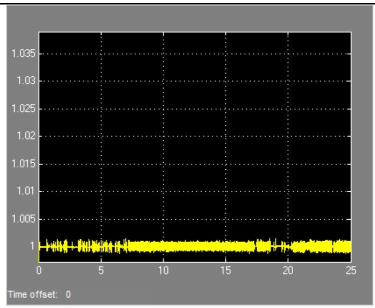
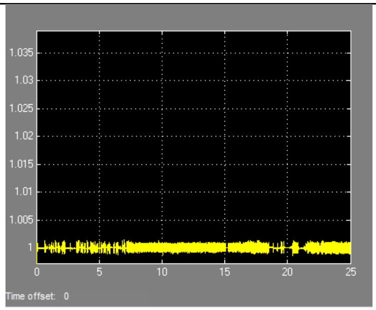
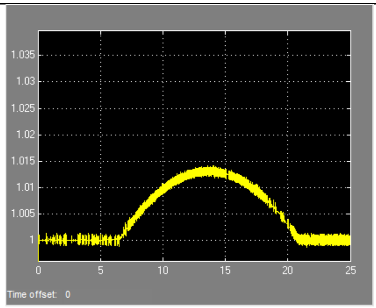
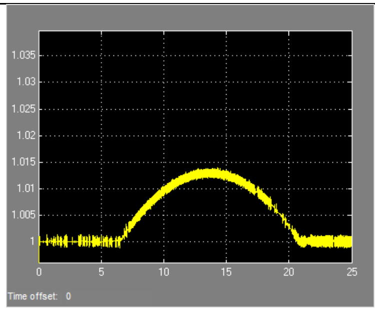
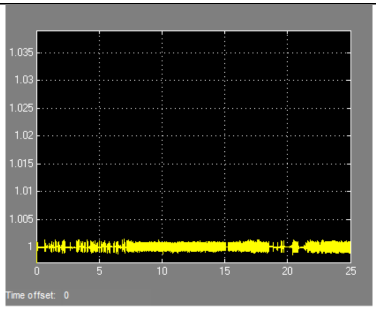
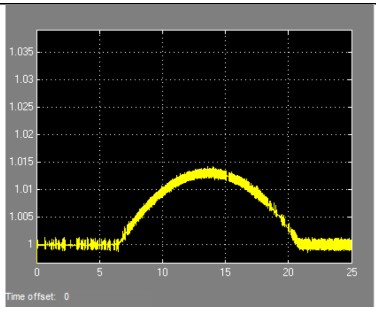
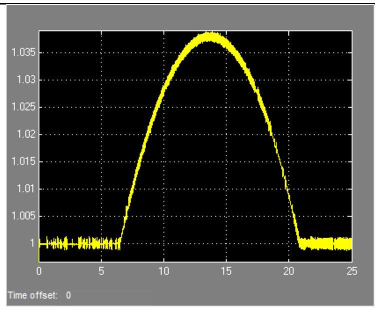
Summer	PV at CP	PV at MP	PV at FP
CP voltage profile			
MP voltage profile			
FP voltage profile			

Table 30: Winter imbalance results for single phase PV injection

Winter	PV at CN / %	PV at MN / %	PV at FN / %
CN Imbalance	Max: 0	Max: 0	Max: 0
MN Imbalance	Max: 0	Max: 1.5	Max: 1.5
FN Imbalance	Max: 0	Max: 1.5	Max: 4

Table 31: Summer imbalance results for single phase PV injection

Summer	PV at CN / %	PV at MN / %	PV at FN / %
CN Imbalance	Max: 0	Max: 0	Max: 0
MN Imbalance	Max: 0	Max: 1.5	Max: 1.5
FN Imbalance	Max: 0	Max: 1.5	Max: 4

Table 32: Winter transformer plots for single phase PV injection

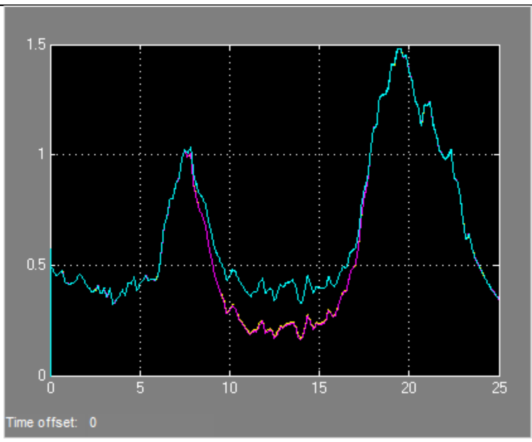
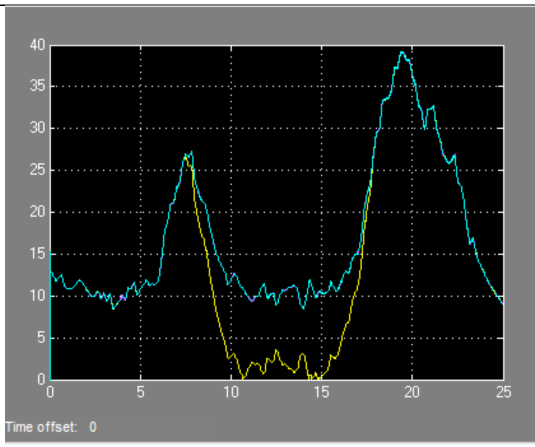
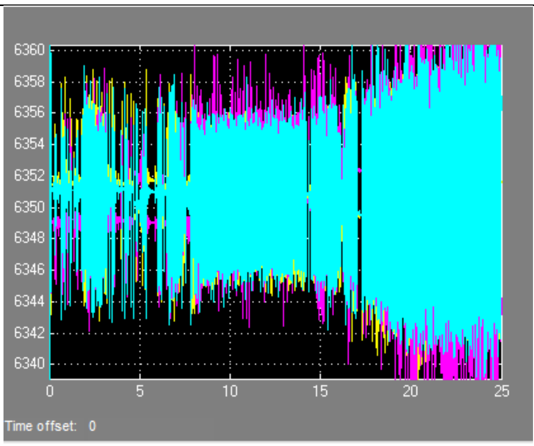
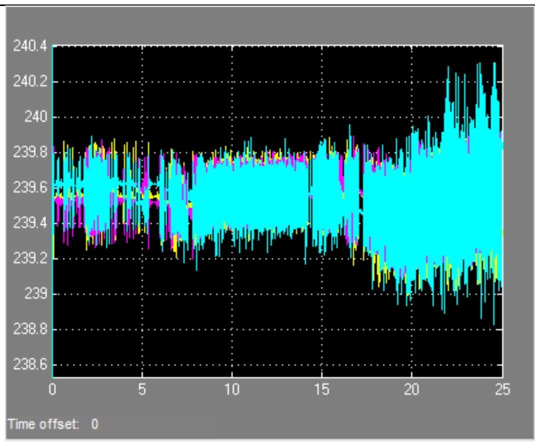
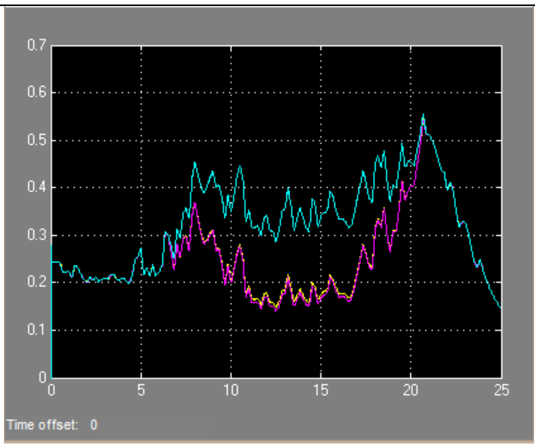
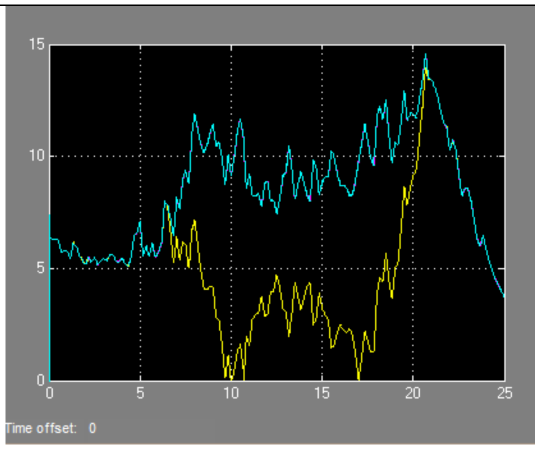
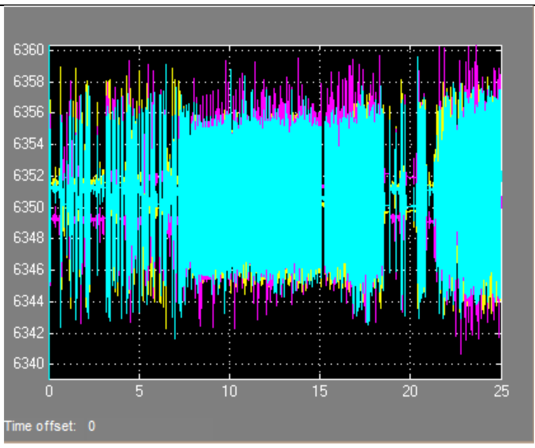
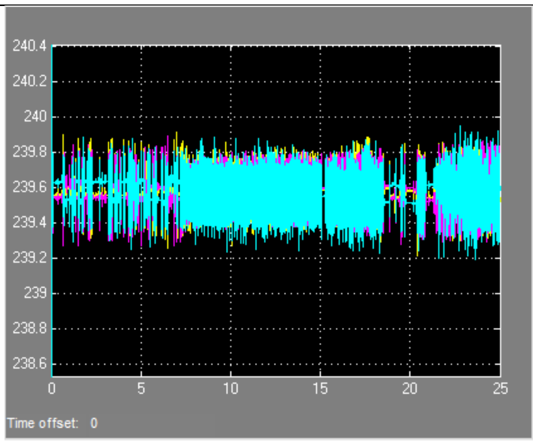
Win	11kV	400V
I		
V		

Table 33: Summer transformer plots for single phase PV injection

Sum	11kV	400V
I		
V		

It was observed that the maximum imbalance achieved for a single phase PV system injection was 4%. The allowable nominal imbalance according to the IEC standard in the EA guidelines is 3%, for areas where there is predominately single phase connected loads. The duration of imbalance is also directly proportional to the amount of sunlight that was available, hence the summer profiles produced a longer imbalance period. The maximum imbalance was noticed when PV injection occurred on the furthest point from the MV/LV transformer and hardly any imbalance is noticed when injection was at the CP.

The single phase PV injection produces a current imbalance on the MV network, which could result in the mal-operation of protection. On the 400V plots of the transformer, between the time period of 1000 hours and 1700 hours, during summer and 1100 hours and 1500 hours during winter, current is actually being injected back into the grid. It was shown as being consumed, because RMS values can’t be shown as negative. Another interesting observation was that the delta side of the Dyn1 transformer shows a current imbalance on phase A and B which was thought to be caused by the delta winding on the MV side of the local transformer.

4.1.2.2 Scenario 7 – Effect of PV cluster on two phases at the same electrical location

The next imbalance scenario focuses on two, single phase, PV units which inject at the same electrical location. This scenario attempts to provide the perspective of two neighbours both having PV units, in very close proximity to each other but on different phases. The electrical injection point was varied to determine the worst case.

