ADVANCED MANAGEMENT OF RESIDENTIAL BATTERY ENERGY STORAGE IN FUTURE DISTRIBUTION NETWORKS

by

Kyriacos Petrou

ORCID ID: 0000-0002-1839-0065

A thesis submitted to The University of Melbourne for the degree of

Doctor of Philosophy

October 2019

Department of Electrical and Electronic Engineering

Melbourne School of Engineering

This thesis is submitted for the total fulfilment of the degree

ABSTRACT

In recent years, Australia and many other countries have seen a sharp rise in the number of residential solar photovoltaic (PV) system installations. This trend has also driven the adoption of residential battery energy storage (BES) systems, as they allow households to use their excess PV generation at other times. However, as it currently stands, most commercially available residential BES systems are controlled for the sole benefit of their owner, i.e., to reduce grid imports. But given their controllability, there exists a large opportunity for these systems to a) help mitigate the well-established PV issues in electricity distribution networks (e.g., voltage and thermal issues), or b) be used in the provision of services to the whole power system (e.g., frequency or energy services).

For a), this thesis first assesses the performance of off-the-shelf (OTS) BES systems and demonstrates their inability and limitations to provide support in mitigating PV impacts. While overcoming these limitations has been the focus of several studies over the past years, there is need for practical and scalable, yet effective BES control strategies that provides benefits to both the customers and the distribution network to be developed. In this context, a decentralised control of BES systems is proposed which dramatically reduces PV impacts on the distribution network with minimal effects on households.

As for b), in this thesis, the impacts of the widespread provision of services from residential BES systems on distribution networks are assessed. It is demonstrated that if left unconstrained, it can lead to severe issues. In this context, a distribution system operator (DSO) framework is proposed, using a three-phase AC optimal power flow-based approach, to ensure network integrity and fairness. The results show that it is not only possible to achieve this for multiple service providers, but it also unlocks much larger volumes of services compared to those achieved with the currently adopted fixed export limits of 5kW per phase.

To assess the network performance as realistically as possible, this thesis uses an integrated medium voltage (MV) – low voltage (LV) network to consider the interactions of multiple voltage levels and fully capture the effects of DER (and the resulting reverse power flows). More specifically, a 22kV (i.e., MV) real feeder is used from Victoria, Australia, whereas the 400V (i.e., LV) circuits are modelled based on regional network design principles. Furthermore, the analyses utilise real smart meter demand, generation, and pricing data from the same region. The power flow assessments consider high granularity time-series data using three-phase four-wire unbalanced power flows. Finally, a Monte Carlo approach is adopted in the assessments in this thesis to cater for the uncertainties related to demand, generation, and locational aspects of distribution networks.

DECLARATION

This is to certify that

1. the thesis comprises only of my original work towards the degree of Doctor of Philosophy except where indicated in the preface,
2. due acknowledgement has been made in the text to all other material used, and
3. the thesis is less than 100,000 words in length, exclusive of tables, maps, bibliographies, and appendices.

Kyriacos Petrou, October 2019

PREFACE

Portions of the work of this thesis have been carried in collaboration with Dr Andreas T. Procopiou of The University of Melbourne and Dr Luis Gutierrez-Lagos of The University of Manchester. These collaborations enabled the timely production of research. The list below identifies the publications (both published and unpublished work) that correspond to each chapter, as well as the contributions of each collaborator.

Chapter 3

1. **K. Petrou**, L. F. Ochoa, Deliverable 1 “HV and LV Network Modelling”, prepared for AusNet Services, 2017.
2. **K. Petrou**, L. F. Ochoa, Deliverable 2 “Impact Analysis of Mini Grid Clusters with PV Systems”, prepared for AusNet Services, 2017.
3. **K. Petrou**, L. F. Ochoa, Deliverable 3 “Assessment of Potential Solutions”, prepared for AusNet Services, 2017.

It should be noted that these reports are protected by a non-disclosure agreement between the University of Melbourne and AusNet Services, and have therefore not been made publicly available. Data and results from these reports has been fully anonymised so that they can be included in this thesis.

Chapter 4

1. **K. Petrou**, L. F. Ochoa, A. T. Procopiou, J. Theunissen, J. Bridge, T. Langstaff, K. Lintern, “Limitations of Residential Storage in PV-Rich Distribution Networks: An Australian Case Study”, *in IEEE Power & Energy Society General Meeting*, 2018, pp. 1-5.

Chapter 5

1. A. T. Procopiou, **K. Petrou**, L. F. Ochoa, T. Langstaff, J. Theunissen, “Adaptive Decentralized Control of Residential Storage in PV-Rich MV-LV Networks,” *IEEE Transactions on Power Systems*, vol. 34, no. 3, pp. 2378-2389, May 2019.
2. **K. Petrou**, A. T. Procopiou, L. F. Ochoa, T. Langstaff, J. Theunissen, “Residential Battery Controller for Solar PV Impact Mitigation: A Practical and Customer-friendly Approach”, *in 25th International Conference and Exhibition on Electricity Distribution (CIRED)*, 2019, Accepted.

Dr Andreas T. Procopiou initiated the research that led to the publication of (1) based on work that was included in his doctoral thesis. Prior to the collaboration with the author of this thesis, the control methodology was fundamentally different, and the network assessments were performed on low voltage UK networks. Through the collaboration the control methodology changed dramatically when compared to the original research. Furthermore, new case studies and assessments were performed (Australian integrated medium voltage – low voltage network assessment, customer benefits assessment, effects of estimation errors analysis, etc.). Given that the research project was led by Dr Procopiou, he was appointed as first author of the journal paper in (1). The significantly improved content resulted in the publication of (1), (2), as well as the filing of a provisional patent application. As per regulation of The University of Melbourne, it is hereby declared that I, Kyriacos Petrou, have contributed to the majority (at least 51%) of the content found in (1) *that is also found in this thesis* and claimed as original.

Chapter 6

1. **K. Petrou**, A. T. Procopiou, L. F. Ochoa, T. Langstaff, J. Theunissen, "Impacts of Price-led Operation of Residential Storage on Distribution Networks: An Australian Case Study", *in IEEE PowerTech Milan,* 2019, Accepted.
2. **K. Petrou**, L. F. Ochoa, "Customer-led Operation of Residential Storage for the Provision of Energy Services", *in IEEE Innovative Smart Grid Technologies Conference Latin America (ISGT-LA)*, 2019, Accepted.

Dr Andreas T. Procopiou provided support with the power flow analyses and presentation of results in (1).

Chapter 7

1. **K. Petrou**, A. T. Procopiou, L. Gutierrez, L. F. Ochoa, "A DSO Framework to Facilitate Bottom-Up Services: Determining Operational Limits for Prosumers in MV-LV Distribution Networks", *IEEE Transactions on Smart Grids*, Submitted.

Dr Andreas T. Procopiou provided support with the power flow analyses and presentation of results. Dr Luis Gutierrez provided the three-phase AC optimal power flow constraints used in the DSO framework.

“Give me six hours to chop down a tree and I will spend the first four sharpening the axe.”

– Abraham Lincoln

This page intentionally left blank.

DEDICATION

To Petros and Eleni,

my wonderful and loving parents.

You have raised me to be the person I am today.

Without your support,

none of this would have been possible.

This page intentionally left blank.

ACKNOWLEDGMENTS

I would like to express my uttermost gratitude to my supervisor Prof. Luis F. Ochoa, whom without his continuous supervision and support the completion of this thesis would not have been made possible. His experience and guidance over the past few years have been crucial to not only my development as a researcher, but also helped me build the character required for me to overcome the obstacles in the path ahead.

Very special thanks also to my friend and collaborator Dr. Andreas T. Procopiou, with who we have spent endless hours debating and arguing on everything; from the performance of algorithms to what linewidth plot we should use in the figures. His inputs have greatly contributed to the quality of work presented in this thesis and I hope the future holds many more fruitful collaborations between us.

Furthermore, I would like to thank my friends and colleges here within the Power & Energy Systems group at the University of Melbourne: Sebastian, Dillon, James, William, Michael, and Han for the years of friendship and support. Special thanks also to my international friends that I had the pleasure of working with over the course of my PhD degree: Luis and Tiago.

Last but by no means least, I would like to express my sincere and uttermost appreciation to my partner Katie who has provided me with the all the support and care that was so much needed during the completion of this thesis. She has taught me to always pursue my dreams and aspirations to the fullest, but also that sometimes it is okay to take a step back and enjoy life.

This page intentionally left blank.

TABLE OF CONTENTS

LIST OF TABLES

List of Figures

NOMENCLATURE

AD	Adaptive Decentralised
ADMD	After Diversity Maximum Demand
AEMO	Australian Energy Market Operator
ANM	Active Network Management
BES	Battery Energy Storage
DER	Distributed Energy Resources
DLMP	Distribution Locational Marginal Pricing
DNO	Distribution Network Operator
DNSP	Distribution Network Service Provider
DSO	Distribution System Operator
GSP	Grid Supply Point
HV	High Voltage
LCT	Low Carbon Technology
LMP	Locational Marginal Pricing
LV	Low Voltage
MILP	Mixed Integer Linear Programming
MPC	Model Predictive Control
MV	Medium Voltage
OPF	Optimal Power Flow
OPT	Optimisation-based
OTS	Off-the-shelf
PV	Photovoltaic
SOC	State of Charge
TOU	Time of Use
TSO	Transmission System Operator

VPP	Virtual Power Plant
μCHP	Micro Combined Heat and Power

1 INTRODUCTION

Climate change. Sustainability. Carbon emissions. Global warming. Green energy. Words that no one spoke of fifty years ago, but in the recent years one cannot seem to be able to escape. Once, conversations about renewable energy could only be heard in University lounges and research centres, now, discussions about wind or solar energy are becoming the epicentre of conversations at dinner parties. The public is becoming increasingly alert about the environmental consequences that the current rate of carbon emissions will have to the welfare of the population over the next decades.

Understanding this, the majority of the countries around the world are putting significant efforts to reduce their carbon emissions. For example, the Victorian government in Australia has committed to renewable energy generation targets of 25% by 2020 and 40% by 2025 [1]. To achieve these very challenging targets, the adoption of residential-scale low carbon technologies (LCTs), and in particular renewable generation, has been accelerated through the usage of very generous incentives.

In Australia, the residential-scale LCT that has received most attention over the past decade is solar photovoltaic (PV); the country currently has the largest number of installations per household in the world. Due to the high adoption of solar PV systems, as well as other socioeconomic factors such as high electricity prices, the adoption of residential-scale battery energy storage (BES) systems has also been rapidly increasing over the past few years and forecasts indicate that Australia will soon have the largest number of residential-scale BES systems in the world. As such, Section 1.1 of this chapter aims to provide understanding of the current solar PV status, the corresponding effects that the widescale adoption of these systems can have on distribution networks, and how these issues are currently addressed. Section 1.2 presents the information related to the recent rise of residential BES systems as well as the opportunities that these systems bring in future distribution networks; both in terms of controlling them to mitigate solar PV impacts, but also for the provision of services to the whole power system. However, as the latter can negatively impact distribution networks if left unregulated, the need for distribution network constraints to be incorporated in the provision of services as well as how can this be realised is then discussed in Section 1.3. Furthermore, the aims and objectives of the thesis, the associated challenges in meeting these objectives, and the contributions of the thesis are presented in sections 1.4 - 1.6, respectively. Finally, an outline and short description of all the chapters in the thesis is given in Section 1.7.

1.1 Solar PV and Distribution Networks

Amongst the different types of renewable generation that exist, one of the most popular for many regions around the world is solar photovoltaic. Due to numerous factors, such as the rapid cost reduction of PV panels over the last decade, generous incentives by governments, relatively low complexity of installing the panels on household rooftops, low maintenance, and long lifetime, these systems have become the go-to residential-scale renewable generation technology. Their widespread adoption, however, has been creating technoeconomic challenges in the operation of electricity distribution networks.

1.1.1 Solar PV Status

Enabled by the aforementioned factors, in Australia, the solar PV penetration is currently at 23% [2] (i.e., percentage of households with a solar PV system installed); effectively being the world leader in terms of number of installations per household. And the adoption of residential-scale solar PV does not seem to be slowing down; on the contrary, as seen in Figure 1-1, both the number of new solar PV installations per month as well as the average size of new installations has been increasing steadily over the past few years.

In fact, as seen in Figure 1-2, the continual increase in both the number of monthly installations and the average system size per installation has caused the total PV installed capacity to increase significantly over the past few years. If this trend is to continue, the total solar PV capacity could reach up to 16GW by the start of 2020.

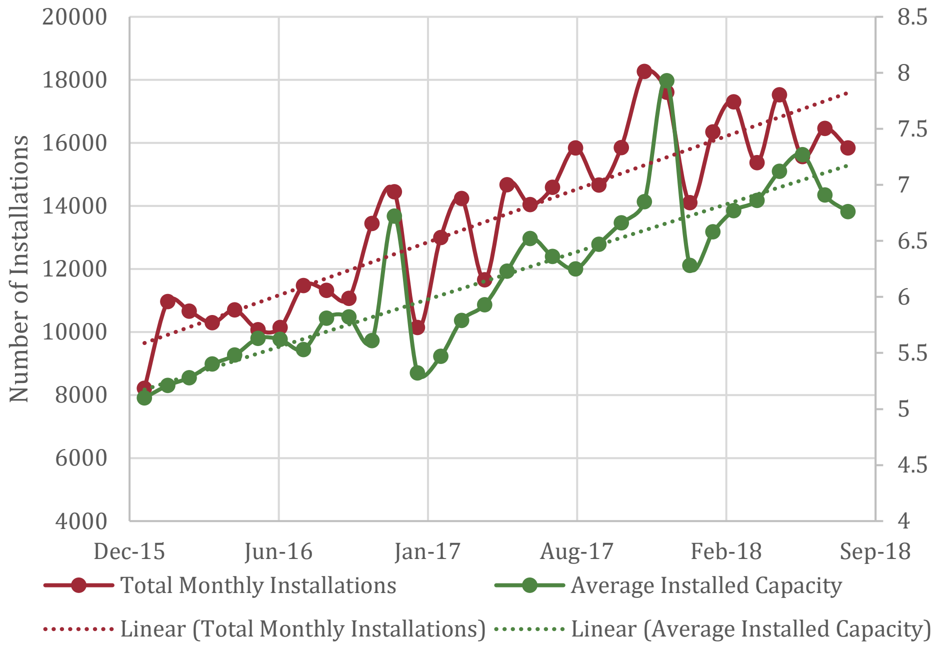


Figure 1-1. Australian PV system installation statistics (2016 onwards) [2]

Nonetheless, the high adoption rate of solar PV is not only limited to predominantly sunny regions such as Australia. Numerous other countries are having significant uptakes of residential-scale solar PV systems. The most prominent example is Germany, one of the earliest adopters of attractive incentives for solar PV systems. Second only to China [3], Germany had a total solar PV installed capacity of 46GW by the end of 2018 [4]. It is also estimated that roughly 75% of this capacity is residential-scale [5].

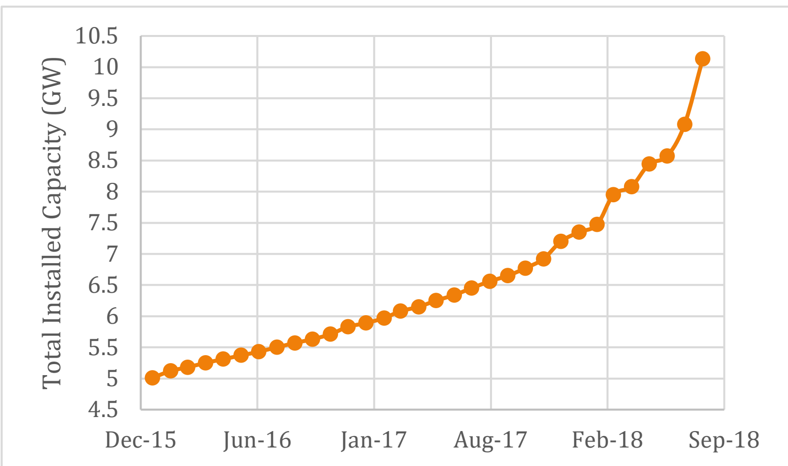


Figure 1-2. Cumulative PV system installed capacity (2016 onwards) [2]

While the rapid adoption of residential-scale solar PV is a step in the right direction in decarbonising the energy production of a country, there are numerous technical issues that are soon to be bottlenecks in the further adoption of these systems. While these issues span across different sectors of the power system, this thesis will only consider the steady-state technical impacts of solar PV generation in distribution networks.

1.1.2 Traditional Distribution Networks

To understand how the widespread adoption of solar PV impacts distribution networks, first, the design principles and characteristics of these networks need to be understood. Traditionally, distribution networks (as well as the whole power system) were designed to be able to supply the load demand in a hierarchical manner; large-scale dispatchable (in most cases, fossil fuel-based) generation of electricity, transmitted in bulk over large areas through a highly meshed, high voltage transmission network, and then distributed to residential, commercial or industrial customers in a region through different voltage levels of a generally radial distribution network. This paradigm, henceforth referred to as the "traditional power system", is illustrated graphically in Figure 1-3.

The design of distribution networks considers numerous constraints (e.g., voltage unbalance, power factor etc.) but in this thesis only two steady-state constraints (the most dominant) are considered: thermal capacity of the assets (e.g., transformers, lines) and keeping the voltage between the regulation voltage limits (a.k.a. voltage statutory limits).

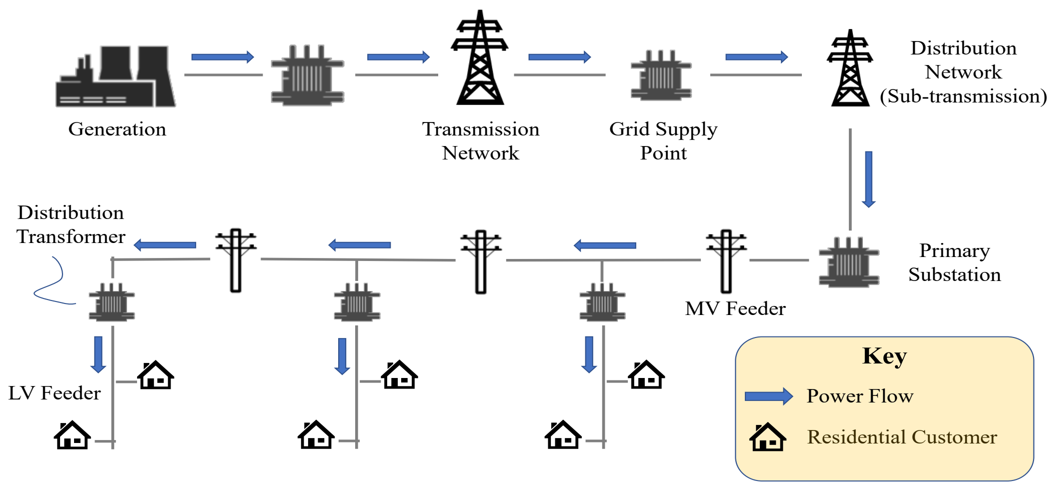


Figure 1-3. Traditional power system diagram

In the traditional power system model, as the monodirectional power flow from the grid supply point (GSP) to the end-customer causes voltage to drop the farther power is being transferred, distribution network service providers (DNSPs)[1] use voltage regulating devices such as on-load tap changers (OLTCs) at the primary substation (e.g., 66kV/22kV interface), off-load tap changers at the distribution transformers (e.g., 22kV/0.4kV interface), and in some cases, capacitors to boost the voltage close to the upper voltage limit. Furthermore, the networks are designed to accommodate the peak demand of a region. Generally, demand is rather diverse (e.g., not all houses turn on their oven at the same time), and thus, DNSPs use a metric known as the after diversity maximum demand (ADMD) to calculate the capacity of the transformers and lines. The ADMD can vary quite substantially between countries and regions. For example, in the UK, where peak demand exists during cold winter nights and heating is provided primarily from gas heating, a 1.5kW ADMD [6] is commonly used. In Australia however, where the peak demand is primarily governed by air-conditioning units during heat waves, a 4kW ADMD is commonly used [7].

1.1.3 Solar PV Impacts on Distribution Networks

The rise of renewable generation, and in particular solar PV systems, are presenting newfound challenges in the design and operation of distribution networks [8-11]. Solar PV generation coincides with periods of low demand in residential regions, as household occupants are likely to be at work during midday hours (i.e., noon). Furthermore, as distribution networks generally occupy small regions, there is very little diversity in the generation from multiple sites, as the effect of clouds on solar irradiation is likely to be similar. Therefore, as the solar PV penetration in a region increased, the local generation from multiple households is expected to exceed the local demand; thus, creating power flows from the end-customers to the distribution substations. This effect is henceforth referred to as “reverse power flow” and is presented graphically in Figure 1-4.

The traditional design and operation of distribution networks with the existence of large volumes of reverse power flow is no longer suitable as it will very likely lead

[1] This term refers to the companies that own and manage the distribution networks in Australia. The equivalent term in the UK is distribution network operators (DNOs).

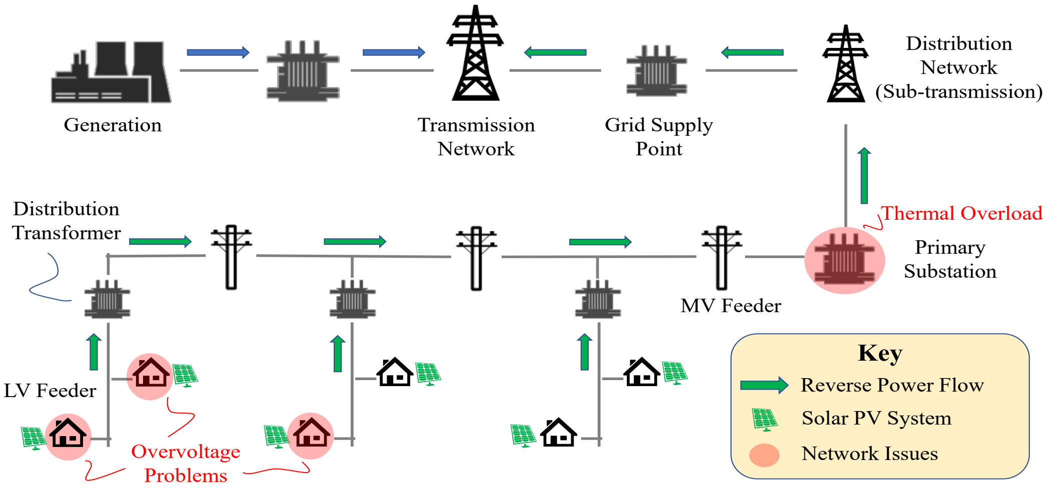


Figure 1-4. Current / Future power system

to the violation of network constraints. Due to the lack of diversity in solar PV generation, network assets can be overloaded during periods of peak generation when a large number of houses have solar PV systems within the same network. When voltages are considered, reverse power flows cause the voltage to increase from the substation to the end-customer. With voltage regulating devices operated to boost voltages, this can cause the voltage to exceed the voltage statutory limit. The quantification of impacts of solar PV in residential distribution networks is generally quite network specific; different networks have different solar PV hosting capacities (defined as the percentage of houses that can have a PV system without compromising network constraints). Therefore, it should be noted that depending on the design and topology of the network, either thermal or voltage problems can exist first [12].

1.1.4 Potential Solutions from Existing Assets

To enable higher penetrations of solar PV in their networks, a simple yet expensive solution would be to reinforce the network infrastructure (e.g., larger transformers and cables). As a more cost-effective alternative on the other hand, DNSPs can leverage existing assets to help satisfy network constraints. These solutions include the usage of either network assets (off-load tap changers, OLTCs), or behind-the-meter assets such as solar PV inverters installed at customers.

1.1.4.1 Off-load Tap Changers

Distribution transformers, i.e., transformers installed at the medium voltage – low voltage (MV-LV) interface, are fitted with off-load tap changers. Off-load tap changers allow changing the transformation ratio of the transformer so that the voltage at the secondary of the transformer can be adjusted. However, the tap position (i.e., the transformation ratio), can only be changed when the transformer is manually disconnected from the power grid (i.e., by a technician, in person).

One of the most common types of distribution transformers in Australia is the Delta-Wye 22kV/0.433kV. In per unit values, using a 22kV base for the MV and a 0.4kV base for the LV, these transformers essentially "boost" the voltage from 1.0pu to 1.083pu when the nominal tap (i.e., default) of the off-load tap changer is used. The off-load tap position can be changed, which allows to increase or decrease the voltage at the secondary of the transformer, usually in 2.5% steps for a small number of steps.

Without the presence of solar PV generation in the network, DNSPs use off-load tap changers to keep the voltage at the secondary side of distribution transformers as close to the upper limit as possible (1.10pu in Australia [13]). With the presence of solar PV generation, however, due to the reverse power flows and the corresponding voltage rise they cause, this would essentially cause voltages in the LV network to exceed the limit. Therefore, it is now common practise for DNSPs, in Australia and internationally, to lower the voltage at the secondary of the distribution transformers to allow for some voltage rise headroom and help solve overvoltage issues. However, off-load tap changers are limited by two factors:

1. there are limited amount of tap positions, and
2. lowering the tap position too much can potentially lead to undervoltage issues during peak demand periods.

Therefore, there is limited support that off-load tap changers can provide. Finally, it should be clarified that off-load tap changers are not able to help with thermal problems from solar PV generation in the network.

1.1.4.2 On-load Tap Changers

Unlike off-load tap changers, OLTCs can change taps while the load is connected. They are typically used at higher voltage substations (e.g., primary substations), to maintain a steady voltage at the head of the feeders. The target voltage of the OLTC is usually network specific. While OLTCs can be leveraged to solve voltage problems in networks, given that different feeders connected to the same primary substation can have substantially different energy mix (residential, commercial, industrial) and very different solar PV penetrations, lowering the voltage target might solve overvoltage problems in one feeder but cause undervoltage problems in another. Similar to off-load tap changers, OLTCs do not help mitigate thermal problems in the network.

1.1.4.3 Solar PV Inverter Functions

Modern solar PV inverters are required, depending on the region/country, to have certain capabilities present and/or enabled. While the number of functions is quite extensive, three are discussed in this section; the Volt-Watt, Volt-Var, and export limit functions.

1.1.4.3.1 Volt-Watt Function

The Volt-Watt function adjusts the power output of the inverter depending on the voltage at the grid side. Generally, as voltage increases, the inverter reduces the power output so as to reduce reverse power flows and thus overvoltage problems in the network. While the Volt-Watt function can help mitigate both voltage and thermal problems, it is relying on curtailment of PV generation. High levels of curtailment could mean that customers might not be able to recover their solar PV system investment, and thus discourage the adoption of these systems. Furthermore, as the curtailment is dependent on the voltage at the customer connection point, customers farther away from the distribution transformers are penalised much more heavily as they are exposed to higher voltages in the presence of reverse power flows. Finally, solving thermal problems using the Volt-Watt function is a bi-product of the curtailment; thus, there are no guarantees that the issues will be solved. Solutions regarding the usage of the Volt-Watt function in LV networks were fully investigated in [14].

Due to the high solar PV penetration in Australia, all new solar PV inverters since 2015 are required to have the Volt-Watt function enabled [15]. The default Volt-Watt curve is shown in Figure 1-5.

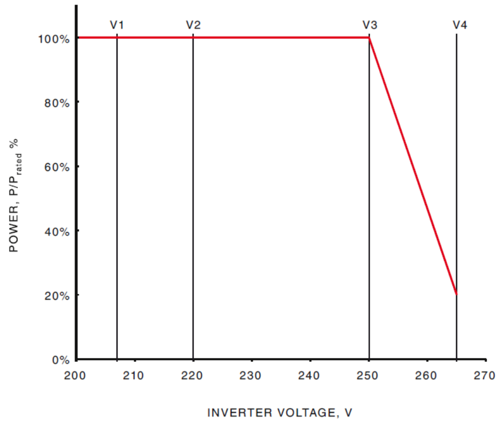


Figure 1-5. Default Volt-Watt curve in Australia (taken from [15])

1.1.4.3.1 Volt-Var Function

The Volt-Var function adjusts the reactive power absorption or injection of the solar PV inverter depending on the voltage at the AC terminal. At higher voltages, the inverter absorbs reactive power, which causes the voltage to be reduced. At lower voltages, the inverter injects reactive power, which causes the voltage to increase. While the Volt-Var function can help mitigate voltage issues without curtailment of solar PV generation, it suffers from two limitations; during peak PV generation, if the inverter is sized equally to the solar panels, it does not have adequate capacity to absorb reactive power; unless a Var priority is given in the inverter, which results in curtailment of active power. Furthermore, it exacerbates thermal problems as the absorbed reactive power causes higher currents in the lines. Both these effects are quantified in detail in [14].

Unlike the Volt-Watt function, the Volt-Var function is required to be available in solar PV inverters in Australia, but not activated [15]. The default Volt-Var curve is shown in Figure 1-6.

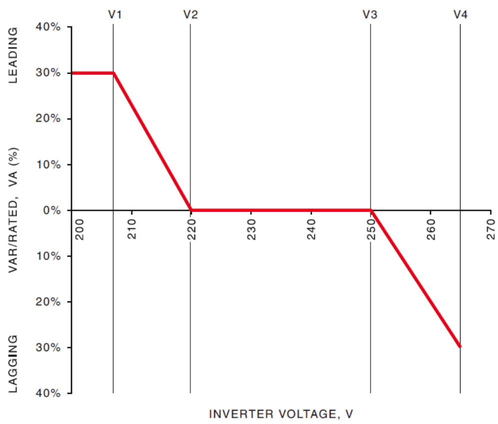


Figure 1-6. Default Volt-Var curve in Australia (taken from [15]).

1.1.4.3.2 Export Limits

Modern solar PV inverters have the capability to reduce the maximum power that can be exported in the network. Such operation is already in effect in Germany, where residential customers are allowed to export up to 70% of their solar PV system capacity into the network [16], and in Australia where in the recent years some DNSPs are enforcing 5kW export limits for single-phase connections [17, 18] (most common type of residential connection). Similar to the Volt-Watt function, export limits can help mitigate both voltage and thermal issues, however, given that they result in the curtailment of solar PV generation, they can prove to be very prohibitive for customers. The definition of export limits in residential networks, as well as the corresponding effects to customers was investigated in [19].

1.1.5 Summary

The widescale adoption of solar PV systems in residential networks is very likely to result in technical issues in the distribution network. As such, DNSPs are leveraging existing assets to help mitigate these issues; either through network elements or assets installed at households with PV systems. Residential BES systems, a relatively new device that has recently entered the market, feature technical capabilities that could be leveraged in similar manner to help DNSPs mitigate solar PV impacts in distribution networks; one of the key research areas addressed in this thesis.

1.2 The Rise of Residential BES Systems

In the recent years, BES systems have become increasingly popular. This is particularly prominent in Australia, which is one of the countries with the highest penetration of residential BES systems in the world. As seen in Figure 1-7, Australia has roughly the same installed capacity of residential BES systems as the USA, being second only to Japan. In 2019 however, it is forecasted that the installed capacity of BES systems in Australia will quadruple, overtaking Japan. Given that the population of Australia is only a fraction of that of Japan and the USA, this shows how popular residential BES systems are currently in Australia. In fact, in 2017, 12% of the new solar PV installations in Australia also included a BES system; a significant increase from the 6% recorded in 2016 [20].

And these trends are fully justified; as seen in Figure 1-8, having a 5kWp solar PV + 13.5kWh/5kW BES system provides significant monetary benefits over a grid-only supply. It is therefore expected that the adoption of residential BES systems, particularly in Australia, will continue to increase dramatically over the next few years, as more and more households opt to supply their energy needs locally, through renewable energy, and at a much lower cost.

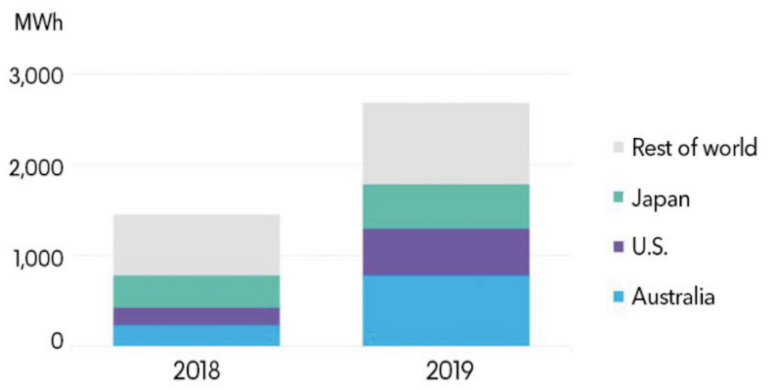


Figure 1-7. Current and forecasted residential BES systems installed capacity (taken from [21])

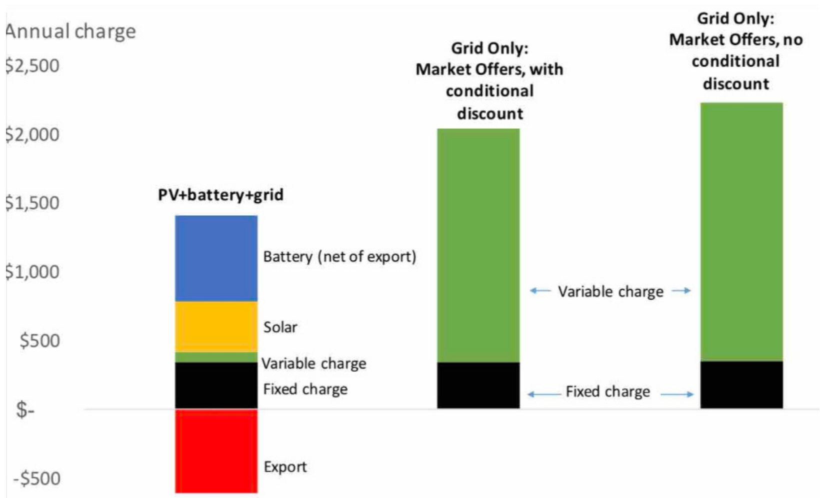


Figure 1-8. Solar PV + Tesla Powerwall 2 + grid supply vs grid only supply (taken from [22])

1.2.1 Technology Overview and Capabilities

The primary purpose of residential-scale BES systems is to store the surplus solar PV generated energy (i.e., the PV generated energy that is not used at a given instance), which is then used to supply the household demand at periods whenever it can no longer be supplied by the solar PV system (i.e., cloudy period, late afternoon, night, etc.). In this thesis, this control paradigm is assumed as the default operation of commercially available BES systems and it is henceforth referred to as the “off-the-shelf” (OTS) control.

The OTS control of residential BES systems provides value to the household due to the difference between energy import and export prices, as the PV generated energy that could be exported (and depending on the region, sold to the energy supplier) during the day is alternatively used to reduce demand during the night (energy that would have alternatively been bought from the energy supplier). Therefore, their adoption in different regions or countries can vary quite substantially on the level of incentives for exporting PV generated energy into the grid as well as the cost of electricity. For example, in countries with net metering incentives (i.e., the amount of energy that is exported into the grid can then be imported without any cost), residential BES systems do not provide any value to the customer. On the other hand, in countries where the electricity price is relatively high, but exporting into the grid does not offer significant benefits, BES systems can be economically feasible.

Generally, BES systems have several key characteristics which are used to understand the capabilities of these systems. These characteristics are explained below. The values of a popular commercially available BES system (Tesla Powerwall 2 [23]) are also given for reference.

1. *Energy rating* (kWh): The amount of energy that can be stored in the battery cells. Tesla Powerwall 2 has an energy rating of 13.5kWh.
2. *Power rating* (kW): The maximum continuous power that the BES system can either absorb (i.e., charge) or export (i.e., discharge). Tesla Powerwall 2 has a power rating of 5kW.
3. *Round-trip efficiency* (%): The percentage of the energy that can be discharged from the BES system per unit of energy that was used to charge the BES system. Tesla Powerwall 2 has a round-trip efficiency of 88%.
4. *Depth of discharge* (%): How much of the energy capacity of the BES system can be discharged. Tesla Powerwall 2 has a depth of discharge of 100% (i.e., the full 13.5kWh can be discharged from the BES system).

One of the most important characteristics of residential-scale BES systems is the flexibility that they offer in terms of controllability. Most commercially available

BES systems can have their operation altered based on external controls that can be physically connected to the device, or even be remotely controlled through network channels (i.e., online). Essentially, this allows for these systems to be controlled for objectives other than to only supply the household demand and charge from surplus PV generation.

1.2.2 Opportunities

Given the inherent controllability of residential BES systems, under the right incentives, schemes, or even regulation, customers could adopt different types of control on their BES systems. This would further unlock the benefits that these devices can bring to different stakeholders.

1.2.2.1 Solar PV Impacts Mitigation

While residential-scale BES systems charge from the surplus PV generation, this creates the general expectation that these systems will inherently reduce peak household exports into the network and thus mitigate issues associated with reverse power flows. However, as commercially available OTS BES systems are not controlled to specifically mitigate these issues, there are no guarantees that they will have adequate capacity to charge during periods of peak PV generation. As an example, a 5kWp PV system can produce up to ~25kWh in Victoria, Australia on a sunny summer day (i.e., capacity factor of ~20%). Given that the Tesla Powerwall 2 can only charge with 13.5kWh, a large portion of the PV generated power is still expected to be exported into the grid.

Given the capabilities of BES systems, there exists the opportunity to adopt more intelligent control strategies so that these systems can not only reduce grid imports for the residential customers, but also help mitigate solar PV impacts on the network. By adapting the charging behaviour of these systems to tackle the very source of solar PV impacts on the network (i.e., peak household *power* exports), they can be utilised to mitigate both thermal and voltage problems without the need for generation curtailment (i.e., wasting energy), and allow larger penetrations of solar PV to be integrated within the distribution networks. Otherwise alternatives would prove to be either to prohibitive (e.g., very conservative Volt-Watt curves or export limits), or too expensive (e.g., network asset reinforcement).

1.2.2.2 Provision of Services

As aforementioned, residential BES systems have the capability to be controlled remotely. This presents the opportunity to dispatch these systems (i.e., plan their operation) so as to provide services to the whole power system, as highlighted in [24]. There exists a wide range of services that can be provided, usually delivered by conventional generators (or, in some countries recently, grid-scale storage systems). Nonetheless, as residential BES systems become more widespread, there also exists the opportunity to utilise these systems in a similar way; in the aggregate, they will have similar effects as providing services in the conventional manner. The services that can be provided are usually country / region specific, as these can vary quite greatly depending on the market structure and regulations.

In Australia, current regulation does not allow for individual residential households to participate in the provision of services directly, but this can be done through aggregators (i.e., third parties that manage a portfolio of BES systems and other resources and participate in the provision of services as a virtual large system). Nonetheless, in the future, the regulatory framework could change so as to also allow individual households to participate directly in the provision of these services [25]. An overview of the markets that BES systems can participate in is given below.

1. *Wholesale Electricity Market*: The wholesale electricity market is where energy is traded as a commodity. All generators submit an offer (in $/MWh) and the available capacity (in MW). The energy price for a given time interval (e.g., every 5-minute period) is determined by stacking up all the offers starting from the cheapest one. Once the demand requirement has been met, the most expensive offer determines the energy price. Given that BES systems can dispatch their discharging, they can participate as generators in the electricity market. This allows to take advantage of energy price spikes due to high demand and therefore obtain revenue.
2. *Frequency Control Ancillary Services (FCAS) Markets*: The purpose of the FCAS markets is to ensure that there is enough available reserved capacity that can respond to changes in frequency so as to maintain it within the allowed limits. BES systems excel at providing inverter-based frequency response as they can change their power output within milliseconds [26].

The provision of such services from residential-scale BES systems is monetised. Customers that provide such services through their systems will have an additional stream of value (besides reducing grid imports). By providing more value to the customers, these systems can become more economically attractive which will in turn further increase their adoption.

1.2.3 Summary

Given the opportunity to utilise residential-scale BES systems to mitigate solar PV impacts in the distribution networks but also provide services to the whole power system, adequate control strategies need to be developed in anticipation of the forecasted adoption of these systems; both aspects are considered in the research carried in this thesis.

However, given that residential BES systems providing services to the whole power system can increase dramatically both the demand or the generation of households within a region, this can potentially cause violation of distribution network constraints (voltage and thermal). As such, distribution network constraints need to be considered in the provision of services. For this to happen, there is strong advocacy in certain countries for DNSPs to transition into a more active role, commonly referred to "distribution system operator" (DSO)[2].

1.3 Towards Distribution System Operators

In the traditional power system model, the procurement of services (wholesale energy, frequency, etc.) by the transmission system operator (TSO) only considers whole system network constraints (e.g., energy balancing, frequency regulation) as well as transmission network constraints (e.g., power flows, voltages). And for good reason; the majority of suppliers of such services (e.g., conventional synchronous generators) are directly connected to the transmission network. With the levels of renewable generation in distribution networks increasing (henceforth referred to as distributed energy resources (DER)), TSOs can now also procure services from these resources.

[2] In some countries, DSO refers to the electricity distribution companies (i.e., same as DNO or DNSP). In this thesis, DSO refers to the entity actively incorporated in the procurement of services from energy resources in distribution networks.

Nonetheless, the same paradigm exists; even with services procured from DER, TSOs do not consider distribution network constraints. As it currently stands, these resources are very scarce and thus the distribution network capacity can be assumed to be infinite. From the available DERs, BES systems is the most prominent technology to be able to deliver such services, as they are highly dispatchable and offer extreme controllability with very fast response times. With the capacity of residential-scale BES systems rapidly increasing, the procurement of services from the TSO will soon need to consider distribution network constraints. However, this falls outside the scope of the TSO, as they are not responsible for the operation of distribution networks.

1.3.1 From Passive to Active

As previously mentioned in Section 1.1.2, traditional distribution networks were designed and operated to accommodate for the peak demand. With the rise of DER and particularly solar PV, DSNPs have been adopting different solutions to mitigate these impacts, but the operational principles remain largely the same; current distribution networks are almost exclusively operated passively, as opposed to the transmission networks that are managed in a rather active and very granular way. And for good reason; distribution networks, while much smaller in geographical size, are several magnitudes larger than transmission networks in terms of buses, devices, lines etc. This makes the active management of these networks very complex, and thus, DNSPs have been putting most of their efforts in the medium and long-term planning and operation. Under such operational paradigm, DNSPs mostly utilise “fit-and-forget” solutions to solve issues (e.g., reinforcement of the network, use of off-load tap changers, OLTCs, capacitor banks, PV inverter functions etc.), that are designed to accommodate for the “worst-case scenario”; i.e., peak demand, peak PV generation etc.

As the levels of DER as well as the level of services that can be provided by them keep increasing, fit-and-forget approaches for distribution network constraint management might prove to be either too expensive (e.g., reinforcement of the network), or too prohibitive in the levels of generation / services that the networks can host. This can effectively act as a bottleneck in the transition to a “greener” power system. A solution to this would be for DNSPs to adopt a more active role in the management of networks, where devices within the network (either network devices or residential devices such as PV inverters and BES systems) are coordinated and orchestrated using real-time network feedback to accommodate higher levels of renewable generation. Such schemes, often referred to as active network management (ANM) in the literature, are the first step in unlocking the potential of distribution networks in terms of hosting DER.

While DNSPs adopting ANM schemes is likely to bring significant benefits in terms of constraint management, a rather prominent problem still remains: the procurement of services through DER by the TSO does not consider distribution network constraints. In fact, the procurement of services in the presence of distribution ANM can even exacerbate problems, as there is no coordination between the operation of DER. A high-level example overview of the current market model is given in Figure 1-9.

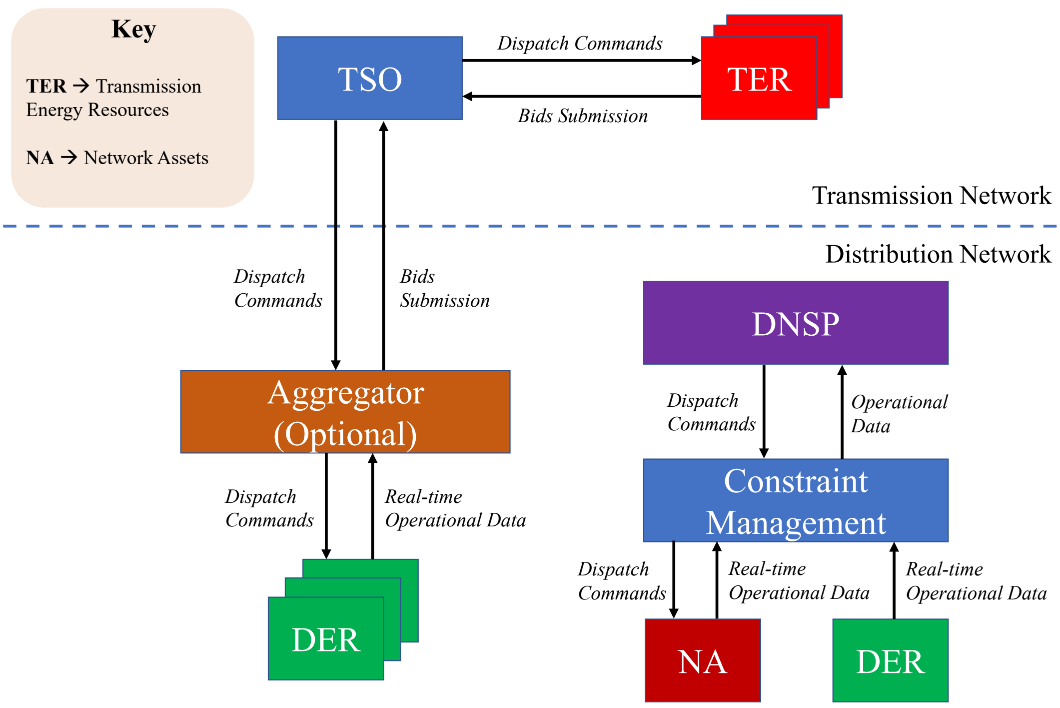


Figure 1-9. Current market model for the procurement of DER services

Therefore, DNSPs will soon be required to be integrated in the service procurement process and ensure that the services provided to the TSO are optimised taking into consideration distribution network constraints. This new role has been recently associated with a new name: DSO.

1.3.1 DSO Framework Examples

There are several challenges associated with DNSPs transitioning to DSOs in the near future. One of the first steps in realising this transition is to define the role of the DSO within the current market. Understanding this, different organisations and DNSPs around the world have recently been investing significant effort and resources in trying to identify suitable future market architectures with the existence of a DSO.

In the UK, one of the more progressive countries in the world in the context of transitioning to DSOs, the Energy Networks Association in partnership with the Great Britain TSO (National Grid), eight DNPSs – or DNOs as referred to in the UK – and one independent network operator, have created the Open Networks Project where one part of the project focused on “Developing a more detailed view of the required evolution from traditional network operation to new Distribution System Operator functions” [27]. Individual DNSPs have also been releasing reports on their views on the role of DSOs in the future market [28]. Different organisations around the world, such as CIGRE, have also been releasing reports which contain proposed DSO frameworks [29].

Similar discussions and reports are also seen in Australia, where the Australian Energy Market Operator (AEMO), the market operator for the eastern transmission grid, in partnership with Energy Networks Australia, have released the Open Energy Networks report which is a consultation on “how best to transition to a two-way grid that allows better integration of DER for the benefit of all customers” [30].

While the proposed frameworks between different reports, organisations and countries can vary, two architectures, the TSO-led and DSO-led market models, seem to be the most prominent in regard to the role of TSO and DSO in the procurement of services from DER.

1.3.1.1 TSO-led Market Model

With the TSO-led model, the procurement of services from DER is still performed by the TSO. However, unlike the current market model, a communication link now exists between the TSO and the DSO. Through this communication link, the TSO has visibility of the distribution network operation and a better understanding of the network constraints. This communication link is particularly important in the presence of ANM, as it can help coordinate the procurement of services from DER and the active constraint management of the distribution network. A high-level example of this framework is shown in Figure 1-10.

