Future grid for distributed energy

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CitiPower and Powercor is Victoria's largest electricity distribution business, delivering electricity to over 1.1 million residential households and commercial customers across Victoria. CitiPower provides power for more than 330,000 customers in Melbourne's CBD and inner suburbs. Powercor provides electricity for nearly 820,000 customers in central and western Victoria, as well as Melbourne's western suburbs.

CitiPower and Powercor engaged ENEA Consulting to undertake the Distributed Energy Resources Hosting Capacity Study. CitiPower and Powercor supported ENEA Consulting by establishing the low voltage network categories, providing the power flow models of the example networks and technical support.

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ENEA Consulting is a strategy consultancy that maximises energy transition opportunities for public and private organisations globally. Through dedicated consulting services and pro bono support to NGOs and social entrepreneurs, ENEA is also committed to improving energy access, especially in developing countries.

As part of this Distributed Energy Resources (DER) Hosting Capacity Study, CitiPower and Powercor commissioned ENEA Consulting to perform power flow modelling of the example low voltage networks, undertake a techno-economic assessment of mitigation measures and write the DER Hosting Capacity Study report.

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The views expressed herein are not necessarily the views of the Australian Government, and the Australian Government does not accept responsibility for any information or advice contained herein. The views expressed herein are based on a reduced number of case studies, and may not apply to every low voltage network.

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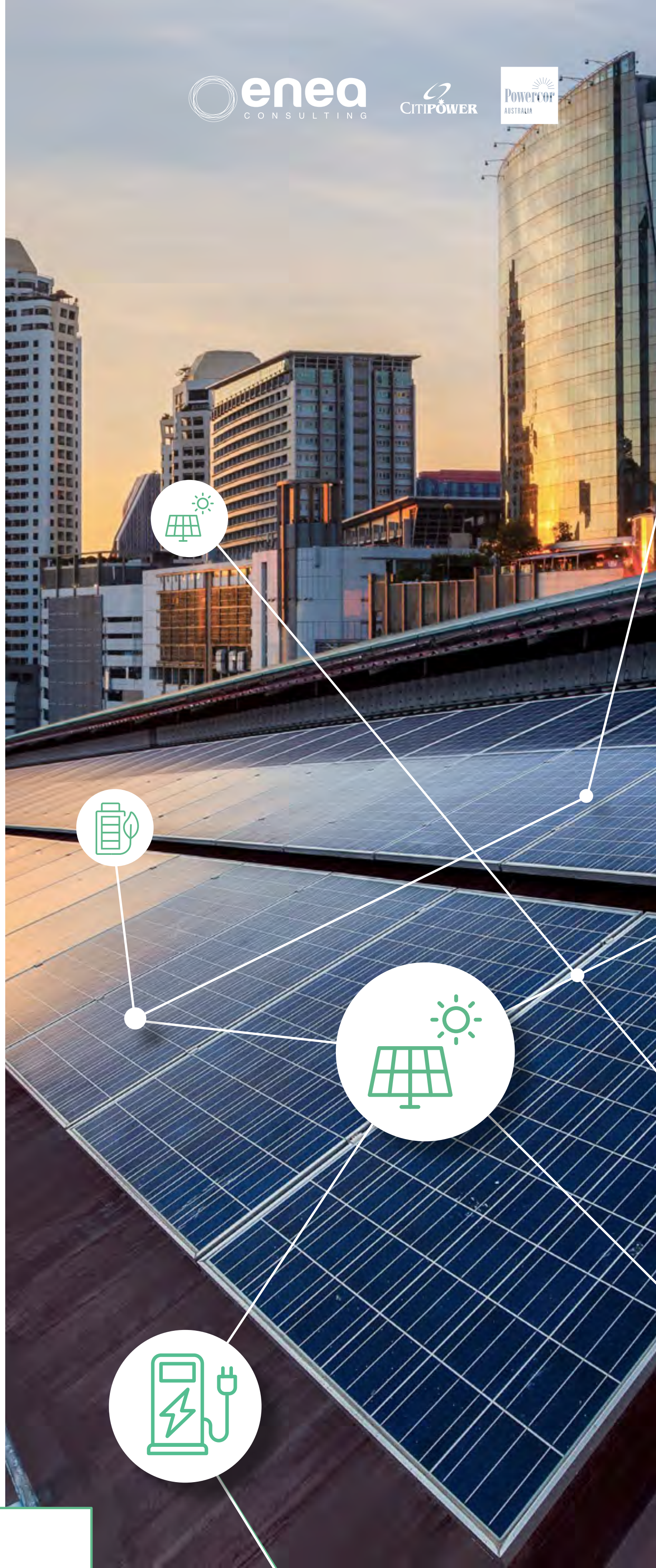

Executive summary

Distributed energy resources are challenging distribution networks

The rise of the 'prosumer' and distributed energy resources (DER)

A global energy transition is underway that supports a low-emissions future. This is in line with the Paris Agreement, which aims to limit global temperature change this century to well below 2 degrees Celsius.