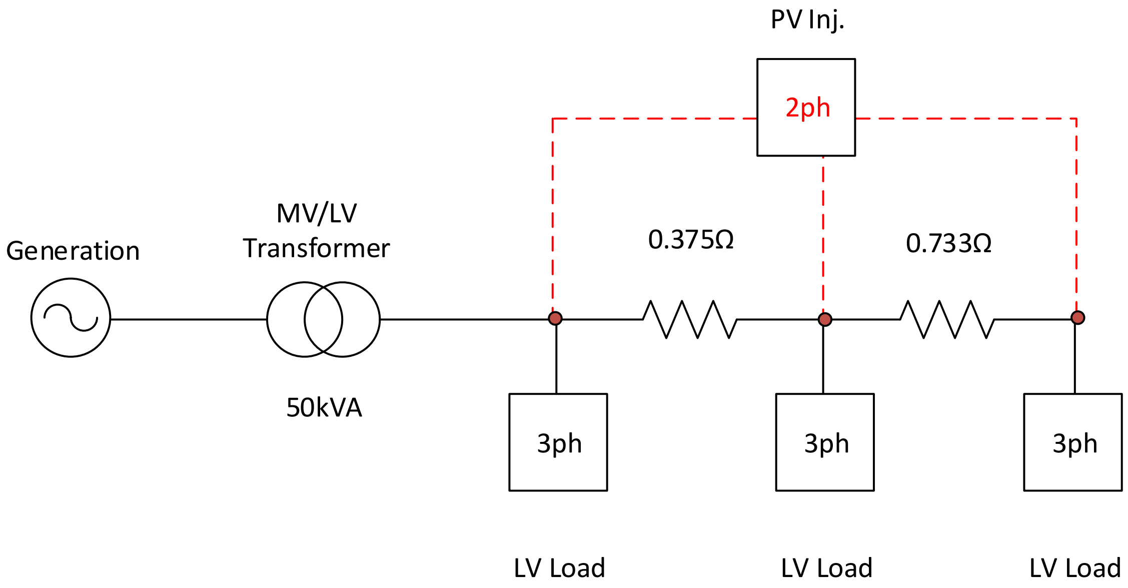


Figure 38: SLD for two phase PV injection at the same electrical node

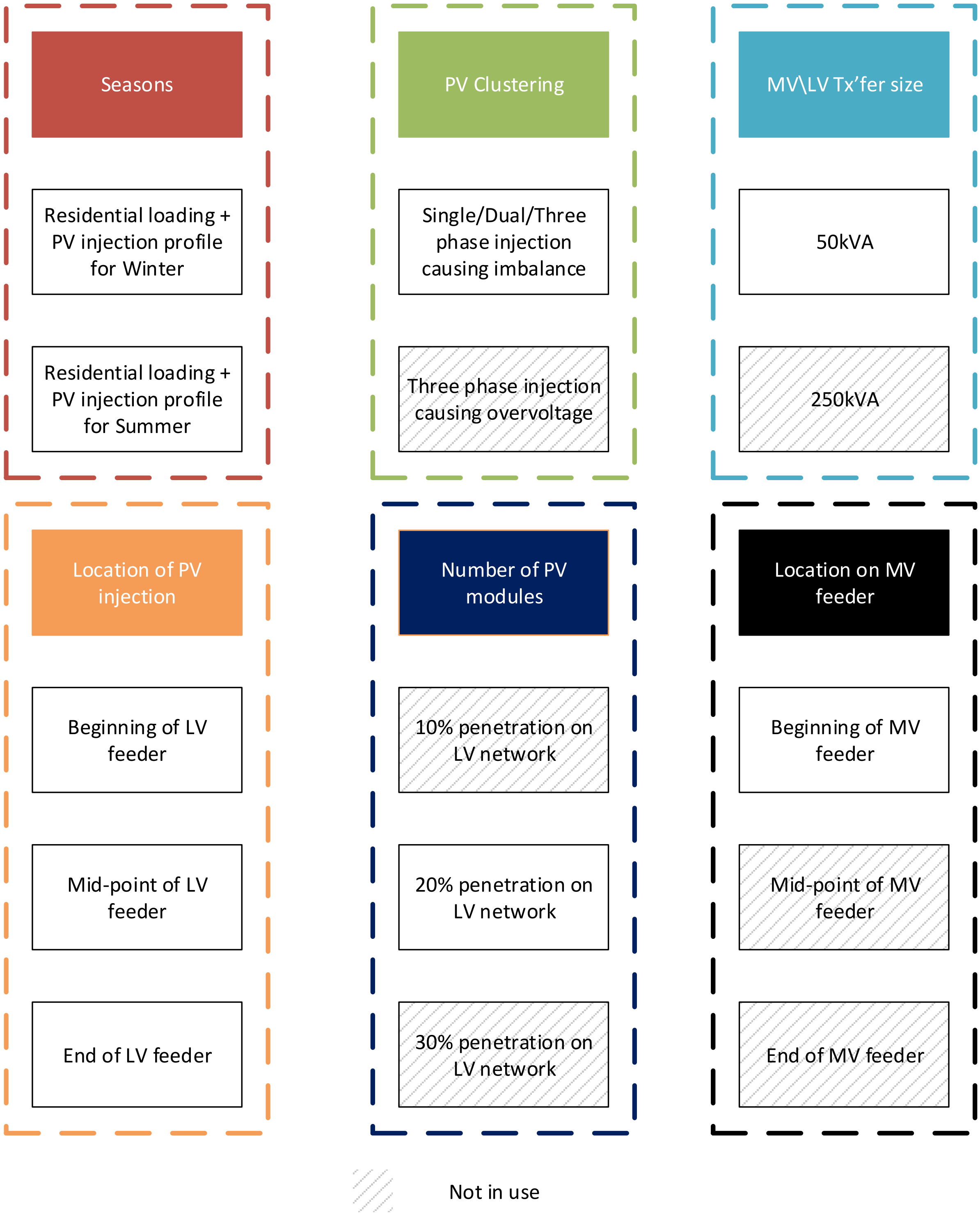


Figure 39: Parameters selected for simulation of two phase PV injection at the same electrical node

Table 34: Winter imbalance s for two phase PV injection at the same point

Winter	**PV at CN / %**	**PV at MN / %**	**PV at FN / %**
CN Imbalance	Max: 0	Max: 0	Max: 0
MN Imbalance	Max: 0	Max: 0.7	Max: 0.7
FN Imbalance	Max: 0	Max: 0.7	Max: 2

Table 35: Summer imbalance results for two phase PV injection at the same point

Summer	**PV at CN / %**	**PV at MN / %**	**PV at FN / %**
CN Imbalance	Max: 0	Max: 0	Max: 0
MN Imbalance	Max: 0	Max: 0.7	Max: 0.7
FN Imbalance	Max: 0	Max: 0.7	Max: 2

Table 36: Winter transformer plots for two phase PV injection at the same point

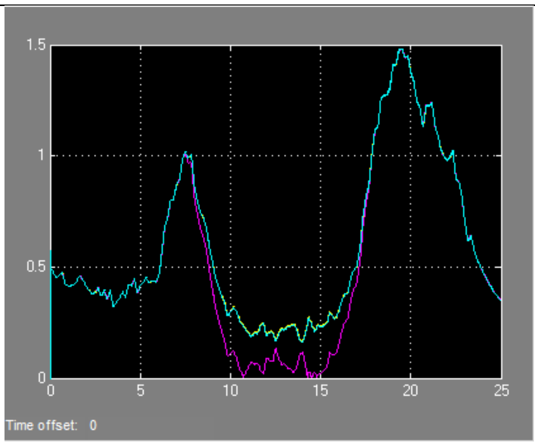
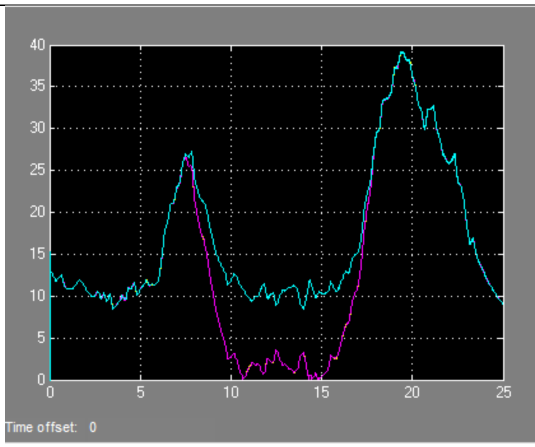
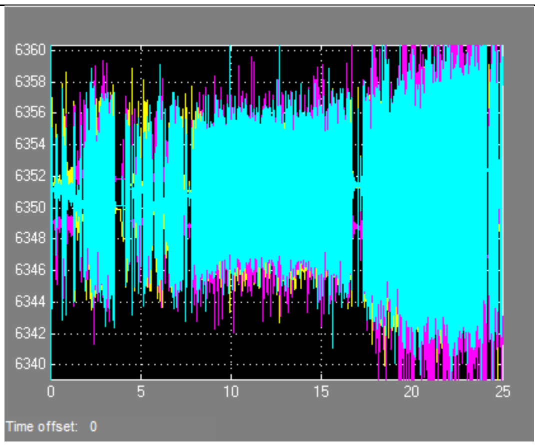
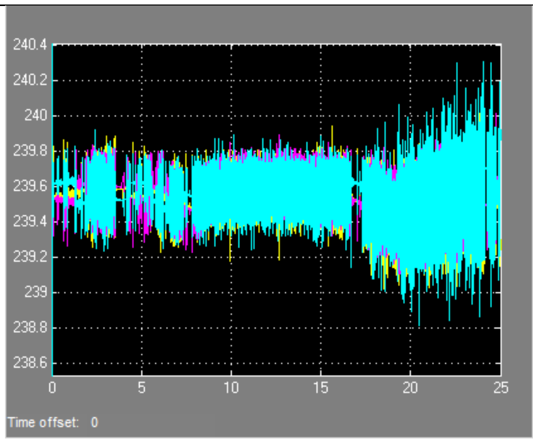
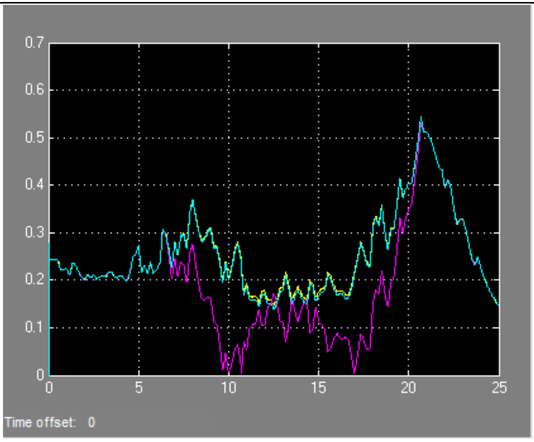
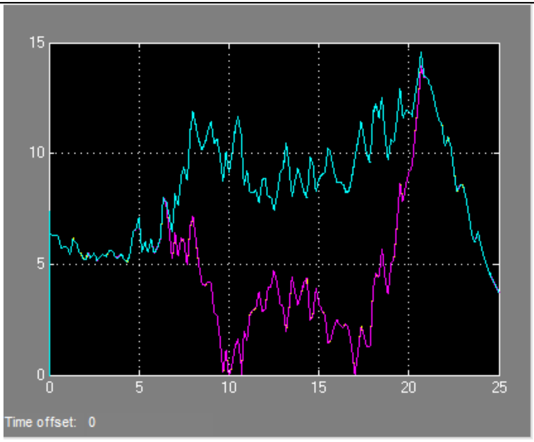
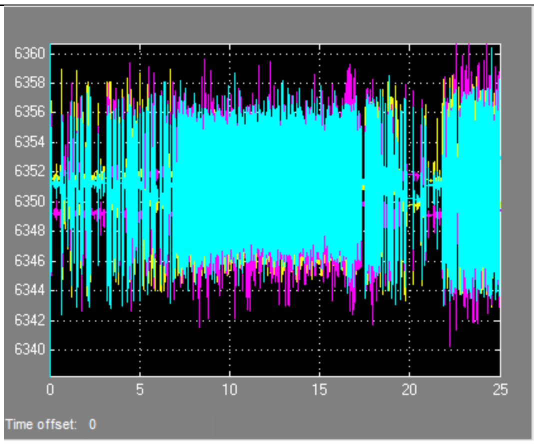
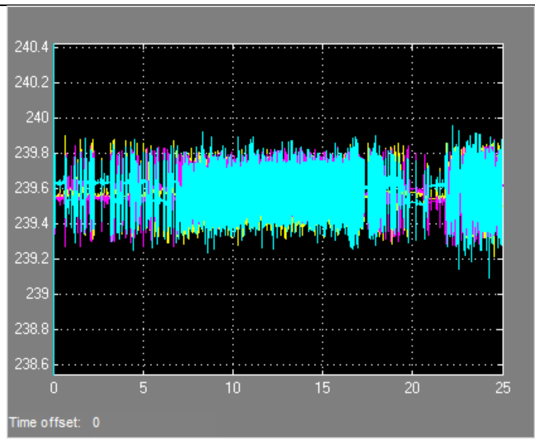
Win	11kV	400V
I		
V		