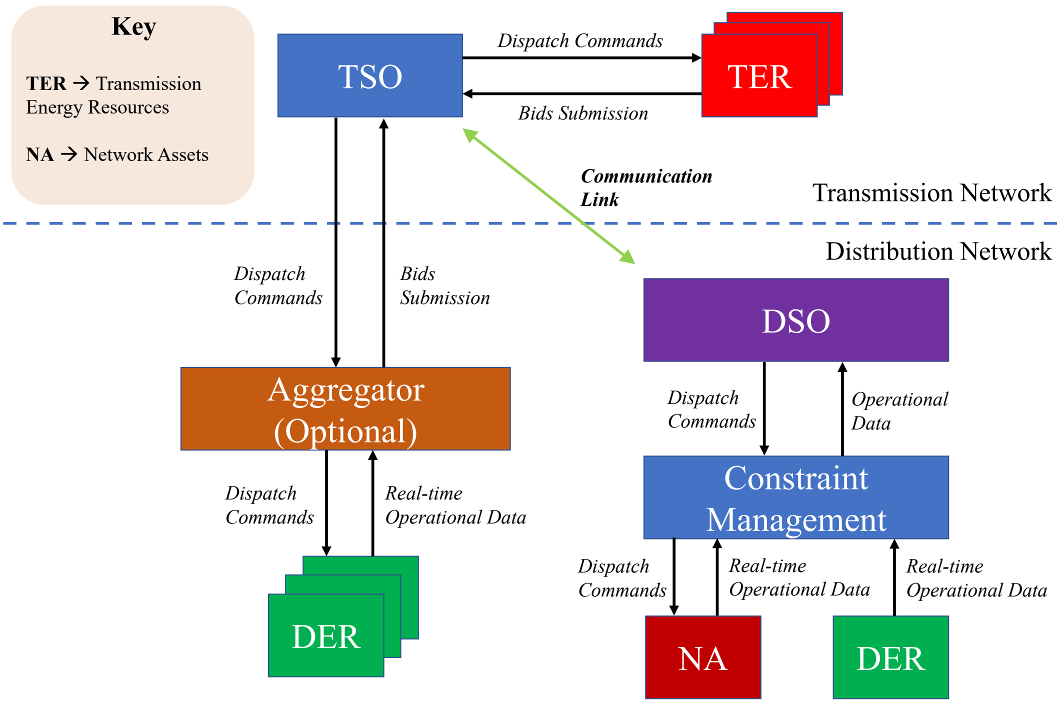


Figure 1-10. TSO-led market model

1.3.1.1 DSO-led Market Model

In this model, the hierarchy of the current market model structure is changed. The TSO procures DER services from the DSO. The DSO optimises the portfolio of available DER and coordinates this operation with distribution network assets (e.g., OLTCs, capacitor banks etc.) to ensure that the maximum available level of services can be provided, while satisfying distribution network constraints. A high-level example of this framework is shown in Figure 1-11.

1.3.1.1 Advantages and Drawbacks of Each Model

Each of these models has its own clear advantages. The TSO-led model is more closely aligned with the current market model. This simplifies the process of DSNPs transitioning into a DSO, as the DSO will not be required to take on a completely new role; procuring services from either aggregators or individual providers. The DSO's responsibilities still lie mostly in constraint management of the distribution network, with the added visibility link between the TSO and the DSO.

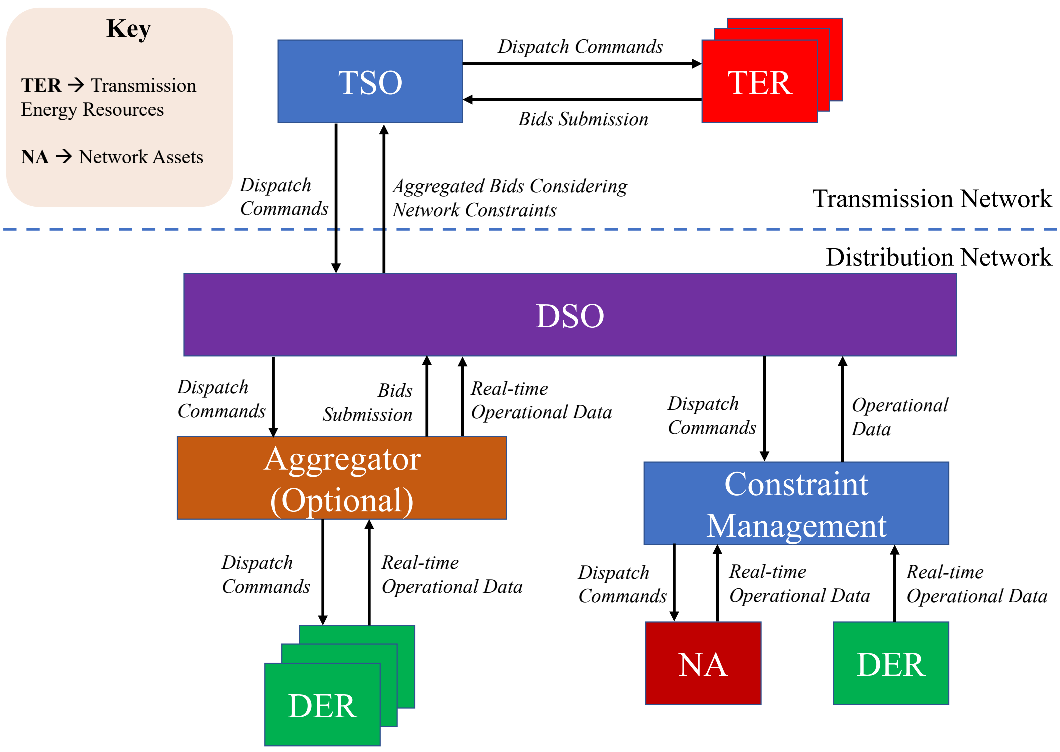


Figure 1-11. DSO-led market model

However, the complexity of the TSO-led model increases dramatically as the volume of services that can be procured through DER further increase. As distribution network constraints become more binding, it is highly unlikely that the TSO will manage to optimize the portfolio of services (some which can be conflicting) across all voltage levels, particularly in the LV networks. This is where the DSO-led market model has clear advantage. DSOs can utilise full network models, low-level observability, and distribution network asset coordination to better manage the procurement of services from a large number of participants across all voltage levels. However, as aforementioned, this adds extremely high levels of operational complexity to the role of the DSO, and as such, the DSO-led model might be unsuitable at the early stages of DNSPs transitioning into DSOs.

Based on the advantages of each model, it is believed that at the initial stages of a market with the presence of a DSO, a TSO-led model will exist. As DSOs become more experienced in this new role, it is believed that the market model will therefore shift towards a DSO-led model [28].

1.3.2 Summary

Due to the high levels of services that are soon expected to be provided from the distribution networks, there exists the need to ensure that the resulting operation of DER complies with distribution network constraints. As such, DNSPs might soon be required to transition into DSOs.

While different DSO market models are being proposed by the industry worldwide, this new role will soon require the development and implementation of adequate technical processes and decision-making engines in anticipation for this transition. This will make it possible to unlock the provision of services through distribution networks by managing participants and coordinating actions amongst network elements whilst meeting network constraints.

1.4 Aims and Objectives

The expected adoption of residential BES systems by households creates the opportunity for these systems to adopt advanced control strategies that can benefit different stakeholders such as DNSPs and TSOs, for added monetary benefit. By doing so, the extra revenue could help further offset the high initial cost of these systems. For this to be achieved, adequate control strategies and frameworks are required to be developed to cater for the different objectives that the BES systems are to be used; effectively unlocking the full potential and benefits that these systems can bring to the power system. First, however, the off-the-shelf (OTS) operation of BES systems needs to be modelled and understood; which will be used as a baseline for comparison for the majority of the studies performed in this thesis. Therefore, the objectives of this thesis are presented below.

1. Modelling and assessment of the performance of OTS BES systems using a real distribution network (network and customer performance).
2. The investigation, development, implementation, and assessment of a practical and scalable BES system controls for solar PV impact mitigation using a real distribution network (network and customer performance).
3. The investigation, development, implementation, and assessment of a BES system control for the provision of services (customer performance).
4. The assessment of the impacts that the widespread provision of services through residential BES systems using a real distribution network (network performance).

5. The investigation, development, and implementation of a DSO framework for the management of prosumers providing services, assessed using a real distribution network (network and customer performance).

1.5 Challenges

In this section, the challenges for achieving the aims and objectives are identified and discussed.

1.5.1 Realistic Network Modelling and Input Data

One of the main challenges in producing credible results in distribution network studies is utilising realistic network models and input data. Generally, real network models are not readily available as DNSPs do not make network information public. This issue becomes even more prominent at lower voltage levels (i.e., 400V). Furthermore, real input data, such as household demand, is difficult to be obtained due to confidentiality issues.

This PhD project utilises MV network data as well as anonymised household demand data that was used in the "HV-LV Analysis of Mini Grid Clusters" project, funded by AusNet Services, a Victorian DNSP. However, as the LV network models were not made available by the DNSP, synthetic LV networks are created based on network design specifications from the same region.

1.5.2 Adoption of Practical and Scalable Solutions

One of the biggest assumptions in many studies available in the literature, is that there will exist an advanced infrastructure and available information in place to support their proposed solutions to mitigate solar PV impacts through BES systems. This includes but not limited to:

1. Full communication and network observability.
2. Accurate network models.
3. Accurate demand and weather forecasting.
4. The ability to control behind-the-meter assets (such as BES systems) by DNSPs.

All these assumptions could be true in the future, but as it currently stands, they are either not available (1-3) or regulation prohibits them (4).

The control strategy for solar PV impact mitigation proposed in this thesis is designed considering that these assumptions could prove to be too prohibitive for a practical and scalable adoption of the proposed control.

1.5.3 The Role of DSOs is Highly Uncertain

While there is a lot of ongoing research and investigations into the transition of DNSPs into DSOs, as it currently stands there are no DSOs anywhere in the world (DSO as defined in Section 1.3). Therefore, the frameworks proposed are mostly hypothetical at this point, and could change dramatically before being implemented in real market structures. Understanding this, it is important that any DSO operational frameworks developed by researchers should, ideally, be robust enough to be applicable to a variety of frameworks proposed around the world. Furthermore, a good understanding of the regulatory environment is also needed, as the proposal of different frameworks could potentially not be allowed based on regulation (e.g., DSOs directly controlling behind-the-meter devices such as BES systems or aggregators controlling network devices).

As such, the DSO framework developed in this thesis does not depend on which DSO model is to become adopted in the future, as it is generic enough to be applied in a multitude of market models with the existence of a DSO. Furthermore, it is designed with consideration of current regulatory limitations (which are very likely to also exist in the future).

1.6 Main Contributions of the Thesis

This section summarises the main contributions of this thesis and the corresponding publications.

1.6.1 Managing Solar PV Impacts through Residential BES Systems

A practical, easily implementable, and scalable BES control approach is proposed in this thesis. One of the main advantages of the proposed approach is that it is able to provide significant benefits in terms of solar PV impact mitigation, without affecting the ability of the BES system to provide benefits to the household (i.e., reducing electricity bills). The control, which can be programmed directly on the BES management system, controlled externally or implemented remotely, operates fully decentralised, which removes all the corresponding complexity associated with centralised control approaches. Furthermore, it does not require network information, offline analyses or forecasting; significantly increasing the practicality of adopting this control. Finally, it should be mentioned that this work has led to the filing of a provisional patent [31].

1.6.2 Customer-led Operation of BES Systems for the Provision of Services

To be able to provide services, a BES system control is designed that is able to optimally dispatch the power settings to respond to a day-ahead service price signal. The design of the control considers the need for the BES systems to respond to very granular changes in demand and generation and thus a time-composite rolling horizon mixed-integer linear program (MILP) optimisation technique is proposed. Furthermore, to ensure that the actions of the BES system do not result in degradation costs that are higher than the benefits brought by providing a given service, a piecewise affine degradation model is integrated in the optimisation problem.

1.6.3 Impacts of Customer-led Operation of BES Systems in Distribution Networks

As previously mentioned, the provision of services from DER without considering network constraints can negatively impact distribution networks. Nonetheless, no studies in the literature have quantified the effect that the provision of services can have on distribution networks. As such, the performance of the customer-led operation of BES systems (used as a proxy for the provision of services in distribution networks) is assessed so as to determine the level of impacts that such operation (e.g., unrestricted provision of services) can have on the distribution networks.

1.6.4 DSO Framework for Management of Prosumers Providing Services

A DSO framework is proposed to ensure that the provision of services through DER (and in particular, BES systems) does not violate network constraints. With the proposed framework, the DSO does not directly control the prosumer assets, but rather sets limits on their operation in near real-time (e.g., every 5 minutes). Under this framework, households that wish to provide services submit their intended operation to the DSO, which is then checked if it violates network constraints. If it is found that network constraints are violated, limits on the operation of the households are determined based on an optimisation program. Since households are individual entities, fairness aspects are embedded in the process in which household limits are determined, so as to not over-penalise households in weak parts of the network.

1.6.5 Publications

The section contains the list of journal papers, conference papers, and technical reports that were authored or co-authored by the author of this thesis. The list contains published, accepted and in review papers.

1.6.5.1 Journal Papers

1. A. T. Procopiou, **K. Petrou**, L. F. Ochoa, T. Langstaff, J. Theunissen, "Adaptive Decentralized Control of Residential Storage in PV-Rich MV-LV Networks," *IEEE Transactions on Power Systems*, vol. 34, no. 3, pp. 2378-2389, May 2019.
   DOI Link: https://doi.org/10.1109/TPWRS.2018.2889843
2. T. R. Ricciardi, **K. Petrou**, J. F. Franco, L. F. Ochoa, "Defining Customer Export Limits in PV-Rich Low Voltage Networks", *IEEE Transactions on Power Systems*, vol. 34, no. 1, pp. 87-97, January 2019.
   DOI Link: https://doi.org/10.1109/TPWRS.2018.2853740
3. **K. Petrou**, A. T. Procopiou, L. Gutierrez, L. F. Ochoa, "A DSO Framework to Facilitate Bottom-Up Services: Determining Operational Limits for Prosumers in MV-LV Distribution Networks", *IEEE Transactions on Power Systems*, in Review.

1.6.5.2 Conference Papers

1. **K. Petrou**, L. F. Ochoa, A. T. Procopiou, J. Theunissen, J. Bridge, T. Langstaff, K. Lintern, "Limitations of Residential Storage in PV-Rich Distribution Networks: An Australian Case Study", *in IEEE Power & Energy Society General Meeting*, 2018, pp. 1-5.
   DOI Link: https://doi.org/10.1109/PESGM.2018.8585998

2. **K. Petrou**, A. T. Procopiou, L. F. Ochoa, T. Langstaff, J. Theunissen, “Residential Battery Controller for Solar PV Impact Mitigation: A Practical and Customer-friendly Approach”, *in 25th International Conference and Exhibition on Electricity Distribution (CIRED)*, 2019, Accepted.
3. **K. Petrou**, A. T. Procopiou, L. F. Ochoa, T. Langstaff, J. Theunissen, “Impacts of Price-led Operation of Residential Storage on Distribution Networks: An Australian Case Study”, *in IEEE PowerTech Milan,* 2019, Accepted.
4. **K. Petrou**, L. F. Ochoa, “Customer-led Operation of Residential Storage for the Provision of Energy Services”, *in IEEE Innovative Smart Grid Technologies Conference Latin America (ISGT-LA)*, 2019, Accepted.

1.6.5.3 Technical Reports

All technical reports were produced for the industry-funded “HV-LV Analysis of Mini Grid Clusters” project and submitted to AusNet Services.

1. **K. Petrou**, L. F. Ochoa, Deliverable 1 “HV and LV Network Modelling”, prepared for AusNet Services, 2017.
2. **K. Petrou**, L. F. Ochoa, Deliverable 2 “Impact Analysis of Mini Grid Clusters with PV Systems”, prepared for AusNet Services, 2017.
3. **K. Petrou**, L. F. Ochoa, Deliverable 3 “Assessment of Potential Solutions”, prepared for AusNet Services, 2017.

1.6.5.4 Patents

1. A. T. Procopiou, **K. Petrou**, and L.F. Ochoa, "A controller for photovoltaic generation and energy storage system," Australia Patent 2018904310, 2018.

1.7 Thesis Outline

This section contains an outline of the thesis, and a corresponding summary of each chapter hereafter.

Chapter 2 – Management of Residential BES Systems: State of the Art

Chapter 2 presents the available research that has been carried out in the literature considering the management and control of BES systems. The literature review is split into three subcategories:

1. Using residential BES systems to mitigate solar PV issues in distribution networks.
2. Controlling BES systems to provide services to the upstream network and the corresponding impacts on the distribution network.
3. Framework for the management of households providing services considering distribution network constraints.

Chapter 3 – Distribution Network Modelling and Assessment

In this chapter, the modelling of the integrated MV-LV distribution network used in the case studies is presented. The usage of integrated MV-LV networks for network studies is uncommon in the literature, but crucial in order to realistically capture the effects of generation in the distribution network. At the MV level, real network data is used to model the network, whereas at the LV level, synthetic networks are used which were created using Australian LV network design principles. The quantification metrics (for both the network and the customers) are also presented in this section. Furthermore, a case study is presented which presents the operation of the integrated network without and with the existence of residential PV generation, at multiple PV penetration levels. The case study utilises smart meter demand and generation data, which is also presented in this chapter.

Chapter 4 – Off-the-Shelf Control of BES Systems

In this chapter, the adopted OTS control of BES systems is first presented. The case study focuses on quantifying the performance of the OTS control in terms of mitigating the PV impacts quantified in Chapter 3. Additionally, the performance of the OTS control in terms of customer benefits is also quantified. The results show that while the OTS control of BES systems can bring significant benefits to households (i.e., reduction of electricity bills), they provide little to no benefits to the distribution network in terms of mitigating solar PV impacts. The chapter ends by highlighting the limitations of the OTS control in mitigating PV impacts.

It should be noted that preliminary results of this chapter were published in [32]. This chapter expands the work carried to also include a single household operation demonstration and an integrated MV-LV network assessment.

Chapter 5 – Adaptive Decentralised Control of BES Systems

In this chapter, the decentralised control for PV impact mitigation is presented. First, the design considerations and how the proposed control aims to overcome the limitations of the OTS BES control are highlighted. Furthermore, the charging and discharging algorithms of the adaptive decentralized (AD) control are presented. The performance of the proposed AD control, both in terms of mitigating PV impacts and customer benefits, is then assessed for multiple PV and BES penetrations using the integrated network presented in Chapter 3. The findings are also compared with an optimisation-based control, which utilizes perfect information, so as to quantify the performance of the AD control against a perfect benchmark. It is demonstrated that the proposed AD control manages to mitigate all PV impacts in the network (almost as well as the benchmark OPT control), while also providing significant benefits to the households (almost as well as the OTS control).

It should be noted this chapter also contains an expansion of the deterministic analysis carried in [33] into a multi-penetration Monte Carlo assessment.

Chapter 6 – Customer-led Operation of BES Systems

In this chapter, the design considerations and control methodology of the customer-led operation of BES systems for the provision of services is presented. The technical characteristics of the control, such as the time-composite rolling horizon optimisation, as well as the degradation model used in the optimisation problem are shown. The chapter then demonstrates the performance of this control using two case studies, one which quantifies the performance of the proposed control in terms of providing added monetary benefits to the household, and one that quantifies the corresponding network impacts from the widescale adoption of this control in a real network. It is demonstrated that while the adoption of this control can offer substantial benefits to the households, it can also severely affect distribution networks due to the coincidental PV generation and discharging of BES systems.

Chapter 7 – DSO Framework To Facilitate Provision Of Bottom-Up Services From DER

Based on the findings of Chapter 6, a DSO framework is developed for the management of households providing services (referred to as "prosumers" in the Chapter) within the distribution network. The framework identifies the required communication pathways between the different parties (i.e., TSO, DSO and prosumers). To ensure network constraints are met, the DSO first runs a power flow analysis on the intended operation of the prosumers. If found to violate network constraints, maximum power limits are determined based on an optimal power flow (OPF) program. The performance of the framework is quantified using a real distribution network. Finally, the effect of network constraints in the ability of prosumers to provide services is also quantified. It is demonstrated that the proposed framework manages to facilitate the provision of services while maintaining distribution network integrity, without being as prohibitive as the fit-and-forget approach currently adopted by DNSPs in Victoria, Australia.

Chapter 8 – Conclusions and Future Work

This chapter presents a summary of the findings and conclusions from the research contained in this thesis. Furthermore, comments on the potential future work and improvements to the research carried are also stated.

2 MANAGEMENT OF RESIDENTIAL BES SYSTEMS: STATE OF THE ART

2.1 Introduction

This chapter presents the research that has been carried out in the literature in regard to the objectives of this thesis. The first section presents the literature review on mitigating solar PV impacts on distribution networks using residential BES systems, split into centralised and decentralised approaches. Furthermore, the literature review continues into the work that has been done in terms of providing services through residential BES systems. This section, besides the literature review on decentralised and centralised approaches, also considers the research done to identify the potential impacts of this operation on distribution networks. The chapter ends with the literature review carried on DSO frameworks for the management of households or other market participants providing services in distribution networks. For all sections, a summary of the gaps in the literature is provided.

2.2 Mitigation of Solar PV Impacts on Distribution Networks using Residential BES Systems

The usage of residential-scale BES systems to mitigate the impacts of high penetrations of PV generation in distribution networks is a relatively new research area. Nonetheless, understanding the potential and technical capabilities of residential BES systems, researchers worldwide have been investigating methods to help mitigate solar PV impacts through the usage of these systems. The research conducted can be categorised into two main areas: centralised and decentralised control. In this section, the available literature on both of these areas is presented and discussed.

2.2.1 Centralised Approaches

In one of the earliest works in this field, the authors in [34] propose reactive power control of BES systems to mitigate voltage problems in an MV feeder. The work assumes that the DNSP provides a subsidy to customers for installing larger BES system inverters and thus absorbing reactive power during periods of high solar irradiation through their BES system. The reactive power settings are calculated using a centralised optimisation technique. While the proposed control shows significant benefits in terms of voltage management, it suffers from several drawbacks. As the DNSP controls only the reactive power output of the BES system, this method has the same limitations as the Volt-Var control of PV inverters briefly discussed in Section 1.1.4.3.1 (i.e., need to oversize the inverter, exacerbates thermal problems). Furthermore, the authors assume that the BES inverters will be able to absorb reactive power when the BES system is idle; a technical capability that is not required currently (and thus not available on BES system inverters) by regulation [15].

In another work in this field, the authors in [35] propose three different model predictive control (MPC)-based BES system controls to mitigate solar PV impacts; a fully centralised control, a distributed control, and a decentralised control. The decentralised control in this work will be discussed in the next section. Starting with the centralised control, the proposed optimisation aims to flatten the total network power profile (demand and solar peaks) through the coordinated use of the BES systems. While this proposed approach is able to solve the solar PV impacts in the network, it suffers greatly from scalability issues as the problem becomes infeasible once the network size is increased. To overcome this limitation, the authors then propose the use of a distributed algorithm, where the optimisation problem is solved locally at each BES system, using communication with a central hub (in this work referred to as the "Market Maker") in order to achieve a network-wide optimal behaviour. Through this approach, the scalability issues are resolved, and the network is kept within its constraints with minimal loss of performance when compared to the centralised control. However, these approaches utilise perfect household demand and PV generation forecast. This poses a large limitation in the implementation of this approach, as accurate individual household demand forecast is extremely difficult to obtain. Finally, the study does not quantify the impacts on the primary objective of the BES systems (from a customer perspective); reducing grid imports. This could prove to be another big limitation in the applicability of this approach, as customers will be unlikely to adopt BES systems if their ability to reduce grid imports – and consequently, electricity bills – is heavily compromised.

The authors in [36] adopt a different approach to the centralised control paradigm. In this work, the operation of the BES systems is done in two levels. At the household level (i.e., decentralised control), the BES system is dispatched based on the preferences of the BES owner (e.g., grid imports reduction or electricity bill reduction), while maintaining adequate energy capacity during a period defined as the "critical period" (i.e., the times of the day that voltage violations could occur). During this period, if a voltage violation in the network is recorded (through voltage measurement devices across the network), new active and reactive power setpoints for the BES systems are determined so as to resolve the issues. The active power control aims to minimise the difference in the power flows between phases, whereas the reactive power control keeps the voltages in the network within the limits. As the active power control only aims to reduce the unbalance between phases, and the reactive power control only to keep voltages within the limits, there are no guarantees that any thermal problems in the network will be resolved. Furthermore, while this work presents a good understanding of the primary objective of the BES systems (i.e., reducing grid imports), it also assumes perfect demand and generation forecast at each household. Therefore, the true impacts to the ability of the BES systems to reduce grid imports in the presence of high errors in forecast are not quantified.

While several other studies [36-38] exist that propose different centralised or distributed approaches, they all make use of advanced communication, accurate network observability/models, and computation infrastructure (usually in conjunction with OPF optimisation techniques) in order to control the BES systems in a given network to solve any constraint violation. In principle, centralised approaches provide better solutions in mitigating PV impacts, as the observability and coordination of the BES systems results in a far more optimal solution than decentralised approaches. However, from a practicality perspective, centralised approaches suffer greatly in terms of adoption and cost (new infrastructure required), scalability (thousands of networks), and are to some extent prohibited by regulation (as it currently stands, DNSPs in many countries are not allowed to control behind-the-meter assets directly). Therefore, in that regard, DNSPs are much more likely to require practical decentralised solutions in the years to come.

2.2.2 Decentralised Approaches

Understanding the need to reduce the complexity associated with centralised control approaches, the authors in [35], in addition to their proposed centralized and distributed control algorithms, also proposed a decentralized control for the BES systems, adopting a network-agnostic approach. The decentralized control proposed also operates based on an MPC optimisation problem, where the power profiles of each house are flattened by quadratically minimizing the household net demand (i.e., power at the connection point) while considering BES system dynamics. While it is demonstrated that this approach performs almost as well as the centralized and distributed control approaches, it assumes perfect day-ahead information for each household demand and PV generation. As previously mentioned, the high margin for error in forecasting when considering individual household demand and generation can result in very different operation in real scenarios, where: a) the net generation (generation minus demand) could be underestimated, which will result in high household exports and thus network problems, or b) the net generation could be overestimated, which can lead to increased household imports and thus a decrease in customer performance.

In an effort to investigate approaches that do not depend on forecast, the authors in [39] try to define, based on an optimisation problem, two parameters for BES systems: a) the energy capacity, and b) an export limit which triggers the charging of the BES system. Figure 2-1, taken from [39], exemplifies this sizing vs export limit definition for different sizes of BES systems (denoted as EESS in the figure). One of the interesting aspects of this study is that the authors do not size the BES system to accommodate for all scenarios, but rather acknowledge the fact that the export limit could be enforced by PV generation curtailment in the cases where adequate BES system capacity is not present (i.e., worse-case scenario days). Their approach is validated using a Danish LV network for different penetration levels, and the results show the ability of the proposed method to mitigate voltage problems in the network.

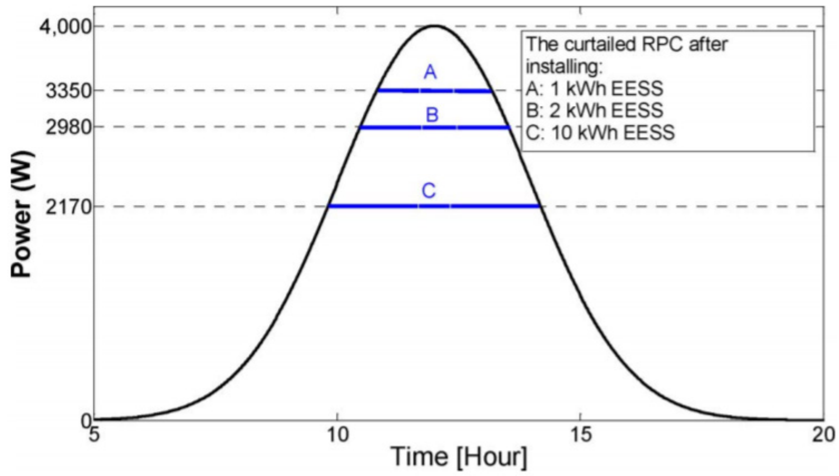


Figure 2-1. Example of different export limits depending on EESS size [39]

However, this approach has some severe drawbacks which are not discussed in the publication. First and foremost, the definition of the BES system size and the export limit is network dependent, and as such, DNSPs would have to simulate hundreds of thousands of LV networks and define sizes and export limits specifically for each one. Furthermore, it assumes that the DNSP has the authority to define what BES system sizes the households will install; a rather unlikely scenario. Finally, as the BES system only charges when the exports of the household exceed a predefined limit, on cloudy days where the household surplus generation is low, the BES system will not charge; effectively limiting the ability of the BES system to perform its primary function, which is to reduce grid imports for customers.

This study is not the only one that explored the application of a charging threshold (i.e., export limit) for BES systems. The authors in [40] also utilize a similar concept, with the addition of a time-based control. In addition to defining a charging threshold, the BES system can only charge between a predefined time, during which it is expected for network issues (i.e., voltage and thermal problems) to happen. Nonetheless, this method exhibits the same limitations as the proposed method in [39], but, mostly, the definition of the charging threshold is network and PV penetration specific. Furthermore, using a charging threshold can be overly prohibitive in the ability of the BES system to reduce grid imports on cloudy days. In fact, the inability of threshold-based approaches to reduce grid imports was demonstrated in [32] by the author of this thesis.

More work in the context of defining settings for BES systems based on a-priori network performance analysis is carried out in [41]. Interestingly, the authors propose the provision of reactive power support from the PV inverters, coupled with voltage droop-based control for charging the BES system during the PV generation period. It is proposed that the PV inverters will provide reactive power support through a predefined Volt-Var curve, subject to their capacity limits. For the BES charging control, which is similar to the Volt-Watt control of PV systems, two methods are investigated: a) a constant droop-based operation, where a single curve is defined for all BES systems in the network, and b) a variable droop-based operation where each household has a different curve depending on their location in the network. It is demonstrated that while both approaches manage to effectively mitigate any voltage problems in the network, the variable droop-based control achieves a better overall performance than the constant droop-based operation. With the variable droop-based curves, a uniform charging profile in the network can be achieved, which means that equivalent sized BES systems can be installed in all households, as opposed to the constant droop-based curve where very small BES systems are installed at the head of the feeder and very large ones are installed at the end. Nonetheless, similar to the previous studies, this approach requires assessing each network individually in order to define the appropriate droop curve. Furthermore, a few impractical assumptions are made. It is assumed that the PV generation of the feeder will not change, as if it does, new droop curves will have to be calculated. Furthermore, it assumes that all households install the BES systems simultaneously (DNSP installing them), which is highly unlikely. Furthermore, as BES systems charge solely based on voltage measurements, during days with low irradiance (and as such, without the existence of high voltages), charging is likely not to occur, and therefore the BES systems will not be able to supply the household demand; severely hindering their attractiveness to households.

In another work that better investigates practical decentralized solutions, the authors in [42] explore the usage of time-based controls for the charging and discharging of the BES system, to solve undervoltage problems associated with peak demand days (winter days in the region assessed), but also solve overvoltage problems associated with high PV generation in the summer. The BES systems are restricted to charge and discharge between pre-allocated times, aligned with peak demand (discharging) and peak generation (charging). Furthermore, the authors also investigate charging the BES system at a reduced rate over the peak generation period. Due to this, the BES systems will not become full as quickly, further helping to mitigate the voltage problems. Additionally, this is one of the few studies that quantifies the effect of the proposed control on the ability of the BES system to reduce grid imports, a major issue that is more-often-than-not neglected in other studies. However, there are a few issues associated with the proposed control. The simulations performed only consider individual days, and thus the effect of the BES system not fully discharging overnight is not considered. As demonstrated in [32], the insufficient discharging of the BES systems overnight leads to having the BES systems full very early during the next day and as such, they are unable to charge during the peak generation period. Furthermore, the definition of the time-based parameters (i.e., time to begin charging, time to begin discharging) needs to consider individual households and their demand characteristics. It should also be noted that the proposed control is only able to slightly increase the hosting capacity of the network and is able to solve problems at higher PV penetration levels. Finally, the study only considers voltage problems in the network, and thus the thermal capacity of the network assets and the corresponding issues are neglected.

2.2.3 Summary of Gaps in the Literature

In general, the literature review suggests that there is strong interest in mitigating solar PV impacts through residential-scale BES systems. To achieve this, there are two avenues that researchers have been focusing on: centralised and decentralised approaches. Centralised controls of BES systems suffer heavily from scalability and implementation issues, as they assume that there exists an adequate communication infrastructure, as well as accurate, readily available network models, to be utilised. As such, it is believed that practical, scalable, and easily implementable *decentralised* approaches are much more likely to be adopted, as they are more aligned with the current philosophy of DNSPs around the world. Nonetheless, the decentralised approaches that currently exist in literature usually consider network-specific implementations, and as such, their implementation can be hindered by the complexity associated with performing the required offline analyses. Finally, in many of the studies performed, the BES system is treated as an asset to help mitigate network problems, whereas in fact the primary objective of the BES system is to reduce energy imports. Network impacts mitigation is a well-needed, but secondary objective. Otherwise, households will very unlikely adopt these systems if no benefits can be brought to them. In summary, the main gap that exists in the literature is the development of a realistic, practical, easily implementable, and scalable control schemes that overcome the limitations of OTS BES systems in terms of mitigating solar PV impacts, while still being able to provide similar level of benefits to customers are needed. This gap is the primary objective to be addressed by the proposed control in Chapter 5.

2.3 Provision of DER Services through Residential-scale BES Systems

In Section 2.2, the review of the available literature focused on utilising the BES systems to mitigate solar PV impacts. However, given the controllability of BES systems, there exists the opportunity for these systems to be controlled in a way that can provide services to the larger power system (e.g., frequency control, wholesale energy). By doing this, households can further benefit from their BES system investment, as these services can be monetised. In this section, a review of the available research in terms of residential-scale BES systems being controlled to provide services is conducted. As previously, two types of control are considered, centralised and individual control; the latter which refers to individual customers participating in the provision of services without a third-party controlling their assets. Furthermore, a brief review of the state-of-the-art is also provided.

2.3.1 Centralised Approaches

When the provision of services is considered in a centralised way, this is usually done by a third-party referred to as the “aggregator”. The responsibility of the aggregator lies in managing a fleet of BES systems (and other DER), so that the total response is significant enough to provide benefits to the whole power system. In one of the earlier works in the field, the authors in [43] propose an aggregator operation to participate in the provision of demand response services. Four aspects of demand response are considered in the study: a) load curtailment, b) load shifting, c) on-site generation, and d) utilising BES systems. As the usage of BES systems is only considered in the latter, a) – c) are not discussed. The study proposes the day-ahead scheduling of BES systems, where the operation of the BES systems is determined. This way, the aggregator can obtain revenue from participation in the energy market. Nonetheless, several drawbacks are associated with the approach in this study. First, the centralised optimisation problem does not consider the local demand and generation that exists at the household-level. This could heavily reduce the ability of customers participating in the provision of services to supply their local demand through their BES system. Furthermore, as the scheduling of the BES system consists of single, day-ahead optimisation, the inter-temporal effects between different days cannot be considered. As such, there is a missed opportunity for the energy stored in the BES systems to be better utilised the day after. Additionally, the case study quantifies the benefits for a single day and only for the benefits that the aggregator receives. A more thorough assessment that considers larger time periods as well as the households is required to fully assess the benefits of the proposed operation. Finally, it should be mentioned that the study assumes that distribution network constraints are infinite; effectively allowing the aggregator to operate the BES systems without any effects to the network integrity. This, while might be true when the volume of services that can be provided is relatively low, as the level of services provided through BES systems increase, the corresponding effects on the distribution network need to be quantified.

In a similar study, the authors in [44] propose a centralised operation where the thermostatically controlled loads as well as BES systems are controlled to provide a response to a price signal. One of the novelties of this study lies in the modelling of the thermal dynamics of the buildings, which are incorporated in the optimisation problem so that the energy required to heat up / cool down and maintain the temperature of the buildings can be taken into consideration. Furthermore, the local demand and generation are taken into account, which ensures that the corresponding economics are considered in the optimisation problem. Similar to the previous study, however, this study has several limitations. First, the optimisation is done considering static, day-ahead horizon at the beginning of the day. Therefore, the inter-temporal relationship between different days and the corresponding benefits that this brings are neglected. Furthermore, the optimisation considers only low granularity periods, and therefore it is unable to capture the highly granular changes in demand and generation. Also, given that the optimisation problem contains binary variables (for the imports/exports of households and charging/discharging of BES), this raises questions regarding the scalability of the approach when hundreds or thousands of devices are considered. Finally, it should be noted that while the study does consider the effect on the network, this is done only from the perspective of the thermal capacity of the transformer without modelling the network (i.e., lines, voltages, and losses are ignored). As such, there is no guarantees that the proposed framework will not result in impacts on the network. This aspect is not quantified in the study.

The authors in [45] try to address the scalability issues of centralised approaches by proposing a cooperative distributed aggregation algorithm. The BES systems solve a local problem based on local demand and generation information. In addition, the BES systems also communicate with each other, and using dual decomposition, a similar aggregated performance is achieved as with fully centralised approaches. As this problem is solved locally, it also allows for battery degradation to be incorporated in the optimisation problem. One of the novelties in this work comes from the ability of the proposed algorithm to operate in the event of loss of data from other devices (referred to as single-point-of-failure in aggregation systems). However, as with the previous studies in this section, this study also considers static day-ahead optimisation at the beginning of the day, where the corresponding drawbacks have been discussed in the previous paragraphs. Furthermore, even if solved locally, only low granularity periods are considered, and as such, the highly granular changes in demand and generation are not captured in the operation of the BES system. Finally, as in previous studies, there is no consideration of how this proposed operation impacts distribution networks.

Generally, there are two drawbacks associated with the centralised operation of BES systems to provide services. First, due to the large number of devices that must be controlled, certain aspects that can be highly beneficial to customers, such as high granularity control, rolling horizon optimisation (to consider the inter-temporal relation of multiple days), or incorporating battery degradation in the optimisation problem are neglected to make the operation more scalable. While this was partly addressed in [45] by the use of a distributed algorithm rather than a fully centralised one, the BES systems in this study are also controlled based on the preferences of the third-party (i.e., the aggregator). As regulation around the world could change in the future to allow for individual prosumers to participate in the provision of services directly, adequate control strategies are needed to allow for these prosumers to participate without the need of a third-party controlling their systems, which will allow them to control their BES systems based on their own preferences.

2.3.2 Individual Control Approaches

Control strategies for individual customers (i.e., without the existence of a third-party controlling the BES system) providing services could be needed in the future as regulation around the world is changing. In one of the earlier works in the field, the authors in [46] propose the shared operation of residential BES systems to be used for active demand response. The study proposes that the capacity of the BES system is shared; one part operated to respond to energy prices (i.e., energy arbitrage) and the other to defer distribution network investments from increasing peak demand (i.e., discharge to avoid network congestion during peak demand). The proposed algorithm defines the periods of low and high wholesale energy prices, where the arbitrage part of the BES system charges and discharges, respectively. It also defines the periods of minimum and peak demand (which could not be coincident with the prices), for the BES system to charge and discharge, respectively. The study also proposes a methodology to identify the ideal capacity sharing ratio between arbitrage and network support. Nonetheless, the study assumes that the BES system will be connected at the residential premises without a PV system; while possible, it is highly unlikely that customers will purchase a BES system without having a PV system installed. Furthermore, the BES systems are operated using a threshold-based control. As such, the lack of optimisation might prove to result in highly suboptimal solutions.

In another work in the field, the authors in [47] operate the BES system based on an optimisation problem which aims to reduce the cost of importing electricity; controlled by a time-varying energy price. A large portion of the novelty of this work comes from the ability of the proposed optimisation problem to capture the dynamics of the BES system and the corresponding efficiencies more realistically than other studies in the field, where usually a constant factor is applied to the charging and discharging. However, despite the study focusing on the optimal operation of the BES system for customers reducing their imports, it does not consider the degradation of the BES system. As previously discussed, this can lead to suboptimal actions (charging or discharging) when the corresponding cost from the degradation of the battery capacity is considered. Furthermore, as with some of the previous studies, the optimisation is only solved at the beginning of each day and only considers low granularity periods; drawbacks that have been previously discussed. Finally, it should be noted that in this study, the potential of the BES systems exporting to provide services is not considered. As such, there is a missed opportunity for the additional energy that is not used to supply the household demand to be used in a more beneficial way for the customers.

Understanding the need to incorporate the exports of BES systems in the provision of services, the authors in [48] propose an energy management system with the existence of local PV generation and BES system for a residential building. The study, which uses Markovian processes and weather models, schedules the BES system to reduce the electricity bill (based on a time-of-use electricity import tariff) of the building considering weather dependent loads, controllable loads, an electric vehicle characterisation model, and resource allocation of the PV and BES systems. Given that the BES system responds to a price signal, this can be seen as a proxy for the provision of services (i.e., when the import price is too high, reduce grid imported energy consumption as much as possible). However, the study has some limitations. First, the optimisation problem is solved only at the beginning of the day, and as such, there is a missed opportunity to better utilise the stored energy the day after. Because of this, the BES system is forced to fully discharge by the end of the night. Therefore, there is an opportunity cost to also optimise the BES system to discharge into the grid at times where the price is high and obtain profits. Furthermore, the study considers only low granularity periods, and as such, the highly granular changes in demand and generation are not considered in the optimisation problem. Also, the study focuses mostly on the control of the devices rather than proving how attractive this operation can be if adopted, and therefore, no economic assessment is carried out. Furthermore, the degradation of the BES system is not considered in the optimisation problem, which means that the BES system could take actions that are suboptimal given the corresponding effect this can have on the lifetime of the asset. Finally, it should be mentioned that since the operation proposed in this study forces the BES system to discharge its remaining energy stored during the night over a short period of time, network studies should be conducted to evaluate whether this operation, in the aggregate, could impact the distribution network.

To incorporate the inter-temporal relations between days, the authors in [49] propose a rolling horizon MILP optimisation to control the BES systems responding to a price signal. One of the benefits of a rolling horizon approach, besides its ability to break down larger optimisation problems into smaller ones which can be more effectively solved, it also reduces errors originating from forecasts or other aspects (e.g., simplification of the charging/discharging efficiencies of the BES system), as the input data to the optimisation problem is periodically updated. However, similar to the previous studies, the optimisation problem only considers low granularity periods, where the corresponding drawbacks from this approach have been discussed extensively. Furthermore, there is no consideration of battery degradation in the optimisation problem, which could lead to suboptimal actions when the cost of the BES system is considered. Finally, the study does not consider how the exports from the provision of services can affect the distribution network.

More in the context of assessing the economic attractiveness of BES systems, the authors in [50] utilise a simple optimisation problem for the optimal dispatch of a residential BES with the existence of local generation from a PV system as well as a micro-combined heat and power (μCHP) system. The BES system is dispatched so as to reduce the cost of electricity of the household, where flat import and export prices are used. Given that the export price is lower than the import price, the BES system tries to charge as much as possible from the local generation. Furthermore, to make the optimisation more realistic, a simple degradation model is also included in the optimisation, to ensure that the actions of the BES system do not result in economically suboptimal actions. The case study, which considers a year’s worth of data, quantifies that purchasing a BES system to store the surplus PV generation to only supply the load (i.e., off-the-shelf operation) is not currently economically attractive (as of 2015 in Germany), as the gap between electricity price and feed-in tariffs (export price) is not significant enough to cover the cost of the BES system. However, the study does not consider the potential of BES systems to provide services to the whole power system, and as such, receive additional monetary benefits. Therefore, case studies that also consider the provision of services need to be conducted in order to better evaluate the potential economic attractiveness of these systems.

Another study that focuses on the economics of BES systems, in this case only considering the provision of services, is presented in [51]. The authors utilise a threshold-based control for the provision of services and quantify the potential benefits that this can bring to customers. In this Australian study, the BES systems are set to discharge with their full power rating in the grid when the wholesale energy price exceeds the defined threshold, and the authors quantify the potential benefits that this can bring to different customers in different states (each state in Australia has different wholesale energy prices) over multiple years (2011-2015). Furthermore, different price thresholds are explored so as to determine the one that results in the most profitable operation considering both grid imports reduction and provision of services. However, as demonstrated, there is high variability in the ideal threshold between different years, as wholesale energy prices in Australia can greatly vary between different periods. Therefore, there exists a missed opportunity to utilise optimisation-based approaches for the BES systems to be more adaptive to the changes in prices between years. Finally, and as with most previous studies, there is no consideration of the impacts that the proposed approach can have on distribution networks. This effect should be particularly prevalent with this study as it utilises a threshold-based control where all BES systems respond to the price exceeding the threshold at the same time.

2.3.3 State of the Art

As demonstrated in some of the studies in the previous sections (particularly in [51]), the provision of services from residential BES systems can bring substantial monetary benefits to residential customers. Understanding this, companies (particularly in Australia where large volatility of energy prices exists) have been promising additional benefits for customers if they allow controllability of their BES system; either in exchange for a cheaper BES system (e.g., AGL, Tesla Energy) or a one-off payment (e.g., Reposit Power). However, as it currently stands, these companies do not consider distribution network constraints in their operation. As the adoption of BES systems further increases and more customers opt to provide services for additional monetary benefits, realistic assessments of the potential impacts that the operation of these companies might have on the distribution network need to be performed; a fast-rising issue that has been largely ignored by industry and academia alike. By identifying the extent of these issues, adequate regulation or new technical frameworks to manage the provision of services from distribution networks can be developed so that the corresponding impacts can be mitigated.

2.3.4 Summary of Gaps in the Literature

In general, the studies found in the literature cover a wide range of aspects that need to be considered in a control approach to enable individual customers to provide services. However, most studies focus on a single objective (e.g., reduce imports, degradation, enhance scalability, etc.), and as such, all the aspects are not captured holistically in a single study. As such, there is a need for a control strategy that adequately captures all the different objectives that need to be considered in the design for customers to participate in the provision of services. These aspects are highlighted below.

- Control of exports for the provision of services. As demonstrated in some studies, the monetary benefits that can be obtained from exporting energy for the provision of services can be quite substantial. As such, they need to be considered in the control design.
- High granularity operation. Most studies focus on the optimal dispatch of BES systems without considering the highly granular nature of residential demand and generation. As such, these aspects need to be captured in the control design to further benefit the customers.
- Battery degradation. Every action that the BES system (either charging or discharging) results to the battery degrading (i.e., losing capacity). While minute, over longer periods this could have a substantial effect on the lifetime of the asset. It is therefore important that any action taken by the BES system does not result in a cost from degradation higher than the monetary benefit it brings (e.g., exporting to supply a service for a given amount of money).
- Realistic assessment of benefits. While the benefits that their proposed control brings to the customers are evaluated in most studies, this usually considers very short periods (single or few days). Given that the level of benefits the customers receive can greatly vary depending on different factors such as season, long-period assessments are needed to realistically evaluate the benefits the proposed control can bring.
- Distribution network impacts. This aspect is the most neglected of all in the literature in this section. Most studies do not quantify the effect that their proposed control can have on the very network that they are connected to.

2.4 Managing the Provision of DER Services through DSO Frameworks

As previously mention in Section 1.3, as the levels of services and flexibility that can be procured through DER further increases over the next years, distribution network constraints can no longer be ignored. As such, DSOs are likely to be integrated in the procurement process to ensure that the provision of services does not result in violation of network constraints. For this to happen however, adequate technical frameworks need to be developed to enable DSOs to manage distribution networks effectively. In this context, in the very recent years, researchers have been proposing different operational and technical frameworks, which are presented in this section.

Generally, the literature with consideration of DSOs falls into two different categories. The first category is studies that utilise locational marginal pricing (LMP), a technique which is more commonly used in transmission networks and where prices are defined for each bus in the network and has recently received attention from researchers in distribution networks. A brief review on the available research on distribution-LMP (DLMP) is provided in Section 2.4.1, along with the corresponding justifications why this approach was not considered in the design of a DSO framework in this thesis. More aligned with the research carried and proposed in this thesis, Section 2.4.2 provides a review of the studies available in the literature that propose DSO frameworks that utilise a more direct control of power flows, either by direct control of the DER or by negotiating/limiting the operation of prosumers.

2.4.1 DLMP Approaches

In this section, a brief review of the available DLMP approaches is provided. As aforementioned, the aim of the review contained in this section is not to identify the gaps of individual studies, but rather to justify holistically why DLPM was not considered in the design of the proposed DSO framework later in this thesis.