In the electricity sector, one aspect of this transition is the rise of the 'prosumer', a customer that both consumes and produces electricity. Prosumers use distributed energy resources (DER) — including rooftop solar photovoltaic (PV) systems, behind-the-meter batteries and electric vehicles (EVs) — to generate, consume and manage electricity at their premises. Electricity they do not consume may then be fed back into the grid.

Australia is already a global leader in rooftop PV installations. Currently, Australians have installed over 2.3 million rooftop PV systems, equating to around 23% of households[1]. CSIRO, the Australian Government's scientific research agency, forecasts that over 40% of Australian customers will use on-site DER by 2027. This includes 29 gigawatts of PV and 34 gigawatt hours of behind-the-meter batteries[2].

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[1]Clean Energy Regulator, "Postcode data for small-scale installations", March 2020.

[2]CSIRO and Energy Networks Australia, "Electricity Network Transformation Roadmap: Final Report," 2017.

Growing PV penetration is causing issues on distribution networks

Distribution network service providers (DNSPs) are responsible for managing and operating electricity distribution networks to maintain safety, reliability and power quality for their customers. On distribution networks, power quality mainly refers to continuous electricity supply at the required voltage. In Australia, electricity must be delivered at a voltage within -6% / +10% of the nominal level of 230 Volts (V).

Historically, electricity infrastructure — comprising power lines, substations and transformers — was designed to deliver electricity in one direction. This was from centralised, utility-scale power plants down to customers on the low voltage (LV) portions of distribution networks. However, customers are becoming more active players, causing electricity systems to become more decentralised.

Increasing PV generation at the customer level can cause a range of issues on existing distribution networks. In particular, the very end of the distribution network where most residential and small commercial and industrial customers are connected, the LV network, is where most problems are expected to occur. The most immediate issue is voltage rise. High export levels of behind-the-meter PV to LV networks during periods of low customer demand — such as during the middle of the day — can increase voltage on the LV networks above the aforementioned +10%. In addition to power quality issues, this can cause power to flow back upstream, which can risk exceeding the thermal limits of some assets on the distribution network.

In Australia, these issues are resulting in reduced power quality, involuntarily reduced PV generation (also known as 'curtailment') and distribution businesses sometimes delaying or refusing prospective PV connections.

Improving LV network visibility can enable better network and customer outcomes

Historically, DNSPs have undertaken limited monitoring of the LV networks because most of the risks and potential issues occurred upstream. Thus, visibility in terms of how LV networks could accommodate growing PV penetration (their 'hosting capacity') is relatively low. New knowledge and capabilities are being developed.

Improving the visibility of LV networks to better establish their hosting capacity will allow DNSPs to make more informed investment decisions for the benefit of the consumers. This will enable increased, cost-efficient generation of distributed PV while maintaining power quality and safe supply.

Given the high PV penetration in Australia, PV is the primary focus of this study. However, Australians are increasingly showing interest in other DER solutions such as batteries. This enables them to store the electricity produced from their PV system for later consumption. In Victoria, this is supported by policy incentives through the Victoria Solar Battery Rebate scheme.

While uptake of EVs is a concern in some overseas jurisdictions, it is comparatively minor in Australia and is yet to have a material impact on Australian distribution networks. As Australians install more on-site (behind-the-meter) batteries and increasingly purchase EVs, these too will have an impact on LV network management.

Other work contributing to DER integration

Australia's energy industry and government bodies are cognisant of these network challenges and a large body of work is already underway to improve network visibility and manage growing DER penetration. For example, the Australian Renewable Energy Agency (ARENA) Distributed Energy Integration Program is a collaboration of governments, market authorities, industry and consumer groups that aims to maximise the value of customers' DER. The project acts as an information exchange for collaboration on DER issues to maximise customer interests. A joint Energy Networks AEMO project, Open Energy Networks (OpEN), has highlighted a primary focus on local network challenges, particularly LV voltage limits due to DER integration. The interim report identified improving network visibility, particularly through real-time monitoring, as a required capability to support DER integration. In addition, establishing Australian standards or guidelines for DER operating envelopes for DER import/export is also required[3].

The Australian Energy Market Commission (AEMC)'s work to transition to the 'grid of the future' highlighted factors that are reducing efficiencies and causing power quality issues as DER penetration increases. These included the lack of visibility of LV networks, inadequate technical standards and compliance, and an industry-wide lack of cost-reflective pricing. In 2019, AEMC made recommendations regarding network challenges of integrating DER, some of which centred around DNSPs improving visibility of loads and voltages[4].