Table 37: Summer transformer plots for two phase PV injection at the same point

Sum	11kV	400V
I		
V		

It was observed that the maximum imbalance achieved for a single phase injection was ~2% and was deemed to be acceptable. Therefore, a solution to compensate for the imbalance caused by one PV system on a LV network, might be to add a separate PV system next door. The maximum imbalance was experienced when both PV injection units were placed towards the end of the LV feeder.

The two phase PV injection produces a current imbalance on the MV network, which could result in mal-operation of protection. The magnitude of injection into the grid increased during the single phase injection. Lastly, it was seen that the delta side of the Dyn1 transformer now shows phase B as injecting back into the grid between 1000 and 1500, and phase A and C have now experienced a reduced demand.

4.1.2.3 Scenario 8 – Effect of PV cluster on two phases at different electrical locations

This scenario was an extension of the previous one. It had two, single-phase, PV units which injected at the different electrical locations. This scenario attempted to provide the perspective of two PV units that are installed at different distances along a LV feeder and on different phases. The electrical injection point was varied, but differently to previous cases. A SLD was not provided, because there were complex connections. These connections are better explained by the headings provided in the tables.

Table 38: Winter imbalance results for two phase PV injection at the different points

Winter	**PV at phase A CN and phase B MN /%**	**PV at phase A MN and phase B FN / %**	**PV at phase A FN and phase B CN / %**
CN Imbalance	Max: 0	Max: 0	Max: 0
MN Imbalance	Max: 1.5	Max: 0.7	Max: 1.5
FN Imbalance	Max: 1.5	Max: 3.3	Max: 4

Table 39: Summer imbalance results for two phase PV injection at the different points

Summer	**PV at phase A CN and phase B MN /%**	**PV at phase A MN and phase B FN / %**	**PV at phase A FN and phase B CN / %**
CN Imbalance	Max: 0	Max: 0	Max: 0
MN Imbalance	Max: 1.5	Max: 0.7	Max: 1.5
FN Imbalance	Max: 1.5	Max: 3.3	Max: 4

Table 40: Winter transformer plots for two phase PV injection at the different points

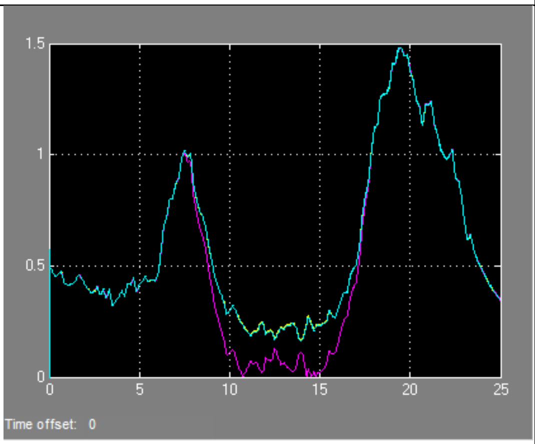
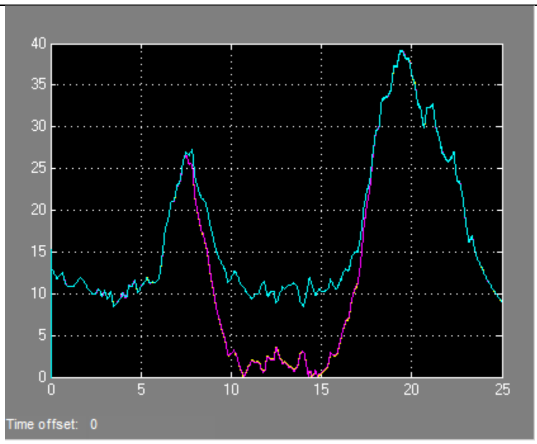
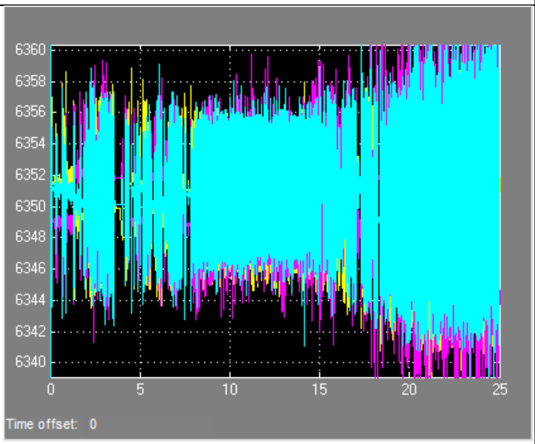
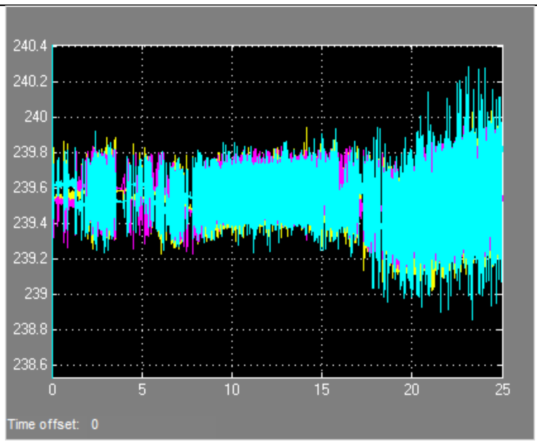
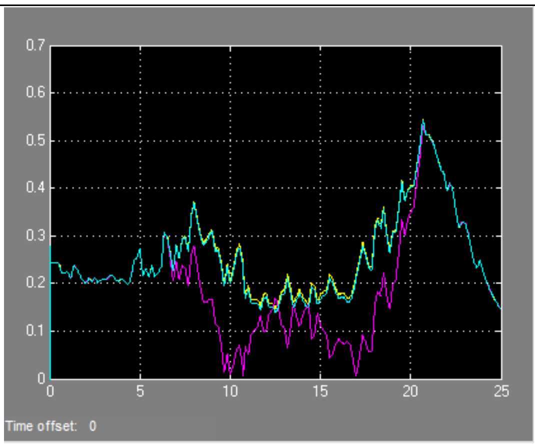
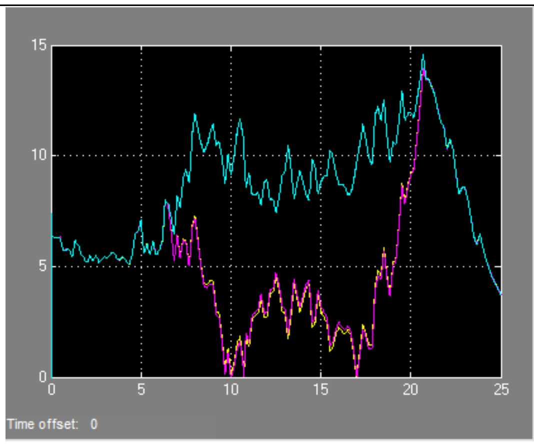
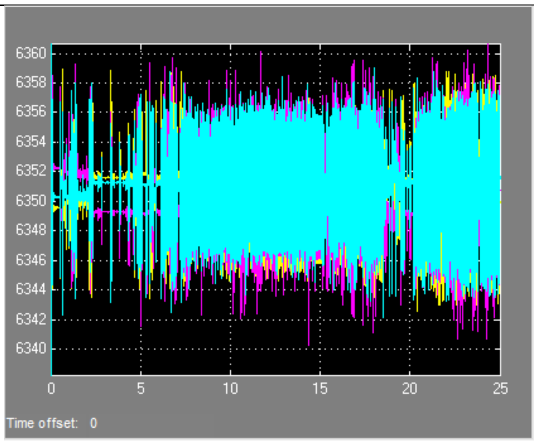
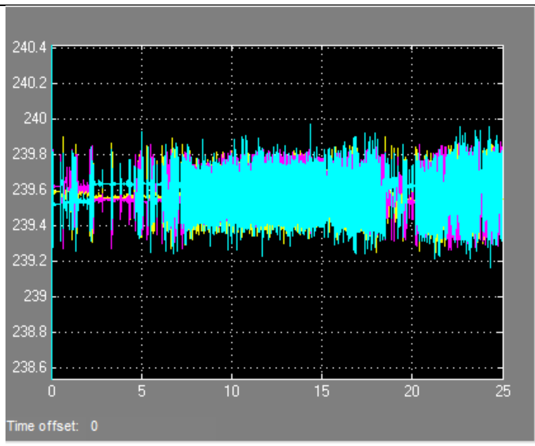
Win	11kV	400V
I		
V		

Table 41: Summer transformer plots for two phase PV injection at the different points

Sum	11kV	400V
I		
V		

Different results were seen; the maximum imbalance achieved for a single phase injection was raised to 4%. This is above the EA guideline threshold. The maximum imbalance was experienced when either of the PV injection points was at the FP of the LV feeder.

The 11kV and 400V measurements at the local distribution transformer were identical to those observed in the previous scenario.

4.1.2.4 Scenario 9 – Effect of PV cluster on three phases at different electrical locations

The final voltage issues scenario focused on a 3 x single phase PV units which inject at different electrical nodes. This connection is best described by the headings on Tables 37 and 38 below. This scenario attempted to provide the perspective of scattered PV across the LV network with penetration occurring on all three phases, but penetration of each phase was at a different distance to the other. A SLD has not been provided, because these were complex connections. These connections are better explained by the headings provided in the tables.