Over the recent years, a number of studies have proposed DSO frameworks that utilise DLMP to solve distribution network issues by creating distribution system markets [52-57]. One common drawback of these studies, however, is that there is no consideration of fairness in the definition of the nodal price; drawback particularly prevalent in voltage-constrained networks. Given the radial nature of most distribution networks (as opposed to the meshed configuration of transmission networks), this would cause prosumers at larger distances from voltage regulating devices (such as transformers) to be either more heavily penalised or rewarded (depending on the objective being solved); even if all the DER connected to the same feeder contribute – to different extents – to the voltage problems. While the consideration of fairness has recently started to receive the attention it requires [58-60], aspects of locational fairness incorporated directly in the definition of the nodal prices have only been considered in [61, 62]. Nonetheless, there are several other issues associated with DLMP which have not yet been addressed in any of the studies in the literature which are summarised below.

- Three-phase unbalanced networks. Due to the large optimisation problems that need to be solved to obtain the nodal prices, all studies in the literature consider single-phase distribution networks. As such, the unbalanced nature of real distribution networks, which needs explicit three-phase models to adequately cater for voltages as well as prosumers (e.g., single-phase connections), is not considered. The authors of [62] acknowledge this limitation, who also state that they will attempt to address it in future research.
- Multi-voltage level networks. Also related to the scalability issues that DLMP faces, the studies in the literature are limited to single-level networks, most commonly at the MV level. This effectively ignores the LV circuits, where issues are likely to be present.

Furthermore, from an implementation perspective, the adoption of DLMP in a DSO framework requires the DSO to create and manage distribution-level system markets; a completely new role for DNSPs transitioning to DSOs, and as such, might prove to have high implementation complexity. While in the future DLMP might become widely adopted by DSOs around the world, it is believed that in the early stages of this transition, DSOs will be more likely to adopt frameworks better aligned with their current operational paradigm (i.e., direct control or limiting power flows and devices).

2.4.2 Direct Control Approaches

In an effort to incorporate distribution network constraints in the procurement of services, the authors in [63] propose a novel framework for the operation of a virtual power plant (VPP). In this work, an MV feeder is modelled as a VPP, where the aggregated power flow (at the head of the feeder) is controlled to respond to price signals or service dispatch commands provided by the TSO. The distribution network constraints are incorporated in the operation of the VPP using current measurements (i.e., thermal constraints) from the head of the MV feeder as well as voltage measurements at different locations within the feeder. While the study is written from the perspective of a VPP operator managing the DER in the MV feeder, the authors do mention that this framework can also be applied for different stakeholders managing the VPP (e.g., a DSO). However, the proposed framework does have some limitations. First, all the controllable DER are assumed to be connected at the MV level. As such, the provision of bottom-up services from residential premises (such as residential-scale PV and BES systems) and the corresponding LV circuits are not considered in the proposed framework. Furthermore, it is assumed that the MV feeder is balanced and it is thus modelled as a single-phase network. Finally, thermal problems are only checked at the head of the feeder. In reality, as distribution networks are comprised of different size conductors, there can exist cases were congestion is present further down the laterals.

It should be noted that the framework in [63] assumes all DER in the network are controlled based on the objective of a single entity that has the authority to directly control the assets. Currently, and likely to continue in the future due to regulatory and market requirements, the provision of bottom-up services is done by multiple entities, prosumers and aggregators, who operate their assets following their individual objectives and operational strategies. In this context, without the ability of directly controlling prosumer’s asset, a DSO will only be able to ensure network integrity by limiting the net exports or imports from prosumers when needed. Therefore, this framework could face significant implementation challenges if it were to be adopted by a DSO.

Following the same philosophy of a DSO being able to directly control the assets in the network, the study in [64] proposes a dual-horizon DSO framework for the provision of services at the DSO/TSO interface (i.e., GSP). At the high level (planning), a day-ahead DER dispatch schedule considering uncertainties in demand, generation, and prices is created, which then any deviation from the schedule is minimised in the lower level (operational) using a rolling horizon approach. To ensure that distribution network constraints are met, AC OPF constraints are utilised in both the high and bottom level optimisation problems. The case study, which uses a UK sub-transmission distribution network (i.e., from the GSP to the primary substations) demonstrates the effectiveness of the proposed framework to ensure distribution constraints are met and the importance of considering uncertainty in the optimisation problem as utilising "perfect forecast" yields unrealistic results. As with the previous study, however, this study also assumes that the DER are to be controlled by a single entity. This neglects the possibility for multiple parties operating the DER in the distribution network under different objectives, and also raises questions regarding the implementation and regulatory challenges such an approach might have. Furthermore, the concepts are validated on a 22-bus single-phase sub-transmission network. As such, the circuits at lower voltage levels (i.e., MV, LV) and the corresponding voltage unbalance that exists at lower voltage levels are neglected. Additionally, the case study only considers four controllable elements (two windfarms, one dispatchable gas turbine, and one utility-scale BES system). Realistically, within a single distribution network there could be hundreds or thousands of devices. Given that the proposed network operates with a rolling horizon approach that considers granular periods (15-minute) and long horizons (4, 8, 24 hours), this approach is very likely to suffer heavily from scalability issues when applied to more realistic scenarios.

In another work in this area [65], the authors propose a DSO framework for which the responsibilities of the DSO are to create flexibility cost maps at the TSO-DSO interface. These maps, of which an example is shown in Figure 2-2, are created based on an iterative process which utilizes non-linear AC OPF optimisation and allow the TSO to quickly and intuitively know how much the active and reactive power can change (i.e., flexibility) at the TSO-DSO interface (i.e., the GSP) and at what cost. The case study, based on a French MV network with 577 distribution transformers, assumes the controllability of the OLTCs at the primary substation, five capacitor banks, a cogeneration unit, and two utility-scale PV systems.

One of the limitations of the proposed framework, that has been stated in the previous paragraphs, is also highlighted by the authors: *"Some of these resources (those provided by third parties) are nowadays not accessible for DSO use due to the current French regulatory framework. But to obtain the most representative*

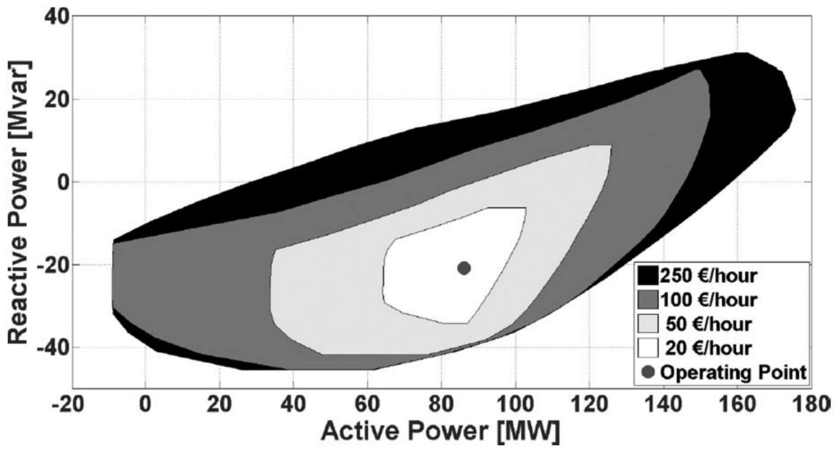


Figure 2-2. Example of flexibility areas for different maximum flexibility costs (taken from [65]).

scenario as well as to anticipate future network codes, all the flexible resources were considered available" [65]. Therefore, this raises questions in regard to the implementability of the proposed framework if the current regulation (common in many countries around the world) persists. Nonetheless, the study also has some technical limitations. The OPF used is highly non-linear and uses discrete variables (for the OLTCs and capacitor banks). Given that the study only considers nine controllable elements (six with discrete, three with continuous variables), it is possible for the optimisation to find a solution in adequate timeframes. However, as the number of controllable elements increases to the hundreds or thousands, questions arise regarding the scalability of this approach. Furthermore, the study considers a single-phase balanced MV network, and neglects the voltage unbalance common in distribution networks as well as the LV circuits.

Similar to the above study, the authors in [66] propose a decomposed [3]optimisation formulation for the TSO and the DSO. At the high level, the TSO optimisation problem is solved, where multipliers are created and passed to the DSO to solve their local optimisation problem. This allows for limited information to be passed between the two parties and respect the autonomy of each section (transmission and distribution network). It should be noted that this study focuses primarily on the decomposition methods and to prove convergence and optimality of the proposed approach. While this falls outside the scope of this thesis, this study has been

[3] In the study, the term "decentralised" is used. However, as this term is used differently in this thesis, the term "decomposed" is used instead.

included in this review for completeness. Nonetheless, similar to the previous study, the DSO operation assumes the direct control of DER in the network, where the corresponding drawbacks have been discussed extensively in the previous paragraphs. Furthermore, the case studies are presented on a 6-bus and 118-bus network, raising questions regarding the scalability of the proposed framework in the existence of thousands of buses (real distribution networks).

Understanding the need for frameworks that do not assume the direct control of DER, the authors in [67] propose a framework where a single aggregator operates within a distribution network and operates the DER based on their own objective. The DSO, first, assesses whether the intended operation of the aggregator will result in congestion of assets (voltage problems are neglected). If congestion in the network if found, the DSO performs reconfiguration of the network topology using circuit breakers. If the problems are not able to be solved using the reconfiguration of the network, an iterative process between the aggregator and the DSO begins where the aggregator proposes new DER schedules in order to comply with the network constraints. However, this study has some severe limitations. First, the usage of real-time reconfiguration of the network is highly questionable; while possible, it is highly unlikely that DSOs will adopt such operation. Furthermore, and more importantly, the voltage constraints of the network are neglected. While this allows for the non-linearities of the distribution network to be removed and remove the complexity in their calculation, voltage limits are usually the most dominant constraint, particularly in the presence of distributed generation. In addition, the framework is only applicable when one aggregator operates within the distribution network, where in reality, multiple aggregators or individual prosumers providing services can exist. Finally, the framework is applied only at the MV network, and as such, the LV circuits are neglected.

2.5 Summary of Gaps in the Literature

In general, the DSO frameworks in the literature mostly consist of two types of studies: a) studies that assume the creation of local distribution markets by the DSO and utilise DLMP to create nodal prices to solve distribution network issues, and b) studies that consider the direct control of DER by the DSO to incorporate distribution network constraints in the provision of services to the TSO. While local distribution markets and DLMP could prove to be how DSOs will operate in the years to come, the current drawbacks associated with this approach (i.e., fairness, scalability, multi-phase systems, high complexity) have been discussed and was concluded that due to these limitations, DLMP is not considered in this thesis. As for the latter category, the biggest limitations in assuming a direct control of DER by the DSO are a) this is currently (and perhaps likely to continue in the future) prohibited by regulation, and b) there is loss of individualism (i.e., different prosumers / entities controlling their assets based on their own objectives) in the provision of services. Furthermore, most of these studies assume the existence of a single entity controlling all DER in the network (e.g., aggregator), which is probably an unrealistic assumption. As such, the gaps in the literature are summarised below.

- Non-direct control of DER. There is a strong need for DSO frameworks that do not assume the direct control of DER, but rather allow individual entities / prosumers to decide their own response to the provision of a service. As such, the role of the DSO lies in limiting this operation when needed.
- Multiple entities/prosumers providing services. Given the likelihood that multiple entities or prosumers will exist in a given distribution network that provide services, the DSO framework needs to be able to adequately capture this in a fair way (locational fairness).
- Scalable frameworks. In reality, distribution networks consist of multiple voltage levels and thousands of nodes and buses. As such, the DSO framework should consider both MV and LV circuits, and be scalable enough to accommodate for thousands of customer and prosumers.

All these gaps are considered and addressed in the proposed DSO framework that is presented in Chapter 7.

3 DISTRIBUTION NETWORK MODELLING AND ASSESSMENT

3.1 Introduction

One of the most important aspects in distribution network assessments is for the input data to be as realistic as possible. Most studies in the literature utilise synthetic demand information and network models for a single voltage level (most commonly at the MV level), and as such, neglect the interactions between the different voltage levels (e.g., effect of voltage rise in the MV network on the LV circuits). And for good reason; real network and demand information is not made publicly available by DNSPs in most parts of the world. Furthermore, when available, the data exists in formats used by specialised commercial software (e.g., PSS Sincal) which do not offer free academic licenses and often do not provide the same level of flexibility as open-source software (e.g., OpenDSS). Furthermore, distribution networks have high levels of uncertainty in terms of locational aspects (demand, PV, etc.), which need to be incorporated in the network studies.

To overcome these limitations, this thesis considers an integrated MV-LV network model for all the case studies. Furthermore, smart meter demand and PV generation data is used to simulate the status of the network as realistically as possible. This data was provided by AusNet Services (a Victorian DNSP) as part of the "HV[4]-LV Analysis of Mini Grid Clusters", however, as only MV and smart meter demand/generation data was readily available (most DNSPs do not have LV networks modelled for power flow studies), the LV networks are modelled based on Australian LV network design principles. Finally, a Monte Carlo assessment methodology is used to cater for the uncertainties previously mentioned.

This chapter is structured as follows. Section 3.2 corresponds to the MV feeder modelling methodology, required to translate the network information that was

[4] In Australia, voltage levels higher than 1kV are referred to as "High Voltage (HV)". However, in this thesis, the international nomenclature is used (i.e., MV).

provided to a network modelled that can be used by open-source software. Furthermore, the LV network modelling methodology is presented in Section 3.3. Then, the Monte Carlo methodology is presented in Section 3.4. Throughout the studies, different network and customer (i.e., households) performance metrics are used to quantify the effects that a control will have on either the network or the customer. The details on these metrics are presented in Section 3.5. Furthermore, the integrated MV-LV network as well as the demand and generation profiles used throughout the thesis are presented in Section 3.6, along with a case study which quantifies the impacts of PV generation in this network across multiple PV penetration levels (defined as the percentage of households). Finally, a summary of the findings of the chapter is provided in Section 3.8.

3.2 MV Feeder

This section presents an overview of the data that was provided for the purposes of modelling the 22kV (line-to-line) feeder, along with any assumptions that were used where there was lack of data. This feeder is one of the six supplied by the same primary substation. The full details of the MV feeder (e.g., number of distribution transformers, total feeder length, R/X ratio, etc.) is provided later in Section 3.6 where the network modelled is presented.

3.2.1 Head of the Feeder

At the head of the feeder, the primary substation consists of two transformers fitted with OLTCs. The OLTCs aim to keep the voltage at the secondary side of the primary substation constant at the OLTC target voltage. However, as the actual voltage on the secondary depends on: a) the power demand of the other feeders, and b) the voltage on the primary side (both not provided), a decision was made not to model the primary substation but use the head of the feeder as the source with a constant voltage supply equal to the target voltage of the OLTCs.

3.2.2 Network Topology Modelling

The network information was translated from PSS Sincal, a software commonly used by DNSPs, to OpenDSS, a free, open-source software developed by the Electric Power Research Institute (EPRI, USA) [68]. The translation was done using scripts developed for the "HV-LV Analysis of Mini Grid Clusters" project by the author of this thesis. The original three-phase network data identified the line impedances (zero and positive sequence), as well as the corresponding nodes (start and end) that each line was connected to. The network information also included geographical information so that the network can be presented graphically based on its real topology.

3.2.3 Distribution Transformers Modelling

Information regarding the connection points of the distribution transformers in the network, the type of the transformer (e.g., three-phase, single-phase, delta-wye etc.), the capacity (in kVA), and the connection point of each transformer in the MV feeder were provided. However, the impedances of the transformers (i.e., on-load losses, off-load losses) were not provided, as were therefore estimated based on their capacity and information found in [69]. It should also be noted that the distribution transformers in Australia are fitted with off-load tap changers. At the nominal tap position, the transformation ratio is 22kV/0.433kV; in per unit values (22kV, 0.4kV), the distribution transformers provide a natural boost to the voltage on the secondary.

3.3 Realistically Modelled Residential LV Networks

Given that real LV networks were not available to be used in the studies, synthetic LV networks were modelled according to design considerations from the same region as the MV feeder. Three aspects were considered in the modelling of the LV networks; the number of customers per LV network, the number of LV feeders and connected customers, and the length of the LV feeders. The modelling of the networks was done based on documentation available from DNSPs in Australia [70-74] which corresponds to their business-as-usual LV network design practise.

3.3.1 Number of Customers per LV Network

The number of customers in each LV network was estimated based on the distribution transformer capacity and the ADMD of the region [70, 71]. The definition and role of the ADMD was given in 1.1.2. The calculation for the number of customers per distribution transformer is given by Equation 3.1.

$$C_{tx}^{\#} = \left\lfloor \frac{\bar{S}_{tx}}{padmd} \right\rfloor \tag{3.1}$$

where $C_{tx}^{\#}$ is the number of customers that each distribution transformer is supplying, $\bar{S}_{tx}$ is the capacity of each distribution transformer, and P^{admd} is the regional ADMD (e.g., 3-5kW depending on the type of the household, i.e., Villa, Townhouse, Apartment, in Victoria, Australia). The downward brackets denote that the value is rounded down to the nearest integer number.

For example, for a distribution transformer with a rated capacity of 500kW, if a 4kW ADMD is used then the number of customers that this transformer supplies is equal to $\frac{500}{4} = 125$.

3.3.2 Number of LV Feeders and Connected Customers

To calculate the number of LV feeders per LV network, the feeder is modelled so it can host the ADMD from all customers connected to it. To do this, the ampacity of the desired cable is converted to the power that the cable can supply using the maximum allowed voltage in the network in Australia [72]. The calculation of the number of customers per LV feeder is given in Equation 3.2.

$$\bar{C}_f^{\#} = \left\lfloor \frac{\bar{I} \times 3 \times \bar{V}}{P^{admd}} \right\rfloor \qquad 3.2$$

where $\bar{C}_f^{\#}$ is the maximum number of customers supplied by each LV feeder, $\bar{I}$ is the ampacity of the line at the head of the LV feeder, and $\bar{V}$ is the maximum allowed line-to-neutral voltage in the LV network (253V, 1.10pu in Australia [13]). It should be noted that a selection of the cable size (e.g., 180mm^2, 240mm^2) and as such, the corresponding ampacity (280A, 325A per phase, respectively), should be done prior to calculating the number of customers per LV feeder. For simplicity, in this work, a single size cable was used for the creation of all LV feeders.

Finally, the total number of feeders in each LV network can be calculated based on Equation 3.3.

$$F_{tx}^{\#} = \left\lceil \frac{C_{tx}^{\#}}{\bar{C}_f^{\#}} \right\rceil \qquad 3.3$$

where $F_{tx}^{\#}$ is the number of feeders for each distribution transformer.

It should be noted that the customers are allocated to the first feeder initially, until the maximum number of customers for that feeder is reached. Then, the next feeder is populated until all customers supplied by the distribution transformer have been allocated to a feeder. This means that the actual number of customers per feeder can be different to the maximum number of customers per feeder. The actual number of customers per feeder f supplied by the distribution transformer tx is denoted by $C_{tx,f}^{\#}$.

For example, for a 240mm^2 cable with 325A ampacity (per phase) and an ADMD of 4kW, the maximum number of customers per feeder is $\frac{325\times3\times253}{4{,}000} = 53.3 \approx 53$. Continuing from the previous example (125 customers), the total number of feeders in the LV network is $\frac{125}{53} = 2.35 \approx 3$.

3.3.3 Length of LV Feeders and Customer Distribution

The calculation of the length of the LV feeders is done based on a parameter defined as the "maximum equivalent length of a 95mm^2 LV cable". The actual maximum LV feeder length is then calculated based on the actual cable cross-section size used and a corresponding scaling factor [73, 74]. This relationship is given in Equation 3.4.

$$\bar{F}_c^{act} = \bar{F}_c^{eq} \times \phi_c^{sc} \tag{3.4}$$

where $\bar{F}_c^{act}$ is the actual maximum length of the cable, $\bar{F}_c^{eq}$ is the "maximum equivalent length of a 95mm^2 LV cable", and ϕ_c^{sc} is the cable size scaling factor.

Once the actual maximum length is defined, the actual length of the feeder can be calculated using Equation 3.5.

$$F_{tx,f}^{l} = \bar{F}_c^{act} \times \left(\frac{C_{tx,f}^{\#}}{\bar{C}_f^{\#}}\right) \tag{3.5}$$

where $F_{tx,f}^{l}$ is the actual length of a feeder f connected to the distribution transformer tx.

Once the length of the feeder has been defined, the customers are distributed using equal distances between them on the feeder. The first customer to be allocated is placed at the end of the feeder, and each subsequent customer's distance from the previous is calculated using Equation 3.6.

$$C_{tx,f}^{l} = \frac{F_{tx,f}^{l}}{C_{tx,f}^{\#}} \tag{3.6}$$

where $C_{tx,f}^{l}$ is the distance between customers at distribution transformer tx and feeder f.

Finally, once the customers have been allocated to the feeder, they are connected to the main cable by a smaller cross-section cable.

For example, based on [73], the maximum equivalent length of a 95mm^2 cable with 310A fuse is 310m and the scaling factor for a 240mm^2 cable is 2.57. Therefore, the actual maximum length of the feeder can be calculated as $310 \times 2.57 = 796.5$m. Using the values from the previous example, the actual length of the feeder is calculated as $796.5 \times \frac{53}{53} = 796.5$m for feeders 1 and 2, and $796.5 \times \frac{125-2\times53}{53} = 285.5$m for feeder 3. Finally, the distance between customers can be calculated as $\frac{796.5}{53} = 15$m (same for all 3 feeders).

3.3.4 Phase Allocation for Single-phase Customers

Real residential LV networks can be significantly unbalanced (i.e., one phase having more loads and/or PVs). Unbalanced power flows in a three-phase feeder can significantly exacerbate voltage drop/rise. Furthermore, unbalance also results in current to in the neutral wire, which can also cause thermal problems particularly in underground cables. To cater for this, for each customer in the network, the phase connection is allocated completely at random. This leads to different LV feeders in the MV-LV network to be severely more unbalanced than others. This allows for the effects of phase unbalance to be captured and studied as realistically as possible.

3.4 Monte Carlo Methodology

When assessing the impacts of a certain technology, deterministic studies could fail to fully capture the true effects on the distribution networks, as there are numerous uncertainties. To capture the effect of these uncertainties, this thesis adopts (where applicable) a probabilistic assessment of the impacts, based on the Monte Carlo methodology presented in [12]. With this approach, different parameters such as daily demand, generation, as well as network topology aspects such as location of PV systems in the network and phase connections are all randomised prior to performing the power flow simulation. Once the simulation is finished, results are collected, and the process is repeated. In addition to the probabilistic analysis, this thesis also considers the expansion of the analysis to a multi-penetration analysis.

The multi-penetration Monte Carlo flow chart is shown graphically in Figure 3-1, and the numbered processes are explained further in the text below.

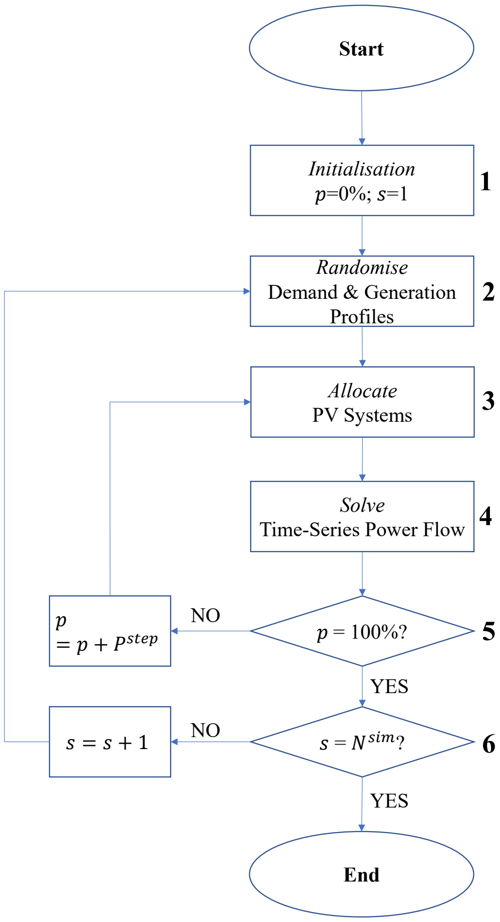


Figure 3-1. Multi-penetration Monte Carlo analysis flowchart

1. Initialisation of the simulation. The PV penetration counter p and the simulation counter s are initialised to 0% and 1 respectively. PV penetration in this thesis refers to the percentage of customers that have a PV system.
2. Individual time-series demand profiles that correspond to the period of interest (e.g., summer) are selected from a pool of demand profiles and allocated randomly to all the customers in the network. Furthermore, a single, normalised, time-series generation profile is selected from the pool of generation profiles.
3. Each time this process is performed, PV systems are allocated to random customers in the network depending on the value of p. To ensure that the increments in PV penetration consider the previous penetration level assessed, the PV systems are added progressively as the penetration is

increased. This means that the PV systems were installed for the 10% PV penetration analysis will still be present for the 20% PV penetration analysis and so forth. The locational aspects of PV systems reset only when the PV penetration is set to 0% again.

4. A time-series analysis is performed for the current status of the network. It should be noted that the time-series analysis can consider either single or multiple days. In the case that controllable elements with intertemporal qualities are used (e.g., BES systems), a flat-start (e.g., zero stored energy) is considered each time the power flow analysis is performed. The results from the analysis are then stored for post-processing analysis.
5. If the p counter is at 100% (i.e., last simulation considered 100% PV penetration), then proceed to block 6. Otherwise, increase the PV penetration by the predefined P^{step} penetration and proceed to block 3.
6. If the s counter has reached the desired number of Monte Carlo simulations, N^{sim}, then terminate the analysis. If not, proceed to block 2.

Once the simulation has been finalised, the results collected from each iteration can be used to present the impacts probabilistically and across multiple PV penetrations.

It should be noted that as it was demonstrated in [12], one hundred Monte Carlo simulations provide an adequate trade-off between numerical accuracy and computational performance.

3.5 Performance Metrics

To simplify the demonstration of results, particularly when a multi-penetration Monte Carlo analysis is performed, performance metrics are used which aim to quickly and intuitively indicate the performance of the network to the reader. The performance metrics used in this thesis fall under two categories; network performance metrics, which quantify whether the network is operating within its limits, and the customer performance metrics which present information regarding the level of benefits the customer receives from their PV or BES systems.

3.5.1 Network Performance

As previously mentioned in Section 1.1.2, this thesis primarily focuses on two issues in distribution network constraints, under/over-voltages and thermal congestion. The voltage issues are quantified based on the "number of customers with voltage problems", whereas thermal congestion is quantified based on the "hourly asset utilisation".

- Number of Customers with Voltage Problems (%): This metric takes the voltage profile simulated for each customer in the network and checks for compliance with the corresponding standard (e.g., Electricity Distribution Code in Australia [13], BS EN50160 in Britain [75] etc.). If the voltage values of a customer are found outside the statutory limits defined in these standards, then the customer is flagged as non-compliant. This process is repeated for all the customers in the network. In summary, the metric provides a value for the percentage of the customers in the network that their voltages fall outside the statutory limits (i.e., they have voltage problems). With the business-as-usual operation of distribution networks, it is expected that the number of customers with voltage problems is 0%.
- Hourly Asset Utilisation (%): This metric takes the maximum hourly rolling average apparent powers for transformers and the per phase currents for the lines in a day. The maximum value recorded for each of the assets (either transformer or line segment) are then divided by the rated capacity of the corresponding asset (usually in kVA for transformers and Amps for lines – also known as ampacity). Therefore, when a value of more than 100% is defined, the asset is considered overloaded. With the business-as-usual operation of distribution networks, it is assumed that all assets should be operating within their rated capacity (i.e., less than 100% hourly utilisation level).

3.5.2 Customer Performance

The work carried in this thesis, besides focusing on resolving technical issues in the distribution networks, also considers heavily the effects that each proposed solution has on the customers. One of the main drivers behind this approach is that PV and BES systems are very likely to be paid for by the customers for their own benefit. As such, any solution that heavily penalises them, is very unlikely to be adopted as it will either require very heavy subsidies to compensate for the lack of customer performance, or the return on investment of customers will be negative. As such, different metrics were designed to quantify how well a technology performs in terms of customer benefits. In this context, two customer performance metrics are used and are described below.

- Grid Dependency Index (GDI) (%): This index quantifies the percentage of the demand of a customer that was supplied by the grid. For example, for a household with no local generation, the GDI would be 100%, as all their energy needs were supplied by the grid. For a household that manages to supply all their energy needs locally, the GDI would be 0%. As such, the value of the GDI can be in the range of 0% (best for the customer) to 100% (worst for the customer). It should also be noted that exports into the grid do not affect the value of the GDI. Mathematically, the GDI per customer can be calculated using Equation 3.7.

$$GDI\ (\%) = \frac{\sum_{t\in T | P_t^{nd}>0} P_t^{nd}}{\sum_{t\in T} P_t^{d}} \times 100\% \tag{3.7}$$

where P^{nd} is the customer net demand (i.e., the power flow at the customer connection point), P^d is the customer demand (i.e., consumption from electrical devices within the house), and T is a set with all the time-series periods from the corresponding analysis.

- Net Benefit Index (NBI) (%): This index quantifies the difference in benefits a customer will receive by adopting a new technology or a new control scheme for their systems. Unlike the GDI, the NBI is a comparative index (i.e., compares between two cases). Furthermore, it takes into consideration both imports and exports, as well as the corresponding payments from each. A value of 0% would indicate that the customer receives equal benefits from the introduction of a new technology/control as previously. A positive value, e.g., 20%, would indicate that a customer will see a 20% increase in their benefits. On the other hand, a negative value, e.g., -20%, indicates that the customer will see a decrease of 20% in their benefits. Mathematically, the calculation of the NBI per customer is given in Equations 3.8 - 3.10.

$$NBI\ (\%) = \left[\frac{(B^+ + B^-)_{nc}}{(B^+ + B^-)_{bc}} - 1\right] \cdot 100\% \tag{3.8}$$

$$B^+ = \sum_{t\in T} P_t^d \lambda_t^+ \,\Delta t - \sum_{t\in T | P_t^{nd}>0} P_t^{nd} \lambda_t^+ \,\Delta t \tag{3.9}$$

$$B^- = -\sum_{t\in T | P_t^{nd}<0} P_t^{nd} \lambda_t^- \,\Delta t \tag{3.10}$$

where B^+ is the benefit from reducing import costs, B^- is the benefit from exporting into the grid, λ^+ and λ^- are the cost of importing and exporting electricity respectively (can be time-dependent), Δt is the discretised time-step considered in the time-series analysis, and the subscripts nc and bc denote the new-case and base-case values respectively. P^{nd}, P^{d}, and T are as previously defined. It should be noted that if desired, the calculation of the NBI can be adjusted to only consider benefits from imports (set $B^{-} = 0$) or benefits only from exports (set $B^{+} = 0$).

3.6 Integrated MV-LV Australian Network Assessment

This section presents the fully modelled network as well as the demand and generation data used in the case studies. Furthermore, for demonstration purposes, an example case study which considers both single-day deterministic case studies as well as a multi-penetration Monte Carlo assessment of the PV impacts in the network is conducted.

3.6.1 Real Australian 22kV Feeder

The topology of the 22kV MV feeder is shown in Figure 3-2. In this figure, the location of the primary substation (i.e., head of the feeder) is shown as a black triangle on the right side of the diagram. The OLTCs at the head of the feeder are assumed to keep the voltage constant at the 22kV (1.0pu) target voltage. The source is modelled with upstream impedances of 0.244Ω, 1.410Ω, 24.159Ω and 0.485Ω for the R1, X1, R0 and X0 values, respectively. The MV feeder supplies an area of approximately 18km^2, with the farthest two points being approximately 6km apart. Further details for the line parameters in the MV feeder are given in Table 3-1.

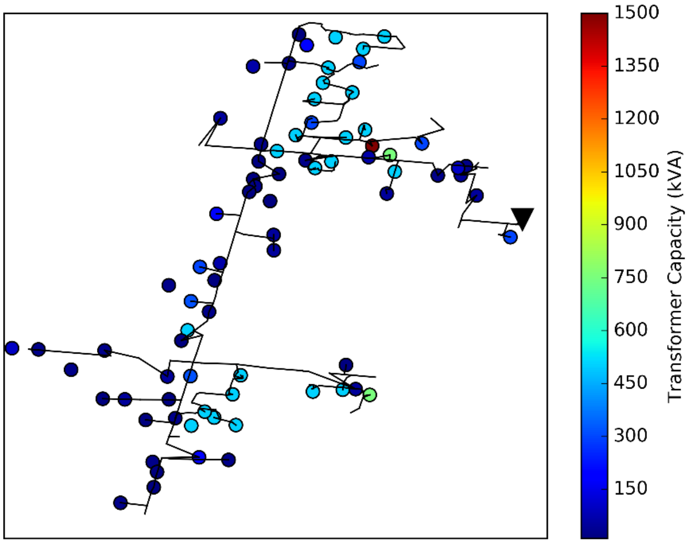


Figure 3-2. Real MV feeder topology

Table 3-1. Integrated MV-LV network line parameters

	Feeders	***Total Length***	***Main Path Length***	***R***	***X***
	#	*(km)*	*(km)*	*(Ω/km)*	*(Ω/km)*
MV Feeder	1	31	11.3	0.864	0.414
LV Networks	175	134	0.5*	0.519*	0.075*

* *Corresponds to the average of all LV feeders*

Each LV network in the MV feeder is supplied by a distribution transformer with a transformation ratio of 22kV/0.433kV (natural boost of 8.25%), which are fitted with off-load tap changers. The off-load tap changers have 5 positions, with the nominal tap at position 3 and a 2.5% voltage change between taps. This allows for the voltage at the secondary of the transformer to vary between 1.0825±0.05pu (assuming 1pu voltage at the primary of the transformer and no load). The 79 distribution transformers (60 three-phase delta-wye, 19 single-phase), are identified as circles in Figure 3-2. The capacity of each of the distribution transformers can be identified using the colour map. An ADMD of 4kW was used to calculate the number of residential customers per distribution transformer, using the methodology presented in Section 3.3. Consequently, the total number of residential customers in the network is assumed to be 4,626.

The LV networks were also designed using the methodology found in Section 3.3, where a 240mm^2 underground cable was used for all LV feeders. Furthermore, all residential customer connections are assumed to be single-phase supplied through a 10 meters 16mm^2 service cable, where the phase-connection (A, B, or C) is randomised every time a power flow is performed. More details on the line characteristics of the LV networks can be found in Table 3-1.

3.6.2 Real Demand and Generation Profiles

The demand profiles used for the analyses in this thesis correspond to anonymised, real smart meter data, collected from 342 AusNet Services customers, randomly selected from various locations across the state of Victoria that AusNet Services operate within, from 2016. For each customer, a timestamped 30-minute resolution, yearly active power profile was provided, which was then broken down into daily profiles to be used in the daily time-series simulations. As there only exist 342 demand profiles per day, to compensate for the 4,626 customers that exist in the assessed network, different customers can be assigned the same demand profile multiple times. A histogram showing the yearly energy consumption from the individual profiles that were provided is given in Figure 3-3. As it can be seen, most of the households in the pool of profiles have an annual consumption in the range of 3-5MWh. However, in some cases, some households have an annual consumption that can exceed 10MWh, up to 23MWh.

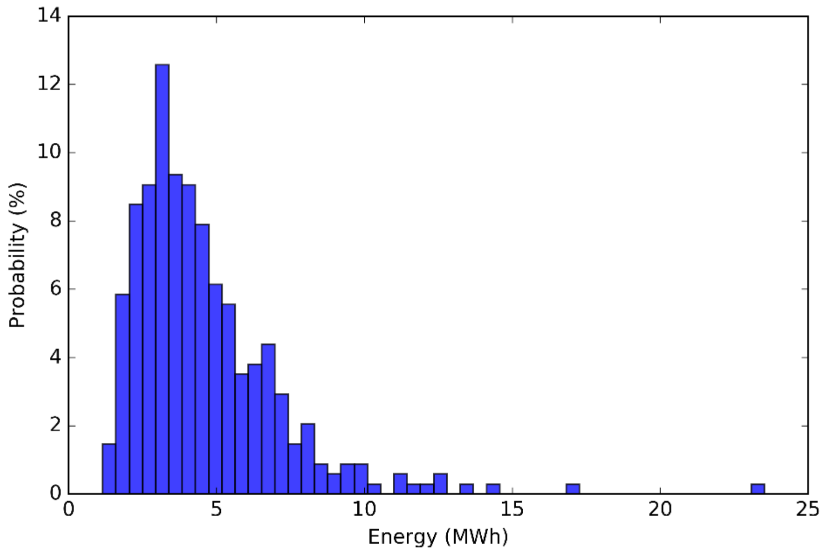


Figure 3-3. Annual demand histogram from the smart meter data

In reality, the power factor of households changes in time and differs from day to day, as different types of loads have different power factors (e.g., AC units are highly inductive). However, the profiles provided only consist of active power readings. Therefore, a constant power factor of 0.95 (inductive) is assumed to determine the reactive power values; value which is aligned with the average power factor across households in Victoria, Australia. The calculation of the reactive power for each customer is done using Equation 3.11.

$$Q_{c,t} = \sqrt{\left(\frac{P_{c,t}}{pf}\right)^2 - P_{c,t}^2}, \qquad \forall c \in C, t \in T \tag{3.11}$$

where P is the active power of the customer, Q is the reactive power, pf is the power factor (0.95 used throughout this thesis), C is the set of all customers, and T is the set of all 30-minute periods in the yearly data (17,520 points).

A real 30-minute resolution normalised annual generation profile was also provided by AusNet Services from the same region and period. The profile was collected based on a real PV system, and as such, the corresponding efficiencies (e.g., effects of temperature, dust, inverter efficiency) are incorporated in the generation profile. Similarly, the PV generation profile was broken down into time-stamped daily profiles, which are all shown in Figure 3-4.

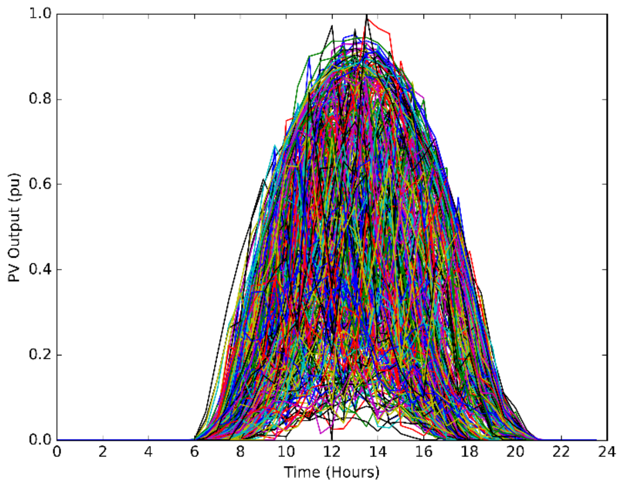


Figure 3-4. Pool of normalised daily PV generation profiles

As aforementioned, the farthest two points in the network are approximately 6km apart. According to [76], 15-minute (and above) resolution PV data is positively correlated for distances up to 10km. Therefore, all PV systems in the network use the same normalised PV generation profile in the daily assessment. However, the size of the PV system is randomly selected based on Australian installation size statistics [2] from 2016 onwards. The distribution for the different PV system installation sizes is shown in Table 3-2. For all the case studies conducted in this thesis, the PV systems are assumed to be operating at unity power factor (i.e., the reactive power capabilities of these systems are not explored as the Volt-Var function of PV inverters is by default disabled currently in Australia).

Table 3-2. PV System Installation Statistics

PV Size (kWp)	2.2	3.5	5.5	8
Distribution (%)	10	30	50	10

3.6.3 PV Impact Analysis

This section demonstrates the impacts of solar PV in the 22kV distribution network. To do so, first, deterministic, single-day assessments are carried out. In the first deterministic assessment, the network is assessed without any PV systems installed. Then, a 50% PV penetration assessment is performed, where the utilisation of different off-load tap positions at the distribution transformers is explored. Finally, a multi-penetration Monte Carlo assessment is done to fully capture the impacts of PV generation in the network.

To make the case study as realistic as possible, based on Australian standards [15], the Volt-Watt function of the PV systems is enabled, and the curve is defined as previously shown in Figure 1-5. Finally, the Australian voltage statutory limits are adopted in this study, which state that the steady-state voltages (>1-minute duration) of a customer should be within the 0.94pu – 1.1pu range (of 230V line-to-neutral) at all times. One limitation of using 30-minute demand and generation data is that it could potentially lead to slight underestimation of steady-state voltage problems (>1 minute in duration) due to the smoothing of the profiles.

The analysis is done based on the demand and generation data on the 13th of January 2016 (summer). This day has been selected as it corresponds to a peak demand day; scenario which defines the design characteristics of distribution networks. The distribution system analysis software package OpenDSS [68] and Python 3.7 are used to run the time-series, three-phase four-wire power flows as well as the control approaches.

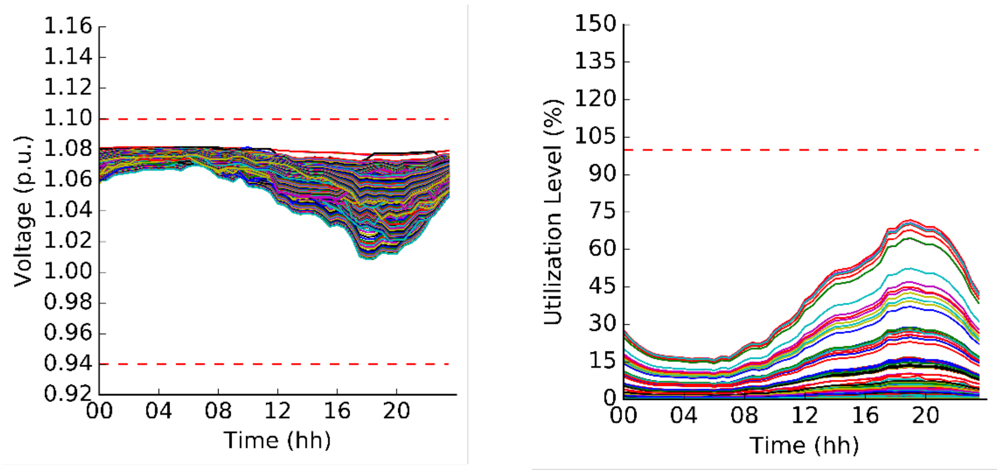
3.6.3.1 0% PV Penetration

In this case study, all the customers (residential households) are modelled only with a demand profile, without a PV system installed. This is done to assess the performance of the network under its original design. The distribution transformer off-load tap changer is set to its nominal position.

Figure 3-5(a) shows the voltage profiles for all customers as well the voltage statutory limits (dashed red line), whereas Figure 3-5(b) shows the utilisation of all line segments in the MV network, along with the 100% capacity limit (dashed red line). The results for the LV transformers and cables have been omitted from this analysis for the sake of brevity.

Starting with the voltage profiles, it can be seen that the voltages for all customers are well within the statutory limits. Given that the off-load tap changes are all set to the nominal position, the customer voltages can be very close to the upper voltage. This could be problematic in the existence of reverse power flows, as there is very little headroom for voltage rise. During the peak demand period, the lowest voltage in the network is at ~1.0pu.

The MV lines are all operating within their rated capacity, with the highest value being recorded during the peak demand period, where the most loaded line is operating at ~75% of its rated capacity.



(a) (b)

Figure 3-5. No PV: Voltage profiles (a), and MV lines utilisation (b)

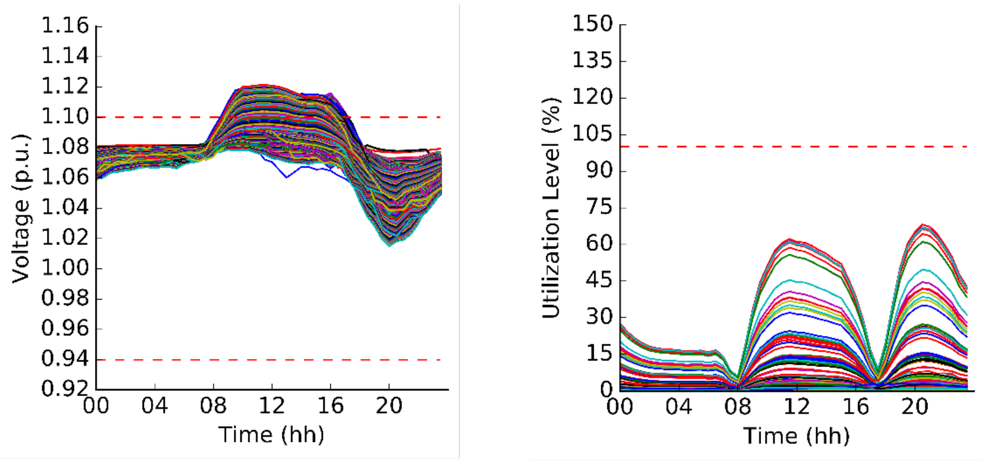
3.6.3.2 50% PV Penetration and Nominal Tap Positions

Now, the PV penetration across the MV feeder is set to 50% (random allocation of PV systems), while the off-load tap changers are kept to the nominal tap position.

As it can be seen in Figure 3-6(a), due to the existence of generation in the network which causes reverse power flows both in the MV feeder and the LV networks, the voltage profiles for customers in this case exceed the statutory limit. Even with the Volt-Watt function enabled by default in all PV inverters, 39% of the customers were found to have voltage problems.

The high voltages in the network also cause curtailment of the PV generated energy (due to the Volt-Watt function). This can be seen in Figure 3-7, where the actual generation profiles for all customers in the network can be seen (the four sets of curves relates to the different PV system sizes, see Table 3-2). Customers closer to the primary substation and the distribution transformers are much less penalised by the Volt-Watt function. However, customers further away from the transformers can have significant portions of their PV generated energy curtailed.

Nonetheless, as shown in Figure 3-6(b), the MV lines are all operating within their rated capacity, despite the existence of reverse power flows. While the reverse power flows do cause more loading of the MV lines during midday (~65% for the most loaded line) when solar generation is at its highest, the maximum utilisation of the lines still exists due to the peak demand. This means that there exists the opportunity to resolve the issues in the network through the usage of the off-load tap changer.



(a) (b)

Figure 3-6. 50% PV, nominal taps: Voltage profiles (a), and MV lines utilisation (b)

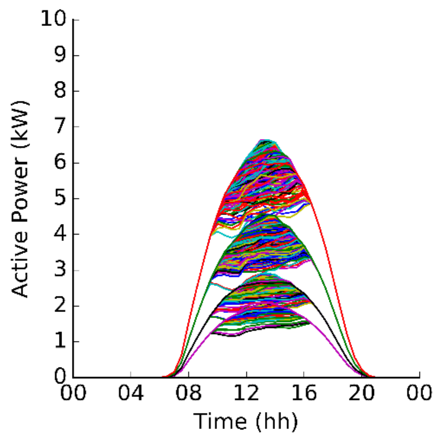


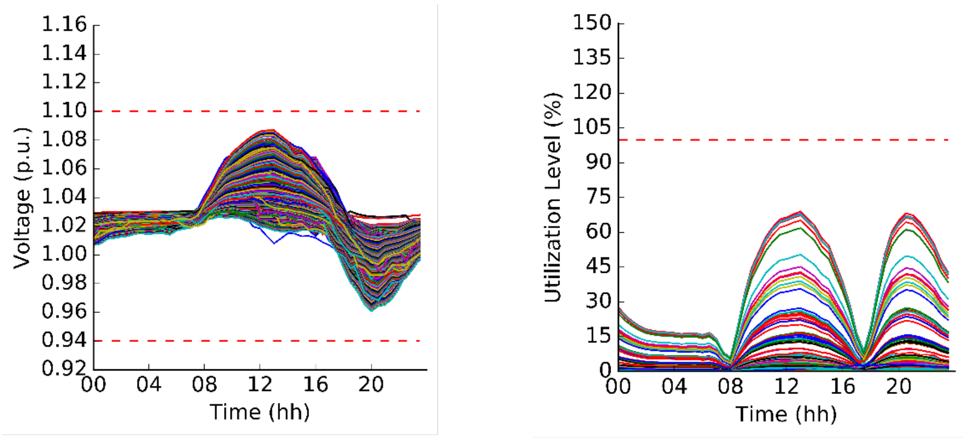
Figure 3-7. 50% PV, nominal taps: Actual PV generation profiles.

3.6.3.3 50% PV Penetration and Reduced Tap Positions

In this case study, the off-load tap positions for all distribution transformers are set to the lowest position (position 1), effectively changing the transformation ratio from 22kV/0.433kV to 22kV/0.411kV.

As it can be seen in Figure 3-8, by changing the tap position of the off-load tap changers, the voltage profiles for all customers are now within the statutory limits, with the maximum recorded voltage in the network at ~1.085pu. The decrease in voltages also has an effect on the curtailment of PV generation. As seen in Figure 3-9, the actual PV generation is the same for all customers in the network (across customers with the same PV size).