Other studies are assessing options for LV voltage management as DER penetration increases. For example, the ARENA-funded University of Technology Sydney Networks Renewed project investigated the potential of smart inverters and battery storage to increase electricity supply quality and reliability[5]. In addition, there are multiple virtual power plant (VPP) pilots and trials occurring, which include assessing their potential for network management.

[3] AEMO and Energy Networks Australia, "Open Energy Networks, Required capabilities and recommended actions (interim report)," July 2019.

[4] AEMC, "Economic Regulatory Frameworks Review," September 2019.

[5] UTS Institute for Sustainable Futures, "Networks Renewed: Project Results and Lessons Learnt," September 2019.

DER Hosting Capacity Study

This DER Hosting Capacity Study fits within the above mentioned body of work on improving network visibility and managing growing DER penetration. It is an ARENA-funded project led by CitiPower and Powercor (CPPAL), a DNSP in the state of Victoria, Australia. The study builds on previous work by leveraging advanced metering infrastructure (AMI) data to model real-world networks.

This study's purpose is to develop a replicable methodology that CPPAL and other energy industry stakeholders can use to improve their understanding of LV networks' PV hosting capacity. This study also explores efficient enablement of further PV uptake without risking quality of supply to customers.

CitiPower and Powercor (CPPAL)'s distribution networks

CPPAL's distribution networks are the perfect case study for this project. CPPAL manages more than 80,000 LV networks across western Victoria and Victoria's capital city, Melbourne. It covers a 150,000 km^2 network area and serves approximately 1.1 million customers.

Installed PV capacity on CPPAL's distribution networks has increased significantly in recent years. In 2019, Powercor experienced a 16% increase in rooftop PV, resulting in over 142,449 additional installations.

Also, with Victoria being the only state in Australia where most customers have smart meters, AMI data about their electricity usage was available for this study.

ENEA Consulting was commissioned by CPPAL to use its distribution networks to:

1. Establish a replicable methodology to assess the hosting capacity of LV networks
2. Assess the techno-economic performance of potential measures to increase hosting capacity in the future.

Establishing a replicable methodology to assess LV network hosting capacity

The first aim of this study was to establish a methodology to assess the hosting capacity of LV networks, considering voltage levels and equipment thermal rating constraints. The adequacy of protection schemes under high PV penetration was not explored, nor were other aspects of power quality that are of less concern, such as harmonics.

There is no official or agreed-upon definition for hosting capacity, but in this study, these three metrics were used:

1. The percentage of the maximum reference[6] PV penetration level when the first breach of the maximum voltage limit or equipment thermal constraint occurs on the LV network
2. The annual average hours per day in breach of a voltage limit or equipment thermal rating as PV penetration increases
3. The increase in annual maximum voltage level as PV penetration increases.

The first metric gives an indication of the level of PV penetration that the LV network can handle before first issues arise.

The second and third metrics show the amount of time spent in breach and the severity of the breach as PV penetration increases beyond the first breach. They aim to demonstrate the magnitude of non-compliance.

The methodology for assessing LV network hosting capacity is illustrated in figure 1.

[6]The reference maximum PV penetration level (in kW) is reached when every residential and commercial and industrial (C & I) customer on an LV network has a 5 kW PV system installed respectively. This is also referred to as '100% PV penetration' or 'saturation'.

Figure 1 • Illustration of methodology

1

Map distribution network and select example LV networks

CPPAL's 80,000 LV networks were mapped into 10 representative categories based on common LV network topologies and features that influence hosting capacity. Ten real-world LV networks were selected, each as an example from one category.

2

Build power flow model for example LV networks

A power flow model[7] was built for each LV network using 2017–18 AMI data, geospatial and topological information. The models were then tested against historical conditions and validated based on historical voltage readings to ensure their accuracy.

3

Perform power flow modelling under increasing PV penetration

Each LV network was modelled under increasing PV penetration levels to saturation until the reference maximum PV penetration level was achieved. Power flow modelling was performed on a 30-minute basis over 12 months for each level of PV penetration.

4

Assess hosting capacity

Modelling outputs were assessed according to the three hosting capacity metrics:

1. PV penetration at first breach
2. Amount of time in breach
3. Voltage rise.

The results from this methodology acted as the baseline against which the techno-economic performance of the mitigation measures was compared.

Assessing the techno-economic performance of five potential mitigation measures

ENEA Consulting investigated five mitigation measures — three network augmentation solutions and two customer-side solutions — and assessed their techno-economic performance in relation to improving the baseline hosting capacity of each example LV network.

Network augmentation refers to upgrading the existing local distribution network to meet customer loads. Examples include installing new poles, wires or transformers to support the supply of electricity. Investments are made by DNSPs and recovered through regulated revenue.

The five potential mitigation measures are outlined below.