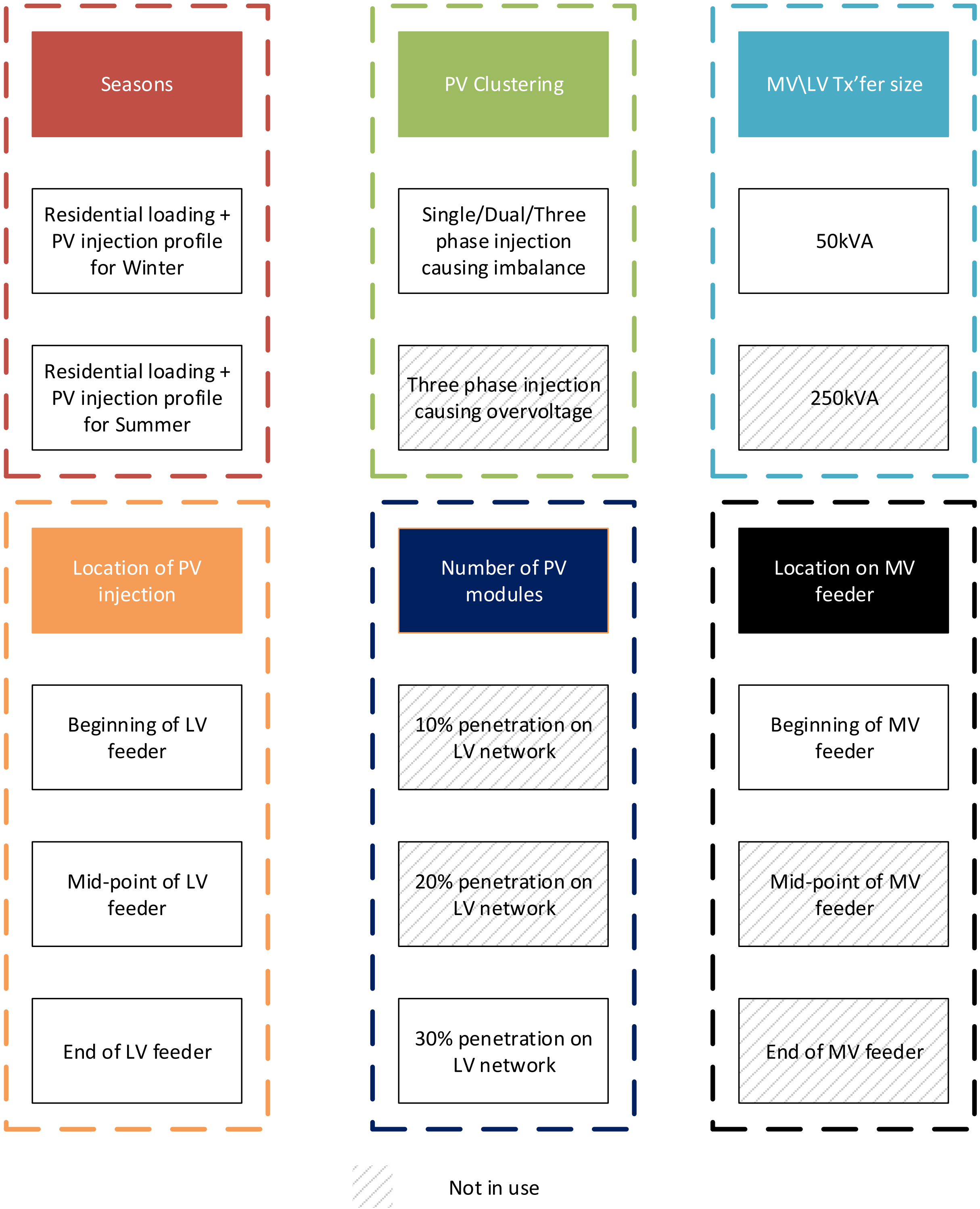


Figure 40: Parameters selected for simulation of three phase PV injection at different electrical nodes

Table 42: Winter imbalance results for three phase PV injection at the different points

Winter	**PV at; phase A FN, phase B MN, phase C CN /%**	**PV at; phase A CN, phase B FN, phase C MN / %**	**PV at; phase A MN, phase B CN, phase C FN / %**
CN Imbalance	Max: 0	Max: 0	Max: 0
MN Imbalance	Max: 0.7	Max: 0.7	Max: 0.7
FN Imbalance	Max: 3.3	Max: 3.3	Max: 3.3

Table 43: Summer imbalance results for three phase PV injection at the different points

Summer	**PV at; phase A FN, phase B MN, phase C CN /%**	**PV at; phase A CN, phase B FN, phase C MN / %**	**PV at; phase A MN, phase B CN, phase C FN / %**
CN Imbalance	Max: 0	Max: 0	Max: 0
MN Imbalance	Max: 0.7	Max: 0.7	Max: 0.7
FN Imbalance	Max: 3.3	Max: 3.3	Max: 3.3

Table 44: Winter transformer plots for three phase PV injection at the different points

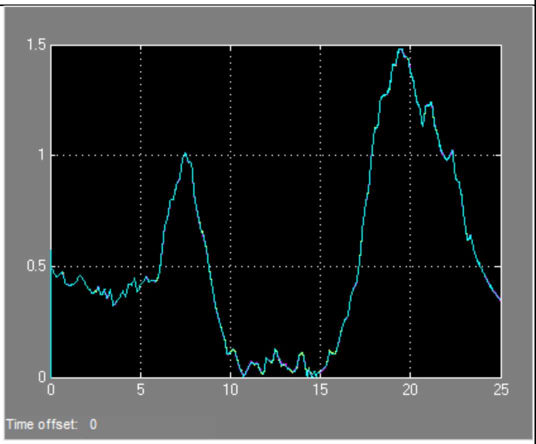
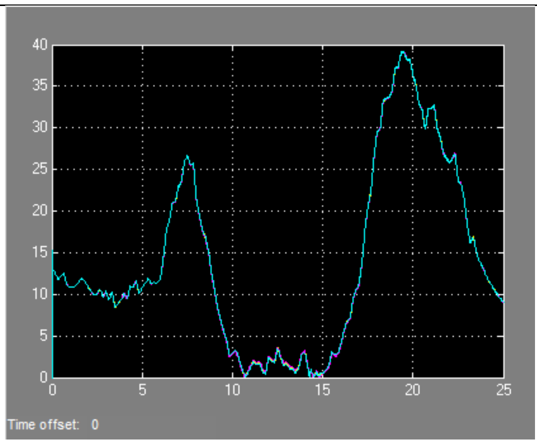
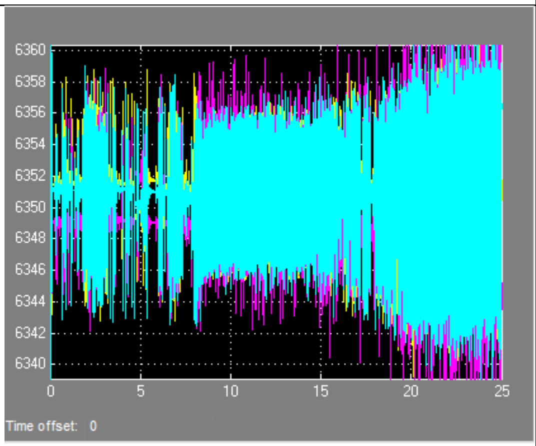
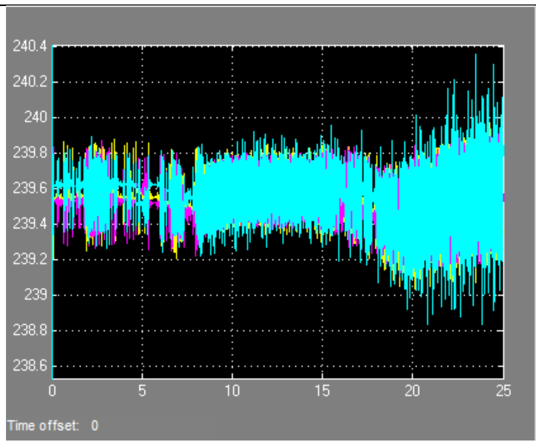
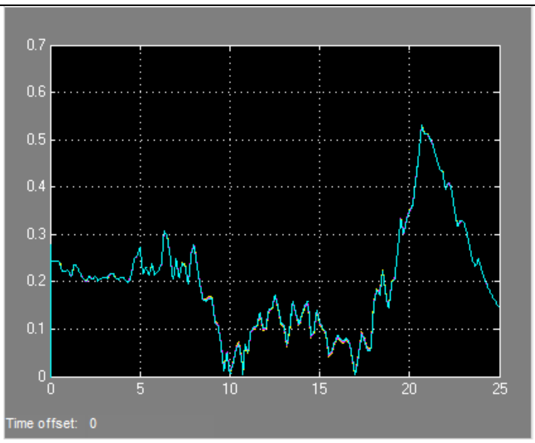
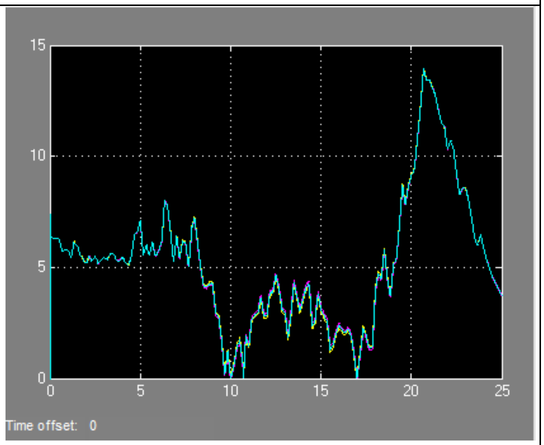
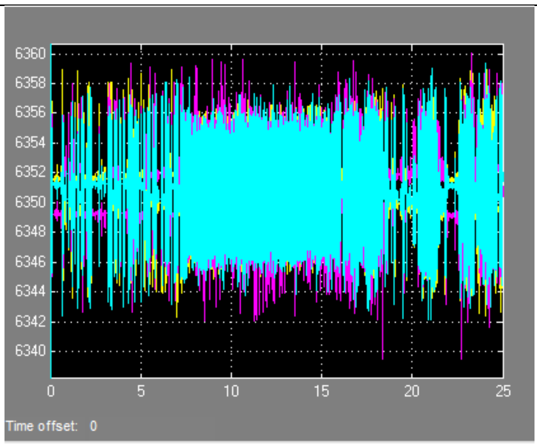
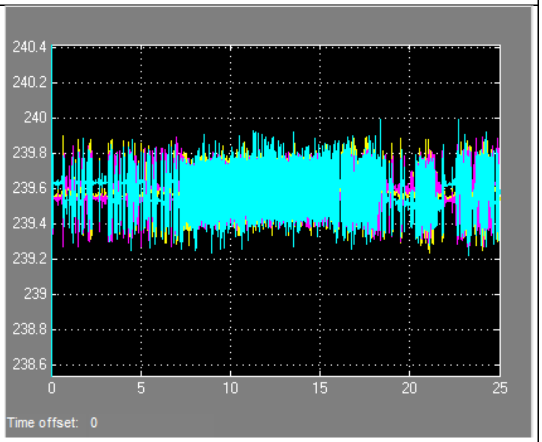
Win	11kV	400V
I		
V		

Table 45: Summer transformer plots for three phase PV injection at the different points

<table>
<tr><td>Sum</td><td>11kV</td><td>400V</td></tr>
<tr><td>I</td><td>
</td><td>
</td></tr>
<tr><td>V</td><td>
</td><td>
</td></tr>
</table>

Identical imbalance results were expected, because at least one of the PV injections occurred at one electrical node. Different results could be expected if there were four electrical nodes and three injection points. Maximum imbalance experienced was ~3.2%. Largest imbalance was experienced on the furthest node LV node. Reverse injection was also observed during both the winter and summer periods. The delta side of the Dyn1 transformer now possessed identical waveforms to the wye side.

4.2 TRIALLED SOLUTIONS

The objective of the solutions is to address the problems that have been observed in the scenarios displayed above. A similar approach to the above is adopted to articulate the results. It is now known which scenarios and simulations produce the worst results for overvoltage, voltage sag and imbalance; therefore, these worst cases were the ones that had the solutions added.