However, as there is no longer PV generation curtailment, this causes the MV line utilisation to increase during midday. While the increase is not significant enough to cause any thermal congestion problems, the maximum utilisation now happens during the peak generation period (~75%) rather during the peak demand period.



(a) (b)

Figure 3-8. 50% PV, reduced taps: Voltage profiles (a), and MV lines utilisation (b)

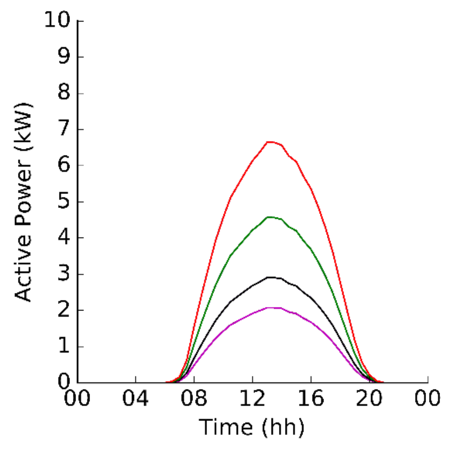


Figure 3-9. 50% PV, reduced taps: Actual PV generation

3.6.3.4 Multi-penetration Monte Carlo Assessment

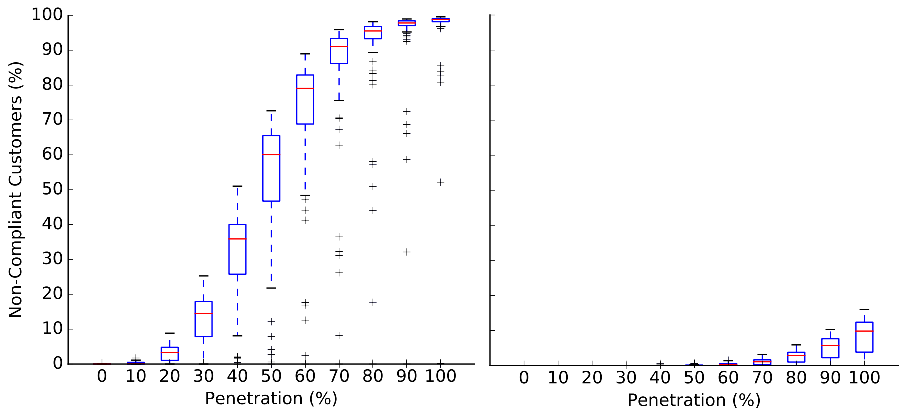
Here we expand the deterministic analyses performed in the previous sections to a multi-penetration Monte Carlo assessment. The assessment is carried for two cases: one with nominal tap positions at the distribution transformers, and one with the lowest tap position available. This assessment also aims to determine the hosting capacity of the network (i.e., the maximum percentage of households in the network that can have a PV system without any distribution network constraints being violated). The Monte Carlo assessment is done considering PV penetration steps of 10% ($P^{step} = 10\%$ in Section 3.4), and 100 simulations for each case ($N^{sim} = 100$ in Section 3.4). All the results are plotted in form of boxplots, where the Tukey interpretation is used. In other words, the red line within the box indicates the median value across the 100 simulations, the upper and lower box bounds are the 75th and 25th percentile, respectively, and the upper and lower whiskers are 1.5 times the interquartile range. Any values outside that range (if they exist) are plotted as outliers (black crosses).

Voltage Issues:

As shown in Figure 3-10(a), when the nominal tap positions of the off-load tap changers at the distribution transformers are used, customers might start facing voltage problems in the network with as low as 10% PV penetration, where a median of 2% of customers with voltage problems were found across the simulations performed. The problems rapidly increase as the PV penetration goes beyond 30%, at which point a median of 16% of customers is found to have voltage problems. At this point, the importance of using a probabilistic analysis can also be highlighted; at 30% PV penetration, across the 100 simulations performed, the range of customers with voltage problems varies from 0 to 28%. This means that a deterministic study could have provided results that indicate that the network can host 30% PV penetration, whereas in reality, that is a very unlikely scenario. Once the PV penetration in increased to 40% and above, the number of customers with voltage problems increases dramatically; up to a median of 98% at 100% PV penetration.

The voltage issues in the network can be reduced significantly by lowering the off-load tap changer to the lowest tap position. As seen in Figure 3-10(b), with these tap settings, voltage problems do not start arising until the 60% PV penetration level. Furthermore, the number of customers with voltage problems at higher PV penetrations also reduces dramatically. At 100% PV penetration, whereas previously a median of 98% of customers had voltage problems, with the lowered tap positions this value drops to 11%.

As demonstrated, the usage of off-load tap changers allows the management of voltage issues in the network in a cost-effective manner, using existing assets in the network. However, given the limited amount of tap positions available, these assets cannot fully mitigate voltage problems at higher PV penetration levels.



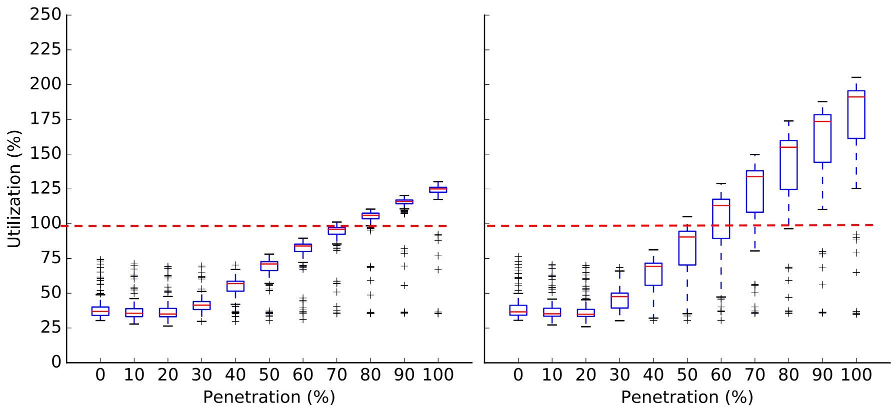
(a) (b)

Figure 3-10. Number of customers with voltage problems with nominal tap position (a) and lowest tap position (b)

Thermal Issues:

Changing the tap position on the off-load tap changers has an interesting effect on the thermal utilisation of MV lines. With the taps at nominal position, thermal issues do not appear until the PV penetration reaches 80%, as shown in Figure 3-11(a). On the other hand, when the lowest tap position is used, issues start arising as early as 50% PV penetration. This effect is primarily due to the enabled Volt-Watt function on PV inverters. With nominal tap positions, as the customers are exposed to higher voltages, the PV inverters curtail higher volumes of PV generation, which also reduces the reverse power flow in the MV networks, which consequently reduces thermal issues. Furthermore, as PV inverters are modelled as constant power devices, a lower voltage results in less current being injected in the network (with the same power output), which also minorly contributes to the increase in thermal utilisation shown in Figure 3-11(b). In fact, at 100% PV penetration, the most utilised line in the network is operating at 125% of its rated capacity when the nominal tap positions are used, whereas this value climbs to 200% with the lowest tap position.

While lowering the tap position on the off-load tap changers does increase the thermal utilisation of the MV lines, the hosting capacity of the network is still increased from 10% to 50% despite this effect. Therefore, off-load tap changers are a very effective way to increase the hosting capacity of the network.



(a) (b)

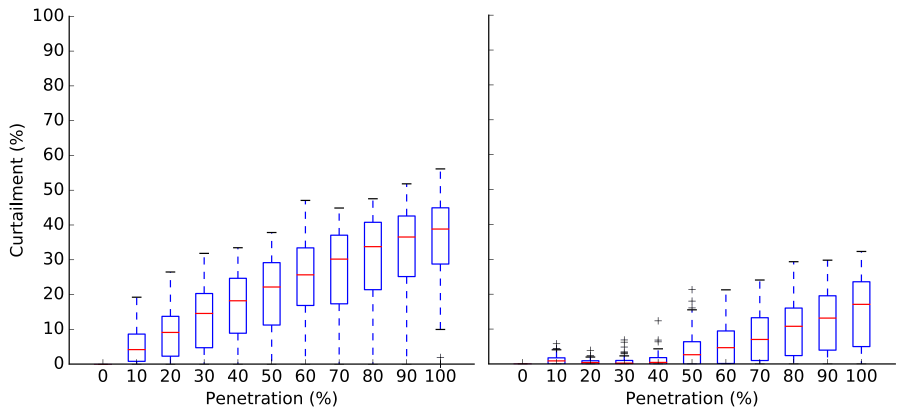
Figure 3-11. Maximum utilisation of MV lines with normal tap position (a) and lowest tap position (b)

<u>Effect of Tap Positions on PV Curtailment</u>:

Changing the tap positions at the off-load tap changers does not only bring benefits to the network. As seen in in Figure 3-12, due to the lower voltages achieved with the lowest tap position, the Volt-Watt function results in much less curtailment of PV generated energy.

Taking 50% PV penetration as an example (hosting capacity of the assessed network), when the off-load taps are at the nominal position, this results in a median of 24% of the PV generated energy to be curtailed. This value is reduced to just 4% when the lowest tap position is used. It should also be noted that this analysis only considers the total PV generation curtailment in the network; in fact, customers at further away from the substation would be much more heavily penalised, particularly if the nominal tap positions are used.

Finally, it should be mentioned that for 100 Monte Carlo iterations, each considering 11 PV penetration levels and 30-minute resolution daily data (i.e., 48 timesteps per day), this assessment required 52,800 power flow simulations to be carried out per case (i.e., nominal taps, reduced taps). For this network (i.e., 9947 three-phase nodes and 4626 single-phase loads and PV) had to be analysed. To compute this (and the following case studies in this thesis), parallel processing using high-performance computing was employed which helped produce results in a timely manner.



(a) (b)

Figure 3-12. Percentage of PV generation curtailment with nominal tap position (a) and lowest tap position (b)

<u>Demonstration Summary:</u>

The findings of this probabilistic case study show that the usage of the off-load tap changers can be an effective way to manage voltages in the LV networks. The hosting capacity can be dramatically increased from 10 to 50%, at which point thermal issues in the network start occurring. The problems cannot be solved using off-load tap changers, and as such, other solutions need to be considered. Furthermore, due to the reduction of voltages at the customer connection points, the PV generation curtailment due to the Volt-Watt function of the PV inverters is significantly reduced; and as such customers are far more benefited from this operation. However, changing the tap positions of off-load tap changers also has some complexities. For example, the network that the distribution transformer supplies needs to be disconnected prior to changing the tap position. Furthermore, given the very large number of LV networks that each DNSP manages, this process can be in fact very time-consuming.

3.7 Model Validation

This section contains the information relevant with the validation of the results. Two different types of validations were carried out. The first, is a comparison of the OpenDSS model against the original PSS Sincal model provided by AusNet Services. This is done considering a snapshot analysis based on two scenarios (peak and very low demand cases). The second validation considers the voltages obtained from the OpenDSS simulation (for the peak and very low demand cases) and are compared against real voltage measurements (from smart meter data) from the same day and time.

3.7.1 Validation using PSS Sincal

For the comparison between the PSS Sincal and the OpenDSS model, two different snapshot scenarios were considered: peak load and very low load. All distribution transformers were loaded with the same P and Q values in both PSS Sincal and OpenDSS. For the comparison, the following parameters were considered: P (three phase), Q (three phase) and current (phase A) at the head of the feeder, voltage at the furthest point in the feeder, and active/reactive power losses. Table 3-3 and Table 3-4 show the results obtained from both software packages in actual values and the corresponding difference in percentage (with PSS Sincal as the benchmark). All errors are well within 1%, which is considered to be satisfactory.

Table 3-3. PSS Sincal and OpenDSS comparison – P, Q, and Current

Variable	*Head of the Feeder P (kW)*			*Head of the Feeder Q (kVAr)*			*Head of the Feeder Current (Phase A)*		
Platform	**PSS Sincal**	**Open DSS**	**Error (%)**	**PSS Sincal**	**Open DSS**	**Error (%)**	**PSS Sincal**	**Open DSS**	**Error (%)**
Scenario									
Peak Load	9465	9463	-0.02	4242	4247	0.12	264	266	0.76
Very Low Load	791	792	0.13	-497	-500	0.60	2.41	2.42	0.41

Table 3-4. PSS Sincal and OpenDSS Comparison - Voltages and Losses

Variable	*Farthest Point Voltage (pu)*			*Feeder Active Losses (kW)*			*Feeder Reactive Losses (kVAr)*		
Platform	**PSS Sincal**	**Open DSS**	**Error (%)**	**PSS Sincal**	**Open DSS**	**Error (%)**	**PSS Sincal**	**Open DSS**	**Error (%)**
Scenario									
Peak Load	0.969	0.967	-0.21	145	146	0.69	-271	-269	-0.74
Very Low Load	0.999	0.999	0.00	1.4	1.4	0.00	-497	-498	0.20

3.7.2 Validation using Actual Voltage Measurements

In this section the voltages readings at selected distribution transformers are compared against the corresponding OpenDSS voltage results. The 90th percentile of phase voltages (line-to-neutral) at the busbars of certain distribution transformers (22 for 12th January 2016 and 16 for 29th November 2016) were provided by AusNet Services, along with the corresponding tap ratios of each of these transformers. Five distribution transformers were chosen, all of them at different representative locations in the MV network (farthest possible points of the different branches of the feeder). Table 3-5 shows the results for the peak demand scenario while Table 3-6shows the results for the low midday demand scenario.

Table 3-5. Distribution Transformer Busbar Voltage Comparison – Peak Demand Scenario

Distribution Transformer	*1*	*2*	*3*	*4*	*5*
Mean L-N Voltage (V)	250.7	243.6	244.5	250.5	238.7
OpenDSS (V)	251.4	244.6	244.7	250.7	239.0
Error (%)	-0.26	-0.42	-0.09	-0.09	-0.09

Table 3-6. Distribution Transformer Busbar Voltage Comparison – Low Midday Demand Scenario

Distribution Transformer	*1*	*2*	*3*	*4*	*5*
Mean L-N Voltage (V)	250.9	243.4	244.8	250.9	238.7
OpenDSS (V)	251.8	245.2	245.3	251.4	239.4
Error (%)	-0.37	-0.73	-0.22	-0.19	-0.31

For all distribution transformers, the errors are well within 1%, which indicates that the simulated MV network exhibits behaviour very closely aligned with the real MV network.

3.8 Chapter Summary

In this chapter, the distribution network modelling methodology adopted in this thesis was presented. First, the process as well as the assumptions taken for the extraction of the real MV feeder data were presented. Furthermore, the methodology which was used, based on Australian LV network design guidelines, to model the synthetic LV networks was described. Additionally, the Monte Carlo methodology as well as the performance metrics adopted in this thesis were also presented. Finally, a demonstration of the realistic integrated MV-LV network, operating without and with the existence of PV generation was carried out, which aimed to quantify the hosting capacity of the network. Off-load tap changers as well as the default Volt-Watt PV inverter setting were utilised in the study to more realistically quantify the hosting capacity, using readily available network and behind-the-meter assets. While it was demonstrated that significant improvements can be made through their usage, these assets can be limited in how much network support they can provide (given their current settings).

4 Off-the-Shelf Control of BES Systems

4.1 Introduction

As demonstrated in Chapter 3, the distribution network under investigation presents issues as the penetration of PV systems increases. In this chapter, the usage of OTS BES systems to mitigate these issues is investigated. First, the adopted OTS control methodology is presented in Section 4.2. A simple demonstration of the customer power flows when an OTS BES system is used is shown in Section 4.3. A case study quantifying the performance of the proposed control, both in terms of network performance (PV impact mitigation) and customer performance (reduction of grid imports), is then presented in Section 4.4. Furthermore, the limitations of the OTS BES control in mitigating PV impacts is presented in Section 4.5. The chapter finishes with a summary of the findings and conclusions in Section 4.6. It should be noted that parts of this chapter were published in [32, 33].

4.2 Control Methodology

Although several residential BES systems currently exist in the market, the exact details of the control used in these systems are not made publicly available. In general, manufacturers only provide general descriptions related to the basic operating principles of their products. For example, Tesla describes the operation of their Powerwall 2 BES system as "Surplus energy produced by your solar panels is stored in Powerwall to power your home at night" [23]. Other BES system manufacturers, such as ABB, LG, and SME, describe similar operational principles [77-79]. Based on these descriptions, the OTS BES system operation is assumed to be as follows:

- <u>BES systems charge from surplus generation until full.</u> When PV generation exceeds the household demand, the BES system charges with all surplus PV generation (defined as the remainder of PV generation minus household demand) until it reaches the maximum state of charge that it can operate. Once full, if surplus generation still exists, the BES system remains idle. The charging is also subject to the BES system power rating.

- BES systems discharge to supply surplus demand until empty. When PV generation falls below the household demand, it is used to supply the surplus demand (household demand minus PV generation), until the BES system is empty. Once empty, the BES system remains idle until surplus PV generation exists again. As previously, the discharging is also subject to the power rating of the BES system.

This rather simple control can be represented using Algorithm 4.1, which is performed at every discretisation interval timestep.

Algorithm 4.1: OTS BES Control	
A4.1-1:	Measure P^d, P^g, E^s
A4.1-2:	Let $P^{sd} \leftarrow (P^d - P^g)$
A4.1-3:	**if** $P^{sd} \geq 0$ **do**
A4.1-4:	$P^s = -\min\left(P^{sd}, \frac{E^s\eta^-}{\Delta t}, \bar{P}^s\right)$
A4.1-5:	**else**
A4.1-6:	$P^s = \min\left(\lvert P^{sd}\rvert, \frac{\bar{E}^s - E^s}{\eta^+\Delta t}, \bar{P}^s\right)$
A4.1-7:	**end if**

where P^d, P^g, and P^{sd} are the household demand, PV generation, and surplus demand, respectively (all in kW). E^s, $\bar{E}^s$, P^s, and $\bar{P}^s$ are the BES system stored energy, rated energy capacity (both in kWh), power setpoint (positive denotes charging), and power rating (both in kW), respectively. η^+ and η^- are the charging and discharging efficiency, respectively (both in %). Finally, Δt is defined as the discretisation interval timestep (in hours).

The control first measures the demand, PV generation and BES system stored energy (A4.1-1). Then, it defines the surplus demand (A4.1-2). If the surplus demand is positive (A4.1-3), the BES system discharges. The discharge is defined by the minimum of three values: the surplus demand, the available energy (converted to the amount of power that can be delivered over the Δt timeframe), and the power rating for the BES system (A4.1-4). If the surplus demand is negative (A4.1-5), the BES system charges with a power rate defined as the minimum of the absolute value of the surplus demand, maximum energy that can be stored over the Δt timeframe, and the power rating for the BES system (A4.1-6). Furthermore, the stored energy in the BES system for the next timestep (E^s_{+1}) can be calculated using Equation 4.1.

$$E_{+1}^{s} = E^{s} + \begin{cases} \eta^{+} P^{s} \Delta t, & if\ P^{s} \geq 0 \\ \dfrac{P^{s}}{\eta^{-}} \Delta t, & if\ P^{s} < 0 \end{cases} \tag{4.1}$$

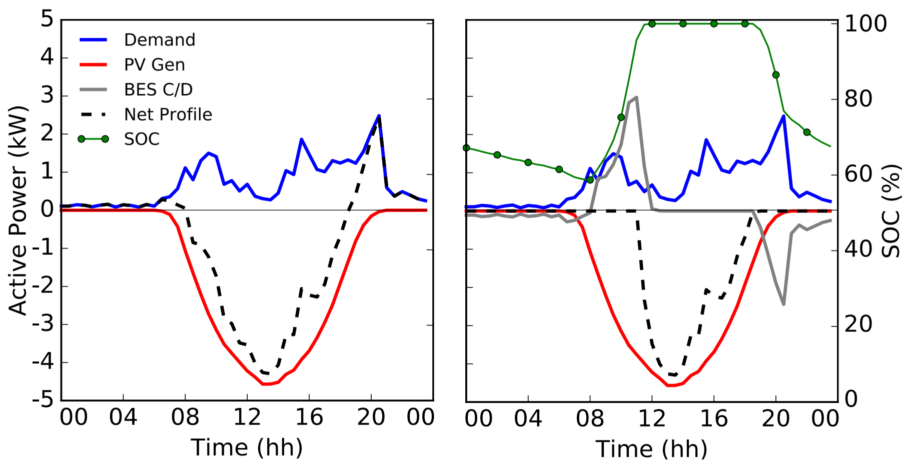
where all the parameters are as previously defined.

4.3 Simulated Operation Demonstration

In this section, the daily operation of the OTS control is presented for a single household. The PV system is assumed to be 5.5kWp, with the inverter sized equally to the PV panels. The BES system simulated has the same characteristics as a Tesla Powerwall 2 [23], which is a popular BES system amongst residential customers in the Australian market [80] (5kW/13.5kWp, 100% depth of discharge, and 88% round-trip efficiency). The day simulated uses real smart meter demand data, as well as PV generation data for two types of days: a summer clear-sky day, and a summer cloudy day. As the SOC at the beginning of the day is dependent on the operation of the previous day, two continuous days are simulated where in the first day the BES system is assumed to start empty. However, results are only presented for the second day as they are more realistic. For comparison purposes, the operation without a BES system is also presented, referred to as the "PV only" case. It should be noted that in Figure 4-1 and Figure 4-2 a solid black zero line is plotted to easily differentiate between imports/charging (positive) and exports/discharging (negative).

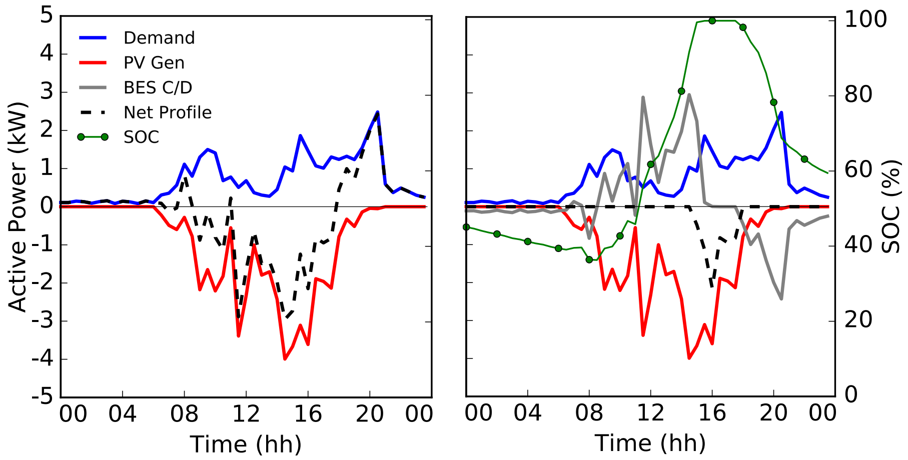
The household net demand (dashed black line) is presented in Figure 4-1(a) and Figure 4-2(a) for the "PV only" case, for the clear-sky and cloudy day, respectively. As both of these days correspond to summer days (long sunlight period), a large portion of the demand (blue line) of the household is supplied through locally generated energy (PV generation, red line). For the clear-sky day case, 69% of the household energy consumption is supplied by the PV system. For the cloudy day case, this value is reduced slightly to 62%. It is also important to highlight that for both cases the PV generation during midday far exceeds the demand, which results in significant household power exports into the grid. In the aggregate (i.e., large number of households with similar behaviour), such operation will result in the PV impacts that were previously demonstrated in Section 3.6.3.

When the presence of an OTS BES system is considered, the household receives significant benefits in terms of reducing the import of energy from the grid. As shown in Figure 4-1(b) and Figure 4-2(b) for both the clear-sky and cloudy day cases, respectively, the household becomes fully energy self-sufficient (i.e., no energy imports from the network) as the full demand is supplied by the PV and BES systems. However, when the network is considered, the presence of the OTS BES system fails to bring any benefits in reducing the peak power exports, particularly for the clear-sky day. During midday, the household still exports >4kW and >2kW for the clear-sky and cloudy days, respectively. This is happening as the BES system becomes full prior to the peak generation periods. As such, during the peak generation period, the BES system remains idle and unable to absorb any further



(a) (b)

Figure 4-1. Household operation for customers with PV system (a) and PV/ OTS BES systems (b) for a sunny day



(a) (b)

Figure 4-2. Household operation for customer with PV system (a) and PV/ OTS BES systems (b) for a cloudy day

PV generation. From the perspective of the network, the household behaviour during this time is the same as if the household did not have a BES system installed. To better understand the reasoning behind this behaviour, the SOC of the BES systems is also plotted (green line). For the clear-sky day, the BES system has 58% SOC at 8:30am when it starts charging, whereas for the cloudy day, it starts charging with 36% SOC. Particularly during the clear-sky day, having such a high SOC at the beginning of the generation period coupled with the fact that OTS BES systems prioritise absorbing the full surplus PV generation, results in the BES system being full very early during the day (11am).

These findings identify one massive red flag associated with OTS BES systems. While the BES system has the capability to charge from PV generation and thus reduce the exports into the grid, due to the prioritisation of charging from the full available surplus generation, there is no available capacity to charge during the times were the PV generation can adversely impact the network. If the behaviour found in this single-house operation also exists with all the customers with BES systems, it is highly unlikely that OTS BES systems will bring any benefits in terms of mitigating PV impacts during sunny days.

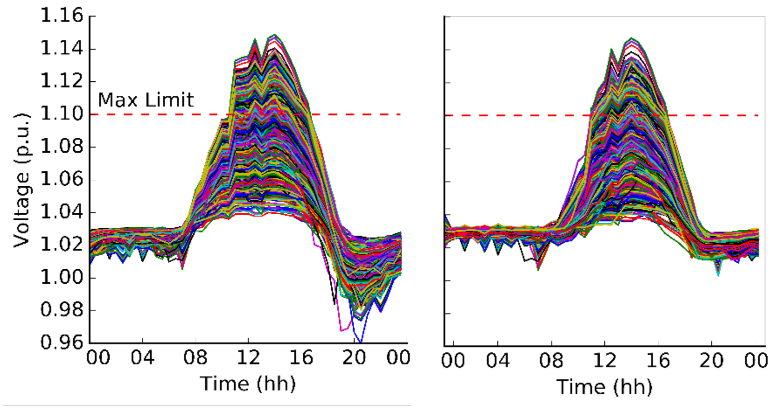
4.4 Case Study

The case study performed in this section aims to quantify whether OTS BES systems can bring benefits in terms of mitigating PV impacts in the distribution network, previously modelled and assessed in Chapter 3. In this case study, the same demand, generation, and network data is used as in the case study presented in Section 3.6. For comparison purposes, all results obtained from the OTS analysis are compared against a “PV only” case. Furthermore, in the OTS analysis, it is assumed that all customers with PV systems also have a BES system.

Given the significant benefits that the off-load tap changers bring in increasing the PV hosting capacity of the network, only the lowest tap position (position 1) is used (i.e., transformation ratio of 22kV/0.411kV, or 1.0pu/1.0275pu) in this analysis. However, the Volt-Watt function of PV inverters has been disabled. This is done to remove the support that the PV inverter is providing, and therefore better quantify the level of benefits that the OTS BES systems bring.

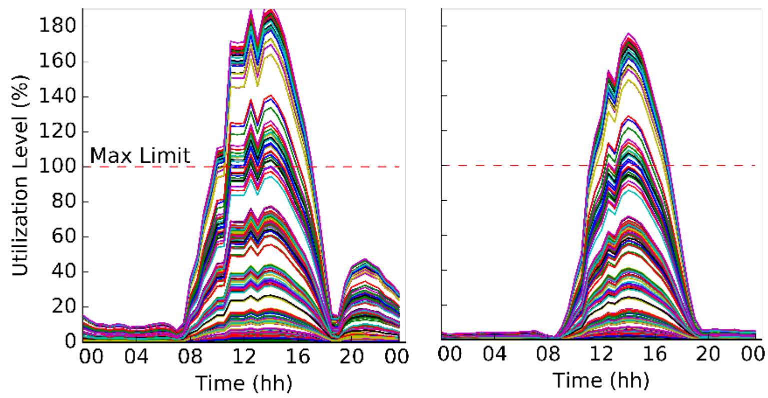
4.4.1 Network Performance

To assess the network performance of OTS BES systems, first a deterministic time-series analysis is conducted. The assessed day corresponds to the 8th of January 2016 (summer in Australia), and the PV penetration is set to 100%. This day has been selected as it corresponds to a day with low midday demand and high PV generation. This is a "worst-case scenario" when assessing PV impacts.



(a) (b)

Figure 4-3. Customer voltages for PV Only (a) and OTS BES (b)



(a) (b)

Figure 4-4. MV line utilisation for PV Only (a) and OTS BES (b)

Table 4-1. Summary of network performance

	PV Only	*OTS*
Customers with Voltage Problems (%)	18	10
Maximum Utilisation of Transformers (%)	125	125
Maximum Utilisation of MV Lines (%)	186	171
Maximum Utilisation of LV Lines (%)	110	105

Figure 4-3(a) and Figure 4-3(b) show the daily voltage profiles for all the residential customers in the network, for the "PV Only" case and where OTS BES systems are used, respectively. In Figure 4-3(a) can be seen that for a large number of customers, their voltage profiles during midday far exceed the upper voltage statutory limit (dashed red line, 1.10pu). As presented numerically in Table 4-1, 18% of the customers are not compliant with the voltage standard. The adoption of OTS BES systems by all the customers in the network helps reduce the voltage rise slightly, as seen in Figure 4-3(b). However, a significant portion of the customers (10%) still experience voltages significantly higher than the 1.10pu limit.

A similar behaviour is also identified when the thermal utilisation of assets in both the MV and LV network is observed. Figure 4-4(a) and Figure 4-4(b) show the daily utilisation of the MV lines in the network for the PV only and OTS BES cases. For the PV only case, MV lines in the network become congested up to 187% of their rated capacity. The introduction of OTS BES systems manages to reduce the congestion just slightly to 171%; a value that still far exceeds the 100% limit. Similarly, as seen in Table 4-1, the OTS BES control fails to bring any significant benefits to LV assets either. The LV transformers (distribution transformers) maximum utilisation remains the same at 125% despite the introduction of the BES systems, whereas for the LV lines it is only slightly reduced from 110 to 105%.

To truly assess the extent to which the OTS control of BES systems could potentially benefit distribution networks in terms of mitigating PV impacts, a stochastic analysis is performed. The Monte Carlo methodology is applied in this section, where results from each deterministic case are collected and presented in a probabilistic manner. The simulations are performed for different penetration levels (from 0 to 100% of houses with PV and BES systems, in step of 10%). For each penetration, 100 iterations are performed. Besides the previously presented metrics (i.e., voltage compliance and MV line utilization), the stochastic analysis is expanded to also include the LV line and transformer utilization. In this analysis, only summer days (December to February) are considered as it is the period that most likely will present issues resulting from reverse power flows.

Starting with the number of non-compliant customers (i.e., voltage problems), as shown in Figure 4-5, the problems with the PV only case start at the 60% penetration level, where up to 2% of the customers experience voltage issues amongst the assessed cases. The usage of OTS BES systems manages to provide some benefits to the network by reducing the number of non-compliant customers in the 60% penetration case to 0.2% (negligible). As the penetration keeps further increasing, the OTS BES systems are able to reduce the number of non-compliant customers slightly but are not able to further increase the PV hosting capacity of the network.

A similar behaviour is also seen with the thermal utilisation of the assets (MV lines, LV lines, and LV transformers in Figure 4-6 - Figure 4-8, respectively). Starting with the MV utilisation of the lines, network problems start appearing at 70% penetration for the PV only case, whereas with the OTS control the problems are pushed to 80% penetration. Given their very robust design – common in Australia due to high ADMD - the LV lines do not display any issues across all penetration. For the LV transformers on the other hand, problems start appearing around the 70% penetration, where both the PV only cases and the OTS BES control display similar results.

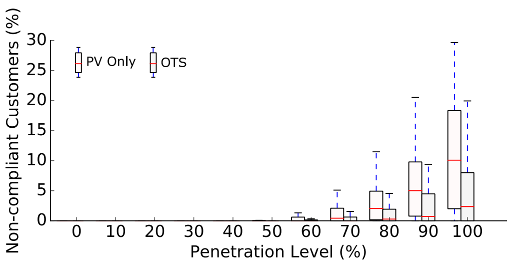


Figure 4-5. Percentage of customers with voltage problems

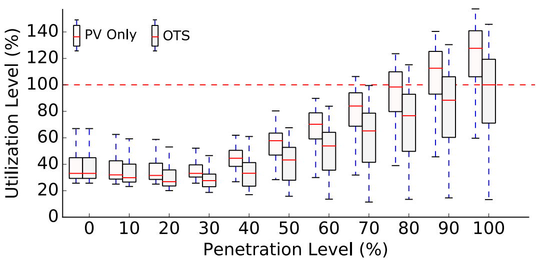


Figure 4-6. MV lines maximum utilisation level

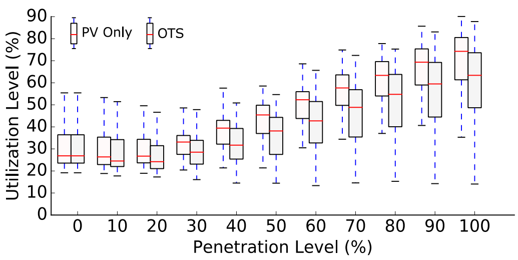


Figure 4-7. LV lines maximum utilisation level

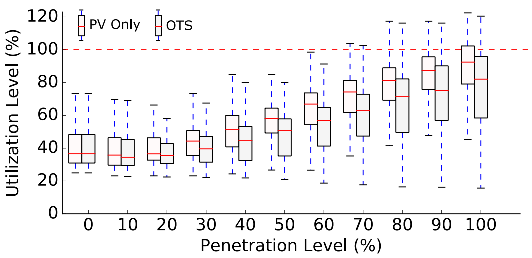


Figure 4-8. LV transformers maximum utilisation level

As it has been demonstrated in this section, the OTS control of BES systems is not able to provide significant benefits to the distribution network in terms of mitigating PV impacts. While they contribute to a slight reduction of network impacts, they are unable to tackle the very source of the issues: reducing peak household exports during the critical generation periods. As such, more advanced control strategies are required to fully explore the capabilities of BES systems to mitigate solar PV impacts. Nonetheless, this needs to be done with consideration of the BES system owners.

4.4.2 Customer Performance

In this section, the customer performance is quantified using the GDI metric previously defined in Section 3.5.2. In this analysis, the data for the customers is analysed for a whole year (rather than only for summer days as in the previous section), where the BES systems are modelled to run continuously for the whole period. This is done to more realistically understand the benefits that the BES systems can bring to customers, as individual daily simulations would assume the BES system being empty at the beginning of each day; not fully utilising the stored energy from the day before. Similar to the network performance assessment, the customer performance of the OTS BES system is compared with a "PV Only" case.

Starting with the PV only case seen in Figure 4-9, the grid dependency of a median customer with a PV system is 62%, with the lowest recorded GDI being 41% and the highest 82%. The difference in variance can be for multiple reasons: Consumption behaviour (customers that consume more during the night will have a higher GDI when they only have PV systems), PV system size, and demand levels. The reduction in the GDI (from 100% when no PV system is installed) is due to the demand that is supplied locally during the day. However, given that PV systems only generate during the day, a large portion of the demand needs to still be supplied by the grid.

The OTS boxplot on the other hand demonstrates the massive benefits that a BES system can bring to the median customer who has a GDI of 11%. This indicates that 89% of the annual energy needs of the household were supplied through locally generated energy. This becomes even more impressive in certain cases, where almost 100% of the energy needs were supplied through the PV and BES systems. These, however, were identified as customers with small demand levels and large PV systems, a combination that exists in the simulations performed given the random allocation process of PV sizes and demand, but could be unrealistic in real-life scenarios. On the other hand, some customers experience very high GDI even with the existence of a BES system (rare cases up to 71%). These cases correspond to customers with very large demand and very small PV system; as such, it is very unlikely that this will create surplus PV generation to be stored in the BES system.

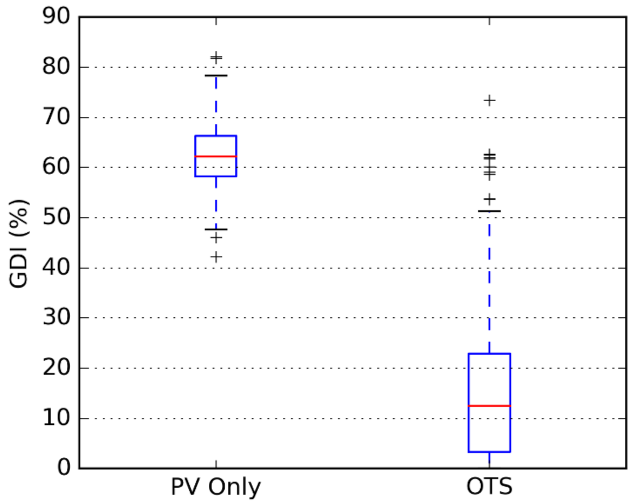


Figure 4-9. Statistical analysis for the customer GDI

These results demonstrate that customers could in fact receive massive benefits from installing a BES system along their PV system, as now their locally generated energy during the day can also be used during the night thanks to storing it in the BES system. It should be noted that appropriate sizing of the BES system is also required for such benefits to be achieved.

4.5 Limitations

To understand the reason behind the inadequacy of OTS BES systems to mitigate the PV impacts in the network, one needs to first understand how the BES systems operate within the day. To this extend, the SOC of all BES systems for a problematic day (low demand, high PV generation) is presented in Figure 4-10.

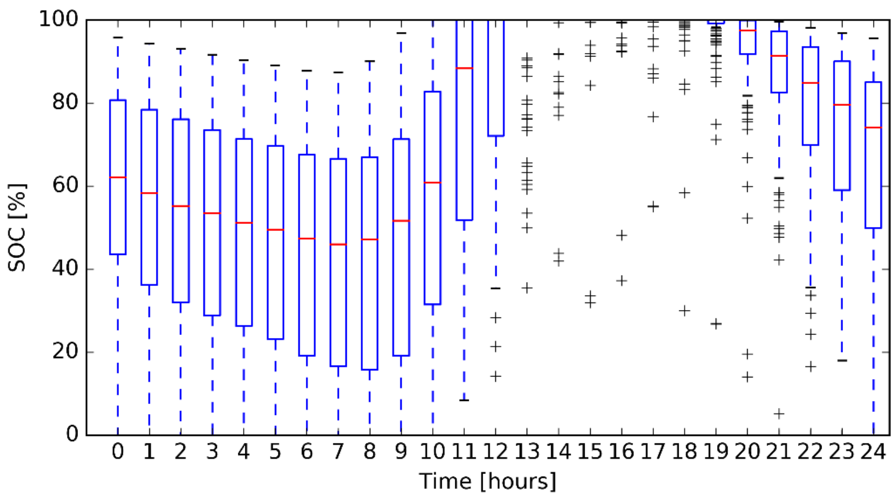


Figure 4-10. Statistical analysis for the SOC of all BES systems

As it can be seen, half of the BES systems in the network are full by 12pm, with almost all of them being full by 1pm. At this point, given that the BES systems cannot charge any further, all surplus PV generation is exported back to the network. While this is highly beneficial for the customers, who now have a full BES system to supply their local demand needs, from a network perspective this results in the same operation as customers not having a BES system at all. Therefore, the same level of issues that existed with the PV only case also exist when OTS BES systems are used.

Given the data at hand, there are two factors that contribute to OTS BES systems becoming full very early during the day.

- BES systems do not adequately discharge overnight. As it can be seen in Figure 4-10, the median SOC for the median BES system is at 45% at 7am (lowest point). As such, there is limited capacity that can be used during the next generation period to store the surplus PV generation. This also highlights that using larger BES systems at customers will still not solve PV impacts, as the headroom that is created in the BES system energy capacity to accommodate for next day's generation is not affected by the size of the BES system.
- BES systems reach full SOC very early. This is partly related to the point above. However, as it can be seen from Figure 4-10, even BES systems that started the generation period with an empty BES system still achieved a full SOC by 1pm. And for good reason; at its maximum charging rate, the 13.5kWh/5kW BES system assessed in this case study needs only 3 hours to charge fully when charging with its maximum power capacity. Therefore, by charging with the full surplus PV generation, the BES systems become full very early during the day, and are therefore not able reduce the household exports during the peak generation period (~10am-4pm).

Having a good understanding of the limitations of the OTS BES systems in mitigating PV impacts is the first step in designing new control strategies that can adequately do so. However, the true challenge is not only overcoming the limitations, but also not compromising the strengths of OTS BES systems (i.e., reducing grid imports).

4.6 Chapter Summary

Residential BES systems installed in households aim to make the most of the PV generated energy. They charge from the surplus PV generation (i.e., PV generation minus demand) and discharge to supply the surplus demand (i.e., demand minus PV generation). This, theoretically, could reduce or fully eliminate PV exports into the network, which in turn can mitigate the PV impacts (voltage and thermal issues) associated with high penetrations of PV systems in a given distribution network. In this chapter, the potential of OTS BES systems to inherently mitigate these impacts has been explained.

The case study, which utilised an integrated MV-LV distribution network with 4,600+ customers, demonstrated that customers adopting OTS BES systems receive significant benefits in terms of reducing their grid imported energy throughout the year, by making the most of their PV generated energy. It was also found that, on average, they contribute slightly in the reduction of voltage and thermal problems in the network. However, during problematic days (low demand and clear-sky summer days), the OTS control of BES systems is unable to help reduce any issues on the network when compared to the PV only case. Two reasons were found to be the cause: a) The demand levels during the night are not high enough to adequately discharge the BES system, and b) by charging from the full surplus PV generation, the BES systems are full prior to the peak PV generation period; essentially becoming idle and unable to reduce household exports in the network.

Therefore, it is concluded in this Chapter that controlling BES systems for the sole benefit of the customer does not bring any benefits to the network. If BES systems are to bring benefits to future distribution networks and allow for higher penetrations of PV systems to exist without the need of network reinforcement, advanced control strategies need to be developed. However, it is of paramount importance that these control strategies do not only consider benefits to the network, but to keep also providing similar level of benefits to the customers.

5 ADAPTIVE DECENTRALISED CONTROL OF BES SYSTEMS

5.1 Introduction

In this chapter, an adaptive decentralised (AD) control strategy of BES systems is proposed, which aims to overcome the limitations of the OTS BES control, whilst still allowing customers to receive significant benefits from the BES system. Along with the AD control, an optimisation-based (OPT) control strategy is also used in this chapter. This control, which utilises perfect forecast and optimally dispatches the BES system to flatten the customer power profile is used as an unrealistic "perfect benchmark" on what can be achieved in a fully decentralised and network-agnostic control strategy, solely used for comparison purposes. Thus, the full control methodology of the AD and OPT controls is presented in Section 5.2, with their operation demonstrated and compared in Section 5.3. Finally, the case study which quantifies the performance of the AD and OPT controls, both in terms of network and customer performance, is presented in Section 5.4. A summary of the findings and conclusions is given in Section 5.5.

5.2 Control Methodology

In this section the control methodology of the AD and OPT controls is presented. Some of the contents of this section are as published in [33].

5.2.1 Adaptive Decentralised (AD) Control

The AD control is designed so as to overcome the limitations of the OTS control that were identified in Section 4.5, while also making as realistic assumptions as possible (e.g., without using accurate forecasting). The charging behaviour of the BES system is changed to charge proportionally to the PV generation, rather with the full surplus. Furthermore, it ensures adequate capacity at the beginning of the generation period by discharging overnight. However, both aspects need to be carefully designed, as if incorporated incorrectly, they can result in sharp decline in the performance of the BES system to reduce grid imports.

Starting with the proportional charging, the control strategy needs to take into consideration not only days of maximum irradiance but also cloudy days and be able to adapt to such conditions without the use of forecasting. To achieve this, first, the "maximum PV generation profile" (i.e., clear-sky profile) is estimated. This profile can be calculated either using readily available software, or by using well-established methods based on information that is specific to each customer (e.g., location, orientation of panels, etc.) at the time of the BES system installation by a technician. The maximum generation profile can then be scaled down to an "ideal charging profile" with similar shape and an area-under-the-graph (i.e., energy) that is equal to the BES system energy capacity, as shown in Figure 5-1(a). This allows for the charging of the BES system to be proportional to the maximum generation throughout the day which ensures that: a) adequate capacity will be available for charging during the "critical generation period" (i.e., high PV generation), and b) exports will be reduced more during this critical period. The ideal charging profile also allows defining the time at which the BES will start charging (α in Figure 5-1(a)). The end of the charging period can be extrapolated from the clear-sky profile and it is the time at which the PV system is calculated that it will stop generating (β in Figure 5-1(a)). However, in reality, due to the existence of clouds as well as local demand, the surplus PV generation at a given time could be below the ideal charging profile, shown as a gap in Figure 5-1(b). To counteract the negative effect this will have to the customers, when the surplus PV generation is below the ideal charging profile, the BES system charges from the surplus PV generation instead. Furthermore, if the demand is higher during this period (between α and β), the BES system discharges to supply the surplus demand (not shown graphically for the sake of brevity). However, such operation causes an energy mismatch in the actual energy stored in the BES system from what was originally calculated (i.e., from the ideal charging profile). To cater for this, the ideal charging profile is recalculated periodically using the actual SOC of the BES system which increases the power rate of the ideal charging profile following the gap in generation, as seen in Figure 5-1(b).

This proposed charging strategy can only be successful if the BES system has adequate available capacity at the beginning of the charging period; otherwise, the ideal charging profile calculated will be very small. To ensure adequate capacity, a baseline discharging power rate for the BES system is calculated (between β and

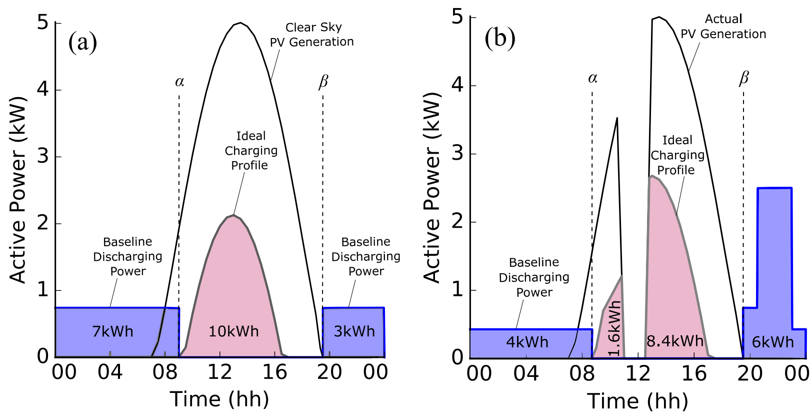


Figure 5-1. BES Operation Example without (a) and with (b) Generation Gap

α), which without the existence of any demand will ensure that the BES system will reach a pre-defined SOC at time α, seen in Figure 5-1(a). However, as the household demand can exceed the baseline discharging power, if this happens, the BES system adjusts the discharging accordingly to supply the full demand. After this, the baseline discharging power is recalculated; both these effects are seen in Figure 5-1(b).

5.2.1.1 Ideal Charging Power Profile

The ideal charging power profile is calculated at each sampling interval, Δt (in hours). From the current instant i to the time at which PV generation ends, β, this profile is defined by a set of charging power values, C_t (kW), where $t \in [i, \beta]$ in steps of Δt. This is calculated by iteratively reducing the corresponding clear-sky generation profile (a set of maximum PV power generation values, CS_t, where $t \in [i, \beta]$ in steps of Δt), so that the resulting area (i.e., energy to be stored) is less or equal to the energy required to achieve full SOC, shown in Equation 5.1.

$$\sum_{t=i}^{\beta} C_t \, \Delta t \leq \frac{\bar{E}^s - E_i^s}{\eta^+} \qquad 5.1$$

where $\bar{E}^s$, E_i^s and η^+ are the rated capacity (kWh), stored energy (kWh), and the charging efficiency, respectively.

The calculation of the daily clear-sky power generation is relative to the day of the year (i.e., changes every day), the location of the PV system on Earth (i.e., longitude and latitude), and PV system characteristics (i.e., azimuth, panel tilt, panel efficiencies, ground or roof-mounted, etc.). This information can be used to produce clear-sky profiles for a given PV system for a whole year (one per day), which can then be inputted in the controller of the BES system at the time of installation. To create these clear-sky profiles, either models such as the ones found in [81] can be programmed manually, or readily available software such as [82] can be used. If readily available, historic clear-sky data of the PV system can also be used (e.g., cases where the PV system was installed for a few years prior to the installation of the BES system).

Based on the above, the ideal charging profile for a given day and PV installation can be calculated based on Algorithm 5.1. All the values in the clear-sky profile, CS_t, are reduced iteratively by an arbitrarily small value, n, until Equation 5.1 is satisfied (i.e., the energy in the ideal charging profile is less than or equal to the energy that can be charged into the BES system). The adequate definition of the n value is a trade-off between accuracy (smaller n) and computational efficiency (larger n).

Algorithm 5.1: Ideal Charging Power Profile	
A5.1-1:	Let $\boldsymbol{C_t[i,\beta]} \leftarrow \boldsymbol{CS_t[i,\beta]}$
A5.1-2:	while Equation 5.1 = ***False*** do
A5.1-3:	for $\boldsymbol{t = i}$ to $\boldsymbol{\beta}$ do
A5.1-4:	$\boldsymbol{C_t \leftarrow C_t - n}$
A5.1-5:	end for
A5.1-6:	$\boldsymbol{C_t[C_t < 0] \leftarrow 0}$
A5.1-7:	end while
A5.1-8:	return $\boldsymbol{C_t}$

5.2.1.2 Baseline Discharging Power

The baseline discharging power D (kW) is defined at the current time instant i to ensure that the BES system will discharge to the pre-defined SOC by the start of the next charging period, α. This is given by Equation 5.2

$$D_i = \eta^- \frac{E_i^s - E^{min}}{(\alpha - i)} \tag{5.2}$$

where $(\alpha - i)$ is the remaining period (hours) until the start of the next charging period, η^- is the discharging efficiency and E^{min} (kWh) is the pre-defined minimum energy that should always be stored (manufacturer or user preference).

5.2.1.3 Start and End of the Charging Period

As previously stated, the parameters α and β, denote the time where the charging period starts and ends respectively. These, as shown in in Figure 5-1, are automatically defined at the beginning of each day (i.e., i=1 as shown later in lines A5.3-3) based on A5.2-2 and A5.2-3, where the reduced ideal charging profile, (i.e., calculated in Algorithm 5.1) is passed to Algorithm 5.2 (A5.2-2). The value α is defined as the first period where the C_t is larger than zero (i.e., BES starts to charge, shown in A5.2-3). On the other hand, the end of the charging period, β, is defined as the last period where CS_t is larger than zero (i.e., PV generation stops, shown in A5.2-1).

Algorithm 5.2: Defining $\boldsymbol{\alpha}$ and $\boldsymbol{\beta}$	
A5.2-1:	$\boldsymbol{\beta \leftarrow CS_t[CS_t > 0]_{-1}}$
A5.2-2:	$\boldsymbol{C_{t\in[1,T]}} \leftarrow$ **Algorithm 5.1**
A5.2-3:	$\boldsymbol{\alpha \leftarrow C_t[C_t > 0]_1}$
A5.2-4:	return $\boldsymbol{\alpha, \beta}$

5.2.1.4 Daily Operation of the BES System

Based on the defined ideal charging profile and baseline discharging value at instant i, the daily operation of the BES system (split into a number of discrete Π periods), is thereby described in Algorithm 5.3, where P_i^d and P_i^g are the demand and PV generation (kW), respectively. The BES system power output, P_i^s, and energy stored in the BES system are constrained as shown in Equations 5.3 and 5.4, respectively.

Algorithm 5.3 Daily operation of the BES system	
A5.3-1:	**for** $i = 1$ **to** Π **do**
A5.3-2:	**if** $i = 1$ **do**
A5.3-3:	$\alpha, \beta \leftarrow$ **Algorithm 5.2**
A5.3-4:	**end if**
A5.3-5:	Measure E_i^s, P_i^d, P_i^g
A5.3-6:	**if** $(i < \alpha$ or $i > \beta)$ **do**
A5.3-7:	**if** $E_i^s \geq E^{min}$ **do**
A5.3-8:	$D_i \leftarrow$ **Equation 5.2**
A5.3-9:	$P_i^s \leftarrow -\max(D_i, P_i^d - P_i^g)$
A5.3-10:	**end if**
A5.3-11:	**else**
A5.3-12:	$C_{t\in[i,\beta]} \leftarrow$ **Algorithm 5.1**
A5.3-13:	$P_i^s \leftarrow \min(C_i, P_i^g - P_i^d)$
A5.3-14:	**end if**
A5.3-15:	**end for**

$$P_i^s \in [-\bar{P}^s, \bar{P}^s] \quad 5.3$$

$$E_i^s \in [\bar{E}^s \times (100 - DoD)/100, \bar{E}^s] \quad 5.4$$

where $\bar{P}^s$ is the BES power rating (kW), and DoD is the maximum permitted depth of discharge (%).

It is worth mentioning that Algorithm 5.3 is designed to maximize benefits to customers. As such, during the charging period $[\alpha,\ \beta]$, any time there is a positive net demand, $P_i^d - P_i^g > 0$, the available energy stored will be used (lines A5.3-12, A5.3-13). This means that in periods in which the PV generation is smaller than demand (positive net demand), the BES system will use the stored energy to supply the required demand (that would otherwise be imported from the grid). This feature is aligned with the operation of commercially available BES systems as it helps reducing electricity bills. Similarly, outside the charging period, the BES system will supply the full demand if larger than the baseline discharging power rate (lines A5.3-8, A5.3-9).

5.2.2 Optimisation-based (OPT) Control - Benchmark

To understand the extent to which the proposed control strategy, or any other control, provides effective network management while reducing the customers' energy grid dependence, this section presents an ideal optimisation-based decentralized control to be used as benchmark. Such comparison allows understanding of how far the performance of any control approach is from an ideal optimal operation.

The OPT control operates based on a multi-period mixed-integer quadratic program (MIQP) using perfect day-ahead demand and generation forecasts. This control aims at minimizing both grid imports (benefitting customers) and exports (benefitting the network). To achieve this, the objective function minimises the square of the household's net demand power (denoted P_t^{nd} for $t \in [1, \mu\Pi]$, where μ is the number of days considered in the optimisation problem and split into a number of discrete Π periods) throughout the day; as given in Equation 5.5. This is subject to the household's power and energy balance equations, shown in Equations 5.6 - 5.8, and operational constraints given in the Equations 5.9 - 5.12.

$$\text{minimise} \sum_{t \in [1, \mu\Pi]} {P_t^{nd}}^2 \qquad 5.5$$

subject to:

$$P_t^{nd} = P_t^d - P_t^g + P_t^s \qquad ,\forall t \qquad 5.6$$

$$P_t^s = P_t^{s,+} - P_t^{s,-} \qquad ,\forall t \qquad 5.7$$

$$E_t^s = E^{s,init} + \sum_{n=1}^{t} \left[P_n^{s,+}\eta^+ - \frac{P_n^{s,-}}{\eta^-} \right] \Delta t \qquad ,\forall t \qquad 5.8$$

$$P_t^{s,+} \leq \begin{cases} P_t^g - P_t^d, & if\ P_t^g - P_t^d \geq 0 \\ 0, & else \end{cases} \qquad ,\forall t \qquad 5.9$$

$$P_t^{s,+} \leq \bar{P}^s b_t,\ P_t^{s,-} \leq \bar{P}^s (1 - b_t) \qquad ,\forall t \qquad 5.10$$

$$E_t^s \in [\bar{E}^s \times (\,100 - DoD)/100\,, \bar{E}^s\,] \qquad ,\forall t \qquad 5.11$$

$$b_t \in \{\,0,1\,\} \qquad ,\forall t \qquad 5.12$$

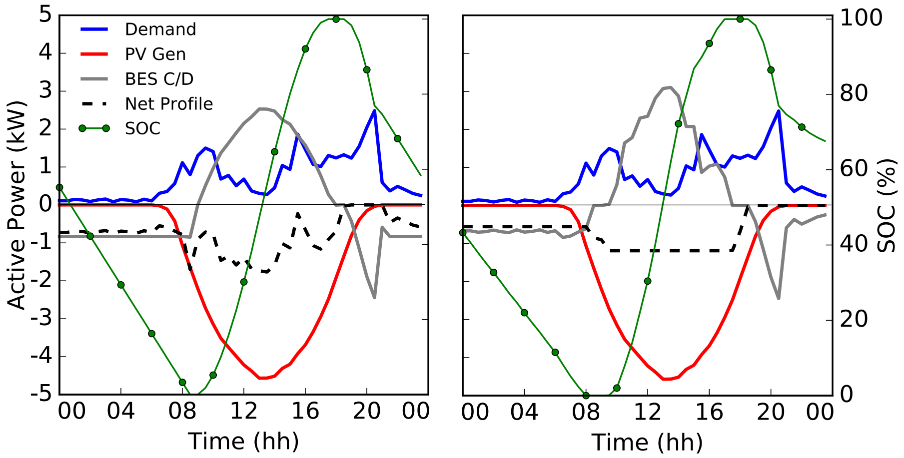
where P_t^d and P_t^g are the household forecasted demand and generation, respectively; E_t^s is the energy stored in the BES; P_t^s is the BES power input/output (positive denotes charging); $\overline{E^s}$ and $\bar{P}^s$ are the energy and power rating of the BES, respectively; η^+ and η^- are the charging and discharging efficiencies of the BES; and, DoD is the permitted depth of discharge.

The power of the BES is split into the nonnegative charging, $P_t^{s,+}$, and discharging, $P_t^{s,-}$, components (so that the charging and discharging efficiencies can be applied) through the usage of a binary variable, shown in 5.10. The charging of the BES is limited to the surplus PV generation, as shown in 5.9. This is important, as it ensures that in days of low irradiance, the BES does not charge from the grid.

It is worth highlighting that while uncertainties due to forecasting errors could be incorporated in the formulation, the use of perfect forecast allows a “perfect benchmark” to be compared with the proposed AD control.

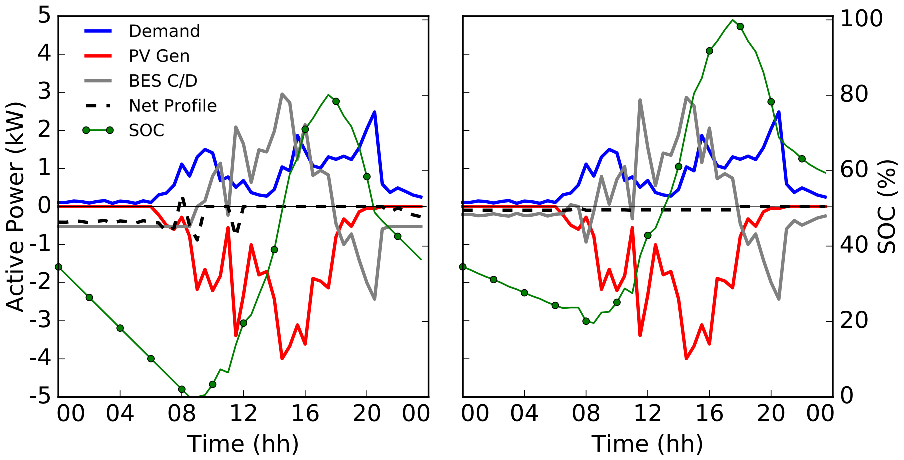
5.3 Simulated Operation Demonstration

In this section, the demonstration of the PV only and OTS BES systems previously carried out in Section 4.3 is expanded to also demonstrate the operation when the AD and OPT controls are used, with the same PV and BES system sizes. The results, obtained for a sunny and a cloudy day, are shown in Figure 5-2 and Figure 5-3, respectively. The PV only and OTS graphical results can be found on page 80. As in the previous chapter, a solid black zero line is also plotted to easily differentiate between imports/charging (positive) and exports/discharging (negative).



(a) (b)

Figure 5-2. Household operation for customer with the AD (a) and OPT (b) BES control for a sunny day



(a) (b)

Figure 5-3. Household operation for customer with the AD (a) and OPT (b) BES control for a cloudy day

The proposed AD control overcomes the limitations of the previously demonstrated OTS control (i.e., not adequately discharging overnight, becoming full very early during the next day), without sacrificing the ability of the BES system to reduce grid imports. except between 8-8:30am at which time a small fraction of the demand (0.8%) had to be supplied from the grid. As it can be seen in Figure 5-2(a) and Figure 5-3(a) the AD control supplies the morning demand, and combined with the baseline discharging it is fully empty by 8:30am for both cases (i.e., clear-sky and cloudy day cases). This means that the full capacity of the BES system is available throughout the next generation period. For both cases, from 8:30am (defined by α using Algorithm 5.2) the BES system starts to proportionally charge with the rate defined by the AD control. For the clear-sky day case, as there is significant surplus PV generation, the charging profile (i.e., grey line) follows the shape of the clear-sky profile but at a reduced power rate; effectively allowing the BES system to charge throughout the critical generation period and significantly reduce power exports into the grid (1.8kW vs. 4.4kW for the OTS case). For the cloudy day case on the other hand, Figure 5-3(a) shows the ability of the AD control to adapt the charging of the BES system when the surplus PV generation is less than the ideal charging profile. Due to the periodic recalculation of the ideal charging profile from inadequate PV generation during the morning hours (8:30 to 11am), the BES system after 11:30am charges with the full surplus PV generation which reduces household exports to 0kW. The recalculation of the ideal charging profile is evident when comparing the maximum charging power for both days. For the clear-sky day, the maximum charging rate of the BES system was 2.5kW at 1pm, whereas for the cloudy day the maximum charging rate was 3.1kW at 3pm. For the latter, the lower SOC of the BES system at this point results in a recalculated ideal charging profile that allowed for a higher charge rate; an effect that was previously explained in Section 5.2.1.1 and shown in Figure 5-1(b).

In the afternoon (between 5 and 8pm), the PV generation is less than the local demand, and the BES system discharges to match it and eliminate grid imports. This shows that the AD control is also able to supply any additional demand during the “charging period” despite the existence of PV generation. After 8pm (β), the PV system stops generating and therefore the baseline discharging process begins. For the clear-sky day, as the SOC of the BES system at this moment is higher (88% vs 59% for the cloudy day), a higher baseline discharging value is calculated (0.85kW and 0.5kW for the sunny day and cloudy day, respectively). However, as the demand is higher than this value, the BES systems discharge with a rate equal to the demand instead. Once the demand falls below the continuously recalculated baseline value (dependent on the current SOC), then the BES system start discharging into the grid. While this results in household exports during the night, they are considerably smaller than the exports during the PV generation period, and as such, they are unlikely to result in impacts on the network.

By using the benchmark OPT control (unrealistic perfect 24 hours-ahead demand and generation forecast) on the other hand, a slightly better performance can be achieved when compared to the AD control. The household peak power export is reduced slightly (1.1kW vs 1.8kW of the AD control for the clear-sky day case), as the usage of the perfect forecast results in a full flattening of the power export profile. It should be highlighted that for the clear-sky day case, the OPT control also results in household exports during the morning hours; an effect that was not forced in the optimisation formulation. This highlights the importance of using the baseline discharging power in the AD control.

The analysis performed in this section demonstrates that the proposed AD control can provide significant benefits in terms of reducing power exports from PV generation into the grid with limited or no impact to the customers. The usage of the ideal charging profile, periodically recalculated based on the clear-sky profile and the current SOC, coupled with the periodically recalculated baseline discharging power results in a performance that is not far from the ideal optimal operation.

5.4 Case Study

The case study performed in this section aims to quantify the benefits that the AD control can bring in mitigating PV impacts in the distribution network. The customer performance of the AD control (i.e., reducing grid imports) is also assessed, so as to understand what effect the adoption of this control might have on residential customers. For comparison purposes, its performance is compared with the PV only and OTS control cases previously demonstrated in Section 4.4, but also with the “perfect benchmark” OPT control.

5.4.1 Network Performance

In this section, the network performance of the AD control is assessed against the benchmark cases. The assessment, which considers the integrated MV-LV network modelled and presented in Chapter 3, along with the corresponding real demand, and generation data and PV system sizes, is performed for 100% PV penetration case. As previously, the off-load tap changers are set to the lowest position, and the Volt-Watt function of PV inverters is disabled. As in the previous chapter, the assessed day corresponds to the 8th of January 2016. This day has been selected as it corresponds to a day with low midday demand and high PV generation. This is a "worst-case scenario" when assessing PV impacts.

As it can be seen from the customer voltages in Figure 5-4 and the thermal utilisation of MV lines in Figure 5-5, both the AD(a) and OPT(b) BES controls, due to their ability to significantly reduce customer power exports to the network, manage to successfully mitigate all PV impacts. The OPT control results in generally more flat voltage and thermal utilisation profiles, as it fully flattens the customer export profile through the utilisation of perfect information. Due to the lack of forecast, the AD control results in several spikes during midday (11am-1pm). However, these spikes do not result in violation of the limits.

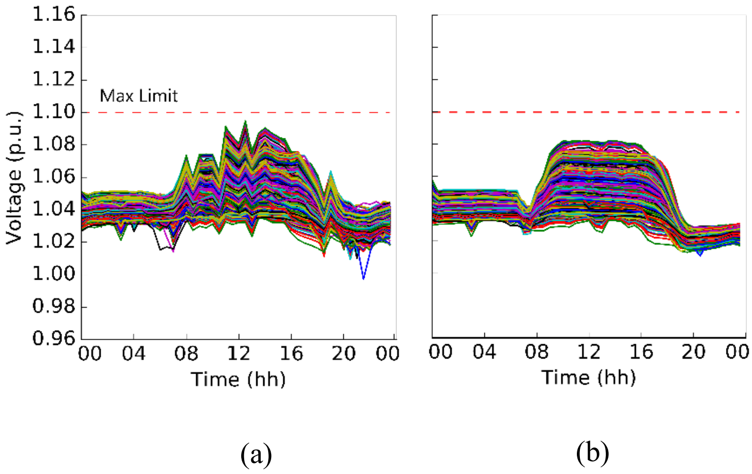


Figure 5-4. Customer voltages for the AD (a) and OPT (b) controls

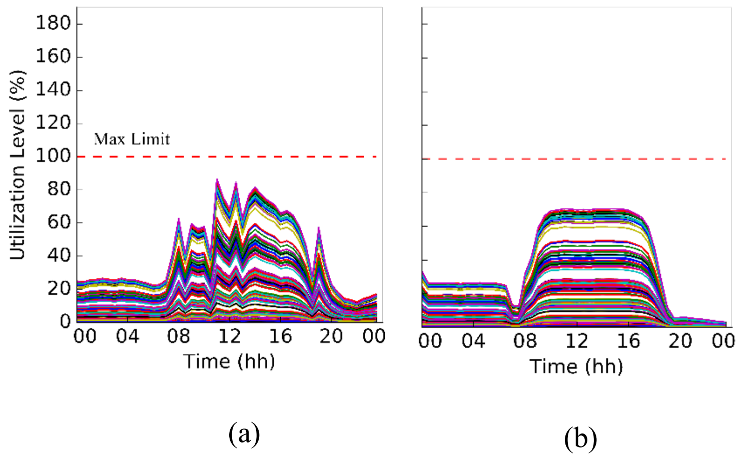


Figure 5-5. MV line utilisation for the AD (a) and OPT (b) controls

For completeness, a summary of the network performance including the utilisation of the LV assets (i.e., lines, distribution transformers) is given in Table 5-1. As it can be seen, both the AD and OPT controls manage to mitigate all problems in the assessed network. Even without the use of forecasting, the AD control is able to perform almost as well as the benchmark OPT control.

Table 5-1. Summary of network performance

	PV Only	*OTS*	*AD*	*OPT*
Customers with Voltage Problems (%)	18	10	0	0
Maximum Utilisation of Transformers (%)	125	125	68	59
Maximum Utilisation of MV Lines (%)	186	171	82	78
Maximum Utilisation of LV Lines (%)	110	105	50	43

To further understand how the AD and OPT controls perform much better in terms of mitigating PV impacts in the network than the OTS control, the average net demand profiles of all customers in the network is plotted in Figure 5-6. The OTS control, while it slightly reduces the average power profile between 8am and 1pm when compared to the PV only case, between 2 and 6pm their average profile is roughly identical. With the AD and OPT controls on the other hand, the exports are significantly reduced (more than halved). This resulting operation does not cause violation of the distribution network constraints.

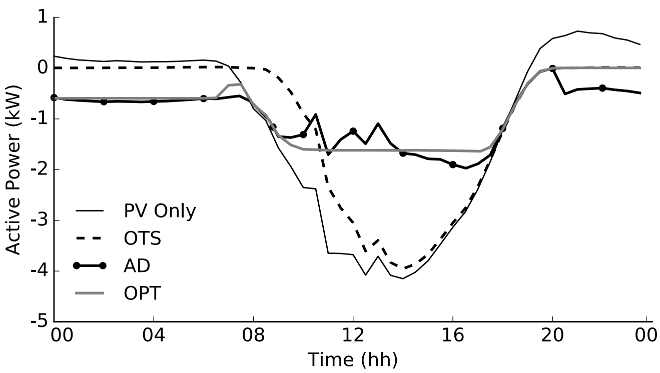


Figure 5-6. Average customer net demand profile

It should also be noted that due to the power exports during the morning hours (midnight till 8am) that allow for the BES system to have adequate capacity during the day, both the AD and OPT controls result in slightly higher voltages than the PV only and OTS cases. Despite the slight voltage rise, however, the voltage values are well within the allowed limits.

In addition to the time-series analysis performed, this case study also aims to demonstrate locational behaviour of voltages (i.e., distance of node from primary substation), the maximum MV and LV voltages at all nodes during the peak generation period are shown in Figure 5-7 for all control cases.

Starting with the MV nodes (grey dots), for all control cases, as the node is further from the primary substation, the voltage increases. However, due to the reduced reverse power flows in the MV lines, both the AD and OPT controls result in much lower voltages at the end of the MV feeder (1.015pu for the AD/OPT controls vs 1.035pu for the PV only/OTS). This, in turn, cases the voltages at the busbar (secondary side) of the distribution transformers to have a lower voltage. The effect of the reduced reverse power flows in the LV networks can also be seen. With the AD and OPT controls, the voltage at the LV nodes rises (black dots) is significantly less than the PV only and OTS cases.

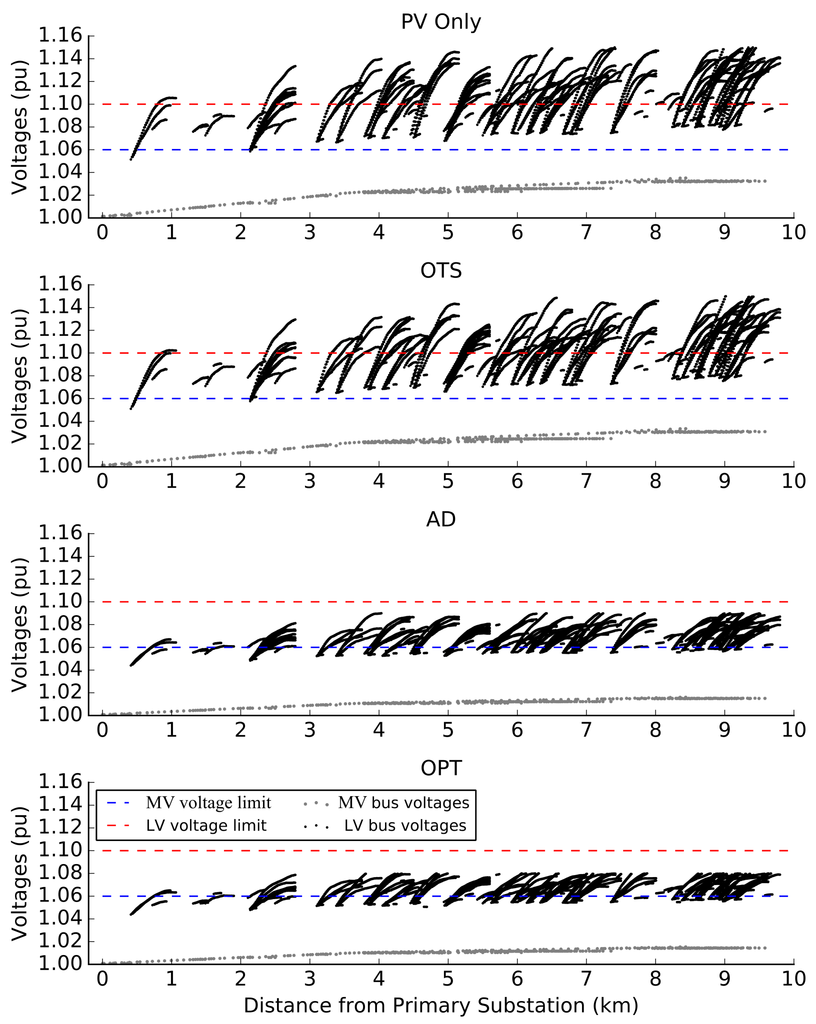


Figure 5-7. MV and LV voltages during peak generation

This figure can also be used to highlight the importance of considering integrated MV-LV network assessments to more realistically capture the effects of reverse power flows. If an MV-only analysis was carried out, the MV nodes would appear to all lie within the MV voltage limit (1.06pu, blue dashed line) for all cases, and it could have been wrongly concluded that the network can host 100% PV penetration (based on voltages, neglecting thermal issues). On the other hand, if standalone LV analysis was considered, the number of customers with voltage problems would have been wrongly miscalculated, as the LV networks close to the primary substation have very few customers with voltage problems even for the PV only / OTS cases. As such, the PV impacts on the network would have been massively underestimated. Despite the importance of considering integrated MV-LV network assessments, their usage in the literature is very limited [83-85] as researchers tend to focus solely either on MV or LV networks.

As with the previous chapters, to truly assess the benefits that the AD control brings to distribution networks, a stochastic analysis is performed. The Monte Carlo methodology is applied in this section, where results from each deterministic case are collected and presented in a probabilistic manner. The simulations are performed for different penetration levels (from 0 to 100% of houses with PV and BES systems, in step of 10%). For each penetration, 100 iterations are performed. Besides the previously presented metrics (i.e., voltage compliance and MV line utilization), the stochastic analysis is expanded to also include the LV line and transformer utilization. In this analysis, only summer days (December to February) are considered as it is the period that most likely will present issues resulting from reverse power flows. For comparison purposes, the results for the PV only and OTS control cases, which the results were previously presented in Chapter 4, are also included in the figures.

Starting with the number of customers with voltage problems, as it can be seen in Figure 5-8, the usage of the AD control in BES systems is able to overcome the limitations of the OTS control of BES systems and fully mitigate voltage problems across all penetration levels. Similarly, the thermal utilisation of the assets in the network is below their rated capacity across all assessed scenarios and penetration levels; as seen in Figure 5-9 - Figure 5-11 for the MV lines, LV lines, and LV transformers, respectively. For the 70% penetration level, where the thermal utilisation of the MV lines would exceed their rated capacity for the PV only case (107% for the worst-case scenario) and where the OTS control case would marginally mitigate the issues (100% for the worst-case scenario), the usage of the AD control brings maximum utilisation down to 62% across all assessed scenarios; a rather significant reduction. This demonstrates the ability of the proposed control to bring significant benefits to the network (in terms of PV impacts) due to the reduction of household exports. Finally, it should be noted that the proposed AD control manages to achieve a similar performance in terms of mitigating PV impacts as the unrealistic benchmark OPT control without the use of accurate demand and generation forecasting.

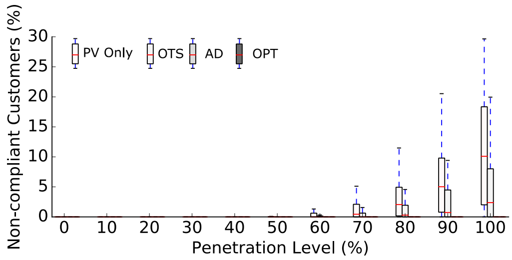


Figure 5-8. Percentage of customers with voltage problems

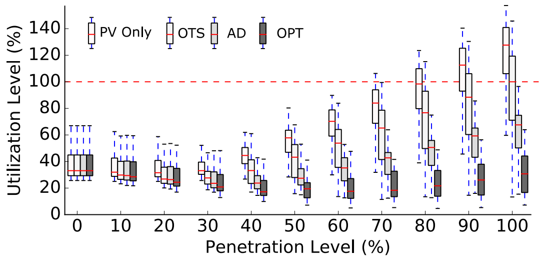


Figure 5-9. MV lines maximum utilisation level

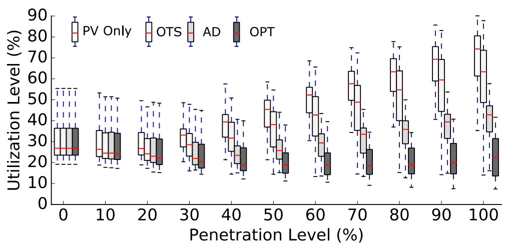


Figure 5-10. LV lines maximum utilisation level

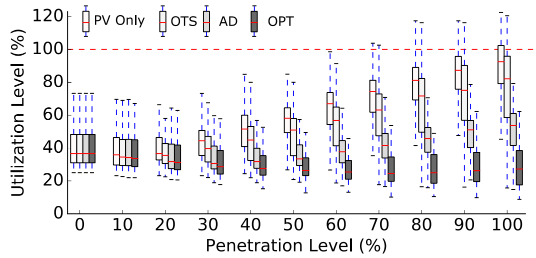


Figure 5-11. LV transformers maximum utilisation level

5.4.2 Customer Performance

Despite the significant benefits that the AD control was found to bring to the distribution network in terms of mitigating PV impacts, it is also required to understand whether the adoption of this control will have any significant impacts on the residential customers. To assess this, the GDI analysis previously performed in Section 4.4.2 for the PV only and OTS cases, is expanded to a seasonal GDI analysis for also the AD and OPT controls, and is shown in Figure 5-12. The analysis considers all the 4,626 customers in the network and the whole year data is used.

When the customers do not have a BES system installed, the median GDI for the customers during the sunny seasons (spring and summer) is 48 and 56%, respectively. During the cloudier seasons (winter and autumn), the customers have an increased GDI of 72 and 62% respectively. This results in an annual GDI of 62% as previously shown in Section 4.4.2.

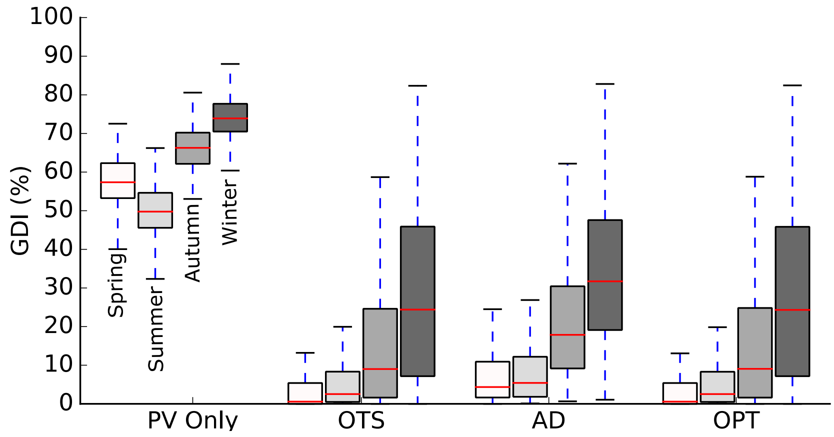


Figure 5-12. Seasonal GDI for all assessed cases

When OTS BES systems are adopted, which is used as the benchmark for the "best-case scenario" for customer performance, there is a massive reduction in the GDI across all seasons. During summer and spring, the median GDI of customers is at 2 and 1%, respectively; as such, almost half of all customers are fully energy self-sufficient during this period. A small increase in the GDI is experienced during winter and autumn, where the median GDI for customers is at 23 and 9%, respectively. Given that in this region, energy consumption is higher during the winter, the median annual GDI for customers with OTS BES systems is at 11%. Not surprisingly, the exact same performance is also achieved by the OPT control. Due to utilising perfect demand and generation forecast, it is able to achieve the best possible performance for residential customers. However, it should be noted once more that such level of accuracy in the forecast is unrealistic, and as such these values should only be taken as a "perfect benchmark" solution.

On the other hand, the proposed AD control, without the use of forecast, manages to achieve a similar performance with the OTS/OPT controls in terms of customer performance. While a small increase in the GDI can be seen across all seasons, the annual GDI is only increased slightly (from 11 to 14%). As such, customers with BES systems operating with the AD control are expected to experience only a very slight increase in their energy consumption.

The reason that the AD control results in higher GDI than the OTS/OPT controls is primarily due to the discharging of the BES system regardless of what the next-day irradiance will be like. However, actions can be taken to improve the GDI of the AD control to even lower values, which were not considered in this study. In this case study, the E^{min} value was set to 0kWh. This means that at the start of each generation period, the BES systems must be empty. While this achieves a better network performance when two consecutive sunny days exist, when a cloudy day follows a sunny day the stored energy from the previous day that could have been used in the cloudy day is "wasted". This could be improved by not fully discharging the BES system, but allowing a small reserve (e.g., $E^{min} = \bar{E} \times 10\%$). However, this might result in some decrease in the network performance, and as such, a trade-off solution between network and customer performance needs to be established. Furthermore, simple forecasting can also be adopted which changes the E^{min} value depending if a sunny or cloudy day is expected.

One more aspect that needs to be considered when the default OTS control is changed, is the effect that this might have on the warranty of the BES system. Usually, manufacturers only consider a time-based warranty (e.g., 10 years). However, in other cases, when other controls are used, they also define other conditions for the warranty. In the case of Tesla Powerwall 2 (used in this case study) this corresponds to an output value of 37.8MWh [86]. Once that output has been reached, the 10-year warranty of the system becomes void. As such, the individual cumulative output (per year) for the AD and OPT controls is shown in Figure 5-13 to quantify their effect on the BES system warranty. It should be noted that while the OTS falls under the "normal operating mode" and therefore the warranty applies without any output limitations, it is included in Figure 5-13 for reference purposes.

Starting with the AD control, all the assessed BES systems are fully under warranty for at least 9 out of the 10 years. During the last year of the warranty, 17% of the systems record an output higher than the warranty limit. Interestingly, this effect becomes worse for the OPT control, where 2% of the customers are found to have their warranty void in the 9th year, and 19% in the 10th. This effect is due to the fact that the OPT control allows charging at higher levels during cloudy days, and as such more energy can be discharged. Nonetheless, it is highlighted here that the AD control results in very small impacts to the system warranty, and for very few customers.

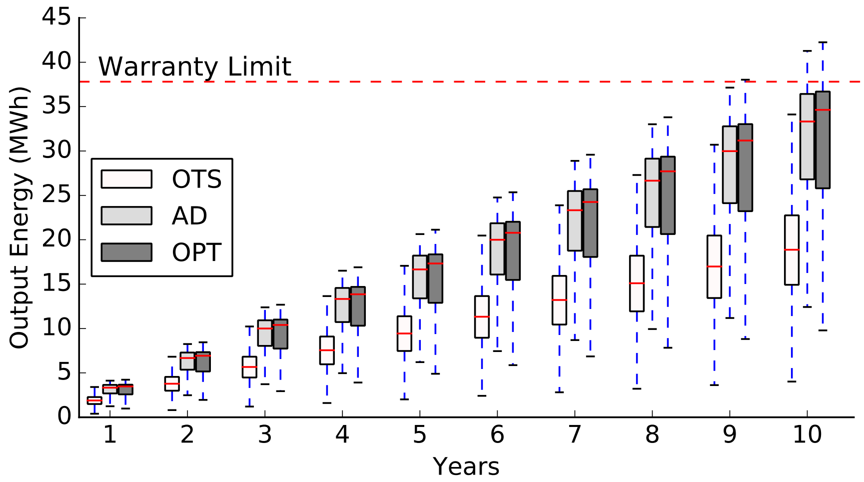


Figure 5-13. Cumulative BES system output for the AD and OPT controls

5.4.3 Effect of Estimation Errors

The estimation methods for the clear-sky generation profile are very well established. However, in reality, several errors can exist in this calculation; primarily related to the efficiencies of real PV systems. The efficiency can vary based on factors such as temperature, ground reflectance (dry vs wet soil), as well as the conditions on the surface of the PV panels (e.g., rain, dust).

To evaluate the effect that the miscalculation of the clear-sky profile has on the performance of the AD control (both in terms of reducing grid exports and customer benefits), the analyses performed in Section 5.3 are repeated for two miscalculated clear-sky profiles with: 1) a 10% overestimation of the total energy, and 2) a 10% underestimation of the total energy. The results, quantified numerically for the peak export and the GDI, are shown in Table 5-2 for the different clear-sky profiles (CSP).

For the clear-sky day, an underestimated clear-sky profile results in an increase of 0.07kW in the peak exports (or 1.3% of the PV system size, 5.5kWp). The overestimated clear-sky profile on the other hand does not result in any increase in the peak exports. For the cloudy day, both the under and overestimated clear-sky profiles result in 0.02kW of increase in the peak exports (0.4% of the PV system size). The GDI of the customer remains the same for all clear-sky profiles.

Table 5-2. Performance Considering Estimation Errors

	Clear-sky Day		*Cloudy Day*	
	Peak Export (kW)	*GDI (%)*	*Peak Export (kW)*	*GDI (%)*
Without BES	4.29	31.2	2.95	38.7
Accurate CSP	1.70	0.0	0.88	0.9
Underestimated CSP	1.77	0.0	0.90	0.9
Overestimated CSP	1.70	0.0	0.90	0.9

These results highlight that due to the periodic recalculation of the ideal charging profile, as well as using measurements for the demand and generation, the miscalculation of the clear-sky profiles results in negligible loss of performance; both in terms of reducing power exports and reducing grid imports.

5.4.4 Computational Efficiency

Using a Windows OS machine with Intel Core i7-7500U processor at 2.7 GHz and 16GB of DDR3 RAM, the algorithms of the AD control are able to define the charging and discharging power rate of each customer in under 0.2 milliseconds (per customer). This shows that the proposed AD control can potentially operate within the timeframes needed in real BES systems (usually sub-second sampling times). Nonetheless, these processing time results should be taken as an indication only. In reality, these algorithms are going to be implemented in BES systems, where the processing units are likely to be several times weaker than the testbed.

5.5 Chapter Summary

In this chapter, the AD control of residential BES systems was proposed. The control was designed to overcome the limitations of OTS BES system and reduce household power exports into the grid during the critical PV generation period; effectively tackling the source of voltage and thermal issues in the network. This was also done considering the primary objective of BES systems: reduce household grid imports. With this control, the charging and discharging rate of the BES system constantly adapts throughout the day based on demand, PV generation, clear-sky irradiance, and SOC.

The performance of the AD control was evaluated in the integrated MV-LV network using both deterministic and Monte Carlo analyses, and was compared against the benchmark OTS (best for the customer) and OPT controls (best for the network). The results demonstrate that the proposed approach manages to overcome the limitations of the OTS control and provide significant benefits to the network in terms of mitigating PV impacts across all penetration levels; performance was found to be similar to the benchmark OPT control which uses perfect day-ahead forecast. Furthermore, a similar customer performance was achieved when compared to the benchmark OTS control.

Considering that the proposed AD control can provide significant benefits to both the network and to the customers simultaneously, coupled with the practicality and scalability of this approach, this could prove to be an attractive solution to increase the hosting capacity of distribution networks in the years to come. This could be adopted either through incentives (e.g., discounted BES systems) or through regulation similar to the PV inverter functions (e.g., Volt-Watt, Volt-Var) that are required in some parts of the world [87].

6 CUSTOMER-LED OPERATION OF BES SYSTEMS

6.1 Introduction

As was demonstrated in the previous chapter, the adoption of advanced management of BES systems can bring significant benefits to the distribution network in terms of mitigating PV impacts. Nonetheless, PV impact mitigation is just one of the benefits that BES systems can provide. In this chapter, another stream is explored; the usage of BES systems to provide services to the upstream power system, i.e., the TSO. To do this, a new control is proposed, which acts on day-ahead forecasted information such as local demand, generation, and prices, in order to provide services through residential-scale BES systems. This control is designed with the consideration of individual households participating in the provision of services (i.e., not an aggregator controlling the BES systems, but rather, individual BES systems responding autonomously). The objective of this chapter is to first quantify whether the proposed control can bring monetary benefits to residential customers, but also, quantify any unforeseen effects that this might have on the distribution networks.

First, the control methodology, which considers a time-composite rolling horizon optimisation, BES system steady-state characteristics, and battery degradation, is presented in Section 6.2. The operation of the proposed BES system is demonstrated in Section 6.3. Furthermore, a case study which implements the proposed control is presented in Section 6.4. The case study first quantifies the benefits that the proposed control can bring to residential customers based on a year-long assessment. Furthermore, the proposed control is used in the operation of BES systems in the distribution network previously presented, and the corresponding impacts are quantified. A summary and the conclusions of the chapter are given in Section 6.5.

6.2 Control Methodology

This section first discusses the assumptions that are made with regards to the market structure/regulation as well as the available infrastructure; both aspects that could influence the control design. Furthermore, the concepts behind conventional and time-composite rolling horizon optimisation are discussed. Finally, the proposed time-composite optimisation used to control the BES system is then described in detail, including battery degradation.

6.2.1 Assumptions

One of the first and most important assumptions required to facilitate the customer-led operation is the existence of adequate platform and/or regulation that allows individual, small-scale DER to participate directly in the provision of services. While such operation is not permitted currently, [25] outlines that this is one of the key priorities to be addressed over the next decade as part of the power system transformation in Australia. The first step towards this transition requires regulatory changes; as it currently stands there is a minimum capacity requirement for service providers in the National Electricity Market (NEM) which prohibits individual households to participate. Furthermore, adequate platforms need to be developed for customers to be exposed to real-time market prices and be correctly rewarded when participating in the provision of services.

Furthermore, the control methodology used for the customer-led operation of residential BES systems assumes that customers providing services are *price-takers*. This effectively means that the volume of services that can be provided through them is not large enough to influence the price of the service provided. This can be considered as a valid assumption in the current and near-future power system where the penetration of residential BES systems is yet relatively low.

6.2.2 Rolling Horizon Optimisation Framework

This section first describes the principles behind the classical rolling horizon optimisation, followed by the time-composite rolling horizon optimisation used in the control of the BES systems.

6.2.2.1 Classical Rolling Horizon Optimisation

The optimal operation of BES systems should ideally consider a horizon that is as long as possible (e.g., days, weeks) so as to achieve the most beneficial outcome for the customer. However, since this is not practical (e.g., computational burden, forecasting errors [88]), this problem can be tackled by solving finite horizon problems repeatedly, as shown in Figure 6-1. The resulting continuous update of set-points from this approach, known as rolling horizon optimisation, allows for a near-optimal solution to an otherwise infeasible problem [89].

As illustrated in Figure 6-1, consider an infinite horizon of $[1, \infty]$ discrete periods. The first finite horizon corresponds to a set of $[1, T]$ periods, indexed by t, where T is calculated based on the adopted finite horizon length (e.g., 24 hours) and the corresponding low granularity discretization interval, ΔT^L (e.g., 1 hour). The immediate timeframe for which set-points need to be produced is known as the "control horizon" ($t = 1$ in Figure 6-1). To find these set-points whilst also considering the interactions with the remaining periods in the horizon ($[2, T]$ in Figure 6-1, known as "prediction horizon"), the optimisation (op_1) determines the optimal schedule considering the state of charge at the beginning of the finite horizon and the forecast (demand, generation, price) for the corresponding periods $[1, T]$. The power set-point corresponding to the control horizon is then adopted by the BES system. Once the control horizon is over, another optimisation is run (op_2) for the new horizon $[2, T + 1]$ using updated information (e.g., state of charge, demand/generation/price forecast). This process is repeated indefinitely as long as the system is online.

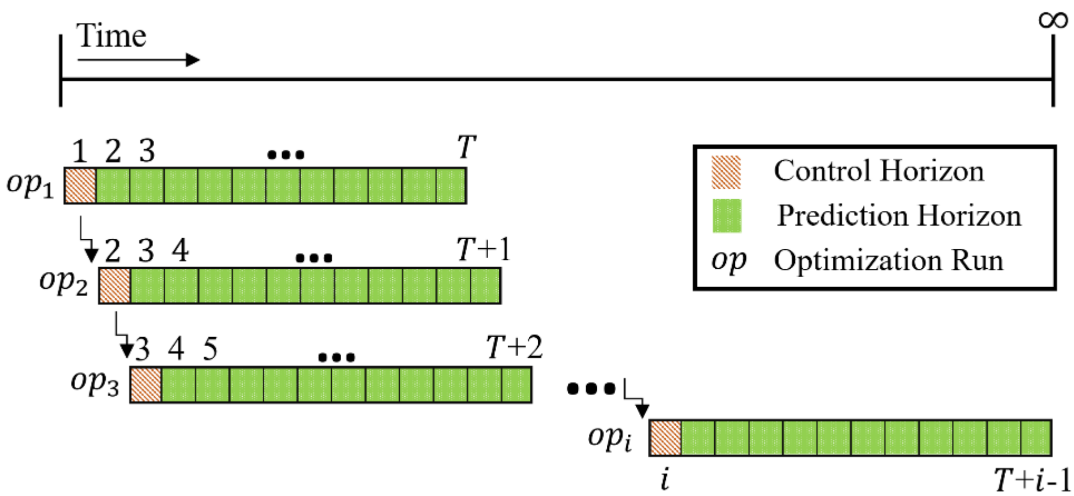


Figure 6-1. Classical rolling horizon optimisation

6.2.2.2 Time-composite Rolling Horizon Optimisation

Ideally, the discretization of the rolling horizon optimisation should consider periods as granular as the sampling period of the BES system, so as to fully capture the changes in demand and generation that occur at very high granularity (e.g., every minute). However, this can increase the computational burden (particularly for MILP problems), potentially making solution times larger than the control horizon. To allow for an optimisation problem that can compute fast enough to cater for these granular changes, while also considering the full scheduling horizon, a rolling horizon framework that uses time periods of different lengths is proposed (hereafter referred to as time-composite). The new process is shown in Figure 6-2.

The new control horizon corresponds to a much smaller one, with a length, ΔT^H, equal to the desired time between control actions (e.g., 1 min). This allows directly using measurements (demand, generation, SOC and pricing) as input to the optimisation. However, because of this smaller control horizon, an intermediate horizon is also created with a length equal to the remaining time until the next low granularity period. This also means that the total number of periods corresponds to $T+1$. In this way, from the optimisation perspective, a combination of actual measurements (control horizon) and forecasted values (intermediate and prediction horizons) are used.

To illustrate this, ΔT^H was considered in Figure 6-2 to be one third of ΔT^L. The first (op_1) and second (op_2) optimisations are comprised of the control, intermediate, and prediction horizons. The intermediate horizon becomes smaller from op_1 to op_2, and then equal to zero in the third (op_3) optimisation. The process is then repeated in op_4 adding a new low granularity period.

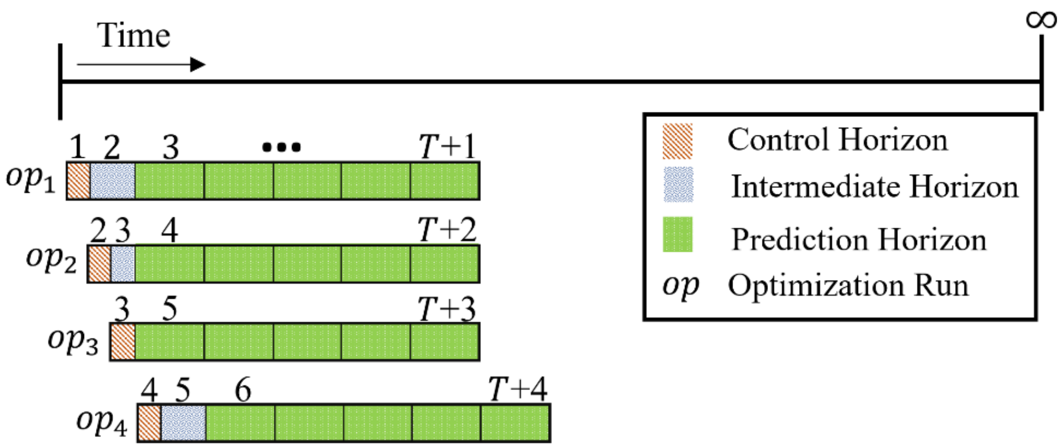


Figure 6-2. Time-composite rolling horizon optimisation

It is possible to implement the time-composite optimisation without the use of an intermediate horizon by constantly shifting the low granularity periods. However, such approach might not be practical as price settlement periods in most countries is commonly done in time static blocks (e.g., UK, 30-minute settlement periods [90]).