4.2.1 Solution 1 – Reactive Power Consumption

The reactive power consumption solution involves the suppression of the overvoltage produced during PV injection periods. This was done through the use of phase shifting techniques to simulate a smart inverter which transforms the real power produced by the PV system into a reactive and real component (i.e. complex power).

This solution was trialled on the basic PV injection scenario for overvoltage and all of the imbalance scenarios. Only the basic PV injection scenario for overvoltage was chosen because all the other voltage regulation scenarios showed variance in sag but the magnitude of overvoltage didn't change and this solution only focuses on overvoltage and not sag. Lastly, only summer simulations have been shown below. This is to avoid repetition, because the overvoltage suppression can be applied in a very similar way to the winter simulations. The only observed difference would be the duration of overvoltage experienced, which would be shorter during the winter period.

The schematics were the same as previous scenarios, except a phase shift component was added to the PV unit subsystem, as per the methodology discussed in chapter 3.

Table 46: Summer results for overvoltage with PV injection at the different points and reactive power solution implemented

Summer	**PV at CN / V**	**PV at MN / V**	**PV at FN / V**
CN Voltages	Max: 243	Max: 243	Max: 243
	Min: 239	Min: 239	Min: 239
MN Voltages	Max: 240	Max: 241	Max: 241
	Min: 236	Min: 236	Min: 236
FN Voltages	Max: 235	Max: 240	Max: 249
	Min: 233	Min: 233	Min: 200

Table 47: Summer results for imbalance with single PV injection at the FN and reactive power solution implemented

Summer	**PV at FN / %**	**With reactive power compensation / %**
CN Imbalance	Max: 0	Max: 0.7
MN Imbalance	Max: 1.5	Max: 1
FN Imbalance	Max: 4	Max: 1.5

Table 48: Summer results for imbalance with two PV injection units at the same point and reactive power solution implemented

Summer	PV at FN / %	With reactive power compensation / %
CN Imbalance	Max: 0	Max: 0.5
MN Imbalance	Max: 0.7	Max: 0.5
FN Imbalance	Max: 2	Max: 0.7

Table 49: Summer results for imbalance with two PV injection units at the different points and reactive power solution implemented

Summer	PV at phase A FN and phase B CN / %	With reactive power compensation / %
CN Imbalance	Max: 0	Max: 0.5
MN Imbalance	Max: 1.5	Max: 0.5
FN Imbalance	Max: 4	Max: 1.3

Table 50: Summer results for imbalance with three PV injection units at the different points and reactive power solution implemented

Summer	PV at; phase A FN, phase B MV, phase C CN / %	With reactive power compensation / %
CN Imbalance	Max: 0	Max: 0
MN Imbalance	Max: 0.7	Max: 0.1
FN Imbalance	Max: 3.3	Max: 0.7

In the overvoltage simulations, an unusual swell in voltage was noticed at the CN, which originally didn't occur. This swell occurred for all placements of PV injection. This swell was as a result of the additional reactive injection. However, this swell was below the 243.8V threshold set by the PQ guidelines. A suppression in voltage was also experienced at the other locations which now kept the voltage within the upper limit.

The maximum voltage imbalance was seen to be 1.7% which was a dramatic reduction to previous results. This meant both imbalance and voltage regulation thresholds were not breached when reactive power compensation was used as a solution.

This does, however, mean that the power that is generated by the customer is reactive and not active and so the customer may not get compensated for injecting into the grid by generation companies. A subsidy might need to be provided by the network owner, to maintain PQ standards without having to schedule reinforcement projects.

4.2.2 Solution 2 – Battery

The next solution trialled was the battery. It consisted of both power storage (artificial load creation) and dissipation. The strategy adopted was to use power storage to control overvoltage and power dissipation to control the sag. This solution was trialled on the basic PV injection and maximum sag scenarios and all of the imbalance scenarios. Both summer and winter simulations were conducted, due to the difference in battery charge and discharge profiles.

The schematics are the same as previous scenarios, except with the addition of a separate current source which consumed and delivered power based on the battery methodology discussed in chapter 3. The results are shown below.

Table 51: Summer results for overvoltage with PV injection cluster at FN and battery solution implemented

Summer	PV at FN (original) / V	With battery / V
CN Voltages	Max: 240	Max: 240
	Min: 239	Min: 239
MN Voltages	Max: 242	Max: 240
	Min: 236	Min: 237
FN Voltages	Max: 250	Max: 241
	Min: 233	Min: 235

Table 52: Summer results for overvoltage + sag worst case, with PV injection cluster at FN and battery solution implemented

Summer	PV at FN (original) / V	With battery / V
CN Voltages	Max: 243	Max: 238
	Min: 233	Min: 234
MN Voltages	Max: 243	Max: 240
	Min: 234	Min: 231
FN Voltages	Max: 250	Max: 240
	Min: 226	Min: 230

Table 53: Summer results for imbalance with single PV injection at the FN and battery solution implemented

Summer	PV at FN / %	With battery / %
CN Imbalance	Max: 0	Max: 0
MN Imbalance	Max: 1.5	Max: 0.7
FN Imbalance	Max: 4	Max: 2

Table 54: Summer results for imbalance with two PV injection units at the same point and battery solution implemented

Summer	PV at FN / %	With battery / %
CN Imbalance	Max: 0	Max: 0
MN Imbalance	Max: 0.5	Max: 0.3
FN Imbalance	Max: 2	Max: 1

Table 55: Summer results for imbalance with two PV injection units at the different points and battery solution implemented

Summer	PV at phase A FN and phase B CN / %	With battery / %
CN Imbalance	Max: 0	Max: 0
MN Imbalance	Max: 1.5	Max: 0.6
FN Imbalance	Max: 4	Max: 2

Table 56: Summer results for imbalance with three PV injection units at the different points and battery solution implemented

Summer	PV at; phase A FN, phase B MN, phase C CN / %	With battery / %
CN Imbalance	Max: 0	Max: 0
MN Imbalance	Max: 0.7	Max: 0.3
FN Imbalance	Max: 3	Max: 1.5

Table 57: Winter results for overvoltage with PV injection cluster at FN and battery solution implemented

Winter	PV at FN (original) / V	With battery / V
CN Voltages	Max: 240	Max: 240
	Min: 239	Min: 239
MN Voltages	Max: 242	Max: 240
	Min: 230	Min: 233
FN Voltages	Max: 250	Max: 241
	Min: 220	Min: 224

Table 58: Winter results for overvoltage + sag worst case, with PV injection cluster at FN and battery solution implemented

Winter	PV at FN (original) / V	With battery / V
CN Voltages	Max: 240	Max: 236
	Min: 218	Min: 223
MN Voltages	Max: 242	Max: 236
	Min: 210	Min: 215
FN Voltages	Max: 250	Max: 238
	Min: 210	Min: 207

Table 59: Winter results for imbalance with single PV injection at the FN and battery solution implemented

Winter	PV at FN / %	With battery / %
CN Imbalance	Max: 0	Max: 0
MN Imbalance	Max: 1.5	Max: 1.5
FN Imbalance	Max: 4	Max: 4.3

Table 60: Winter results for imbalance with two PV injection units at the same point and battery solution implemented

Winter	PV at FN / %	With battery / %
CN Imbalance	Max: 0	Max: 0
MN Imbalance	Max: 0.7	Max: 0.7
FN Imbalance	Max: 2	Max: 2

Table 61: Winter results for imbalance with two PV injection units at the different points and battery solution implemented

Winter	PV at phase A FN and phase B CN / %	With battery / %
CN Imbalance	Max: 0	Max: 0
MN Imbalance	Max: 1.5	Max: 1.5
FN Imbalance	Max: 4	Max: 4.3

Table 62: Winter results for imbalance with three PV injection units at the different points and battery solution implemented

Winter	PV at; phase A FN, phase B MN, phase C CN	With battery / %
CN Imbalance	Max: 0	Max: 0
MN Imbalance	Max: 0.7	Max: 0.7
FN Imbalance	Max: 3.3	Max: 3.4

In the summer overvoltage simulations, it was noticed that swell was reduced and no swell was noticed at the CN, which was seen in the reactive power solution. A better voltage regulation was seen. The other observation was that the battery didn't complete a full cycle during the summer period. Only 20% of its total capacity was discharged and 120% was incoming from the PV unit. This may negatively affect the battery if it is to be cycled on a daily basis.

The winter voltage regulation simulations showed a significant improvement in voltage sag, of ~5V which brought the minimum voltage on the LV network to 225V, making it conform to the PQ guidelines. Under extreme sag conditions, however, the battery support was still insufficient to raise the voltage to the minimum requirement of 220V, only managing ~207V. The battery during winter was cycled, but the maximum charge stored was ~85%, due to the amount of available irradiation and load demanded by the residence.

In the imbalance simulations, examinations showed improvements for both summer and winter simulations during PV injection periods. A strange phenomenon though was seen during both winter and summer simulations. This was seen in winter when charge was injected from the battery into the system, as demand increased towards the evening peak. During summer, a tapering off of the imbalance was observed (figures are provided in the appendices). This was in contrast to the peaking profile that was seen during winter. Further investigation was conducted into this imbalance peak and tapering off. The reasoning is best explained by the figure below.

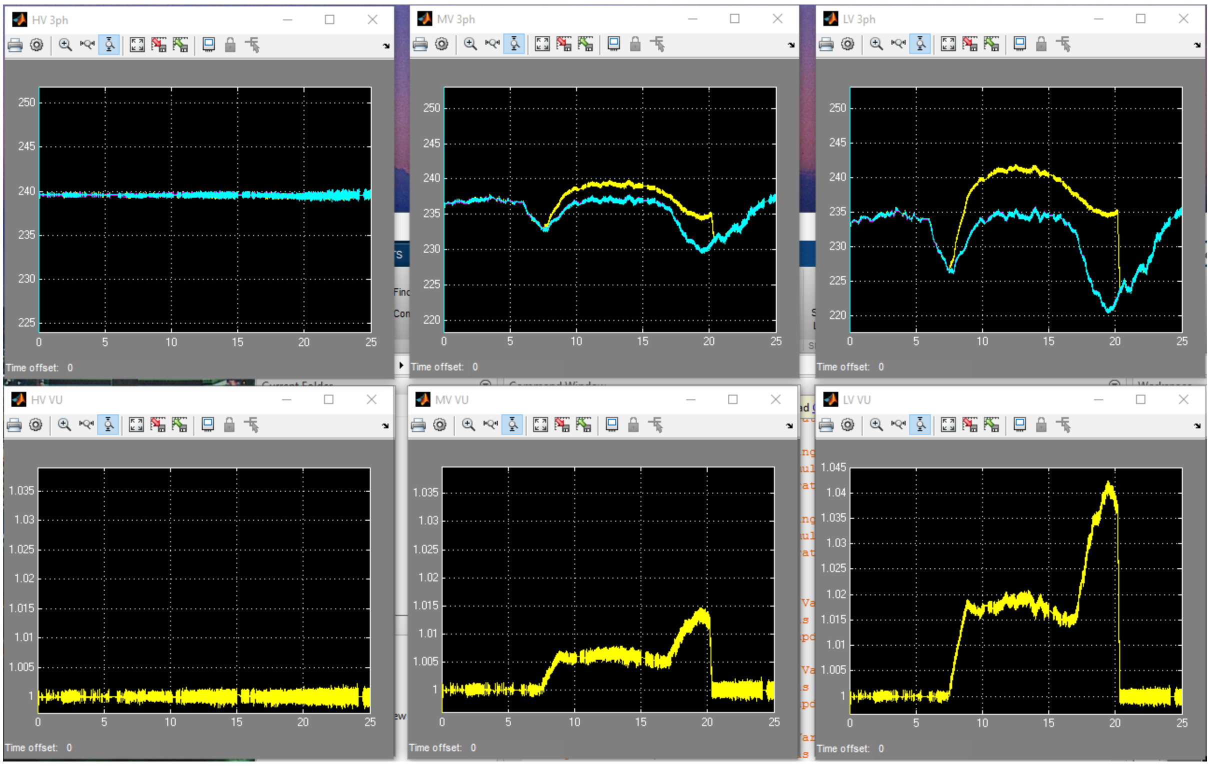


Figure 41: Peak of winter imbalance compared with actual voltage at the node

It was noticed that the peak was created because the battery was very close to the load compared to the local transformer. This resulted in a much better regulation of voltage when compared with a load that didn't have a battery at the same electrical node. It explains why the imbalance was worse during winter, because the improvement in voltage, when compared against the other phases at the same node, was enough to result in a significant imbalance. Therefore, the imbalance PQ criteria is exceeded during winter and within the limits during summer.