6.2.3 BES System Operation

First, the full problem formulation of the proposed BES control is presented, followed by the calculation of the time intervals in the time-composite optimisation. Then, the adopted battery degradation model is introduced. Finally, the methodology used to assess the performance of the approach is described.

6.2.3.1 Problem Formulation

For a horizon of interest H, where the first period is the control period that the BES system was brought online, the optimisation problem runs for $[i, T+i]$ periods where i is the current control period. The optimisation is a MILP problem where binaries are used to decouple the BES charging and discharging so that the efficiencies of the system can be incorporated in its operation. Furthermore, the imports and exports of the household are also split using binaries so that the corresponding prices can be used accordingly.

The objective function of the proposed TCRH control, given in Equation 6.1, maximizes the customer benefits in the day-ahead schedule (divided into T+1 periods each with a time interval δ_t) based on the revenue created from exporting energy into the grid minus the costs of grid imports and battery degradation.

$$\text{maximise} \sum_{t \in [i, T+i]} \phi_t \left(P_t^{nd,-} \lambda_t^- - P_t^{nd,+} \lambda_t^+ - Q_t^{deg} \right) \delta_t \tag{6.1}$$

where $P_t^{nd,+}$ and $P_t^{nd,-}$ are the customer imports and exports, respectively, λ_t^+ and λ_t^- are the import and export prices, respectively, and Q_t^{deg} is the cost of battery degradation. ϕ_t is a gradually reducing discount factor (e.g., $\phi_t \in [1,0)$) that prioritizes actions to be taken during the control horizon ($t = i$). For instance, if the BES has limited SOC and prices do not vary, it should prioritize supplying the load at $t = i$ because the demand is known accurately (based on measurements). To achieve this, ϕ_t is set such that for the current control horizon the value is larger than that of the subsequent periods, i.e., $\phi_t > \phi_{t+1}$. However, the difference should be small, i.e., $\phi_t - \phi_{t+1} \approx 0$, to ensure that this factor does not create non-optimal actions.

The power balance equation, given in Equation 6.2, links the net demand of the household (split into imports and exports) with the demand, P_t^d, PV generation, P_t^g, and power of the BES system (split into charging, $P_t^{s,+}$, and discharging, $P_t^{s,-}$).

$$P_t^{nd,+} - P_t^{nd,-} = P_t^d - P_t^g + P_t^{s,+} - P_t^{s,-}, \qquad \forall t \tag{6.2}$$

To ensure that a house can only either import or export at a time, the non-linear expression $P_t^{nd,+} P_t^{nd,-} = 0$ is considered. Similarly, $P_t^{s,+} P_t^{s,-} = 0$ ensures that a BES system can only charge or discharge. However, these two non-linear expressions are implemented linearly through the usage of binary variables, as shown in Equations 6.3 - 6.8.

$$P_t^{nd,+} \leq \bar{P}^{nd,+} y_t, \qquad \forall t \tag{6.3}$$

$$P_t^{nd,-} \leq \bar{P}^{nd,-}(1 - y_t), \qquad \forall t \tag{6.4}$$

$$P_t^{s,+} \leq \bar{P}^s b_t, \qquad \forall t \tag{6.5}$$

$$P_t^{s,-} \leq \bar{P}^s (1 - b_t), \qquad \forall t \tag{6.6}$$

$$P_t^{nd,+}, P_t^{nd,-}, P_t^{s,+}, P_t^{s,-} \geq 0, \qquad \forall t \tag{6.7}$$

$$y_t, b_t \in \{0,1\} \qquad \forall t \tag{6.8}$$

where $\bar{P}^{nd,+}$ and $\bar{P}^{nd,-}$ is the maximum power the house can import and export, respectively, and $\bar{P}^s$ is the BES system power rating.

The energy balance equation for the BES system is given in Equation 6.9, where E^{si} is the SOC (in kWh) of the BES system, i.e., a measurement used just before the optimisation. The SOC of the BES system is thereby bounded by the corresponding technical and physical characteristics as shown in Equation 6.10.

$$E_t^s = E^{si} + \sum_{n \in [i,t]} \left(\eta^+ P_n^{s,+} - \frac{P_n^{s,-}}{\eta^-} \right) \delta_t, \qquad \forall t \tag{6.9}$$

$$E_t^s \in \left[\frac{100 - DOD}{100} \bar{E}^s , \bar{E}^s \right], \qquad \forall t \tag{6.10}$$

where E_t^s is the BES system SOC in the optimisation problem (variable), η^+ and η^- are the BES charging and discharging efficiencies, respectively, $\bar{E}^s$ is the BES system energy capacity, and DOD is the maximum permittable depth of discharge.

The degradation cost function for the battery is implemented linearly as shown in Equation 6.11. The full formulation for the degradation model is given later in Section 6.2.3.3.

$$Q_t^{deg} \geq \left(\zeta_d^1 (P_t^{s,-} - P_t^{s,+}) + \zeta_d^2 E_t^s + \zeta_d^3\, \bar{E}^s\right) \frac{C^{st}}{(1-EOL)\, \bar{E}^s}, \qquad \forall t, d \in D \tag{6.11}$$

where the $\zeta_d^{1,2,3} \forall d \in D$ values correspond to the degradation map plane parameters, C^s is the total cost of the BES system (in \$, includes system and installation cost), and EOL is the end-of-life capacity (in %).

This chapter focuses on the provision of energy services and for simplicity the reactive power capabilities of the BES system are not modelled in the optimisation problem. As such, the power factor of the system is set to unity.

6.2.3.2 Calculation of Time-composite Parameters ($\boldsymbol{\delta_t}$)

The optimisation problem is comprised of periods with different time intervals according to the horizon: control, intermediate and prediction. The periods within the control and prediction horizons have predetermined time intervals. However, the duration of the intermediate horizon needs to be calculated prior to each optimisation run.

The time intervals of the control, δ_i, and prediction horizons, $\delta_{[i+2,T+i]}$, are equal to ΔT^H and ΔT^L, respectively; as shown in Equation 6.12 and Equation 6.14. Therefore, the time interval for the intermediate horizon can be calculated using the remainder of $(i-1)$ divided by $\Delta T^L / \Delta T^H$, as shown in Equation 6.13.

$$\delta_i = \Delta T^H \tag{6.12}$$

$$\delta_{i+1} = \Delta T^L - \Delta T^H - \left\{ (i-1) \bmod \frac{\Delta T^L}{\Delta T^H} \right\} \Delta T^H \tag{6.13}$$

$$\delta_{[i+2,T+i]} = \Delta T^L \tag{6.14}$$

6.2.3.3 Battery Degradation Model

Charging and discharging actions taken by the battery have an effect on its lifespan; the more it operates, the more it degrades. These actions could potentially result in degradation of the battery that is more costly than the benefits that the customer could receive. To consider this in the operation of the BES system, this work incorporates battery degradation in the optimisation problem.

The piecewise affine battery degradation cost maps (i.e., three-dimensional maps comprising of entirely linear planes) developed in [91] are used in this work as they encapsulate most of the aspects associated with battery degradation. The use of linear planes allows the degradation cost map to be incorporated in a linear optimisation. The loss of capacity of the battery at a given time can be expressed based on three parameters: the charge/discharge power, SOC, and the total energy capacity of the system. The corresponding energy capacity degradation per unit of time (kWh/h) is the maximum value from the all the linear plane parameters, as shown in 6.15. The loss of energy capacity can then be converted into cost by relating it to the BES system size, cost and end-of-life (EOL) capacity, shown in 6.16. The EOL capacity is a value defined by the manufacturer and indicates that the BES system is no longer operational.

$$J_t^{deg} = \max\left(\zeta_{d\in D}^1 (P_t^{s,-} - P_t^{s,+}) + \zeta_{d\in D}^2 E_t^s + \zeta_{d\in D}^3 \bar{E}^s\right), \qquad \forall t \tag{6.15}$$

$$Q_t^{deg} = J_t^{deg} \frac{C^{st}}{(1-EOL)\bar{E}^s}, \qquad \forall t \tag{6.16}$$

where J_t^{deg} is the battery degraded capacity (kWh/h).

For the benefit of the reader, and to better understand how different actions of the BES system lead to different levels of degradation, an example of a piecewise affine battery degradation map for a 5kW/13.5kWh BES system is shown in Figure 6-3. The degradation map consists of three axes which are the power of the BES system (in kW), the energy of the storage system (in kWh) and the corresponding degradation (in kWh/h). For this specific degradation map, it can be observed that most of the degradation happens when the BES system is completely empty. At this SOC, the battery degrades quite highly even when it remains idle (i.e., no charging/discharging). Higher charging/discharging at this SOC produces severe degradation of the battery. Once the BES system has a little bit of energy stored, the degradation is at its lowest, with almost zero when the BES system is idle, and increasing linearly as the power charging/discharging rate of the BES system increases. The degradation also increases linearly as the SOC of the BES system increases, with the exception at full SOC where there is a small non-linear increment (i.e., a "jump") in degradation.

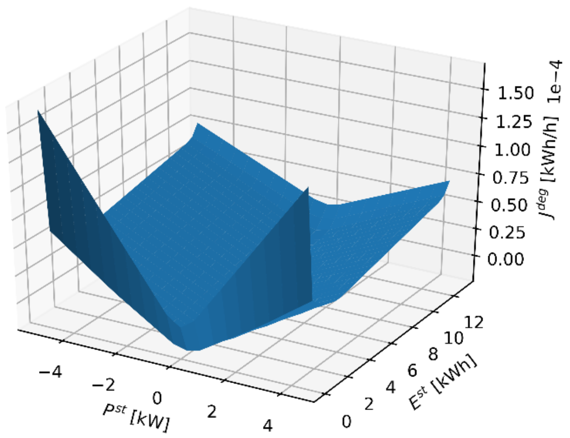


Figure 6-3. Battery degradation map for a 5kW / 13.5kWh BES system

6.3 Operation Demonstration

In this section, the operation of the proposed customer-led BES system control is demonstrated using a single household. As the degradation model used leads to a rather unique operation, for the benefit of the reader this section is split into two categories: operation ignoring degradation, and operation with the degradation model enabled. It should be noted that in this section, the original 30-minute resolution demand data was converted to higher granularity data by inducing Gaussian noise. To perform the conversion of low-granularity to high-granularity profiles, a small high-resolution pool of real demand profiles provided by AusNet services was used to extrapolate average and standard deviation values. Using these parameters, Gaussian noise was then added to the larger pool of profiles to simulate variations in demand found in very granular data. Similar process has been used in other works found in literature such as in[92].

Furthermore, the proposed BES control strategy considers T equal to 48 periods, ΔT^L equal to 30 minutes, and ΔT^H equal to 1 minute, i.e., a control horizon of 1 minute and a prediction horizon of 23.5 hours. Each optimisation run considers perfect forecast. This means that the inputs for the intermediate and prediction horizon periods correspond to the average of the 1-minute values within each of the periods. Finally, the ϕ_t values gradually reduce in the range $\phi_t \in [1,0.99]$. The analysis is performed in Python 3.6, where the demand, PV system and BES system models are implemented. The optimisation processes are performed through AIMMS, using the CPLEX 12.8 solver [93].

6.3.1.1 Operation Ignoring Degradation

This section demonstrates the effectiveness of the proposed BES control (and the use of time-composite rolling horizon, hereafter denoted TCRH) against two other controls: one that uses a single optimisation run at the beginning of the day (SOPT) and one that uses a conventional rolling horizon (CRH). In this case study, a single-customer, two-day deterministic case study is considered. For simplicity, a flat \$0.20/kWh time-of-use (TOU) profile is used for both days and the service price (i.e., money paid for exports during for each period) is set at \$0/kWh all times except between 1 and 4pm on the second day where it is set to \$0.05/kWh for demonstration purposes. The import (λ^-) and export (λ^+) energy price profiles, along with the superimposed demand and PV generation of the household ($P^d - P^g$) are shown in Figure 6-4. The BES system is assumed to be empty at the start of the first day.

The net demand (grey line), BES power (blue line) and BES SOC (green line) of the household are shown in Figure 6-5(a) for the SOPT control. In this case, the optimisation problem is only solved once at the beginning of each day, considering 24-hours ahead perfect forecast (average values within each 30-minute period). During the first day, as there is no service price, there is no incentive for the household to export energy at any time. Therefore, the BES system stores just enough surplus PV generation to meet the demand at the end of the first day, at which point the BES system is empty. During the second day, due to the existence of the export price, the BES system stores all the available surplus generation prior to 1pm, at which time it stops charging (with ~39% SOC, 5.3kWh) and starts exporting once the price has spiked. During the price spike period (1-4pm), due to the limited energy stored in the BES system, the optimisation discharges at full output (5kW) for approximately 1 hour (in two 30-minute periods). It is important to highlight that during the time that both the PV and BES systems are exporting, the combined power causes exports of up to 8.9kW, which is much higher than the PV system capacity; raising concerns about the network effects from multiple BES systems providing services. After the service price returns to \$0/kWh, the BES

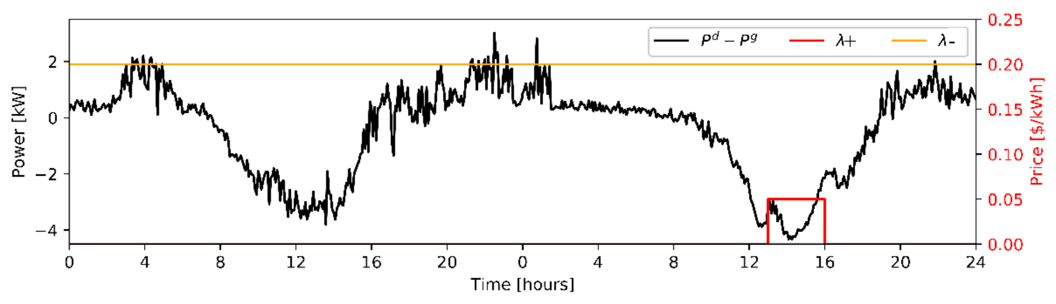


Figure 6-4. Demand, generation and pricing input data

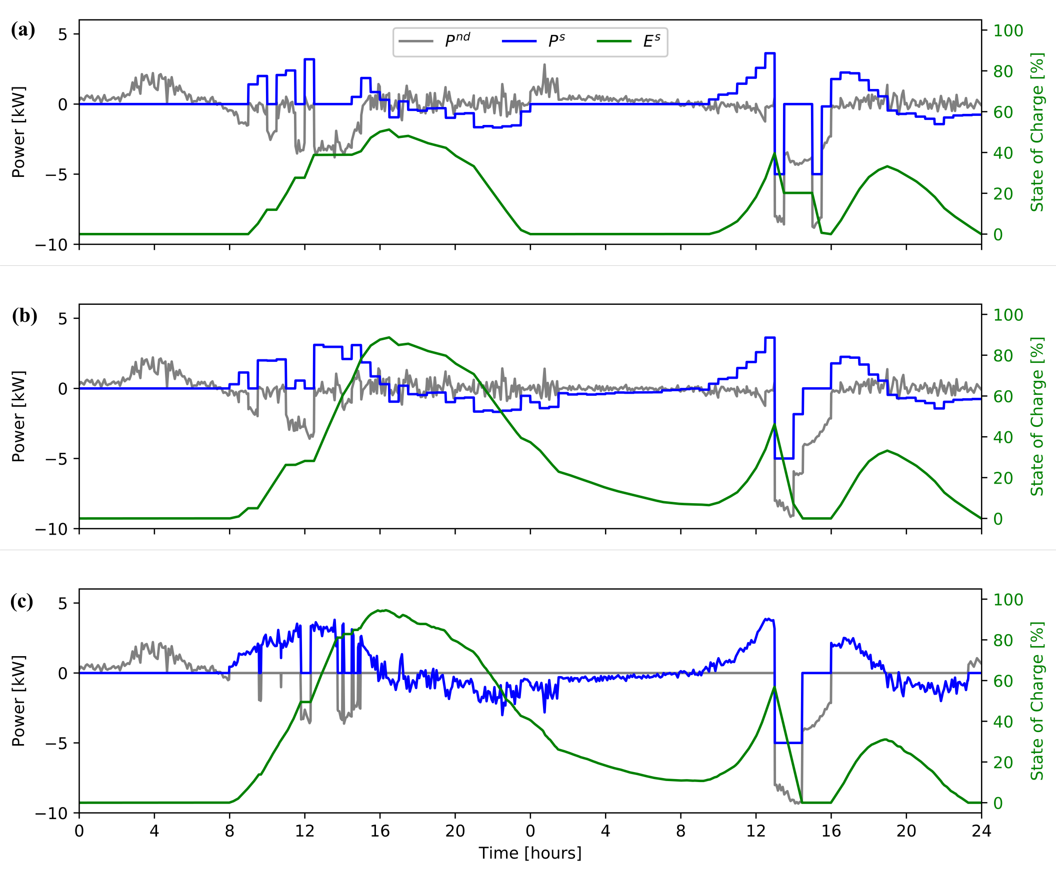


Figure 6-5. Net demand, and BES power and SOC for the (a) SOPT, (b) CRH, and (c) TCRH control strategies

system stores again the surplus generation so that it can meet the household demand during the evening. With this SOPT operation, what becomes rather evident is that there is a missed opportunity for the BES system to charge further during the first day, so that it can supply the demand in the early hours of the second day (12-7am) or supply more energy during the price spike. In addition, the issue of granularity exists; as the BES control is not able to capture the intra-period variations in demand and generation (within each 30-minute). This leads to non-optimal imports and exports throughout both days. For instance, between 4pm and midnight of the first day, the BES system is discharging to cover the net demand. However, since it only considers 30-minute averages, the scheduled discharge (blue line) does not match the more granular net demand (grey line), resulting in minor imports and exports.

With the CRH control, the importance of using rolling horizon in the operation becomes evident. As seen in Figure 6-5 (b), the BES system now charges further during the first day in anticipation of the demand after midnight in the second day. This is possible because the rolling horizon can link the operation of the two days as it progresses in the first day. Besides the demand reduction between 12 and 7am on the second day, there is also more available energy in the BES system to export during the price spike (~46% SOC at 1pm). The issue of not being able to capture the highly granular changes in demand remains.

The results from the proposed TCRH BES control are shown in Figure 6-5(c). Due to its ability to integrate the high-granularity variations in the optimisation problem, the BES system is now able to match these variations in demand and generation, which results in a flat net demand profile during times that the BES system is charging from the surplus PV generation, or supplying the household demand (e.g., between 3pm on the first day and 1pm on the second day). This ability to more precisely match net demand allows the BES system to be better prepared for events. This can be observed at 1pm (start of the price spike) where the SOC reaches ~57%; a value much higher than before.

The performance of each of these controls is shown and compared in Table 6-1. The usage of a rolling horizon helps substantially in reducing import costs. Comparing the SOPT and CRH controls, the import cost was reduced from \$2.96 to \$2.33; which is a major component of the net cost as export revenues are similar. More importantly, given the ability of the proposed BES control to match the granular variations in demand and generation, the import cost is reduced to \$1.80 and the export revenue increased to \$0.86, making it the overall best performing control when degradation is ignored.

6.3.1.1 Operation with Degradation

In this section, the degradation model is incorporated in the operation of the proposed TCRH control. The BES characteristics which are required for the degradation modelling are given in Table 6-2 and are similar to that of a Tesla Powerwall 2. The charging and discharging efficiencies are assumed to be equal;

Table 6-1.Performance of controls (Ignoring Degradation)

Control	*Import Cost ($)*	*Export Revenue ($)*	*Net Cost ($)*
SOPT	2.96	0.78	2.18
CRH	2.33	0.82	1.51
TCRH	1.80	0.89	0.91

meaning that the square root of the round-trip efficiency is applied for each. The degradation cost map used for this analysis was previously shown in Figure 6-3, which corresponds to a $LiFePO_4$-based cathode technology and has been used in previous works such as [94]. While the BES system used in this case study (i.e, the Tesla Powerwall 2) uses a different cathode technology, after consultation with the author of [91] and [94], this map was selected as it is the most realistic for this application from the ones found in [91].

Table 6-2. BES System Characteristics

Parameter	***Value***	***Parameter***	***Value***
Power Rating (kW):	5	*Depth of Discharge (%):*	100
Energy Rating (kWh):	13.5	*Round-trip Efficiency (%):*	88
End of Life Capacity (%):	60	*System Cost (AU$):*	9,600

The operation of the BES system with the degradation model is compared with the previously demonstrated TCHR in Section 6.3.1.1, where the degradation model is ignored. A case where a cheaper BES system is used (50% of the current cost) is also presented to demonstrate the effect that the initial investment has on the operation of the BES system, and subsequently, on the provision of services.

The operation of the BES system when degradation is incorporated in the control (BES cost of $9,600) can be seen in Figure 6-6(a). At the very beginning of the first day the BES system charges a small amount from the grid. This happens to reduce the cost of degradation from having the BES system idle at 0% SOC (this can be observed in the degradation map, Figure 6-3). From 7:30am to 12pm, the first surplus of PV generation occurs. However, the BES system charges from it only slightly, allowing exports into the grid. By keeping a low SOC, the BES system is reducing degradation over time. At 12pm, the BES system starts charging from all available surplus PV generation to have adequate energy stored to supply the demand during the evening. During the second day, between 1 and 6am, the BES system discharges slightly to help reduce the net demand but does not match the granular changes. This behaviour can be understood by observing the degradation map in Figure 6-3, where discharging more power causes more degradation, particularly at low SOC levels. Furthermore, despite the presence of a price spike, the cost of degradation becomes prohibitive to fully enable the provision of services. The BES system charges only slightly from surplus PV generation (from 9.30am to 1pm) to then discharge an equivalent small amount during the price spike. This is because the revenue from the energy market is less than the cost of degradation associated with the required BES operation. This new operation not only results in higher import cost and lower export revenues, as seen in Table 6-3, but also in an objective function (net cost) higher than the operation ignoring degradation. This, however, is misleading. The capacity degradation that results from the operation ignoring degradation (also shown in Table 6-3) can be converted into monetary cost using (17). Thus, the actual net cost corresponds to \$3.62, i.e., four times the objective function when ignoring degradation. When the degradation model is used, this value is reduced by 23%, which highlights the importance of incorporating degradation in the control of the BES system.

The operation of a cheaper BES system (50% of the current cost) can be seen in Figure 6-6 (b). Due to the reduction in the degradation cost (due to the lower unit cost), it is now possible to further degrade the battery if there is an economic benefit. Indeed, the BES system now participates in the provision of energy services during the 1 to 4pm price spike. Different from the case when degradation is ignored (Figure 6-5(c)), the discharging power during this period is flat only for a short time, becoming elliptical afterwards. This progressive reduction in the discharging power minimises the degradation cost, which can be observed from the degradation map in Figure 6-3. Overall, with a cheaper battery, the actual net cost when degradation is ignored (\$2.27, 50% BES) can be reduced by 15% when adequately incorporated in the BES control.

For completeness, the time-series cost of degradation is plotted in Figure 6-7. This helps illustrate the points noted previously; charging the BES system so it is not idle at 0% SOC reduces degradation dramatically during between 12 and 8am on the first day. Furthermore, delaying the charging of the BES system from PV generated energy reduces the degradation at the later stages of the first day, when compared to control without degradation. Finally, the degradation cost during the price spike (1 to 4pm) can be seen for the different BES system costs. With the 50%

case, the elliptical discharging during the price spike results in less degradation than the case when degradation is ignored. With the full system cost case, the battery does not degrade at all during the price spike.

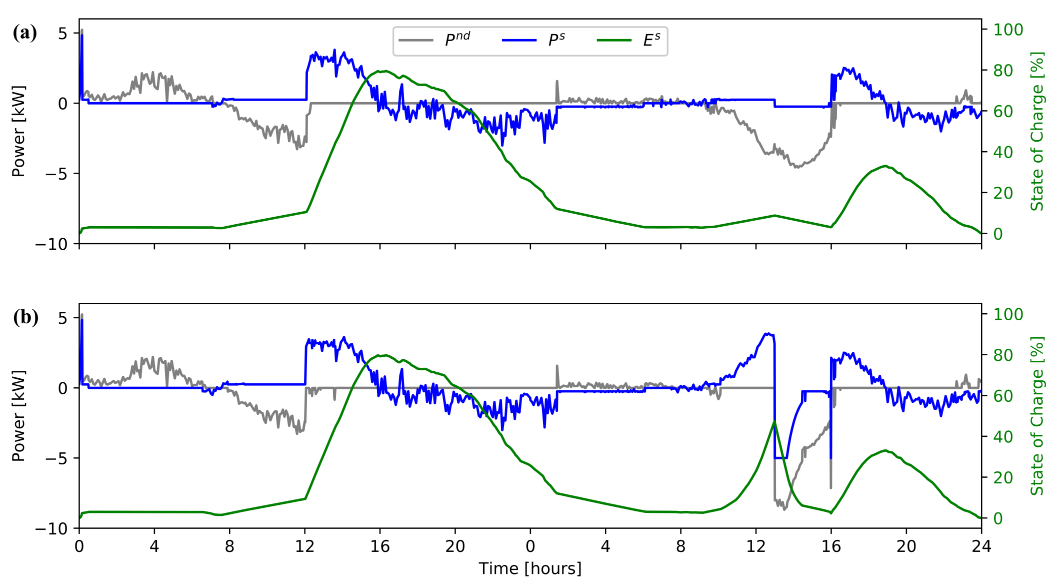


Figure 6-6. Net demand and BES power and SOC of the BES system considering degradation for (a) 100% BES system cost, and (b) 50% BES system cost

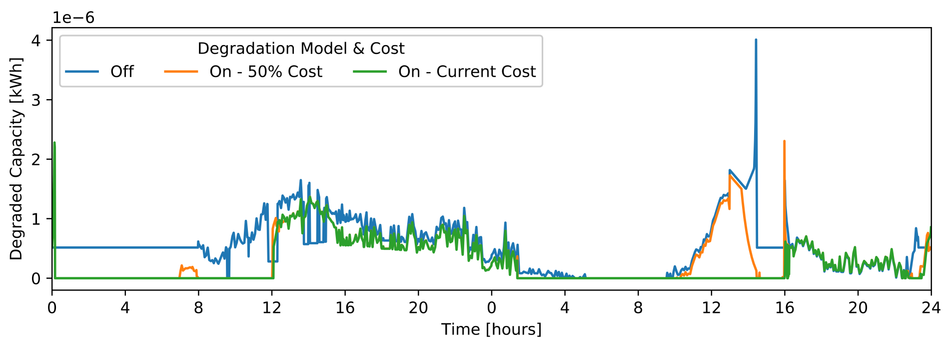


Figure 6-7. Time-series degradation for different BES system costs

Table 6-3. Performance of assessed controls with degradation

<table>
<tr><th colspan="2">Control</th><th>Ignoring Deg</th><th>Deg 100% BES System Cost</th><th>Deg 50% BES System Cost</th></tr>
<tr><td colspan="2">Import Cost ($)</td><td>1.80</td><td>1.96</td><td>1.94</td></tr>
<tr><td colspan="2">Export Revenue ($)</td><td>0.89</td><td>0.56</td><td>0.81</td></tr>
<tr><td colspan="2">Degradation Cost ($)</td><td>0</td><td>1.23</td><td>0.81</td></tr>
<tr><td colspan="2">Obj. Function Net Cost ($)</td><td>0.91</td><td>2.63</td><td>1.94</td></tr>
<tr><td colspan="2">Capacity Degradation (kWh)</td><td>15.3x10^{-4}</td><td>6.9x10^{-4}</td><td>9.1x10^{-4}</td></tr>
<tr><td rowspan="2">Actual Net Cost ($)</td><td>100% BES</td><td>3.62</td><td></td><td></td></tr>
<tr><td>50% BES</td><td>2.27</td><td></td><td></td></tr>
</table>

6.4 Case Study

In this section, the performance of the proposed TCRH control is assessed. First, the performance of the control in terms of benefits to the customer is quantified, followed by assessing the impacts that this control can have when widely adopted in a distribution network.

6.4.1 Customer Performance

In this section, the operation of the proposed BES control presented in Section 6.3 is expanded to 100 customers and a year-long assessment. For comparison purposes, all the controls previously presented are also assessed. Additionally, the OTS control of the BES system is also included for benchmarking purposes.

As in previous case studies, the annual household demand and PV generation data used corresponds to the data previously presented in Section 3.6. All customers are assumed to have a 5kWp PV system installed, which is aligned with the average installation sizes in Australia during the assessed period [95]. In this case study, wholesale energy prices are used as service price signals. They correspond to the 30-minute interval NEM prices for 2016, obtained from the Australian Energy Market Operator (AEMO) website [96]. The prices, shown in Figure 6-8, are plotted on logarithmic scales to better demonstrate their variability. Furthermore, the residential adopted TOU prices are obtained from an Australian energy provider and shown in Table 6-4. For demand, 1-minute resolution data is used (same as Section 6.3), whereas for PV generation and energy prices, 30-minute resolution data is used instead.

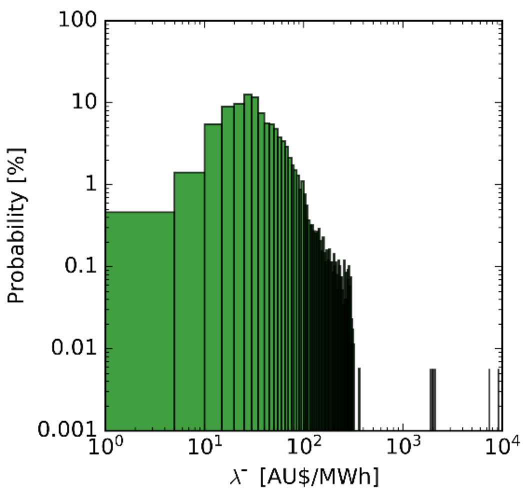


Figure 6-8. NEM wholesale energy prices from 2016 histogram

Table 6-4. Residential TOU energy prices

Type	*AU$c per kWh*
Peak (3pm to 9pm Mon to Fri)	43.2
Shoulder (7am to 3pm & 9pm to 10pm Mon to Fri, 7am to 10pm Sat/Sun)	24.7
Off-peak (All Other Times)	19.05

6.4.1.1 Economic Assessment

The economic assessment of the analysis ignoring degradation is shown in Figure 6-9, and is demonstrated in terms of import, export and net cost (the latter being the summation of the other two). It should be noted that since exports are paid (revenue), the revenue cost is plotted as a negative.

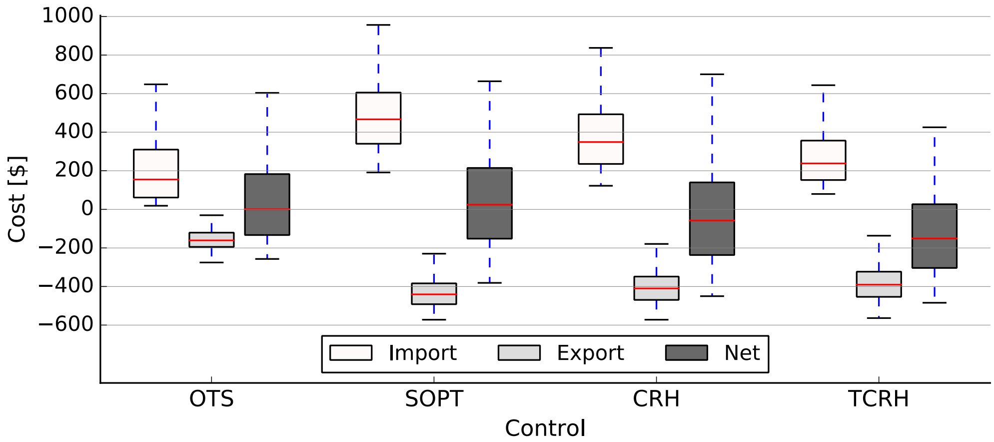


Figure 6-9. Yearly economic assessment for the assessed controls ignoring degradation

In terms of import cost, the OTS control outperforms all the others. This is expected, as the main purpose of current off-the-shelf BES systems is to reduce the imported energy from the grid by storing PV generated energy. However, it is also the worst performing control in terms of monetary benefits from exporting energy (i.e., highest export cost), as it is not meant to export during peaks in energy prices. The SOPT, due to the lack of rolling horizon results in the lowest export cost, as it is better to fully discharge the BES system by the end of each day. Nonetheless, it also has the highest import cost amongst the assessed controls, with its net cost being worse than the OTS control; resulting in $15 increase for the median customer. With the CRH control, a rather significant reduction in import cost is seen (when compared with the SOPT control), which in turn makes it outperform the OTS control by $50 a year for the median customer, demonstrating the importance of rolling horizon in the operation. This added benefit can be further increased by utilizing the proposed TCRH control, where a net cost of -$150 (i.e., profit) is seen annually for the median customer. This better performance is due to the ability of the BES system to capture granular variations. For the median customer, the proposed TCRH control can reduce the total annual cost by \$180 compared to the OTS control; highlighting the significant benefits that could be brought.

The results when degradation is considered are shown in Figure 6-10, where the import, export, degradation, and net costs are plotted for different BES system costs, from 25 to 100% of the current AU\$9,600, in 25% steps. Interestingly, for the 25 to 75% BES system costs, the median import cost remains roughly the same (~\$240). As the BES system cost increases to 100%, the import cost increases slightly, which means that sometimes it is more beneficial to supply the load from the grid than degrading the BES system. The export cost, on the other hand, increases steadily as the BES system cost increases, from -\$355 for the 25% case to -\$290 for the 100% case. In terms of the degradation cost, it can be seen to remain roughly the same in all cases. This demonstrates that the cost of degradation can significantly constraint the operation of the BES system. In summary, as BES systems become cheaper, households will be able to further lower the electricity import costs and obtain more revenue from the provision of services.

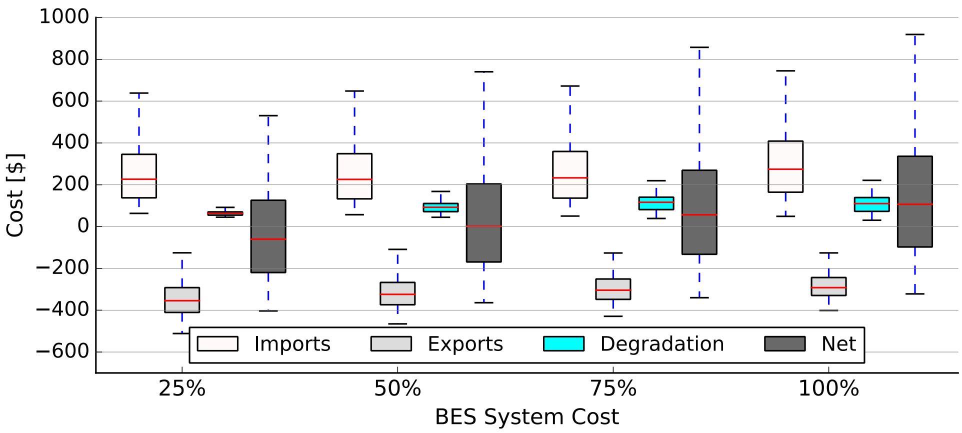


Figure 6-10. Yearly economic assessment for the proposed TCRH control with degradation

6.4.1.2 Capacity Degradation Assessment

To also demonstrate the effect of BES system cost on the capacity degradation of the BES system, Figure 6-11 shows the annual degraded capacity (in kWh/year) resulting from the four assessed BES system costs (25, 50, 75, and 100%). For comparison purposes, the resulting annual degradation from the TCRH control that does not consider degradation is also plotted. As it can be seen, the degradation of the capacity of the BES system reduces dramatically, from 0.27kWh/year for the median customer when no degradation is considered, down to 0.06kWh/year with the current BES system cost. This happens as the resulting cost from the degraded capacity becomes very prohibitive in the optimisation, and therefore, in many instances it prioritises minimizing degradation rather than reducing import/export costs. It should be noted, however, that other factors also affect the degraded capacity of a BES system (temperature, aging, etc.) which have not been considered in this analysis. Therefore, the actual degradation of a real BES system is expected to be higher than the values shown in Figure 6-11.

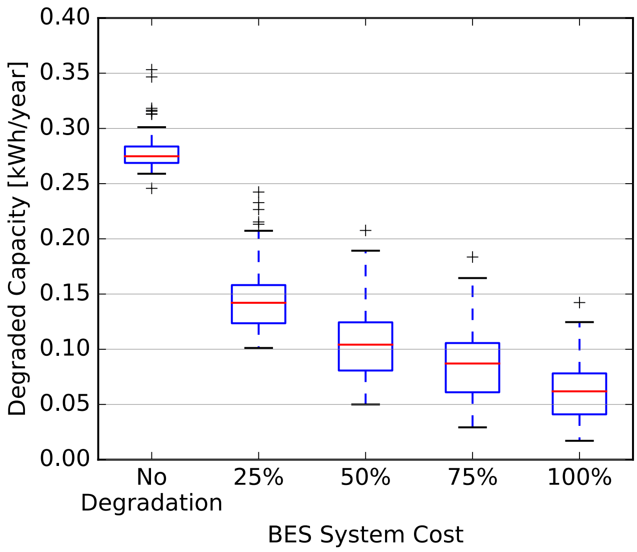


Figure 6-11. Annual degraded capacity

6.4.1.3 Effect of Forecasting Errors

The control methodology for the TCRH control, presented in this chapter, uses deterministic optimisation to determine the operation of the BES system. The case study, on the other hand, uses perfect demand, PV generation, and pricing information as input to the optimisation problem. Since, in reality, this is highly unrealistic, this section quantifies the effect of forecasting errors on the economic assessment. For simplicity, the forecasting errors are compared for the TCRH control only, without considering degradation. To include error in the optimisation problem all periods, minus the control period (uses real measurements, no error), have their values multiplied by an error factor. The error distribution, which has a standard deviation of 10%, is shown in Figure 6-12.

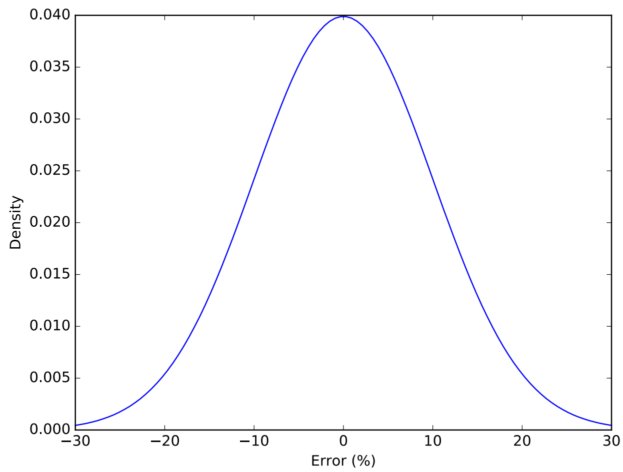


Figure 6-12. Error distribution applied to each period the intermediate and prediction horizons

The import, export, and net costs for the cases where perfect forecasting (Section 6.4.1.1) as well as erroneous forecasting is used is shown in Figure 6-13. As it can be seen, the effect of forecasting error is very small on the economic performance of the proposed control. This is primarily due to the time-composite rolling horizon approach, which updates frequently and periodically with real measurements. In fact, the import cost for both cases (without and with error), is roughly the same (~$235/year for the median customer). The export cost, on the other hand, increases slightly (from -$390 to -$380 for the median customer) when erroneous forecasting is used. Based on this assessment, it can be therefore concluded that the proposed approach is able to adapt well to forecasting errors with minimal impact on the economic performance of the BES system.

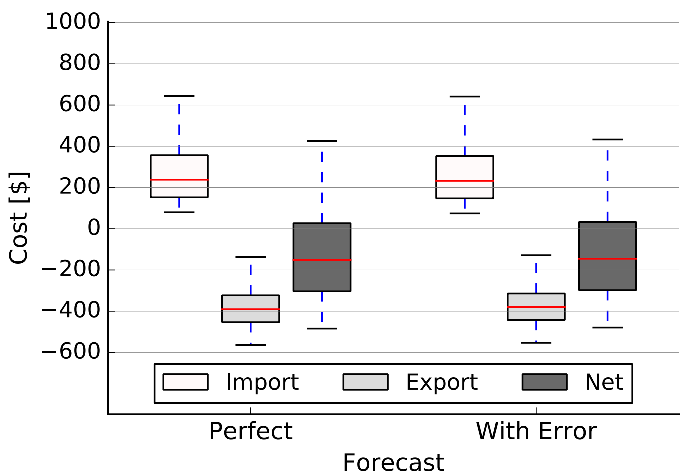


Figure 6-13. Yearly economic assessment for the TCRH control with perfect and erroneous forecast

6.4.1.4 Computational Efficiency

As aforementioned, one of the benefits of adopting the proposed methodology in BES systems is its ability to compute in timeframes appropriate for real systems. The computational time for the 100 households was recorded for each instance in which the proposed control was executed. For benchmarking purposes, the optimisation program was also solved using the CBC 2.9 solver [97], a not-so-computationally-efficient but open-source solver that can be used for free. On an Intel i7-8700k 4.5GHz with 16GB of RAM machine, the computational time distribution for both solvers can be seen in Figure 6-14.

Based on the results, CPLEX 12.8 was able to solve the majority of optimisation runs in less than 80ms, whereas the maximum was at 180ms. CBC 2.9 on the other hand, solved the majority of the optimisation runs in under 250ms with the slowest run taking 610ms. These results demonstrate the ability of the proposed TCRH control to operate in BES systems that are controlled using extremely high granularity using commercial and open-source MILP solvers.

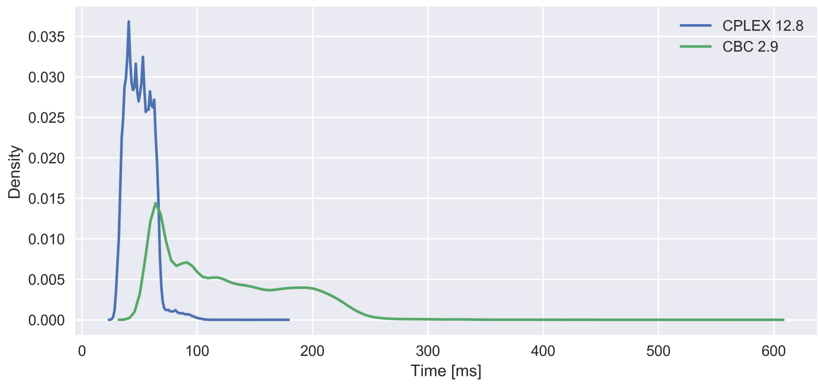


Figure 6-14. Computational times for the two assessed solvers

As previously mentioned, these processing time results should be taken as an indication only. In reality, these algorithms are going to be implemented in BES systems, where the processing units are likely to be several times weaker.

6.4.2 Network Performance

Residential customers can receive additional benefits from their BES system by participating in the provision of services. As such, in the future it is expected that more and more customers will opt to participate in provision of services. However, as previously demonstrated in Section 6.3, the discharging of BES systems for the provision of services during periods of high solar irradiance can result in total household exports that could exceed those expected from PV systems alone. The occurrence of simultaneous BES and PV systems injections from multiple households could potentially exacerbate network problems associated with reverse power flows (overvoltage and thermal congestion). As such, in this section, the performance of the proposed TCRH BES control in the distribution network previously presented in Chapter 3 is evaluated, based on demand, generation, pricing, PV system sizes, and network data previously presented. For simplicity, degradation is not considered in the optimisation problem for this case study. As with the previous assessments, the off-load tap changers are set to the lowest position, and the Volt-Watt function of PV inverters is disabled. As in this section a network impact analysis is considered, the simulation timestep is set to 30 minutes (same as Chapters 3 to 5).

First, the performance of the network is assessed deterministically, where 50% of the customers are assumed to have a PV and BES system. The wholesale energy price signal as well as the normalised PV generation profile for the assessed day (24th December 2016) are shown in Figure 6-15.

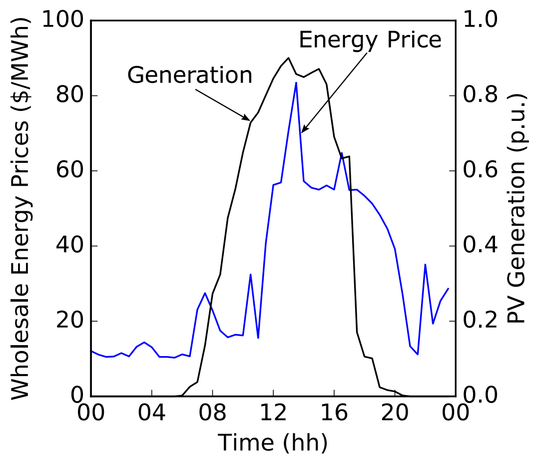
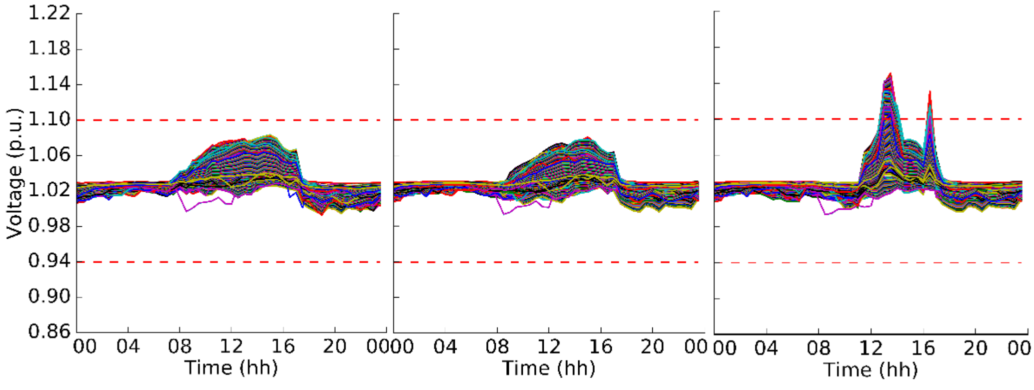


Figure 6-15. Wholesale energy prices and PV generation profiles

This day has been selected as it exhibits a price spike during period of high PV generation. This is expected to cause both BES and PV systems to be exporting into the network at the same time, exacerbating reverse power flows. To realistically capture the effects of the TCRH BES control systems, as the optimisation operates based on a rolling horizon approach, the previous and next day (23rd and 25th of December 2016) are simulated, however, the results are omitted for the sake of brevity. For comparison, analyses are also carried out for the case where BES systems are not installed ("PV only") and the case where BES systems are installed and operate according to their embedded OTS control. Finally, it should be mentioned that all the previous controls will result in similar network behaviour. For the sake of generality, the text henceforth refers to the TCRH control as "customer-led control".

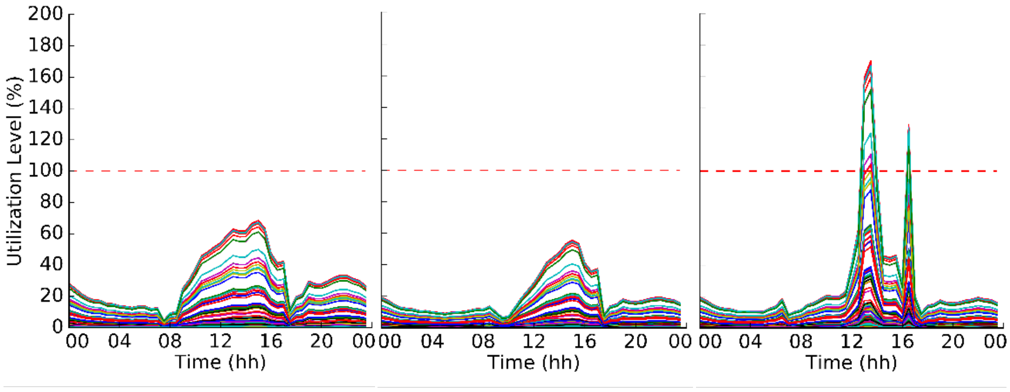
Figure 6-16 presents the daily voltage profiles of all residential customers. For both the PV only and OTS cases, the reverse power flows from the PV systems cause voltage rise during the period of high generation. However, this voltage rise does not exceed the statutory limit; hence, all customers are compliant with the voltage standard. Nonetheless, Figure 6-16(c) shows that the customer-led operation of BES systems leads to significant voltage rise (i.e., 1.15p.u.) above the statutory limit during 1:30 and 4:30pm. As a matter of fact, this behaviour, which resulted in 16% of non-compliant customers, is an effect driven by the energy price spikes (shown in Figure 6-15) at the corresponding times; causing the BES systems to export into the grid.



(a) PV Only (b) OTS (c) Customer-led

Figure 6-16. Voltage profiles of all customers for the three assessed cases

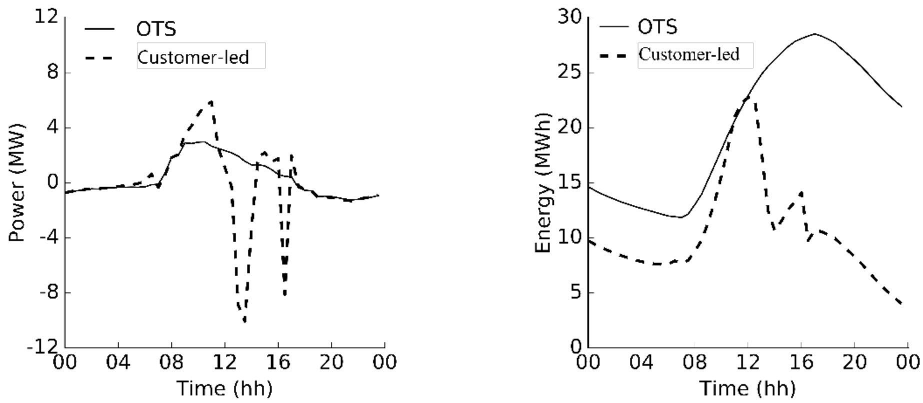
The effect of the reverse power flows caused by the combined exports form the PV and BES systems also have an impact on the thermal congestion of the network. Figure 6-17 shows the MV lines utilization for the three assessed cases. As before, with both the PV only and OTS cases, the lines operate within their rated capacity even with reverse power flows. With the customer-led BES operation, the added exports result to the loading of MV lines up to 168% of their rated capacity. This results in 11.7% of the total length of the MV lines to be congested.



(a) PV Only (b) OTS (c) Customer-led

Figure 6-17. Thermal utilisation of all MV Lines for the three assessed cases

To better understand the reasoning behind these impacts, the aggregated operation of the BES systems can be visualized in Figure 6-18 for both the OTS and the customer-led BES control. With the OTS control, the active power of the aggregated system only discharges to follow the load of each household. This does not lead to any exports from the BES system into the grid. With the customer-led control, the BES systems export energy to be sold to the wholesale market, and therefore during the price spike there is an aggregated 10MW export of power from the 2313 BES systems; an average of 4.3kW per BES system. This, coupled with the PV system exports (average of 4.4kW per PV system), contributes to significant injections per household. When unrestricted, as shown in this case study, these injections result in very large reverse power flows that severely impact the integrity of the distribution network.



(a) Active Power (b) Stored Energy

Figure 6-18. Aggregated Power (a) and SOC (b) for all BES Systems

To truly assess the extent to which the customer-led operation of BES systems might have on distribution networks, a stochastic analysis is performed. The Monte Carlo methodology presented in Chapter 3 is applied in this section, where results from each deterministic case are collected and presented in a probabilistic manner. The simulations are performed for different penetration levels (from 0 to 100% of houses with PV and BES systems, in step of 10%). For each penetration, 100 iterations are performed. Besides the previously presented metrics (i.e., voltage compliance and MV line utilization), the stochastic analysis is expanded to also include the LV line and transformer utilization, as well as the percentage of the overloaded lines in the MV-LV network. In this analysis, only summer days (December to February) are considered as it is the period that most likely will present issues resulting from reverse power flows.

Starting with the number of customers with voltage problems, shown in Figure 6-19, for the cases where only PV systems are considered, voltage problems do not appear until 70% penetration level (PV only) where a median of 1% of customers might face experience issues. These issues, however, are slightly shifted to 80% penetration when OTS BES systems are used. On the other hand, the customer-led operation of BES system was found to cause voltage problems at penetration levels as low as 30%, with a median of 2% of the customers experiencing problems. At 70% penetration, where no voltage problems are observed when OTS BES systems are used, the customer-led operation causes a median of 13% of customers to exceed the voltage statutory limit.

A similar trend is also seen with the thermal congestion of assets in the network. Figure 6-20 to Figure 6-22 show the MV lines, LV lines and LV transformer maximum utilization respectively. From these assets, it appears that the biggest bottleneck in the network are the MV lines, as they are the first to be congested. With the PV only case, the first congestion problems appear at the 60% penetration level, while for the OTS BES control the first problems arise at the 70% penetration level. With the customer-led control, the first problems still arise at the 30% penetration level, where congestion appears both at the LV transformers and at the MV lines. For the 70% penetration level, where the OTS control of BES systems marginally congests the network, the customer-led control congests the MV lines with a median of 150% and up to 300% in the worst-case recorded.

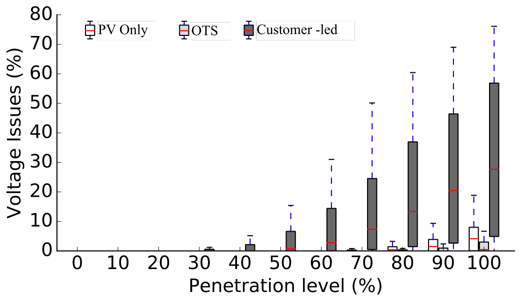


Figure 6-19. Percentage of customers with voltage problems

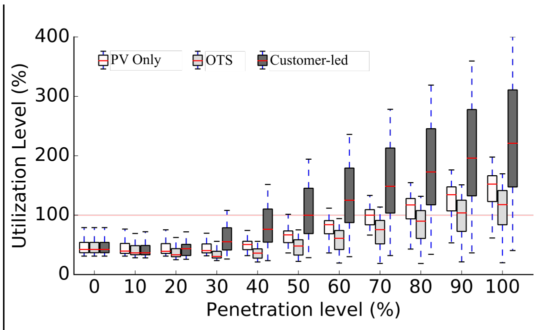


Figure 6-20. MV lines maximum utilisation level

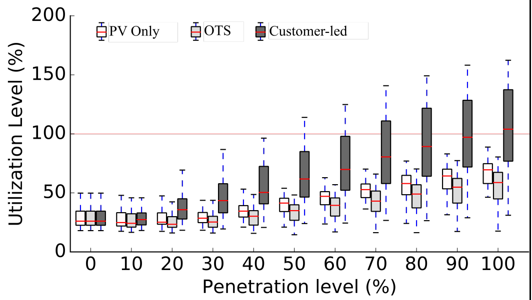


Figure 6-21. LV lines maximum utilisation level

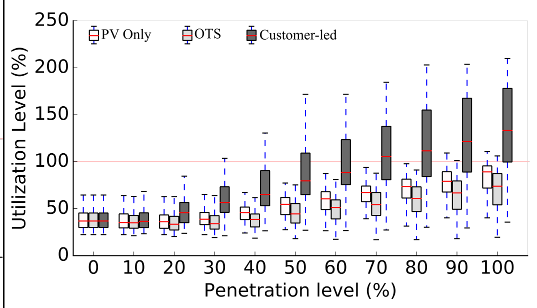


Figure 6-22. LV transformers maximum utilisation level

To fully evaluate the impacts of the customer-led operation of BES systems in the network, Figure 6-23 shows the percentage of the overloaded conductor length in the network that are operating above the 100% utilization level. Starting with the "PV only" case, while in Figure 6-20 the utilization of the MV lines exceeded the 100% limit at 60% PV penetration, the length of those overloaded conductors was negligible in comparison to the length of the full network. However, at 70% penetration, up to a total of 9.5% of the network is congested for roughly 50% of the assessed cases. With OTS BES systems, the same is observed at 80% penetration level. However, with the BES systems operating under a customer-led control, the first major congestion in the network is observed at 40% penetration, where up to 8.4% of the lines are overloaded for 45% of the cases. When the penetration is increased to 100%, the maximum percentage of the conductor length that is congested is 26% for the customer-led control case, and congestion is present for 90% of the cases. This is almost double than the congestion present with the PV only and OTS BES cases.

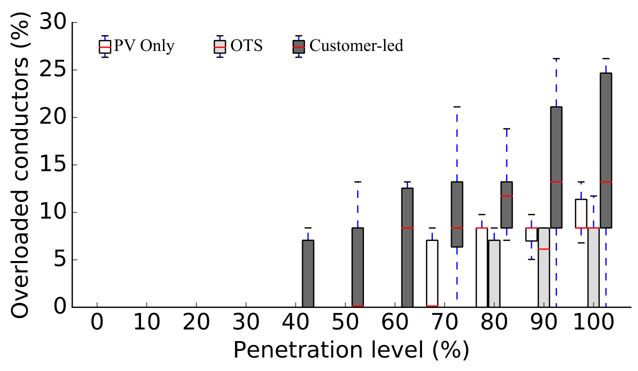


Figure 6-23. Percentage of overloaded conductor length in the network

Based on this case study, it has been demonstrated that the unrestricted injections from households resulting from the customer-led operation of BES systems can significantly affect the integrity of distribution networks, heavily reducing their ability to host PV and BES systems. While this particular network is able to host 60% PV penetration without BES systems and 70% with OTS BES control, it is able to only host 30% penetration under the assessed customer-led control.

6.5 Chapter Summary

The growing adoption of residential BES systems creates the opportunity for these devices to be used in the provision of services. To date, such services have been limited to large-scale suppliers. As the power system is undergoing massive transformation in certain parts of the world, services from DER will be needed to support the bulk power system [24]. In this context, individual customers can or will soon be able to directly participate in the provision of services, and thus, maximize their investment return. This, however, requires the development of new strategies to adequately control the BES system.

In this context, this chapter proposed and evaluated a time-composite rolling horizon optimization-based control, also considering battery degradation, implemented and controlled at the household level for the provision of energy services. The results, based on real Australian demand, generation and pricing data demonstrate that individual customers can significantly improve the benefits they receive from their BES system when transitioning from the traditional "off-the-shelf" control to the proposed customer-led operation. In particular, it has been demonstrated that the time-composite rolling horizon optimization outperforms the conventional optimization techniques found in the literature due to its ability to adapt to very granular variations in demand and generation. Furthermore, it was shown that ignoring degradation can result in misleading benefits to customers as the actual cost (because of degradation) could be significant. Nonetheless, by incorporating degradation in the BES control, it is possible to find the operation that, while slightly reduces the ability of the BES system to provide services, results in a much more beneficial outcome for customers.

It was also demonstrated that the unrestricted customer-led operation of BES systems combined with price spikes during periods of high PV generation (common in Australia) can exacerbate reverse power flows resulting in much higher voltages and asset utilization than off-the-shelf operation; severely hindering the hosting capacity of distribution networks. While the analyses were performed using the proposed customer-led control, similar effects can possibly exist from any other unrestricted control for the provision of services. Considering the significant technical impacts that the unrestricted household exports can have on the distribution network, there is a clear need for adequate technical solutions that restrict (passively or actively) the corresponding injections. As mentioned in the introduction, there is strong advocacy around the world for DNSPs to transition to a more active role (i.e., DSOs) for them to facilitate the bottom-up provision of services while complying with distribution network constraints.

7 DSO Framework to Facilitate Provision of Bottom-up Services From DER

7.1 Introduction

As was demonstrated in the previous chapter, the unrestricted provision of bottom-up services originating from customers with DER (henceforth referred to as "prosumers") can significantly impact both MV and LV networks. In this Chapter, an MV-LV DSO framework that uses three-phase OPF is proposed, which aims to facilitate the provision of bottom-up services while considering distribution network constraints. The role of the DSO lies in limiting the maximum power that a prosumer can import/export into the network at each instance they participate in the provision of services. Given the radial nature of distribution networks, fairness aspects are incorporated in the OPF so that prosumers in weaker parts of the distribution network are not over-penalised.

Section 7.2, which presents the DSO framework, first presents an overview of the hierarchy and required data flows between the different parties (i.e., TSO, DSO, prosumers). Furthermore, the OPF-based methodology is presented which is used to define the maximum prosumer power limits if constraint violations (voltage and thermal) from their intended operation (checked using a power flow analysis) are found. A demonstration of the proposed DSO framework using a three-bus LV feeder with two prosumers is presented in Section 7.3. A case study demonstrating the ability of the proposed DSO framework to facilitate the provision of services while maintaining network integrity is presented in Section 7.4. Finally, a summary of the Chapter is provided in Section 7.5.

7.2 DSO Framework

In this section, the proposed DSO framework is presented. First, an overview of the framework is provided, which identifies all the necessary processes as well as information exchange between the different parties (i.e., TSO, DSO, prosumers). Furthermore, the OPF methodology, which considers locational fairness between prosumers and DER limits, used to determine maximum prosumer limits (imports or exports) if constraint violations are found is presented. Finally, the corresponding adaptations for the prosumer-level control that are needed so that they can be incorporated in the DSO framework are presented.

7.2.1 Framework Overview

Figure 7-1 provides an overview of the proposed DSO framework. The entity that is requesting a service, such as the TSO, broadcasts (periodically, e.g., every 5 min, or when needed) a signal (e.g., price, request for bids) to prosumers providing services. This service signal is sent at time t expecting a response at or after time $t + \Delta$ so as to cater for the corresponding decision-making processes and delays in communication. Once the service signal has been received by the prosumers, each one decides how they want to respond based on a local decision-making engine (e.g., rule-based, optimization, etc.) based on their own individual objectives. Once each prosumer has decided their intended response (net P and Q exports/imports), this is then passed to the DSO to check network integrity.

The DSO performs a three-phase power flow analysis using: a) accurate MV-LV network models, b) the intended prosumer operation, and c) P and Q values from smart meters of customers that do not participate in the provision of services. If the resulting voltages of customers or the power flows are found to be within network constraints (i.e., statutory voltage limits, asset rated capacity), all intended operations are accepted by the DSO. If not, i.e., network violations occur, a three-phase AC OPF program (which also considers phase coupling to cater for the unbalanced nature of distribution networks) is run using the same data to determine the maximum operational limits of individual prosumers that ensure network integrity as well as locational fairness of prosumers. In this case, each prosumer will have their intended operation accepted or limited by the DSO; if only some prosumers are contributing to a network issue (e.g., overloaded LV transformer), only those prosumers that are contributing to it are limited. These decisions are then passed to each prosumer who decide how to adapt to these limits and, finally, provide the corresponding response to the TSO at time $t + \Delta$ or later.

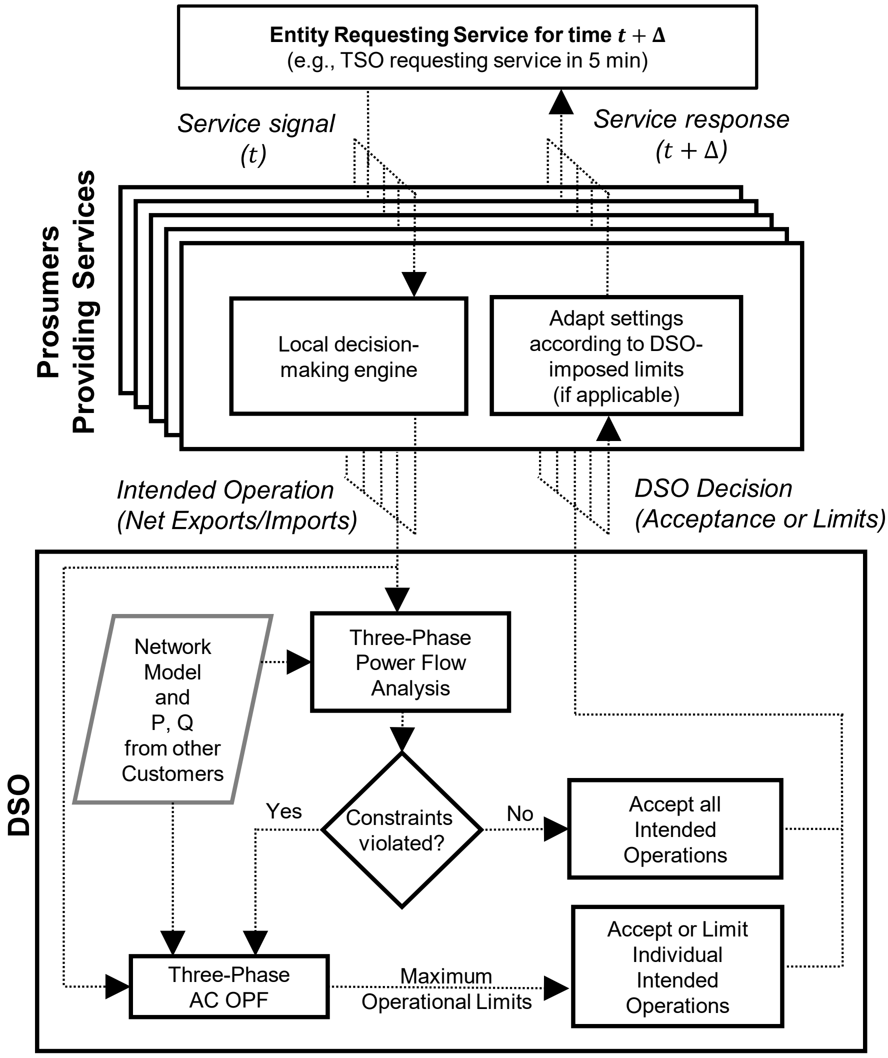


Figure 7-1. Operational Framework Overview Diagram

7.2.2 Three-phase AC OPF Methodology

The three-phase AC OPF used in this work has been adapted from [98] to produce a convex OPF formulation by approximating the non-convex equations and, therefore, improve scalability and speed; key to handle large networks with thousands of decision variables in timeframes aligned with. Furthermore, to ensure a certain level of fairness among the prosumers providing services, the objective function ensures that the square of the distances between the intended operations and the DSO-defined maximum operational limits are minimised.

7.2.2.1 Objective Function and Prosumer Constraints

Let H be the total set of customers and $B \subset H$ the subset for prosumers providing services, indexed by b and h, respectively. The objective function shown in Equation 7.1, minimises the sum of the squared distances between the intended operation of prosumers ($b \in B$), $\tilde{P}_{nd}^{b}$, and the DSO-defined maximum operational limit, P_{nd}^{b}. A linear minimization can achieve similar aggregated results but can have solutions where restrictive limits are imposed on only a few customers; an unfair outcome. The adoption of squared distances ensures that the burden is spread among prosumers but each with limits as close as possible to the intended operation. This, in turn, will result in a fairer distribution of operational limits compared to a linear minimization.

$$\min \sum_{b \in B} \left(\tilde{P}_{b}^{nd} - P_{b}^{nd}\right)^{2} \tag{7.1}$$

As the OPF defines maximum operational limits for the prosumers ($b \in B$), but does not control their assets directly certain principles need to be considered: 1) If the prosumer wishes to export power, the export power can be reduced to zero but the prosumer cannot be forced to import power. Similarly, 2) if the prosumer wishes to import power, it cannot be forced to export power. Furthermore, the reduction in imports or exports needs also to be technically feasible from the perspective of the prosumer; i.e., non-service related requirements (local demand/generation) must be taken into account, as well as technology limitations. To implement this, each prosumer provides, based on its own decision-making engine, a deviation parameter, ΔP_{E}^{b}, for exports (or ΔP_{I}^{b} for imports) which informs the DSO how much the proposed operation can be limited, if needed. This is formulated using Equation 7.2.

$$\begin{cases} 0 \leq \Delta P_{b}^{I} \leq P_{b}^{nd} \leq \tilde{P}_{b}^{nd} & if\ \tilde{P}_{b}^{nd} \geq 0\ (net\ imp.) \\ \tilde{P}_{b}^{nd} \leq P_{b}^{nd} \leq \Delta P_{b}^{E} \leq 0 & if\ \tilde{P}_{b}^{nd} < 0\ (net\ exp.) \end{cases}, \quad \forall b \in B \tag{7.2}$$

The definition of the deviation parameters is provided later in Section 7.2.2.3. Furthermore, a positive $\tilde{P}_{b}^{nd}$ value indicates that the prosumer intends to import power, whereas a negative value indicates that the prosumer intends to export power.

To demonstrate the ability of the proposed quadratic objective function to incorporate fairness amongst the prosumers, a linear objective function is also used for comparison. As the intended prosumer operation, $\tilde{P}_{b}^{nd}$, can be both positive and negative, if the distance is to be minimised linearly, an absolute function needs to be used, as seen in Equation 7.3.

$$\min \sum_{b \in B} \left| \tilde{P}_b^{nd} - P_b^{nd} \right| \qquad 7.3$$

However, this condition would result in a non-linear program in the optimisation problem. As such, this objective function is reformulated using an auxiliary variable z as shown below in Equations 7.4 – 7.6.

$$\min \sum_{b \in B} z_b \qquad 7.4$$

s.t.

$$z_b \geq \tilde{P}_b^{nd} - P_b^{nd}, \qquad \forall b \in B \qquad 7.5$$

$$z_b \geq P_b^{nd} - \tilde{P}_b^{nd}, \qquad \forall b \in B \qquad 7.6$$

This set of linear equations allows to implement the absolute function in 7.3 in a convex optimisation problem. It should be noted that the results obtained with this objective function would in fact produce similar results (in terms of fairness) with any linear objective function (e.g., minimisation of cost).

It should be made clear that the responsibilities of the DSO lie in limiting the operation of the prosumers (i.e., ensuring network integrity). Therefore, the purpose of the OPF *is not* to find the maximum volume of active power that can be provided at the head of the feeder, but rather to find the maximum at each individual prosumer (i.e., those that are providing the services). An objective function that maximises the active power exports at the head of the feeder (i.e., also considering network losses) is not considered in this thesis as this is in line with works that assume that the DSO is the entity that provides services to the TSO.

7.2.2.2 Three-phase AC OPF Constraints

As stated in the Preface, the three-phase AC OPF constraints in this subsection were provided by Dr Luis Gutierrez as part of a research collaboration. For completeness, a summary of these constraints is included in this thesis. Nonetheless, the author of the thesis does not claim any ownership of this material.

To realistically represent the main network elements, the current injection-based three-phase AC OPF formulation proposed in [98] is adapted. This enables the modelling of phase couplings in three-phase lines and delta-wye connections in distribution transformers.

The formulation uses the real and imaginary parts of voltages and currents per phase as state variables, where $V_{n,\varphi}^{re}$ and $V_{n,\varphi}^{im}$ represent the real and imaginary part of the voltage at node $n \in N$ (set of nodes) and phase $\varphi \in \Phi = \{1,2,3\}$ (set of phases), respectively. Similar indexes are used for the current components (i.e., I_e^{re} and I_e^{im}), where $e \in (H \cup L \cup Y)$ maps a network element with L, Y being the set of lines and transformers, respectively.

In the next paragraphs, a convex OPF formulation is derived by approximating the non-convex equations in [98]. These correspond to customer imports/exports equations and, limits for voltages and line/transformer currents. Here, tap positions are not controlled by the OPF (input parameters). Thus, voltage and current relations for delta-wye transformers ((14) and (15) in [98]) are considered linear.

7.2.2.2.1 Customer currents:

The real and imaginary parts of the current imported/exported by a single-phase customer $h \in H$, connected at node n and phase φ, are represented in per unit in Equations 7.7 and 7.8.

$$I_h^{re} = \frac{\tilde{P}_h^{nd} V_{n,\varphi}^{re} + \tilde{Q}_h^{nd} V_{n,\varphi}^{im}}{{V_{n,\varphi}^{re}}^2 + {V_{n,\varphi}^{im}}^2}, \qquad \forall h \in H \tag{7.7}$$

$$I_h^{im} = \frac{\tilde{P}_h^{nd} V_{n,\varphi}^{im} - \tilde{Q}_h^{nd} V_{n,\varphi}^{re}}{{V_{n,\varphi}^{re}}^2 + {V_{n,\varphi}^{im}}^2}, \qquad \forall h \in H \tag{7.8}$$

For simplicity, customer powers are considered to not vary with voltages (i.e., modelled as constant power loads/generators). For non-participant customers ($u \in H - B$), connected at node n and phase φ, these equations are linearized with a first order Taylor expansion around a predefined voltage point $\left({V_{n,\varphi}^{re}}^*, {V_{n,\varphi}^{im}}^*\right)$ as shown in Equation 7.9. Further details on the linearization of the non-linear equations can be found in [99].

$$I_u^{(re,im)} \approx I_u^{(re,im)}\Big|^* + \frac{\partial I_u^{(re,im)}}{\partial V_{n,\varphi}^{re}}\Big|^* \left(V_{n,\varphi}^{re} - {V_{n,\varphi}^{re}}^*\right) + \frac{\partial I_u^{(re,im)}}{\partial V_{n,\varphi}^{im}}\Big|^* \left(V_{n,\varphi}^{im} - {V_{n,\varphi}^{im}}^*\right) \quad ,\forall u \in U \tag{7.9}$$

For service participants ($b \in B$), Equations 7.7 and 7.8 are approximated using Equations 7.10 and 7.11, respectively (where P_b^{nd} can be limited by the DSO) and $\tilde{Q}_{nd}^{b}$ corresponds to the reactive power intended by the prosumer.

$$P_b^{nd} \approx V_{n,\varphi}^{re^*} I_b^{re} + V_{n,\varphi}^{im^*} I_b^{im}, \forall b \in B \qquad 7.10$$

$$\tilde{Q}_b^{nd} \approx -V_{n,\varphi}^{re^*} I_b^{im} + V_{n,\varphi}^{im^*} I_b^{re}, \forall b \in B \qquad 7.11$$

The accuracy of these linear approximations will depend on the chosen operating point, which can be estimated using recent operating data. To further improve accuracy (if needed), a second OPF could be run where the voltage results of the first serve as estimated operating points for the second [100].

7.2.2.2.2 Network Limits:

The magnitude of phase currents in each line l and transformer y are constrained by their capacity $\overline{I_e}$, with $e \in L \cup Y$. These constraints can be expressed in a quadratic and convex way by relating their square magnitudes as shown in Equation 7.12.

$$I_{e,\beta_e,\varphi}^{re^2} + I_{e,\beta_e,\varphi}^{im^2} \leq \overline{I_e}^2 \quad , \forall e \in L \cup Y, \forall \beta_e \in \{\beta_e^1, \beta_e^2\}, \forall \varphi \in \Phi \qquad 7.12$$

where $\beta_e^1, \beta_e^2 \in N$ are the starting and ending nodes of e.

The constraint for the maximum voltage limit at node n and phase φ, $\overline{V_n}$, is represented in a similar way in Equation 7.13.

$$V_{n,\varphi}^{re^2} + V_{n,\varphi}^{im^2} \leq \overline{V_n}^2 \quad , \forall n \in N, \forall \varphi \in \Phi \qquad 7.13$$

However, the corresponding constraint for the minimum voltage, $\underline{V_n}$, shown in Equation 7.14 is non-convex, and further linearization is needed.

$$\underline{V_n} \leq V_{n,\varphi}^{re^2} + V_{n,\varphi}^{im^2} \quad , \forall n \in N, \forall \varphi \in \Phi \qquad 7.14$$

Therefore, the voltage magnitude squared $\left(V_{n,\varphi}^{re\,2} + V_{n,\varphi}^{im\,2}\right)$ is linearized with a first order Taylor expansion around $\left(V_{n,\varphi}^{re\,*}, V_{n,\varphi}^{im\,*}\right)$, resulting in the linear constraint shown in Equation 7.15.

$$V_{n,\varphi}^{re^{*2}} + V_{n,\varphi}^{im^{*2}} + 2V_{n,\varphi}^{re^*}\left(V_{n,\varphi}^{re} - V_{n,\varphi}^{re^*}\right) + 2V_{n,\varphi}^{im^*}\left(V_{n,\varphi}^{im} - V_{n,\varphi}^{im^*}\right) \geq \underline{V_n}^2 \quad , \forall n \in N, \forall \varphi \in \Phi \qquad 7.15$$

As with all previous linearization, the accuracy of Equation 7.15 depends on the accuracy of the estimated voltage. Ideally, $V_{n,\varphi}^{re^*}$ and $V_{n,\varphi}^{im^*}$ should be equal to $V_{n,\varphi}^{re}$ and $V_{n,\varphi}^{im}$, respectively. As previously mentioned, to improve the accuracy of this linearization, a second OPF run could be performed where the $V_{n,\varphi}^{re^*}$ and $V_{n,\varphi}^{im^*}$ in the second run are initialised with the $V_{n,\varphi}^{re}$ and $V_{n,\varphi}^{im}$ from the first run. More OPF runs could be performed to further increase the accuracy, but as demonstrated in [100] two OPF runs achieve a good trade-off between accuracy and computational efficiency. Furthermore, it should be noted that since the provision of services from prosumers in distribution networks is more likely to consider increasing generation rather than demand, it is more likely that the constraint in Equation 7.13 will be the one most enforced, which is not linearized.

This new set of equations with the quadratic objective function in 7.1 constitutes a convex quadratically-constrained quadratic program (QCQP) (all constraints and objective function are convex) and, therefore, can be solved with efficient commercially-available algorithms such as CPLEX [93].

7.2.2.3 Prosumer-level Adaptations

While the DSO framework does not interfere with the local-decision making engine of the prosumers, the DSO does require the prosumers to provide their deviation bounds (as seen in Equation 7.2). These bounds are calculated at the prosumer level depending on the technologies that are installed and can have their set-points altered (e.g., BES systems, PV systems, electric vehicles, controllable load, etc.). However, in this thesis, only the BES systems are considered as controllable in the DSO framework. Equations 7.16 and 7.17 show how these bounds (export or import) are defined, respectively, based on the power rating of the BES system, the SOC, efficiencies, and intended BES operation.

$$\Delta P_E = \min\left[0, P_i^{nd} + \min\left(\bar{P}^s, \frac{\bar{E}^s - E^{si}}{\eta^+ \Delta t}\right) - P_i^s\right] \tag{7.16}$$

$$\Delta P_I = \max\left[0, P_i^{nd} - \min\left(\bar{P}^s, \frac{E^{si}\eta^-}{\Delta t}\right) - P_i^s\right] \tag{7.17}$$

where the nomenclature is as defined in Section 6.2.3.1.

7.3 Single-phase Three-bus Feeder Demonstration

A single-phase, three-bus LV feeder analysis considering two prosumers providing services is performed. The local decision-making engine of the prosumers is assumed to be operating based on the customer-led operation of BES systems that was demonstrated in Chapter 6 (referred to as TCRH control in the chapter). The topology and line parameters are shown in Figure 7-2. This feeder has been designed to be primarily voltage constrained (high impedance), and therefore the line capacities are neglected.

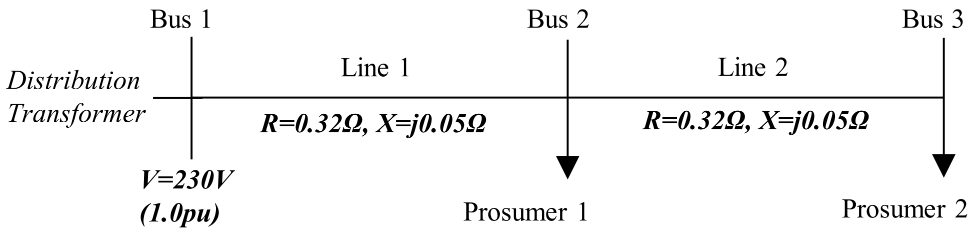


Figure 7-2. Three-bus LV feeder diagram

For simplicity, the same demand and generation profiles, as well as the same PV and BES system sizes are used for each prosumer (5kWp and 5kW/13.5kWh PV and BES systems, respectively). The 30-minute resolution, 24-hour net demand (demand minus generation), as well as import (λ^{-}) and export (λ^{+}) energy price profiles are shown in Figure 7-3. The import price profile corresponds to a time-of-use profile listed by an Australian energy supplier [101], and the export energy profile corresponds to the wholesale energy market price from Victoria, Australia on 11th January 2016. This day has been selected as it exhibits a service price spike which exceeds the time-of-use tariff (energy import price). This is expected to cause prosumers to both want to charge their BES system early during the day from the grid (and potentially causing voltage drop problems) so that they can discharge during the price spike. Furthermore, as the price spike is during a period of high PV irradiance, the simultaneous exports from both the PV and BES systems are expected to exacerbate reverse power flows.

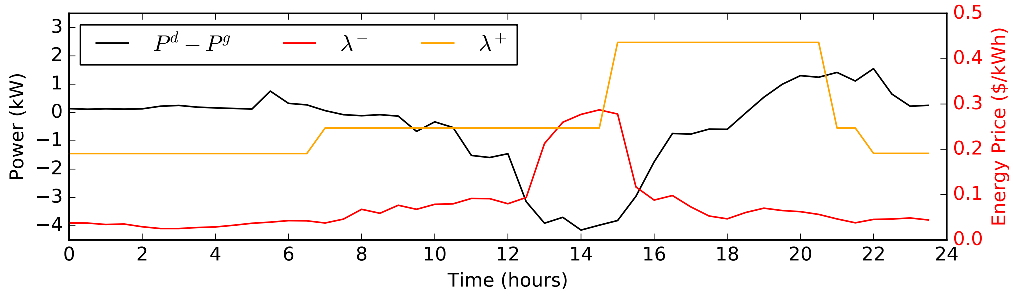
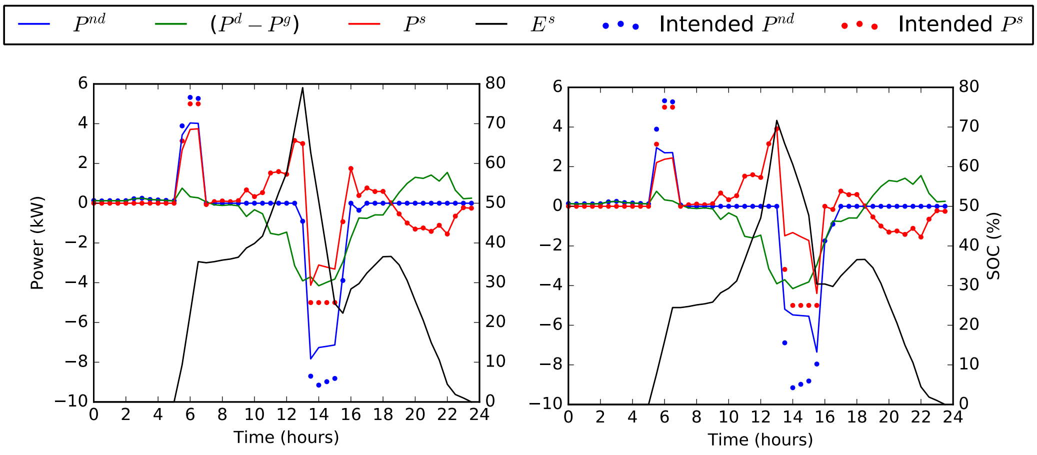


Figure 7-3. Demand, generation, and pricing (imports and exports) data

The time-series operation of the two prosumers is shown in Figure 7-4. From midnight to 5:30am, both BES systems remain idle. The power flow that the DSO performs at each of these timesteps identifies that the voltages at buses 2 and 3 will be within the limits if the BES systems operate at this level (identified as dots in Figure 7-5). Therefore, there is no need to limit the operation of the prosumers. While the low energy import price exists from 12 to 7am, the discount factor in the optimisation (ϕ_t in Equation 6.1) deems optimal that the charging is delayed until 5:30am, as the objective function (i.e., maximise benefits, which means that imports are delayed as much as possible) is prioritised for the earlier times. At that time (5:30am) the two prosumers intend to import 3.9kW, power used to charge the BES system. The power flow performed by the DSO at this instance indicates that such operation would cause the voltage at bus 3 to be 0.92pu, which violates the voltage limit. Therefore, the DSO at this instance runs the OPF to determine the maximum operational limits that satisfy the voltage limits. This results in the imports being limited to up to 3.4 and 3kW for Prosumer 1 and 2, respectively, which ensures that the voltage at bus 3 will be above or equal to 0.94pu. A similar process is repeated for the next two timesteps (6:00 and 6:30am).

Between 7am and 13pm, the BES systems are used solely to charge from the surplus PV generation. This reduces the prosumer exports to zero, which in turn creates a relatively flat 1.0pu voltage profile for buses 2 and 3, and thus, no violations. At 13:30pm, however, due to the existence of an energy price spike, the prosumers intend to export 8.7 and 6.9kW, respectively, values much higher than the rated capacity of the PV system. The power flow performed by the DSO at this instance identifies that such operation would result in the voltage of bus 3 to exceed the 1.10pu limit and, therefore, the OPF is run to calculate the export limits so that the voltages will be kept within the allowed range. The same effect is seen at all half



(a) (b)

Figure 7-4. Intended and actual operation for Prosumer 1 (a) and 2 (b)

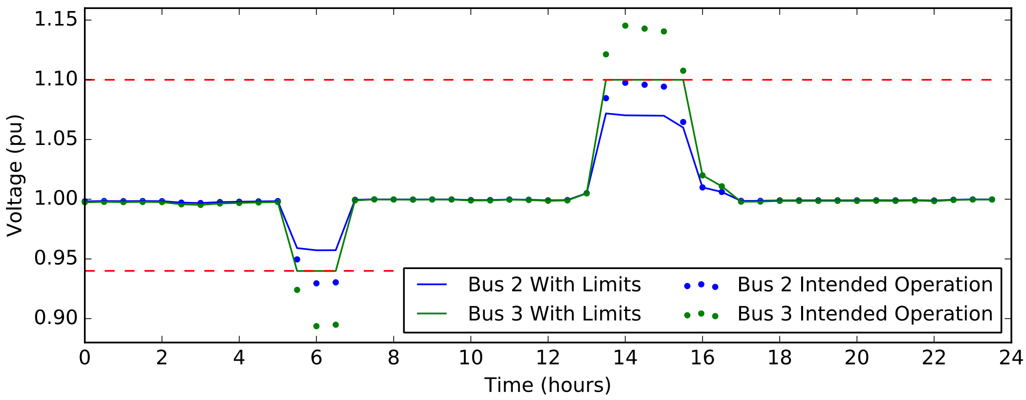


Figure 7-5. Voltages for intended and actual operation

hour intervals between 13:30 and 16:00pm.

Using this single-phase three-bus feeder demonstration, we can see the effect that distribution network constraints have on the provision of services to the TSO. Between 1:30 and 3:00pm, where the price signal is at its highest (most profitable for prosumers to participate in the provision of services), if network constraints were to be neglected, both prosumers would export 17.8kWh into the network (from the PV and BES system). However, due to the limits that the DSO imposed, the two prosumers export 14.7 and 10.9kWh, respectively.

To demonstrate the importance of considering fairness amongst prosumers in the OPF, Figure 7-6 shows the operation of the two prosumers when the objective function in Equation 7.1 is minimised linearly instead of quadratically. What can be observed is that Prosumer 1, as they are located closer to the distribution transformer and, therefore, contribute less to the voltage problem, is not limited at all (intended operation, dots, matches actual operation, line) by the DSO. Prosumer 2, however, is more restricted in charging the BES system between 5:30 and 7am than previously demonstrated. Furthermore, between 1:30 and 3pm where the service price is at the highest, Prosumer 2 is able to participate much less than Prosumer 1. In fact, during this period, Prosumer 1 supplies 17.8kWh to the network (same as unconstrained operation), whereas Prosumer 2 supplies just 9.2kWh. It should be noted, however, that the linear objective function performs better from a system perspective; with the quadratic objective function the two prosumers supplied a total of 25.6kWh between 1:30 and 3pm, whereas with the linear objective function a total of 27.1kWh was supplied during this period. However, this solution comes at the cost of individual prosumers at weaker parts of the network being overly penalised.

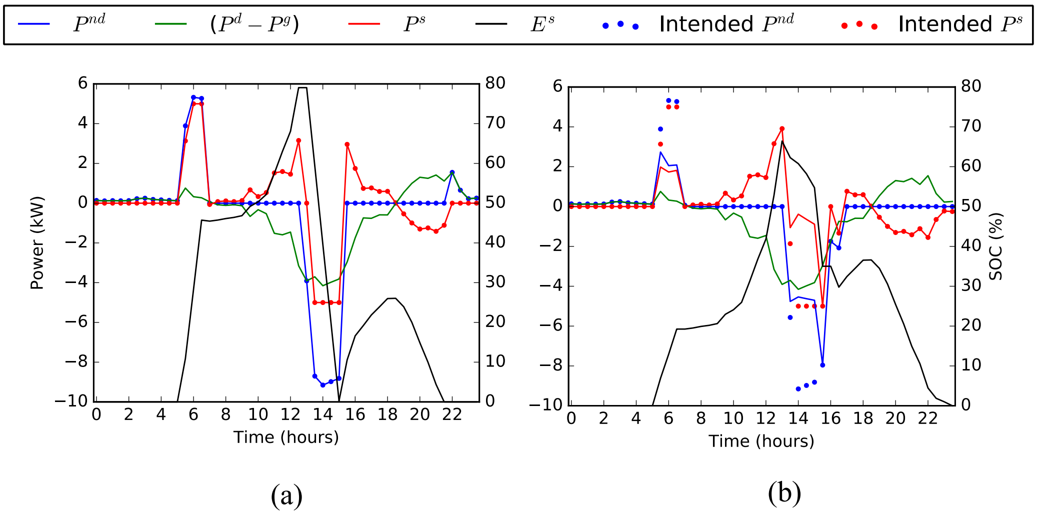


Figure 7-6. Intended and actual operation for Prosumer 1 (a) and 2 (b) with linear minimization of objective function

It should also be noted that if export limits aligned with the ones currently enforced in certain parts of Australia (5kW for single-phase prosumers) were adopted, both these prosumers would be limited to export only 7.5kWh between 1:30 and 3pm; values much lower than the ones obtained with the proposed DSO framework in effect.

7.4 Case Study

The case study performed in this section aims to fully evaluate the ability of the proposed DSO framework to facilitate the provision of bottom-up services while maintaining network integrity. First, the performance of the DSO framework in terms of satisfying network constraints is assessed. Then, the effect of network constraints on the ability of prosumers to provide services is quantified. Finally, given the need of the proposed DSO framework to be implemented in the real-time procurement of services, the computational efficiencies of the power flow analysis and OPF program are assessed.

7.4.1 Network Performance

In this section, the ability of the DSO framework to facilitate the provision of bottom-up services while satisfying distribution network constraints is evaluated. The network analysis considers that 40% of the customers in the network are prosumers who participate in services (with a PV and BES system), whereas the remaining customers do not have any DER installed. The assessed network is the full integrated MV-LV network that was used for the network analyses in Chapters 3 to 6. As with the previous network analyses, the off-load tap changes at the distribution transformers are set to the lowest position and the Volt-Watt function of the PV inverters is disabled.

The assessment considers a deterministic 30-minute resolution 24-hours wholesale energy price signal for the provision of energy services (i.e., generation), obtained from the AEMO website [96] and which corresponds to the market prices from the 11th of January 2016 (same day as in Section 7.3) in Victoria, Australia. The 30-minute resolution price and PV generation profiles are shown in Figure 7-7. This day has been selected for this case study as it exhibits high solar irradiance and a spike in wholesale energy price at the same time. Consequently, this combination is likely to lead in moments where all the BES systems intent to discharge at a similar time that the PV systems are also generating. As highlighted earlier, in an unrestricted and uncoordinated environment, this behaviour is expected to lead or exacerbate existing technical issues in distribution networks, hence, making it a challenging scenario that allows demonstrating and assessing the performance of the proposed DSO framework. The import energy prices are as were defined in Table 6-4.

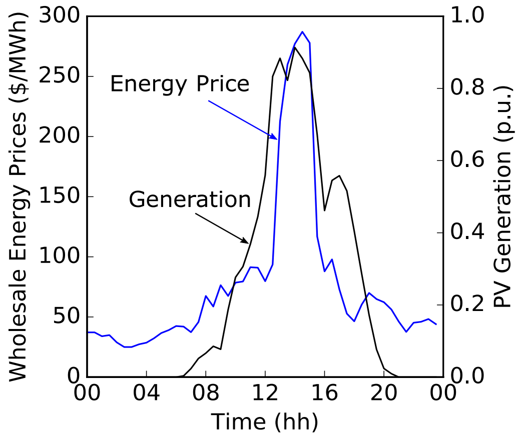
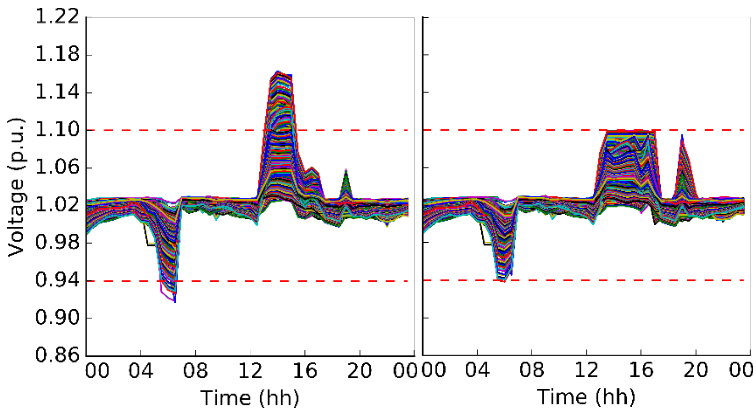


Figure 7-7. Wholesale energy price and normalised PV generation profiles

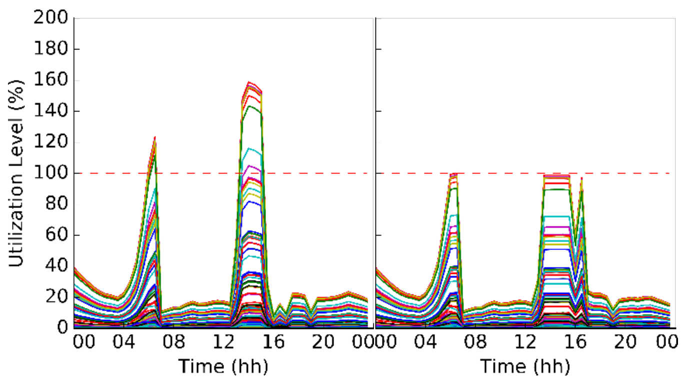
Figure 7-8 shows the daily 30-minute voltage profiles of all 4,626 LV customers for the two investigated cases: (a) without the DSO framework (i.e., unrestricted) and (b) utilizing the proposed DSO framework. As shown in Figure 7-8(a), the unrestricted operation of BES systems leads to voltages that violate both the lower and upper statutory limits. For example, during the morning hours, the low energy import price (before 7am, as discussed in previous the previous section), is leading to moments where most prosumers are simultaneously charging their BES systems from the network at 5:30am; hence leading to voltages dropping below the lower statutory limit. Similarly, at 1:30pm, due to the high exported energy prices, most BES systems start discharging to increase the corresponding prosumer profits. However, given the coincident PV generation, this behaviour increases the corresponding prosumer exports that in turn lead to significant voltage rise issues (i.e., 1.16p.u.). Table 7-1 summarizes the network performance, and as shown, 13% of the total number of customers in the network were found to be non-compliant with the voltage standard.

The effect of the reverse power flows caused by the combined exports from the PV and BES systems also has an impact on the utilization of the network assets (i.e., transformers lines). Figure 7-9(a), which present the utilization level of all the MV feeder lines (i.e., conductors), shows that for those moments where voltage issues exist, assets also experience significant congestion issues. Referring to Table 7-1, the high prosumer exports originating from the provision of services result in the utilization of the MV lines to exceed the rated capacity of the assets at 159 and 129%, respectively. A similar effect is also observed with the LV transformers, where maximum utilisation of the most congested one is at 129%.



(a) (b)

Figure 7-8. Customer voltages without (a) and with the DSO framework (b)



(a) (b)

Figure 7-9. MV line utilisation without (a) and with the DSO framework (b)

Table 7-1. Summary of technical issues in the MV-LV network

	Without DSO	***With DSO***
Customers with Voltage Issues (%)	13%	0%
Max Utilization of MV Lines (%)	159%	100%
Max Utilization of LV Transformers (%)	129%	89%
Max Utilization of LV Lines (%)	92%	61%

Nonetheless, the adoption of the proposed DSO framework, proves to be of critical importance as it helps maintain the integrity of the network (i.e., satisfy technical constraints), while still allowing the different participants (in this case prosumers with PV and BES systems) take part in the provision of services. As Figure 7-8 (b) shows, prosumer daily voltage profiles remain always within the statutory limits and all prosumers are compliant with the voltage standard. Similarly, Figure 7-9(b) and Table 7-1 show that none of the assets are loaded beyond their rated capacities and the maximum utilization levels of the MV lines and transformers dropped down to 100% and 89%, respectively. It is interesting to highlight that the limits defined by the DSO lead to slightly different voltage and asset utilization profiles than the unconstrained case. For example, considering the case where there is a high exported energy price at 1:30pm, although voltages are flattened down to 1.1p.u., they remain up to this level for a longer period compared to the unrestricted case. This is due to the BES systems discharging at lower power rates (effect of the DSO limits restricting them from discharging at higher rates) but for longer periods, in an effort to make the most of the high energy export prices.