4.2.3 Solution 3 – Single Phase Micro-Grid

The single phase micro-grid solution consisted of a battery and a double breaker. The strategy adopted was to use power storage to control voltage and the double breaker would reduce the size of the storage required because power generated by the PV unit was consumed within the same LV network. This solution was trialled on the basic PV injection and the three phase injection imbalance scenario. It was trialled on the other imbalance scenarios and results are available in the appendix. The reason for their exclusion is due to the fact that there was not enough PV generation available to offset demand to improve sag or to disconnect from the grid for a sufficiently long period.

Both summer and winter simulations were conducted, due to the difference in consumption and discharge profiles for the battery.

Furthermore, an additional consideration was required for this simulation to be conducted. This was the location of placement of a battery and whether it would be a single or three phase unit. A decision was made by conducting a simulation with a single PV unit located at the FN and applying the variations of the battery. The results are available below. The breaker disconnection and connection points occurred when the voltage hit 0.

<u>Three phase battery results</u>

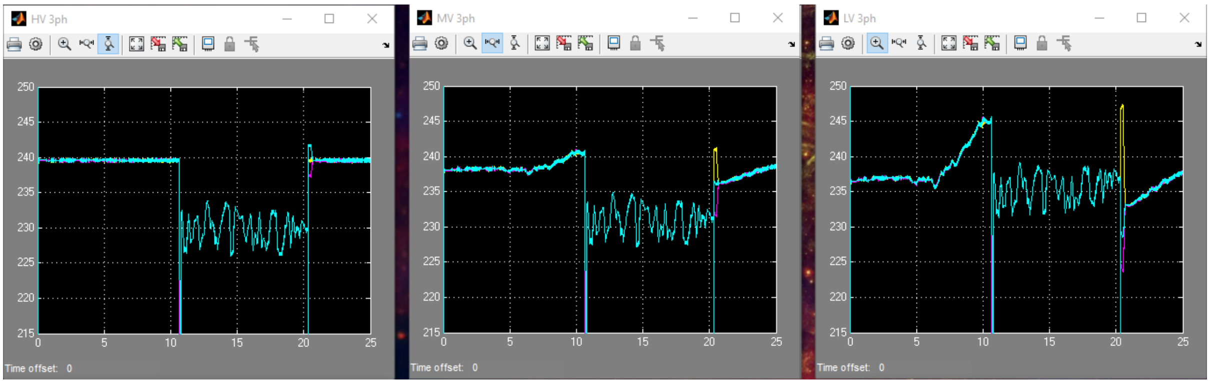


Figure 42: PV injection and FN and battery at FN

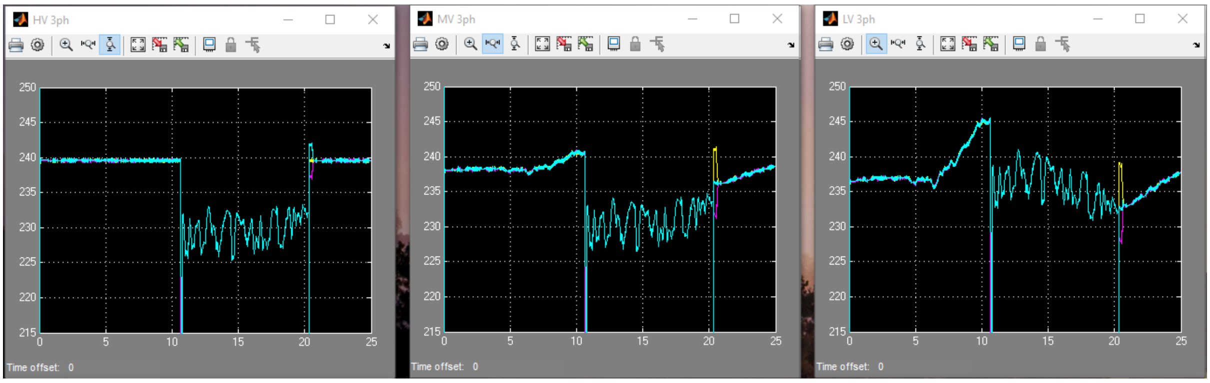


Figure 43: PV injection and FN and battery at MN

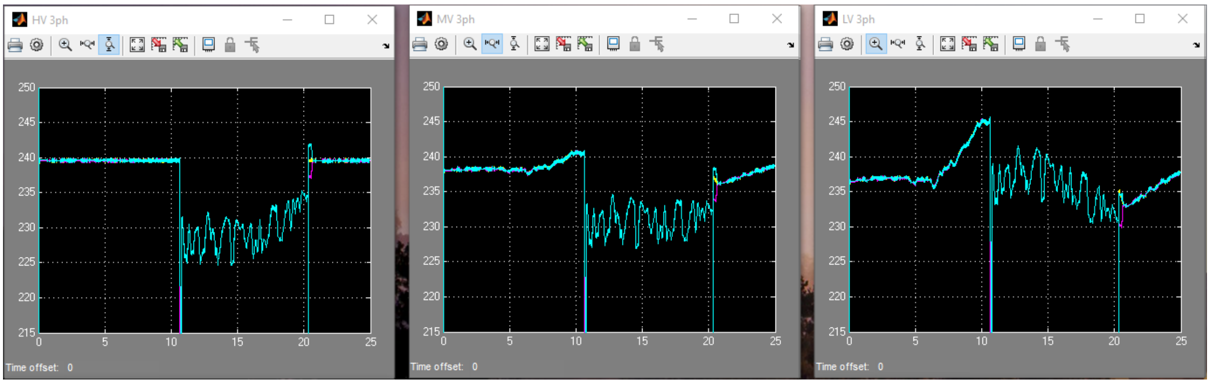


Figure 44: PV injection and FN and battery at CN

It can be seen that as the location of the battery gets closer to the location of PV injection, the voltage regulation, during grid disconnected periods, is better, i.e. deviation between max and minimum voltage is the least.

<u>Single-phase battery results</u>

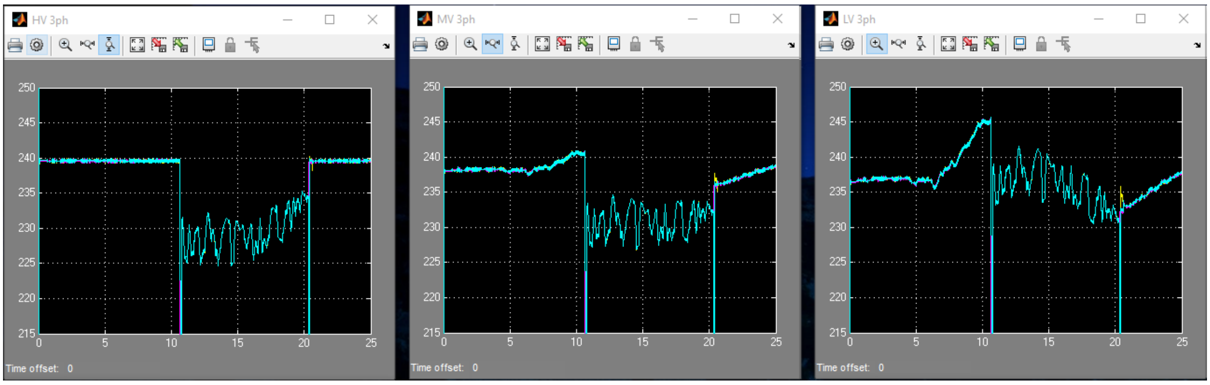


Figure 45: PV injection and FN and battery at FN

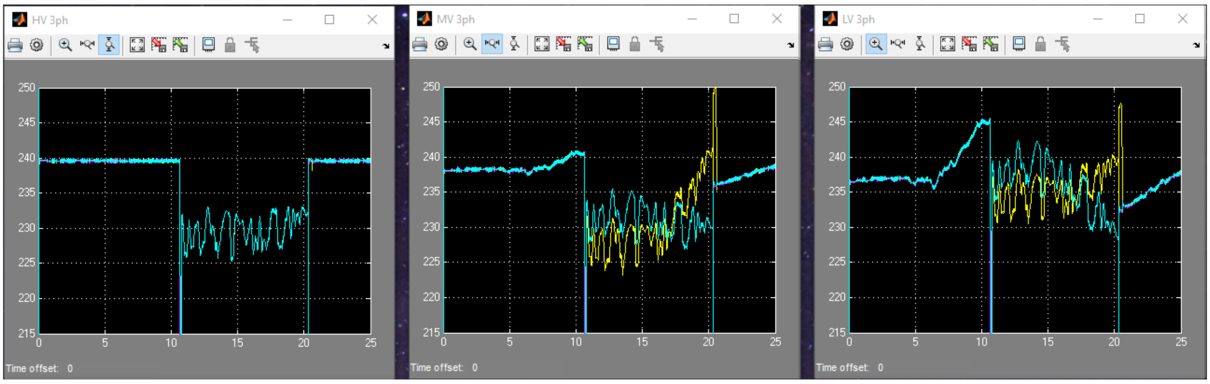


Figure 46: PV injection and FN and battery at MN

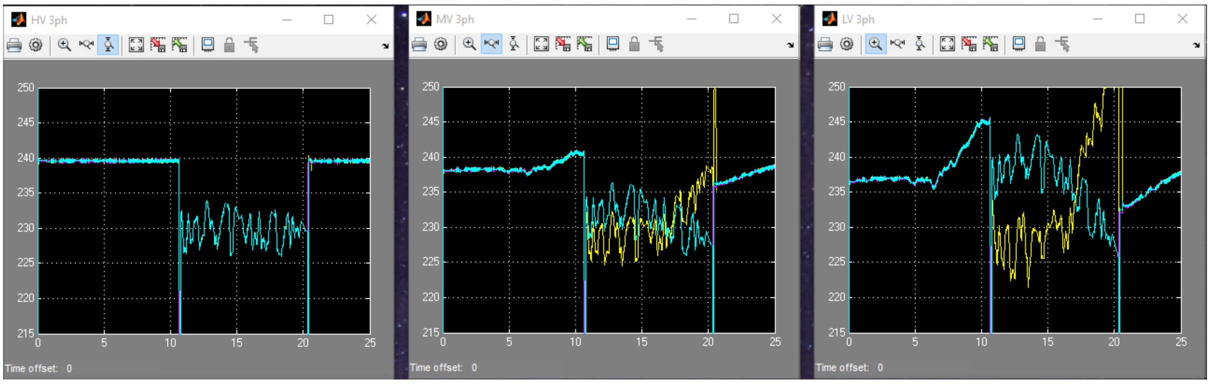


Figure 47: PV injection and FN and battery at CN

When a single phase battery is installed, it was seen that it would be better to place a battery very close to the location of isolation (i.e. breaker point). This is because it is easier to regulate the voltage closer to the common busbar, i.e. Kirchoff's Law, Ohm's Law (less volt drop as you get closer to the load) etc.

Table 63: Summary table for selection of battery type and placement

	Single phase	**Three phase**
Best option	Battery as close to the isolation point as possible. PV can be located anywhere, but PV location at CN is best pre-grid disconnection. Problem: Circuit overvoltage (high risk)	Battery as close to the cluster of PV injection as possible. Both can be located anywhere, but PV location at CN is best pre-grid disconnection. Problem: None

Based on the above results, the best alternative chosen was the three phase battery unit, placed as close to the PV injection as possible.

The SLD for this scenario were different and are provided in the Figures 48, along with the results. The three phase interconnection nature is described by the different colours shown.

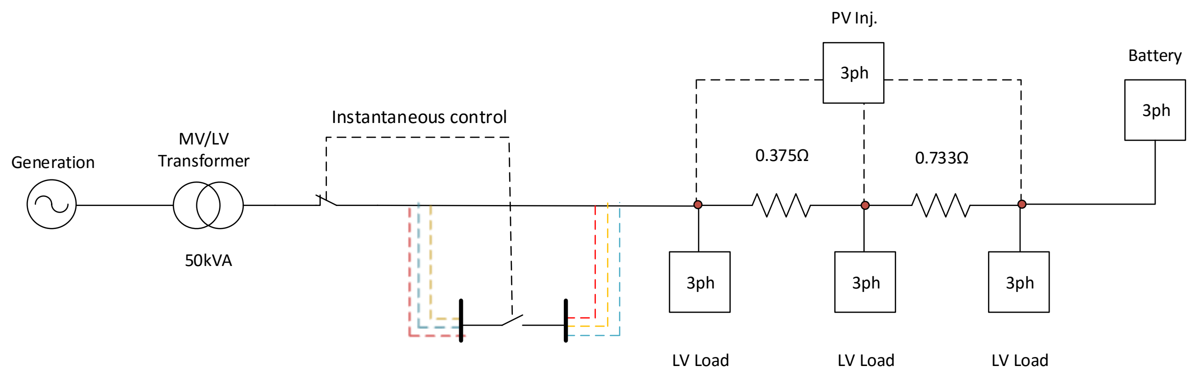


Figure 48: Single phase micro-grid solution SLD

Table 64: Summer overvoltage results for three phase PV injection at the same point and single phase micro-grid solution implemented

Summer	PV at FN (original) / V	With SPM / V
CN Voltages	Max: 240	Max: 240
	Min: 239	Min: 226
MN Voltages	Max: 242	Max: 240
	Min: 236	Min: 227
FN Voltages	Max: 250	Max: 245
	Min: 233	Min: 233

Table 65: Winter overvoltage plots for three phase PV injection at the same point and single phase micro-grid solution implemented

Winter	PV at FN (original) / V	With SPM / V
CN Voltages	Max: 240	Max: 240
	Min: 239	Min: 227
MN Voltages	Max: 242	Max: 240
	Min: 230	Min: 228
FN Voltages	Max: 250	Max: 245
	Min: 220	Min: 220

Table 66: Summer results for imbalance with three PV injection units at the different points and single phase micro-grid solution implemented

Summer	PV at; phase A FN, phase B MN, phase C CN / %	With SPM / %
CN Imbalance	Max: 0	Max: 0
MN Imbalance	Max: 0.7	Max: 0.5
FN Imbalance	Max: 3.3	Max: 2.5

Table 67: Winter plots for imbalance with three PV injection units at the different points and single phase micro-grid solution implemented

Winter	PV at; phase A FN, phase B MN, phase C CN / %	With SPM / %
CN Imbalance	Max: 0	Max: 0
MN Imbalance	Max: 0.7	Max: 0.5
FN Imbalance	Max: 3.3	Max: 2.5

In the summer voltage simulations, it was noticed that the voltage was well regulated during the time of PV injection. The voltage at the point of PV injection was 5V higher than that experienced elsewhere on the LV network. This was expected because of the line impedances in the network. The battery size was also drastically reduced along with the peak consumption and discharge requirements. The battery did complete a full cycle (i.e. discharged fully), unlike the experience in the previous scenario. The total time disconnected from the grid was ~11hours during the summer.

The winter voltage regulation simulations showed a significant improvement in voltage during the period of PV injection; but, the sag experienced during the evening peak was not improved. This was because there was not sufficient charge available. Similarly, to the summer simulation, the PV injection point was 5V higher than that of the rest of the network. The battery performed a complete cycle during the simulation. The total time spent disconnected from the grid was ~6hours.

The imbalance simulations showed improvements for both summer and winter simulations during PV injection periods. The red circles in Tables 59 and 60 attempt to explain the times at which the grid is disconnected, hence the imbalance shown is actually just circuit imbalance and not phase to phase imbalance which means during both summer and winter, the max imbalance is 2.5% and is below the limit specified by the EA PQ guidelines.

CHAPTER 5: DISCUSSIONS

From the results, there were many points of discussion. There are two major points which are debated further and these are:

1. Current PQ guidelines and their suitability measured against the modelled generic LV network
2. Solutions SWOT analysis.

Each point has been broken down into its own sub-section below.

5.1 PQ GUIDELINES SUITABILITY

According to the current EA PQ guidelines, a 6% voltage deviation is allowed on the 11kV feeders, as well as a 6% voltage deviation on 400V feeders. We have observed though from the simulations above, that it is not possible to keep the voltage within the lower threshold of 216.2V during coincidental residential peak load, if the MV feeder also experiences a sag simultaneously. Relationships between the various MV network impedances and the voltage experienced at the LV network is best shown by the graph below. The graph consists of three plots that have been extracted from the data collected in chapter 4. A line of best fit has been inserted with a y-intercept co-ordinate of (0, 0).

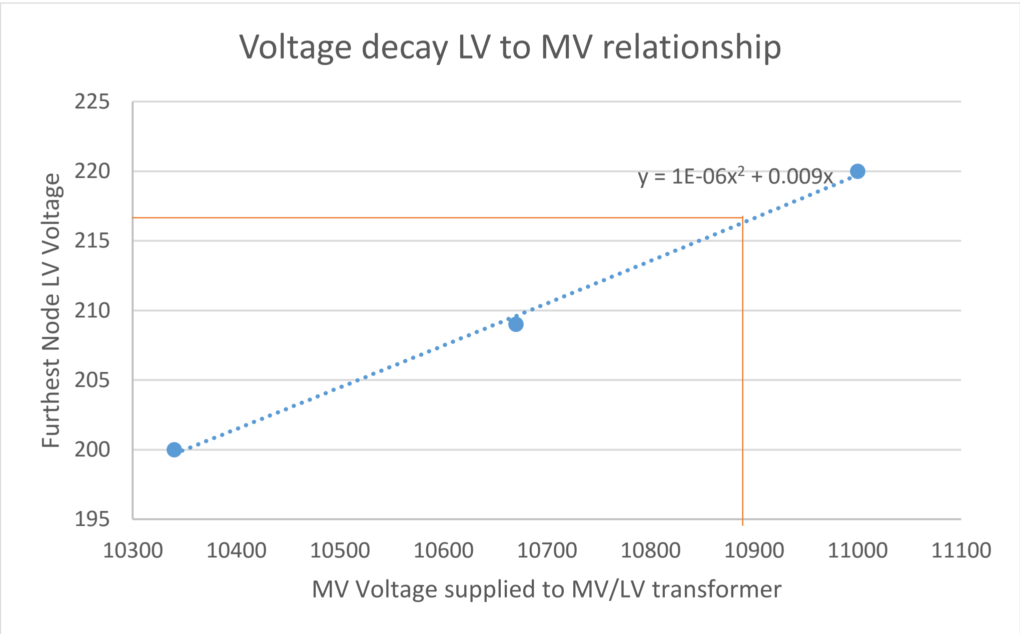


Figure 49: Calculation of minimum 11kV voltage permissible

From the equation of the line in the graph above, a minimum MV feeder node voltage can be derived, assuming that the LV network remains the same size. The calculation steps are provided below.

$$when\ y = 230 \times 0.94 = 216.2 \quad (17)$$

$$x = 10876V = 11000V \times 0.989 \quad (18)$$

∴ Minimum allowable 11kV deviation to keep LV the same length would be=1.1%

To achieve the new lower limit, the DNO would prefer to alter the MV network than the LV network. This is because the LV network would practically, be more difficult to achieve (e.g. existing local transformers are offloaded and have spare capacity that can't be utilised). There are three ways to achieve this new lower limit of the MV network:

- increase the size of the conductor for the MV feeder (partially or fully), reducing the line voltage drop component
- run additional 11kV feeders to support the load, creating new open points
- step up the MV feeders to 22kV. By increasing the feeder voltage, the amount of current drawn is reduced, hence better regulation. In doing this, the current MV/LV transformers must be capable of transforming this to 400V, the switchgear must be able to break the arc, and the lines/cables and joint dielectrics must be rated for this new voltage.

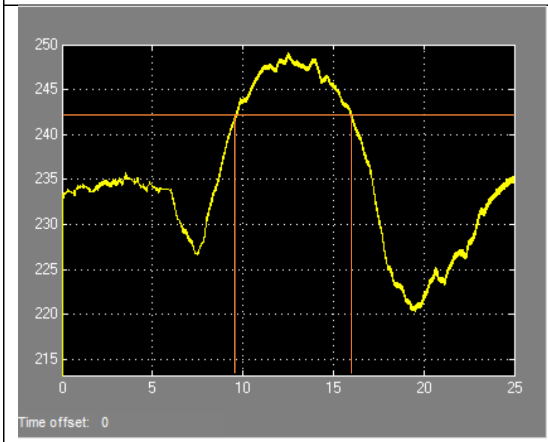
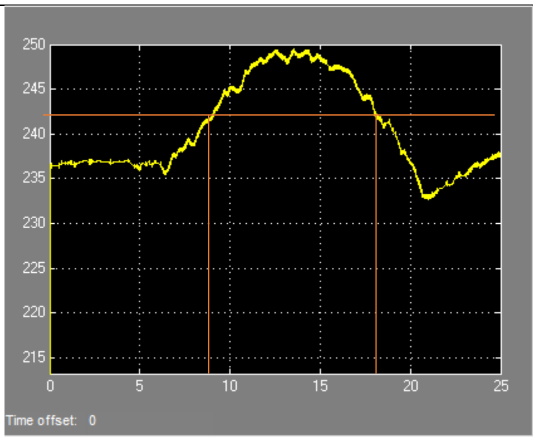
Depending on the restrictions imposed, one of the solutions might be favourable over the others. Restrictions may include:

- new subdivision vs. already developed suburban areas
- condition and rating of existing switchgear and line assets
- funding available to the DNO.

5.2 Solutions SWOT Analysis

In the present environment, customer inverters must disconnect PV units from the grid, once the voltage at the MSB (PCC) is above 243.8V, as per EA regulations. According to the results presented above, this means customers with PV units towards the end of LV will be disadvantaged and will be unable to generate back into the grid during times shown by the graphs below. This is because it was found that they will create conditions of overvoltage and imbalance.