To further understand the effect that network constraints have in the provision of bottom-up services, Figure 7-10 shows the total active power from all prosumers (that participate in the provision of services) in the network. As it can be seen, between 5:30 and 7am, the total power of the prosumers with the existence of a DSO framework is slightly reduced (from 9.3MW to 7.5MW at 7am). This effect is more prominent during the peak pricing period (1:30 to 3pm). During this time, the total power delivered by the prosumers is significantly less when the DSO framework is used, as distribution network constraints are considered. More specifically, at 2pm where the highest export price exists, the total power delivered by prosumers is reduced from 16.2 to 10.5MW. As previously mentioned, however, due to distribution network constraints not allowing the full exports from prosumers, this allows for power (from BES systems) to be delivered for a longer period. Without the existence of a DSO framework, at 3pm the power delivered by the prosumers is reduced significantly. However, with the DSO framework, high levels of power keeps being delivered until 5pm.

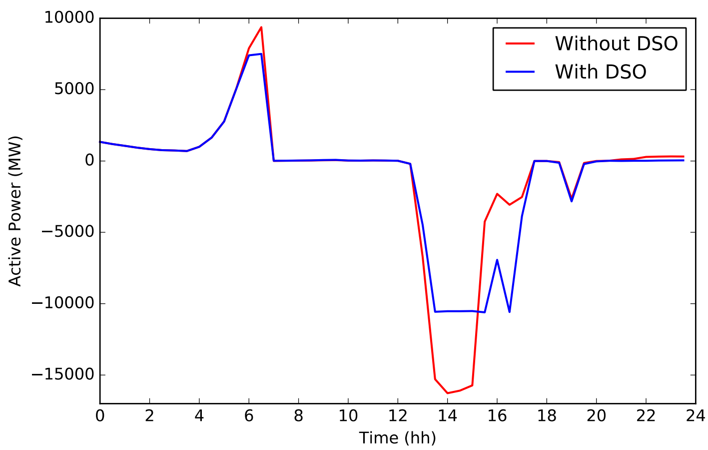


Figure 7-10. Total active power of all prosumers in the network

These results demonstrate the ability of the proposed DSO framework to integrate distribution network constraints in the provision of bottom-up services from prosumers to the DSO. As demonstrated, however, these constraints have an effect on the level of services that can be provided.

7.4.2 Prosumer Performance

This section aims to further quantify the effect that distribution network constraints have to the performance of prosumers providing services. To do this, first, the limits imposed on each prosumer during the peak price period (i.e., 2pm) by the DSO are presented. Due to the large number of prosumers in this network providing services (1,850 out of 4,626), to simplify the presentation of the results, the limits are normalised based on their intended operation at that time (i.e., power limit in kW divided by the intended operation in kW). Furthermore, the limits are sorted from smaller to higher value, and plotted in Figure 7-11. Finally, to demonstrate how the proposed objective function (i.e., quadratic minimisation between intended operation and limit) deals with fairness amongst prosumers, the DSO-imposed limits determined by a linear minimisation objective function are also plotted. It should be noted that a 100% value indicates that the prosumer is allowed to export 100% of their intended operation, whereas a 0% means that they are not allowed to export at all.

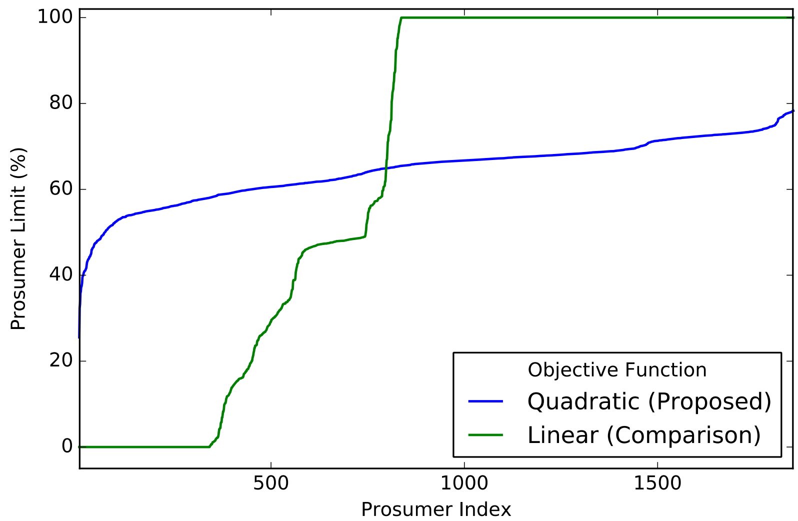


Figure 7-11. Normalised DSO-imposed limit at 2pm for the two assessed objective functions

As it can be seen, with the proposed objective function, the majority of the prosumers are able to export between 50 and 70% of what they intend to export. While a very small number of customers (less than 5, i.e., ~0.25% of all prosumers) are very heavily penalised (allowed to export less than 40% of what they would normally export), this is likely due to the existence of a few LV transformers with very small capacity (less than 10kW).

When a linear objective function is used, however, it can be seen that there is a high degree of unfairness between the prosumers. A majority of the prosumers (~1,000, i.e., ~55% of all prosumers) are able to export their full intended power to provide services. This comes at the cost of many prosumers (~340, i.e., ~20% of all prosumers) not being able to provide any services at that time, as they are connected in weaker parts of the network.

To better understand the effect that the network constraints have on the profitability of prosumers, the network analysis is expanded for a whole month (January 2016) and the NBI metric defined in Section 3.5.2 is used, shown in Figure 7-12. The NBI metric is the difference in the level of benefits that the prosumer will experience due to the existence of distribution network constraints. For comparison purposes, the NBI for the linear objective function is also plotted. Furthermore, to demonstrate the ability of the proposed DSO framework to facilitate the provision of bottom-up services, the adoption of a 5kW export limit is also plotted for comparison.

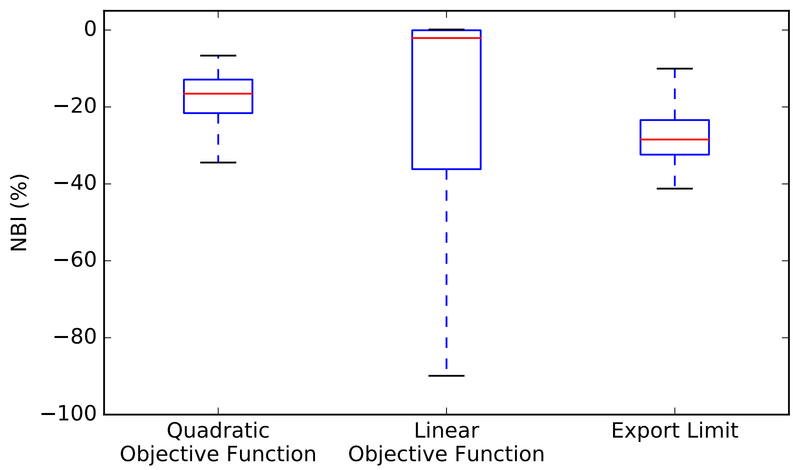


Figure 7-12. Statistical representation of the prosumer NBI

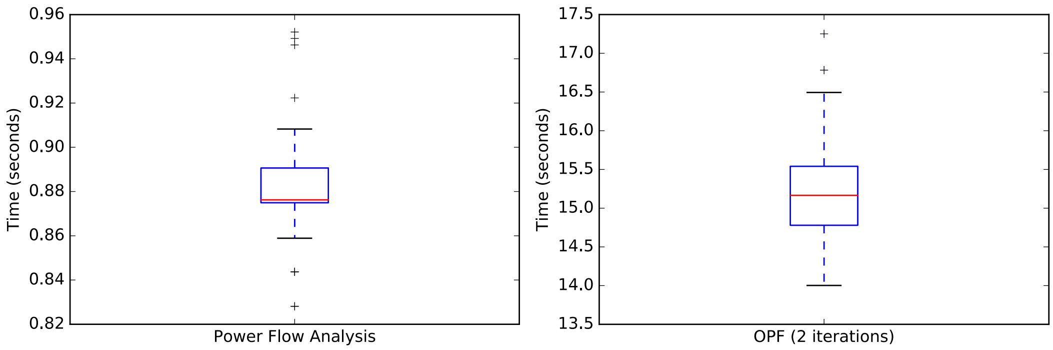
With the proposed DSO framework and objective function, prosumers experience a median of 15% less benefits from providing services when compared to the unconstrained operation. While a certain degree of unfairness does also exist even with the proposed framework, the majority of the prosumers' NBI lies within the -13 and -21% range.

By using a linear objective function in the DSO framework, the median customer experiences only 2% reduction in the level of benefits from providing services with the existence of the proposed DSO framework. However, as also previously demonstrated, this comes at the cost of a large number of prosumers being over-penalised, with some of them experiencing as much as ~90% reduction in their benefits. These results show that while a linear objective function could be beneficial for the majority of the prosumers in the network, it can also be overly prohibitive for the rest. As such, fairness is an important aspect to consider in the design of frameworks to manage the bottom-up provision of services.

To compare the proposed DSO framework with a "fit-and-forget" approach, the NBI of prosumers is plotted when a 5kW export limit is adopted (currently enforced in Victoria, Australia for single-phase connections [17, 18]). In this case, the median benefits from providing services are reduced by 30% when compared to an unconstrained case (no consideration of distribution network constraints). These results highlight that while the adoption of traditional fit-and-forget approaches (i.e., export limits) could prove to be a relatively quick and easy to adopt solution, they can be over-constraining in the provision of services.

7.4.3 Computational Efficiency

As the proposed DSO framework is to be used to manage the prosumers providing services to the TSO in real-time, computational efficiency is highly important. Based on Section 7.2.1, if the delay, Δ, between the service request and the service response is too high, then the framework would be unsuitable to be used in the real-time management of services. The DSO needs to first perform a power flow analysis to determine whether the intended operation of the prosumers results in distribution network constraints to be violated. If violations are found, then two OPF runs are performed (to increase the accuracy of the linearization, as mentioned in Section 7.2.2.2). For the purpose of evaluating the computational efficiency of the algorithm, the power flow analysis and the OPF program are run for 21 days (48 timesteps for each day, total of 1,008 calculations). The time taken to complete each power flow and OPF calculation (on an Intel i7-8700k 4.5GHz with 16GB of RAM machine) was recorded and it is plotted statistically in Figure 7-13, where each point is the time taken to complete the power flow and OPF calculations at each timestep.



(a) (b)

Figure 7-13. Time taken to perform the (a) power flow analysis and (b) OPF

For this MV-LV network (4,626 customers, where 1,850 are prosumers participating in the provision of services), the power flow analysis is performed for all simulations in under 1 second. As such, in cases where the intended operation of prosumers in the distribution network does not result in violation of constraints, the delay is almost negligible. When the OPF program needs to be used to determine the prosumer limits, the computation time lies within the 14 to 17 seconds range (total time for both iterations). These results demonstrate that the proposed framework and the corresponding OPF formulation used is able to determine limits for a large number of prosumers in the network in very small timeframes; making it suitable to be used in real-time applications.

7.5 Chapter Summary

This work proposed a DSO framework to incorporate distribution network constraints in the procurement of DER services by the TSO. The service providers, modelled as prosumers with PV and BES systems, submit their intended response to the DSO who then performs a power flow analysis to check for constraint violation (thermal and voltage limits). If any violations are found, limits are imposed on the intended operation of the prosumers; calculated using a convex quadratically constrained OPF optimization program.

The performance of the proposed DSO framework was assessed based on a real Australian MV feeder with 79 realistically modelled LV networks. Results demonstrate that, while the unconstrained provision of services in the network results in severe violation of network constraints, the proposed framework was able to satisfy all constraints while still enabling the provision of services. Furthermore, the ability of the proposed framework to include prosumer locational fairness in the provision of services was also assessed and compared against a more commonly used objective function in the OPF program. It was found that while the proposed DSO framework results in the majority of the prosumers being able to participate less in the provision of services, it allowed for a still significant number of prosumers to receive significantly more benefits when compared with the linear objective function. Furthermore, a traditional "fit-and-forget" approach such as firm prosumer export limits was also compared. It was demonstrated that the adoption of the proposed DSO framework was significantly better in terms of value obtained from the provision of services.

As the levels of DER in MV-LV networks will further increase over the next few years, adequate DSO frameworks, such as the one proposed in this work, will be required to facilitate the provision of distribution-level services, while managing such a dynamic environment, coordinating actions among network elements and participants and considering technical constraints. While the latter could be – to some extent – managed with traditional fit-and-forget approaches, these can prove to be overly prohibitive on the level of services that can be provided as demonstrated using the 5kW export limit.

8 CONCLUSIONS AND FUTURE WORK

8.1 Introduction

This chapter first presents an overview of the research carried in this thesis along with the main literature gaps and contributions in Section 8.2. Furthermore, a summary of the conclusions of the thesis is presented in Section 8.3. Finally, the thesis ends with identification of potential improvements as well as future work.

8.2 Research Overview, Main Gaps, and Thesis Contributions

In recent years, electricity distribution networks in certain parts of the world (e.g., Australia) have seen a sharp rise in the levels of DER installed at MV and LV networks; with the most prominent technology being residential-scale solar PV systems. The popularity of PV systems has also been recently driving the adoption of BES systems, as they allow households to store their excess PV energy generated during the day to be used during the night; complimenting the intermittent generation nature of PV systems. However, as it currently stands, most commercially available residential-scale BES systems are controlled for the sole benefit of their owner (i.e., reduce grid imports); as such providing no guarantees that they will be able to reduce peak household exports into the grid, and as such, help mitigate the well-known issues related to reverse power flows in distribution network (e.g., voltage and thermal issues). Given the flexible controllability of BES systems, an opportunity exists to adopt advanced BES management strategies to not only provide benefits to their owners but also help increase the PV hosting capacity of distribution networks.

Furthermore, with the right BES control, these systems could also be used to provide services to the whole power system (e.g., generation, frequency control, etc.); services usually reserved for large-scale generators and utility-scale BES systems. However, as it currently stands, the procurement of these services by the corresponding authority (e.g., the TSO) is relatively scarce, and therefore, does not consider distribution network constraints. With the rising popularity of residential-scale BES systems, the levels of services that can be provided through distribution networks are rising, and therefore, distribution network constraints can no longer be ignored. Understanding the need to consider distribution network constraints in the procurement of DER services, there is strong advocacy in certain countries around the world for DNSPs to have an active role in this process. This new role has been recently associated with the term DSO. However, adequate technical frameworks for DSOs to be able to facilitate the provision of DER services with consideration of distribution network constraints need to be developed in anticipation of this transition.

Despite residential-scale BES systems being a relatively new technology, due to its flexible controllability and enormous potentials, it is receiving increasing attention from researchers worldwide. However, several gaps still exist, and are discussed below.

- Realistic network studies using integrated MV-LV networks. Most studies in the literature consider single voltage-level analyses, focusing either only at the MV (e.g., 22kV) or LV (e.g., 400V) networks. As such the interaction of the different voltage levels (effect of voltage rise/drop in the MV network to the LV circuits) are not captured in the corresponding studies. Consequently, to realistically capture these interactions, integrated MV-LV analyses need to be considered in the network studies.
- Practical, scalable, and customer-friendly BES control to mitigate PV impacts in distribution networks. Most studies in the literature either consider centralised approaches that require advanced communication and computation infrastructure in place, decentralised approaches that require network-specific tuning, or do not consider the impact on the BES system owners. For a BES control to be practical, scalable, and adoptable, first and foremost it needs to first consider that the BES systems are likely to be purchased by households whose primary objective is to reduce their electricity imports from the grid. Furthermore, it needs to assume as little new infrastructure as possible.
- Practical and scalable customer-focused control for the provision of services. Most studies in the literature focus on a single objective (e.g., reduce imports, degradation, enhance scalability, etc.), and as such, all the

aspects are not captured holistically in a single study. As such, there is a need for a control strategy that adequately captures all the different objectives that need to be considered in the design for customers to participate in the provision of services.

- In-depth assessment of the impacts that the provision of services might have on distribution networks. The studies in the literature that propose controls for the provision of services from residential customers do not account for the effects that this operation can have on distribution networks. As such, analyses need to be performed to evaluate how the distribution networks are going to be affected by such operation and to what extent.
- DSO framework to facilitate the provision of bottom-up services with consideration of distribution network constraints without direct control of assets, and with consideration of locational fairness. Most studies in the literature either utilise direct control of assets by the DSO, or only consider a single participant (e.g., an aggregator) providing services within a distribution network. However, given the current regulatory limitations, but also a general preference for prosumers to operate under their own objectives, DSO frameworks that do not actively control non-network assets are required. Furthermore, these also need to consider the existence of multiple participants within the network, which also prompts the need for locational fairness to be considered.

Considering these gaps in the literature, multiple control strategies, realistic impact assessments, and a DSO framework have been developed and presented in this thesis. These contributions are summarised in the following sections.

8.2.1 Adaptive Decentralised Control of BES Systems

A practical, easily implementable, and scalable BES control strategy was proposed in this thesis. One of the main advantages of the proposed approach is that it is able to provide significant benefits in terms of PV impact mitigation, without affecting the ability of the BES system to provide benefits to the household (i.e., reducing electricity bills). The control strategy, which can be programmed directly on the BES management system, controlled externally or implemented remotely, operates fully decentralised, which removes all the corresponding complexity associated with centralised control approaches. Furthermore, it does not require network information, offline analyses or forecasting; significantly increasing the practicality of adopting this control. Finally, it should be mentioned that this work has led to the filing of a provisional patent [31].

8.2.2 Customer-led Operation of BES Systems for the Provision of Energy Services

To be able to provide services, a BES system control strategy is designed that is able to optimally dispatch the power settings to respond to a day-ahead service price signal. The design of the control considers the need for the BES systems to respond to very granular changes in demand and generation and thus a time-composite rolling horizon MILP optimisation technique is proposed. Furthermore, to ensure that the actions of the BES system do not result in degradation costs that are higher than the benefits brought by providing a given service, a piecewise affine degradation model is integrated in the optimisation problem.

8.2.3 Impacts of Customer-led Operation of BES Systems in Distribution Networks

As previously mentioned, the provision of services from DER without considering network constraints can negatively impact distribution networks. Nonetheless, no studies in the literature have quantified the effect that the provision of services can have on distribution networks. As such, the performance of the customer-led operation of BES systems (used as a proxy for the provision of services in distribution networks) is assessed so as to determine the level of impacts that such operation (e.g., unrestricted provision of services) can have on the distribution networks.

8.2.4 DSO Framework to Facilitate the Provision of Bottom-up Services from DER

A DSO framework is proposed to ensure that the provision of services through DER (and in particular, BES systems) does not violate network constraints. With the proposed framework, the DSO does not directly control the prosumer assets, but rather sets limits on their operation in near real-time (e.g., every 5 minutes). Under this framework, households that wish to provide services submit their intended operation to the DSO, which is then checked if it violates network constraints. If it is found that network constraints are violated, limits on the operation of the households are determined based on an optimisation program. Since households are individual entities, fairness aspects are embedded process in which household limits are determined, so as to not over-penalise households in weak parts of the network.

8.3 Conclusions

This section contains a summary of the conclusions and findings from all the chapters of this thesis.

8.3.1 Off-the-Shelf Control of BES Systems

The assessment performed in Chapter 4 presented the benefits for customers adopting an OTS BES system; both in terms of mitigating PV impacts on the network as well as reducing their grid imports. The findings highlight that:

- Customers can significantly reduce their grid imported energy by installing a BES system operating with the OTS control, which charges the BES system using the surplus PV generation and discharges to supply the local demand. In some cases, customers were fully grid independent.
- While the adoption of OTS BES systems did result, on average, to a reduction of PV impacts on the distribution network, during problematic days (low demand, high irradiance) the OTS BES systems were unable to provide almost any support.

The inability of OTS BES systems to provide benefits to the distribution network during problematic days was found to be due to the limitations below:

- Due to the low demand, the BES systems did not adequately discharge overnight. As such, there was limited capacity during the next generation period to store surplus PV generation.
- Due to the above, but also because BES systems are charging with the full surplus PV generation, they reach a full SOC prior to the critical period (i.e., peak generation). After achieving a full SOC, they are full and therefore cannot reduce household exports into the network; resulting in similar level of impacts as if the BES systems were not installed.

8.3.2 Adaptive Decentralised Control of BES Systems

The assessment performed in Chapter 5 quantified the benefits that the proposed AD control can bring to distribution networks in terms of mitigating PV impacts, and as such, increase their PV hosting capacity. The findings highlight that:

- The proposed AD control managed to overcome all the limitations of the OTS BES control and mitigate PV impacts on the distribution network by
  - discharging overnight to ensure adequate available capacity the next day, and
  - by charging proportionally to the clear-sky irradiance, it was able to ensure charging throughout the critical period; resulting in significant reduction of household exports into the network.
- This operation resulted in significant reduction of household exports, which in turn, allowed for a much higher penetration of PV systems to be installed in the distribution network.
- The AD control managed to achieve comparable performance with the benchmark controls (OPT for network performance, OTS for customer performance).
- It was demonstrated that errors in the estimation of the clear-sky profile do not result in major loss of performance, neither for the customer nor for the network.

8.3.3 Customer-led Operation of BES Systems

The assessment performed in Chapter 6 quantified the monetary benefits that customers with BES systems can obtain by adopting the proposed control. The findings highlight that:

- Optimisation techniques that only consider daily optimisation, or do not consider the highly granular nature of demand and generation result in highly suboptimal solutions.
- By considering degradation in the local optimisation problem, customers receive less benefits from their BES systems. However, due to the added lifetime of the BES system, the savings in cost (from the degradation of the battery) far outweigh the loss of benefits from providing services.
- Customers can receive significant extra benefits by opting to participate in the provision of services.

Furthermore, the resulting impacts of this operation on the distribution network was demonstrated. The findings highlight that:

- Due to the existence of high price spikes for the provision of services coinciding with high generation from PV systems, the resulting operation (high exports from the PV system along with full discharging of the BES system) heavily impacts distribution networks.

8.3.4 DSO Framework to Facilitate the Provision of Services from DER

The assessment performed in Chapter 7 quantified the performance of the proposed DSO framework in terms of maintaining network integrity while facilitating the provision of DER services. Furthermore, the effects of network constraints on the level of services that can be provided was also quantified. The findings highlight that:

- By limiting the maximum operation of prosumers providing services, the proposed DSO framework managed to keep voltages and thermal utilisation of assets within their limits at all times.
- The proposed quadratic objective function achieves a much fairer allocation of maximum operational limits for prosumers. With the linear objective function, which results in better network-wide performance, there is a high degree of unfairness between prosumers.
- The proposed DSO framework facilitates the provision of bottom-up services without being as prohibitive a more commonly adopted “fit-and-forget” approach, such as firm export limits.

8.4 Future Work

While the research aims and objectives of this thesis have been successfully completed, different aspects of this work could be further improved in future research.

8.4.1 Explore Different Predefined Minimum Energy Levels in the Adaptive Decentralised Control

One of the limitations of the OTS control, as stated in Chapter 4 and in the previous section, is the inadequacy of the local demand to fully deplete the BES system overnight; which results in the BES system not having adequate capacity to reduce household exports in the network. This limitation is overcome in the adaptive decentralised (AD) control by forcing the BES system to discharge overnight. However, in this thesis, only the option of fully discharging the BES system has been explored (i.e., predefined minimum energy level set to 0%). In future work, the trade-offs of not fully discharging the BES system could be explored. It is expected that the less the BES system is discharged, the more customer performance increases and network performance decreases. By exploring the trade-offs, a more appropriate predefined minimum energy level could be defined. Nonetheless, the definition of this value is likely to be case-specific; which is the reason why this was not considered initially in this thesis.

8.4.2 Explore Customer Benefits of Adopting the AD Control from the Perspective of PV Curtailment

In the assessment carried in the Chapter 5, the Volt-Watt function of PV systems was disabled so that the benefits from adopting the AD control could be better demonstrated. One of the benefits of customers adopting the AD control is the reduction of voltages in the network, which means that if adopted, this would result in less PV curtailment; effectively allowing customers to "sell" more electricity back to the network. This has not been quantified in this work but could be considered in future research. As previously, however, this quantification is highly case-specific (network, PV penetration, etc.), which is the reason that it was not considered in this thesis.

8.4.3 Customer-led Operation of BES Systems under Uncertainty

The customer-led control of BES systems proposed in Chapter 6 utilises deterministic forecasts for the demand, generation, and pricing. While this provides a good benchmark for the maximum level of benefits that customers can achieve from providing services, in reality, many uncertainties exist (particularly due to household demand), that could be considered in the optimisation problem. In future research, the proposed customer-led operation could be expanded to stochastic optimisation to incorporate these uncertainties in the operation. However, depending on the technique used to incorporate the stochasticity, this could in turn result in an optimisation problem large enough that it will not be able to be solved in timeframes adequate for real-time control.

8.4.4 Expansion of Customer-led Operation to Ancillary Services

Currently, the customer-led control of BES systems proposed in Chapter 6 only considers the provision of energy services (i.e., generation). This could be expanded in future work to also consider ancillary services (e.g., frequency). This would further increase the benefits that the customers receive from the provision of services.

8.4.5 Adopt more Realistic Market Models

The customer-led control of BES systems proposed in Chapter 6 models the individual customers as *price-takers*. This effectively means that the volume of services that can be provided through them is not large enough to influence the price of the service provided. In reality, however, as the level of services that can be provided through DER increases, this assumption no longer stands. In future research, realistic market modelling could be explored to more realistically capture both the benefits that this control can bring to customers, but also the corresponding effects on the distribution network. For the former, it is expected that as the number of customers providing services increases, the service prices are expected to drop. For the latter, as the number of customers increases, it is expected that each individual customer will contribute less to the provision of services, and as such, this could mean that network impacts might not be as severe as demonstrated.

8.4.6 Implement Algorithms on Real BES Systems

As aforementioned, the performance and computational efficiency of the algorithms found in Chapter 5 and Chapter 6 have been tested on a relatively high specification PC. Processing units found in real BES systems can be rather weak when compared with the testbed PC. This could potentially act as a bottleneck in their adoption, requiring higher specification processing units to be connected to the BES systems. Therefore, to fully evaluate the performance and computational efficiency of the proposed algorithms, they need to be implemented in a real BES system.

8.4.7 Include Controllable Network Elements and Reactive Power Support in the DSO Framework

The proposed DSO framework in Chapter 7 maintains network integrity by defining maximum operational limits for prosumers providing services. Given that the DSO can also operate network elements (e.g., OLTCs), these could be included in the OPF optimisation problem to further unlock the level of services that can be provided through the distribution network. Furthermore, the control of reactive power from PV and BES inverters can also be explored, which could help manage voltages (and perhaps, congestion issues), without the need for active power limits.

REFERENCES

[1] Victoria's renewable energy target. [Online]. Available: https://www.energy.vic.gov.au/renewable-energy/victorias-renewable-energy-targets

[2] Australian PV market Since April 2001. [Online]. Available: http://pv-map.apvi.org.au/analyses#top

[3] A. Rose. China's solar capacity overtakes Germany in 2015, industry data show. [Online]. Available: https://www.reuters.com/article/china-solar-idUSL3N15533U

[4] Net installed electricity generation capacity in Germany. [Online]. Available: https://www.energy-charts.de/power_inst.htm

[5] "Recent Facts about Photovoltaics in Germany," *Fraunhofer ISE*, 2018.

[6] C. Barteczko-Hibbert, "After Diversity Maximum Demand (ADMD) Report," 2015.

[7] "Distribution Network Planning Standards and Guidelines," *AusNet Services*, 2016.

[8] L. F. Ochoa and P. Mancarella, "Low-carbon LV networks: Challenges for planning and operation," *in Proc. 2012 2012 IEEE Power and Energy Society General Meeting*, pp. 1-2.

[9] R. A. Walling, R. Saint, R. C. Dugan, J. Burke, and L. A. Kojovic, "Summary of Distributed Resources Impact on Power Delivery Systems," *IEEE Transactions on Power Delivery*, vol. 23, no. 3, pp. 1636-1644, 2008.

[10] M. M. Haque and P. Wolfs, "A review of high PV penetrations in LV distribution networks: Present status, impacts and mitigation measures," *Renewable and Sustainable Energy Reviews*, vol. 62, pp. 1195-1208, 2016/09/01/ 2016.

[11] A. T. Procopiou and L. F. Ochoa, "Voltage Control in PV-Rich LV Networks Without Remote Monitoring," *IEEE Transactions on Power Systems*, vol. 32, no. 2, pp. 1224-1236, 2017.

[12] A. Navarro-Espinosa and L. F. Ochoa, "Probabilistic Impact Assessment of Low Carbon Technologies in LV Distribution Systems," *IEEE Transactions on Power Systems*, vol. 31, no. 3, pp. 2192-2203, 2016.

[13] "Electricity Distribution Code." Australia: Essential Services Commission, 2015.

[14] A. Procopiou, "Active Management of PV-Rich Low Voltage Networks," dissertation, School of Electrical and Electronic Engineering, The University of Manchester, 2017.

[15] S. A. L. S. N. Zealand, "AS/NZS 4777.2:2015 Grid connection of energy systems via inverters, Part2: Inverter requirements," 2015.

[16] "German Renewable Energy Act," *German Federal Ministry for Economic Affairs and Energy*, 2014.

[17] "Export limits for Embedded Generators up to 200 kVA connected at Low Voltage," *AusNet Services*, 2017.

[18] Powercor. Solar Pre-approval Requirement – Industry. [Online]. Available: https://www.powercor.com.au/industry/electricity-connections/solar-and-other-generation/pre-approval-requirement/

[19] T. R. Ricciardi, K. Petrou, J. Franco, and L. F. Ochoa, "Defining Customer Export Limits in PV-Rich Low Voltage Networks," *IEEE Transactions on Power Systems*, pp. 1-1, 2018.

[20] Sunwiz. Australian Battery Market Trebled in 2017, set to double in 2018. [Online]. Available: http://www.sunwiz.com.au/index.php/2012-06-26-00-47-40/73-newsletter/434-australian-battery-market-trebles-in-2018.html?fbclid=IwAR28JcVojplOwgEEGNEvl_prufjLtAyYqwk4G3ic_bFsLd3H68Dz0HdJTso

[21] S. Vorrath. Australia tipped to add 70,000 home batteries in 2019, lead global demand. [Online]. Available: https://reneweconomy.com.au/australia-tipped-to-add-70000-home-batteries-in-2019-lead-global-demand-64414/

[22] B. Mountain. Tesla battery + solar now “significantly cheaper” than grid power. [Online]. Available: https://reneweconomy.com.au/tesla-battery-solar-now-significantly-cheaper-grid-power-51011/

[23] Tesla Powerwall 2. [Online]. Available: https://www.tesla.com/en_AU/powerwall?redirect=no

[24] N. Hatziargyriou, T. Van Cutsem, J. Milanović, P. Pourbeik, C. Vournas, O. Vlachokyriakou, P. Kotsampopoulos, R. Ramos, J. Boemer, and P. Aristidou, "Contribution to bulk system control and stability by distributed energy resources connected at distribution network," *IEEE*, 2017.

[25] CSIRO and ENA, "Electricity Network Transformation Roadmap," *CSIRO and Energy Networks Australia*, Australia, 2017.

[26] T. Feehally, A. Forsyth, R. Todd, M. Foster, D. Gladwin, D. Stone, and D. Strickland, "Battery energy storage systems for the electricity grid: UK research facilities," 2016.

[27] ENA, "Opening Markets for Network Flexibility," 2017.

[28] Western Power Distribution. DSO Strategy. [Online]. Available: https://www.westernpower.co.uk/dso-strategy

[29] CIGRE, "System Operation Emphasizing DSO/TSO Interaction and Coordination," 2018.

[30] E. N. Australia and AEMO, "Open Energy Networks," 2018.

[31] A. T. Procopiou, K. Petrou, and L. N. Ochoa, "A controller for photovoltaic generation and energy storage system," in *https://goo.gl/VYsFMJ*, vol. 2018904310, I. A. Australian Government, Ed. Australia, 2018.

[32] K. Petrou, L. F. Ochoa, A. T. Procopiou, J. Theunissen, J. Bridge, T. Langstaff, and K. Lintern, "Limitations of Residential Storage in PV-Rich

Distribution Networks: An Australian Case Study," *in Proc. 2018 2018 IEEE Power & Energy Society General Meeting (PESGM)*, pp. 1-5.

[33] A. T. Procopiou, K. Petrou, L. F. Ochoa, T. Langstaff, and J. Theunissen, "Adaptive Decentralized Control of Residential Storage in PV-Rich MV–LV Networks," *IEEE Transactions on Power Systems*, vol. 34, no. 3, pp. 2378-2389, 2019.

[34] H. Sugihara, K. Yokoyama, O. Saeki, K. Tsuji, and T. Funaki, "Economic and Efficient Voltage Management Using Customer-Owned Energy Storage Systems in a Distribution Network With High Penetration of Photovoltaic Systems," *IEEE Transactions on Power Systems*, vol. 28, no. 1, pp. 102-111, 2013.

[35] K. Worthmann, C. M. Kellett, P. Braun, L. Grüne, and S. R. Weller, "Distributed and Decentralized Control of Residential Energy Systems Incorporating Battery Storage," *IEEE Transactions on Smart Grid*, vol. 6, no. 4, pp. 1914-1923, 2015.

[36] I. Ranaweera, O.-M. Midtgård, and M. Korpås, "Distributed control scheme for residential battery energy storage units coupled with PV systems," *Renewable Energy*, vol. 113, pp. 1099-1110, 2017/12/01/ 2017.

[37] M. Zeraati, M. E. H. Golshan, and J. M. Guerrero, "Distributed Control of Battery Energy Storage Systems for Voltage Regulation in Distribution Networks With High PV Penetration," *IEEE Transactions on Smart Grid*, vol. 9, no. 4, pp. 3582-3593, 2018.

[38] F. H. M. Rafi, M. J. Hossain, and J. Lu, "Hierarchical controls selection based on PV penetrations for voltage rise mitigation in a LV distribution network," *International Journal of Electrical Power & Energy Systems*, vol. 81, pp. 123-139, 2016/10/01/ 2016.

[39] S. Hashemi, J. Østergaard, and G. Yang, "A Scenario-Based Approach for Energy Storage Capacity Determination in LV Grids With High PV Penetration," *IEEE Transactions on Smart Grid*, vol. 5, no. 3, pp. 1514-1522, 2014.

[40] F. Marra, G. Yang, C. Træholt, J. Østergaard, and E. Larsen, "A Decentralized Storage Strategy for Residential Feeders With Photovoltaics," *IEEE Transactions on Smart Grid*, vol. 5, no. 2, pp. 974-981, 2014.

[41] M. N. Kabir, Y. Mishra, G. Ledwich, Z. Y. Dong, and K. P. Wong, "Coordinated Control of Grid-Connected Photovoltaic Reactive Power and Battery Energy Storage Systems to Improve the Voltage Profile of a Residential Distribution Feeder," *IEEE Transactions on Industrial Informatics*, vol. 10, no. 2, pp. 967-977, 2014.

[42] F. Lamberti, V. Calderaro, V. Galdi, and G. Graditi, "Massive data analysis to assess PV/ESS integration in residential unbalanced LV networks to support voltage profiles," *Electric Power Systems Research*, vol. 143, pp. 206-214, 2017/02/01/ 2017.

[43] M. Parvania, M. Fotuhi-Firuzabad, and M. Shahidehpour, "Optimal Demand Response Aggregation in Wholesale Electricity Markets," *IEEE Transactions on Smart Grid*, vol. 4, no. 4, pp. 1957-1965, 2013.

[44] H. Wang, N. Good, P. Mancarella, and K. Lintern, "PV-battery community energy systems: Economic, energy independence and network deferral analysis," *in Proc. 2017 2017 14th International Conference on the European Energy Market (EEM)*, pp. 1-5.

[45] A. Castelo-Becerra, W. Zeng, and M. Y. Chow, "Cooperative distributed aggregation algorithm for demand response using distributed energy storage devices," *in Proc. 2017 2017 North American Power Symposium (NAPS)*, pp. 1-6.

[46] Z. Wang, C. Gu, F. Li, P. Bale, and H. Sun, "Active Demand Response Using Shared Energy Storage for Household Energy Management," *IEEE Transactions on Smart Grid*, vol. 4, no. 4, pp. 1888-1897, 2013.

[47] Y. Wang, X. Lin, and M. Pedram, "A Near-Optimal Model-Based Control Algorithm for Households Equipped With Residential Photovoltaic Power Generation and Energy Storage Systems," *IEEE Transactions on Sustainable Energy*, vol. 7, no. 1, pp. 77-86, 2016.

[48] M. Nistor and C. H. Antunes, "Integrated Management of Energy Resources in Residential Buildings - A Markovian Approach," *IEEE Transactions on Smart Grid*, vol. 9, no. 1, pp. 240-251, 2018.

[49] H. Wang, K. Meng, Z. Y. Dong, Z. Xu, F. Luo, and K. P. Wong, "Efficient real-time residential energy management through MILP based rolling horizon optimization," *in Proc. 2015 2015 IEEE Power & Energy Society General Meeting*, pp. 1-6.

[50] D. Metz and J. T. Saraiva, "Economics of energy storage in a residential consumer context," *in Proc. 2016 2016 13th International Conference on the European Energy Market (EEM)*, pp. 1-5.

[51] E. Franklin, D. Lowe, and M. Stocks, "Assessment of Market Participation Opportunities for Behind-the-meter PV/ Battery Systems in the Australian Electricity Market," *Energy Procedia*, vol. 110, no. Supplement C, pp. 420-427, 2017/03/01/ 2017.

[52] Z. Yuan, M. R. Hesamzadeh, and D. R. Biggar, "Distribution Locational Marginal Pricing by Convexified ACOPF and Hierarchical Dispatch," *IEEE Transactions on Smart Grid*, vol. 9, no. 4, pp. 3133-3142, 2018.

[53] H. Yuan, F. Li, Y. Wei, and J. Zhu, "Novel Linearized Power Flow and Linearized OPF Models for Active Distribution Networks With Application in Distribution LMP," *IEEE Transactions on Smart Grid*, vol. 9, no. 1, pp. 438-448, 2018.

[54] S. Huang, Q. Wu, S. S. Oren, R. Li, and Z. Liu, "Distribution Locational Marginal Pricing Through Quadratic Programming for Congestion Management in Distribution Networks," *IEEE Transactions on Power Systems*, vol. 30, no. 4, pp. 2170-2178, 2015.

[55] S. Hanif, K. Zhang, C. M. Hackl, M. Barati, H. B. Gooi, and T. Hamacher, "Decomposition and Equilibrium Achieving Distribution Locational Marginal Prices Using Trust-Region Method," *IEEE Transactions on Smart Grid*, vol. 10, no. 3, pp. 3269-3281, 2019.

[56] M. Caramanis, E. Ntakou, W. W. Hogan, A. Chakrabortty, and J. Schoene, "Co-Optimization of Power and Reserves in Dynamic T&D Power

Markets With Nondispatchable Renewable Generation and Distributed Energy Resources," *Proceedings of the IEEE*, vol. 104, no. 4, pp. 807-836, 2016.

[57] L. Bai, J. Wang, C. Wang, C. Chen, and F. Li, "Distribution Locational Marginal Pricing (DLMP) for Congestion Management and Voltage Support," *IEEE Transactions on Power Systems*, vol. 33, no. 4, pp. 4061-4073, 2018.

[58] P. Jacquot, O. Beaude, S. Gaubert, and N. Oudjane, "Analysis and Implementation of an Hourly Billing Mechanism for Demand Response Management," *IEEE Transactions on Smart Grid*, pp. 1-1, 2018.

[59] Z. Baharlouei, M. Hashemi, H. Narimani, and H. Mohsenian-Rad, "Achieving Optimality and Fairness in Autonomous Demand Response: Benchmarks and Billing Mechanisms," *IEEE Transactions on Smart Grid*, vol. 4, no. 2, pp. 968-975, 2013.

[60] Z. Baharlouei and M. Hashemi, "Efficiency-Fairness Trade-off in Privacy-Preserving Autonomous Demand Side Management," *IEEE Transactions on Smart Grid*, vol. 5, no. 2, pp. 799-808, 2014.

[61] A. K. Zarabie, S. Das, and M. N. Faqiry, "Fairness-Regularized DLMP-Based Bilevel Transactive Energy Mechanism in Distribution Systems," *IEEE Transactions on Smart Grid*, pp. 1-1, 2019.

[62] S. Hanif, P. Creutzburg, H. B. Gooi, and T. Hamacher, "Pricing Mechanism for Flexible Loads using Distribution Grid Hedging Rights," *IEEE Transactions on Power Systems*, pp. 1-1, 2018.

[63] E. Dall'Anese, S. S. Guggilam, A. Simonetto, Y. C. Chen, and S. V. Dhople, "Optimal Regulation of Virtual Power Plants," *IEEE Transactions on Power Systems*, vol. 33, no. 2, pp. 1868-1881, 2018.

[64] A. Saint-Pierre and P. Mancarella, "Active Distribution System Management: A Dual-Horizon Scheduling Framework for DSO/TSO Interface Under Uncertainty," *IEEE Transactions on Smart Grid*, vol. 8, no. 5, pp. 2186-2197, 2017.

[65] J. Silva, J. Sumaili, R. J. Bessa, L. Seca, M. A. Matos, V. Miranda, M. Caujolle, B. Goncer, and M. Sebastian-Viana, "Estimating the Active and Reactive Power Flexibility Area at the TSO-DSO Interface," *IEEE Transactions on Power Systems*, vol. 33, no. 5, pp. 4741-4750, 2018.

[66] A. Mohammadi, M. Mehrtash, and A. Kargarian, "Diagonal Quadratic Approximation for Decentralized Collaborative TSO+DSO Optimal Power Flow," *IEEE Transactions on Smart Grid*, vol. 10, no. 3, pp. 2358-2370, 2019.

[67] D. Koraki and K. Strunz, "Wind and Solar Power Integration in Electricity Markets and Distribution Networks Through Service-Centric Virtual Power Plants," *IEEE Transactions on Power Systems*, vol. 33, no. 1, pp. 473-485, 2018.

[68] R. C. Dugan and T. E. McDermott, "An open source platform for collaborating on smart grid research," *in Proc. 2011 IEEE Power and Energy Society General Meeting*, pp. 1-7.

[69] J. M. BARROSO, "Commission Regulation (EU) No 548/2014 for 21 May 2014 on implementing Directive 2009/125/EC of the European Parliament and of the Council with

regard to small, medium and large power transformers," *Official Journal of the European Union*, vol. 57, 22 May 2014.

[70] A. Jehad, "Electrical Design Standard for Underground Distribution Cable Networks, Technical Standard - TS-100." Australia: SA Power Networks, 2012.

[71] A. Seneviratne and J. Murphy, "Electrical Design Information for Distribution Networks: After Diversity Maximum Demand," in *Standard HPC-3DC-07-0001-2012*. Australia: Horizon Power, 2013.

[72] J. Bridge, "Distribution Annual Planning Report 2017 -2021," AusNet Services, 2017.

[73] A. Seneviratne and J. Murphy, "Distribution Design Manual – Underground Cable Distribution," in *Standard HPC-5DC-07-0004-2014*, vol. 4: Horizon Power, 2014.

[74] "Distribution Substation Manual (DSM) Section 1 - Customer Supply Arrangements." Australia: Western Power, 2009.

[75] British Standards Institution, "Voltage characteristics of electricity supplied by public electricity networks," 2010.

[76] R. Perez, S. Kivalov, J. Schlemmer, K. Hemker, and T. E. Hoff, "Short-term irradiance variability: Preliminary estimation of station pair correlation as a function of distance," *Solar Energy*, vol. 86, no. 8, pp. 2170-2176, 2012/08/01/ 2012.

[77] "ABB REACT-3.6/4.6-TL," ABB, 2018.

[78] "LG Chem Residential Energy Storage," LG, 2017.

[79] "Sunny Boy 3600/5000 Smart Energy - The perfect combination of PV inverter and battery," SMA, 2017.

[80] "Household Solar Power and Battery Survey." Australia: Ausgrid, 2017.

[81] G. M. Masters, *Renewable and efficient electric power systems*. Hoboken, NJ: John Wiley & Sons, 2004.

[82] I. Richardson and M. Thomson, "Integrated simulation of Photovoltaic Micro-Generation and Domestic Electricity Demand: A one minute resolution open source model." United Kingdom: Loughborough University, 2011.

[83] A. Ballanti and L. F. Ochoa, "Voltage-Led Load Management in Whole Distribution Networks," *IEEE Transactions on Power Systems*, vol. PP, no. 99, pp. 1-1, 2017.

[84] N. Etherden and M. H. J. Bollen, "Overload and overvoltage in low-voltage and medium-voltage networks due to renewable energy – some illustrative case studies," *Electric Power Systems Research*, vol. 114, pp. 39-48, 2014/09/01/ 2014.

[85] H. Sugihara, T. Funaki, Y. Matsuura, K. Abe, and M. Minami, "PV-Installable Capacity in Medium-Voltage and Low-Voltage Distribution

Networks with Optimal Line-Drop Compensation Parameters," *Journal of Energy Engineering*, vol. 143, no. 3, pp. F4016002, 2017/06/01 2017.

[86] "Tesla Powerwall 2 Warranty Documentation." USA: Tesla Inc., 2018.

[87] A. T. Procopiou, "Active Management of PV-Rich Low Voltage Networks," Doctor of Philosophy dissertation, Electrical Energy and Power Systems Group, The University of Manchester, Manchester, 2017.

[88] J. Silvente, G. M. Kopanos, E. N. Pistikopoulos, and A. Espuña, "A rolling horizon optimization framework for the simultaneous energy supply and demand planning in microgrids," *Applied Energy*, vol. 155, pp. 485-501, 2015/10/01/ 2015.

[89] W. H. Kwon and S. H. Han, *Receding horizon control: model predictive control for state models*: Springer Science & Business Media, 2006.

[90] Elexon. Trading & Settlement. [Online]. Available: https://www.elexon.co.uk/operations-settlement/trading-settlement/

[91] P. Fortenbacher and G. Andersson, "Battery degradation maps for power system optimization and as a benchmark reference," *in Proc. 2017 2017 IEEE Manchester PowerTech*, pp. 1-6.

[92] D. Leiva, C. Araya, G. Valverde, and J. Quirós-Tortós, "Statistical representation of demand for GIS-based load profile allocation in distribution networks," *in Proc. 2017 2017 IEEE Manchester PowerTech*, pp. 1-6.

[93] J. Bisschop and M. Roelofs, *AIMMS - Language Reference*: Lulu.com, 2006.

[94] P. Fortenbacher, A. Ulbig, and G. Andersson, "Optimal Placement and Sizing of Distributed Battery Storage in Low Voltage Grids Using Receding Horizon Control Strategies," *IEEE Transactions on Power Systems*, vol. 33, no. 3, pp. 2383-2394, 2018.

[95] A. P. Institute. Solar PV Maps and Tools. [Online]. Available: http://pv-map.apvi.org.au/

[96] AEMO. Data Dashboard. [Online]. Available: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data-dashboard

[97] R. Lougee-Heimer, "The Common Optimization INterface for Operations Research: Promoting open-source software in the operations research community," *IBM Journal of Research and Development*, vol. 47, no. 1, pp. 57-66, 2003.

[98] L. Gutierrez-Lagos and L. F. Ochoa, "OPF-based CVR Operation in PV-Rich MV-LV Distribution Networks," *IEEE Transactions on Power Systems*, pp. 1-1, 2019.

[99] L. Guitierrez-Lagos, M. Liu, and L. F. Ochoa, "Implementable Three-Phase OPF Formulations for MV-LV Distribution Networks: MILP and MIQCP," *in Proc. 2019 of Conference IEEE Power & Energy Society Innovative Smart Grid Technologies Conference (ISGT) Latin America*, in Review.

[100] J. F. Franco, L. F. Ochoa, and R. Romero, "AC OPF for Smart Distribution Networks: An Efficient and Robust Quadratic Approach," *IEEE Transactions on Smart Grid*, vol. 9, no. 5, pp. 4613-4623, 2018.

[101] alintaenergy. Victoria Energy Pricing. [Online]. Available: https://www.alintaenergy.com.au/energy-products/customer-information/victoria-pricing