Table 68: Disadvantaged people's profiles at the end of LV feeders

<table>
<tr><th>Winter voltage profile @ FP</th><th>Summer voltage profile @ FP</th></tr>
<tr><td>
</td><td>
</td></tr>
</table>

The times at which they must remain islanded are periods where PV injection is at its peak and can start making a financial return for the customers. Switching off the PV injection during this period may result in a form of unwanted attention for the DNO. Therefore, the solutions trialled above could be used to ease the pressure on the DNO. Each solution, however, has its own strengths, weaknesses, opportunities and threats. These four points for each solution are explored in the sections below.

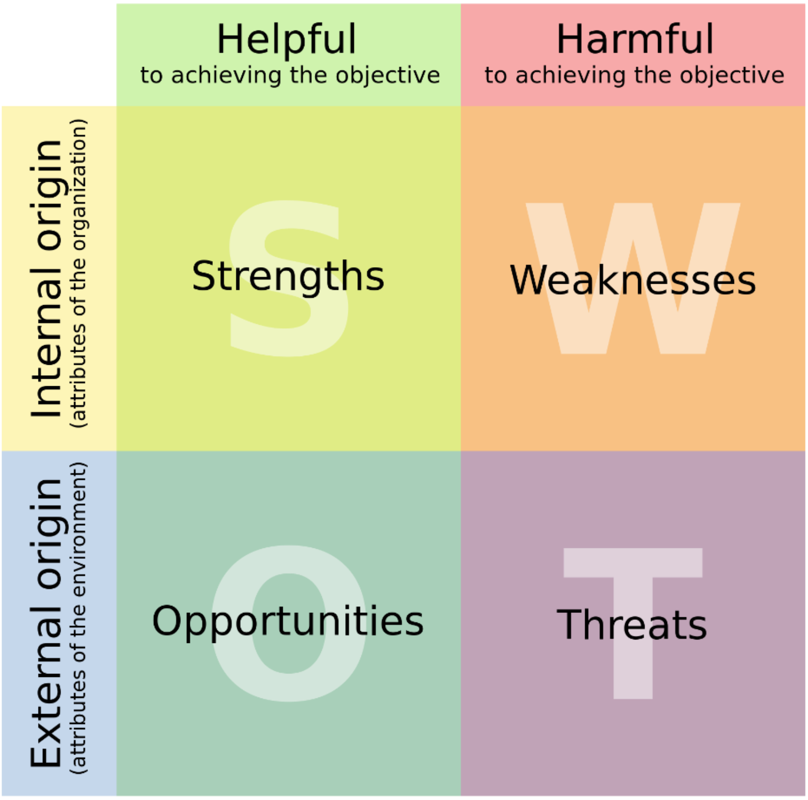


Figure 50: SWOT analysis diagram

5.2.1 Reactive Power

The strength of the reactive power solution was that it lowered the node voltage, by injecting the current generated by the PV unit at a phase shift to the nominal grid. This ensured that whenever the PV unit had available excess current, it would be injected into the grid as reactive power. It has the ability to regulate the overvoltage and reduce the characteristic of voltage imbalance, keeping them within the limits set by the EA PQ guidelines.

The weakness of the reactive power solution was that it flooded the network with reactive power which was not demanded by any of the loads, which resulted in a voltage swell. This swell was noticed in chapter 4 above, but was disregarded because the voltage remained within the specified limitations. If the reactive power injected into the network exceeds the real power drawn from the network, the voltage could swell uncontrollably and imbalance the network.

Generation companies in New Zealand in residential environments, are paid based on the real power that is consumed by the customer. Generation companies are also willing to pay customers for any generated power of their own. If the generated power by the customer is reactive, the generation companies may choose not to reimburse the customer for their generation. It would then put pressure on the DNO to provide some kind of solution for customers at the end of LV feeders, to enable them to compete with other customers on the LV network for financial gain. This is the threat that the reactive power solution poses.

Therefore, this presents an opportunity for the DNO to make it fair for everyone. The DNO may choose to compensate customers at the end of a LV feeder and top them up for the reactive power that they generate. This may defer the need for immediate reinforcement of the LV network and will keep customers happy temporarily at a small cost (when compared with other trialled solutions). But it is not an ideal solution for the DNO, because the DNO is paying customers to essentially not generate real, useful, power. It should be used as a transition phase to move to a more permanent solution such as batteries or single phase micro-grids.

5.2.2 Batteries

Batteries were seen to improve both voltage swell and sag for customers located at the furthest node on a LV feeder. By applying batteries, LV and MV feeders could be increased in length, as peak demand is shaved and the efficiency of the network is increased. This would be both beneficial to the DNO and to the customer as line charges drop due to the reduced number of reinforcement projects required.

The weakness of batteries is that it will introduce imbalance into the network. This is highlighted in the simulations above. Batteries do reduce the voltage swell and sag attributes, but in doing so induce imbalances in the LV network, because other customers on other phases may not have batteries and still continue to draw the same peak load which results in a sag on the phase(s) without the battery installations.

The batteries solution provides storage of power. This provides the opportunities that enable excess generated power to be stored and then dissipated when the customer's demand ramps up. The purpose of this is to reduce as much as possible, the customer demand on the grid. As outlined earlier, the power consumption rates for customers are ~3 times higher than injection rates. Therefore, this makes this solution highly attractive and favourable for the customer. The DNO also has an opportunity to use these customers or network-owned batteries during periods of high transmission costs, to shave operating costs and play in the reserve markets.

However, due to the cost (per kWh ~$500 – Telsa) and the technology restrictions (maximum charge/discharge and capacity ratings), customers may push towards alternatives. For example, under the assumption of a 10kWh daily cycle able battery and 3kW solar panel system, the following calculations have been constructed:

Table 69: Battery pay-back period calculation

	Summer	Winter	Units	Assumptions
Daily consumption	15.73	31.28	kWh	
Normal cost daily	4.09	8.13	$	$0.26 per kWh
Cost annually	2263		$	6m Summer 6m Winter
Daily consumption with Batt + solar	0	23.03	kWh	According to results
New daily cost daily	0	5.98	$	

Cost annually	1091.35	$	
Pay-back period	(2263-1091.35)/10,000 = 8.53	years	$10,000 for PV unit plus Battery

This is a major threat to batteries, because the other alternatives are cheaper and have shorter pay-back periods.

5.2.3 Single Phase Micro-Grid

The unconventional method that was successfully introduced in this thesis was a single phase micro-grid. The solution performed well; it improved voltage regulation, phase imbalance and achieved a reduction in battery capacity and charge/discharge rates. This hybrid managed to meet the PQ guidelines set by the EA in both voltage cases. The only thing it failed to improve was the voltage sag and that was because there was not enough PV generation available.

The weakness of this solution was that the double breaker switching produces inrush currents which might require oversized switches. There must be accurate measurements and forecasting of loads, battery and available PV generation which must be communicated and actioned within 20ms (i.e. 1 50Hz cycle). This is so that customers don't notice a changeover when the system toggles between grid disconnected and grid connected modes. This complexity may be very difficult to achieve in a practical environment and may blow out the cost of the equipment.

The opportunity that this solution presents, is that communities can gain the maximum cost savings by using this combination system. DNO's also have an opportunity to strategically place themselves to offer the solution as well as run and maintain it once installed. The way to maximise the cost efficiency is to have PV installation on only a few houses that have roofs which are north-west facing and can maximise the amount of sun that is captured throughout a day. The other customers in the community can contribute by offering land for battery and breaker installations.

The threat is that this option is by far the most expensive and has not been trialled in a practical environment. The first installation would be required to be a research and development type. Another drawback is that it might be easier to install in locations where new subdivisions are being created, rather than in already developed areas. Lastly, it requires a community of customers which are supplied by the same local service transformer to agree to have this installed. The customers which do manage to get this implemented could enjoy a better cost efficiency and pay-back periods compared to individual battery + PV installations.

CHAPTER 6: CONCLUSIONS AND RECOMMENDATIONS

6.1 CONCLUSION

The project undertaken was challenging, and provided a great insight into the operations and planning that DNO's need to go through. The learning outcomes involved: derivation and analysis of a generic LV network, the effect of solar panels in this generic network, and an investigation of potential solutions. The aims of the project have been achieved.

Investigations into the voltage issues on low voltage networks can be summarised by stating that the severity of voltage issues is amplified as the point of injection moves further away from the local distribution transformer. The changing of transformer capacity and the addition of inductive line parameters, results in a negligible effect on the voltage profiles. A maximum swell of 250V was noticed during both summer and winter simulations, with the duration of overvoltage lasting longer during the summer simulations. The voltage sag was seen to drop down to 200V, when a parallel 5MVA load and 6% voltage drop was added to the MV network. Therefore, it was derived that to keep voltage levels within the LV tolerances, the maximum allowable 11kV deviation should be 1.1% (10876V min). The imbalance parameter was seen to be in its worst case when PV injection occurred on a single phase or on multiple phases but at different electrical locations (i.e. nodes). The maximum observed imbalance was 4%. The overvoltage, sag and imbalance values would be deemed unacceptable according to the current EA PQ guidelines, and would instigate reinforcement projects by the DNO.

The trialled solutions were able to improve all of the above voltage criteria and bring them within the stated limits. Each solution had its own set of strengths, weakness, opportunities and threats. The reactive power solution was able to comply with the voltage requirements, but made a sacrifice in terms of real power output and can be viewed as a transitional solution. Batteries provided improvements for overvoltage and sag, but induced imbalance into the network and were expensive. The single phase micro-grid, an original idea, achieved the best of both worlds, but would require the co-operation of a community and practical trials before being implemented as a solution.

In conclusion, a thorough investigation has been completed and the purpose of the thesis satisfied. However, there are many gaps to be investigated as part of this research, most of which are covered by section 6.2. Given the nature of the project and the imposed restrictions (i.e. knowledge level, time, etc.), it was felt that a satisfactory effort has been made to achieve an outcome which has produced useful results and learning. It was felt that this thesis provided a good foundation for a trial of solutions to PV injection in the New Zealand environment.

6.2 FUTURE RESEARCH OPPORTUNITIES

There are many avenues for further research from the foundation that this thesis provides. The author attempts to cover the most important avenues and the reasoning for further investigation below. This should not, however, be interpreted as the only or the most important avenues for further work.

The load profile of residential loads during weekdays vs. weekends was not considered and neither was the effect of cloud cover. It could be that the customer draws a very different type of demand during the two different periods and a cloud cover co-efficient might need to be used in future to create more realistic results.

The practical findings to compare the theory: it would be ideal to understand the comparison between the theoretical simulations and the true practical standpoint in terms of PQ as it stands now on the MV network, as well as the effects of the solutions once implemented. In particular, the partial applicability of a single-phase micro-grid solution and stability analysis would be an avenue for further investigations. Algorithms used in this thesis were derived and based on known parameters and penetrations, further work on control mechanisms in an uncontrolled environment would prove to be beneficial area of further work.

Ranking and prioritisation of solutions based on the severity of the problems experienced on a DNO's system could help the planning teams decide on future project timings and deferment programmes, as the customer migrates to becoming self-sustainable and the DNO attempts to become the retailer of that solution.

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GLOSSARY & DEFINITIONS

Term	Meaning
DG	Distributed Generation
MV	Medium voltage (11kV and lower)
LV	Low voltage (1kV and lower)
PV	Photovoltaics
PCC	Point of Common Coupling
MV	Medium Voltage
ADMD	After diversity maximum demand
SCC	Short Circuit Capacity
SLD	Single Line Diagram
DNO	Distribution Network Operators
EA	Electricity Authority in New Zealand
PQ	Power Quality
MSB	Main Switch Board
ACDB	A.C. Distribution Board
Tx’fer	Transformer

APPENDICES

Provided in the attached CD.