Network augmentation solutions

1. **Transformer upgrade/reconductoring:** This included replacing a distribution transformer to include an off-load tap changer with additional manual buck taps, increasing the distribution transformer rating and/or increasing the quality of the LV conductor. An off-load tap changer adjusts the voltage ratio between the HV network and the LV network. Boost taps increase the output voltage and buck taps reduce the output voltage. The taps are manually adjusted based on network conditions.
2. **On-load tap changer (OLTC):** An OLTC automatically adjusts the output voltage at the distribution substation (DSS) in real-time, based on load characteristics on the LV network. In this study, the distribution transformer was replaced with a transformer fitted with an OLTC.
3. **Low voltage regulator (LVR):** LVR(s) use a controllable transformer to increase or decrease the voltage on LV networks.

[7] A power flow model is a numerical representation of the flow of electricity through an energy system and allows estimation of voltage levels based on network characteristics, consumption and generation data.

Customer-side solutions

4. **Smart inverter:** A smart inverter has extended capabilities (Volt-Watt and Volt-VAR settings) to sense and react to grid voltage by adjusting the real and reactive power exported from the PV system. In this study, a smart inverter was installed alongside each PV system.
5. **Behind-the-meter batteries:** Batteries can store and time-shift energy. In this study, a battery was installed behind-the-meter alongside each PV system. The batteries were assumed to charge as soon as there was excess PV generation. Equally, they were assumed to discharge as soon as electricity is imported from the grid to maximise customer self-consumption.

Technical performance

The technical ability of each mitigation measure to improve the network hosting capacity was assessed under increasing PV penetration levels.

Economic performance

A cost-benefit analysis was used to assess the economic performance of each mitigation measure. The cost-benefit analysis compared the value of additional PV generation enabled by each mitigation measure with their annualised cost to give their net-benefit under increasing PV penetration. The cost-benefit analysis used the historical 2017–18 wholesale price to value additional PV generation.

Key findings

This section outlines the key findings of this study. Firstly, the baseline results are discussed in reference to the three metrics for assessing hosting capacity. Next, the techno-economic performance of mitigation measures is summarised according to the three metrics and the results of cost-benefit analysis.

Baseline hosting capacity results

The example LV networks' behaviour under increasing PV penetration was diverse across the three metrics for assessing the baseline hosting capacity.

PV penetration level and the PV penetration level when the first breach occurs: Power quality issues occurred at low PV penetration levels (below 25%) for seven of the 10 example LV networks. Two of the 10 LV networks never experienced a breach and were able to reach maximum penetration.

Annual average hours per day spent in breach: Without mitigation measures, six out of the 10 example LV networks would theoretically spend more than eight hours per day in breach at PV penetrations above 40%. On the other hand, three of the example networks would experience a very low number of hours per day in breach (below 10 minutes at PV saturation).

Increase in annual maximum voltage level: Without mitigation measures, three out of the 10 example LV networks would theoretically experience more than 50 V in voltage rise at PV penetrations above 40%. Four out of the 10 example networks would experience moderate voltage rises (below 6.5 V at PV saturation).

Additionally, a comparison of the example LV networks showed that distribution substation (DSS) position influenced materially its HV bus voltage on Rural long HV feeder types, but not on shorter HV feeder types (for example, CBD and Urban). Distribution transformers step down voltage at a fixed ratio for delivery to customers on its associated LV network. This fixed ratio means that if voltage is high on the HV side of the transformer, the effect will be passed on to the LV network.

This study found that with moderate PV uptake, the voltage on an unmanaged HV feeder can breach the +10% voltage limit before stepping down to the LV level. In these cases, voltage rise within an LV network compounds with the rise seen at HV level and could reach extremely high levels without intervention. To address this voltage rise, management is required both within the HV and LV network portions.

It is important to note that these results are based on theoretical PV installations that were unmanaged, without additional augmentation or voltage management. Realistically, the DNSP would never allow voltages to reach problematic levels.

Techno-economic performance of mitigation measures

Table 1 summarises the effectiveness of the five mitigation measures at increasing the LV networks' ability to host additional PV systems, in terms of techno-economic performance. The range of outcomes in the following table shows that there is **no single solution to improving hosting capacity** that can be applied across all the LV networks. This reflects the variability across CPPAL's distribution network, where the preferred mitigation measure is highly sensitive to local network characteristics.

Table 1 • Summary of the techno-economic performance of each mitigation measure

Mitigation measure	PV penetration at first breach	Average hours per day in breach	Maximum voltage levels (voltage rise)	Cost-benefit analysis
1. Transformer upgrade / reconductoring	**Increases the PV penetration at first breach of six LV networks**	**Significantly reduces hours in breach**	Reduces maximum voltage levels	The best option in many cases, but only on LV networks with more than a few customers
2. OLTC	**Increases the PV penetration at first breach of six LV networks**	**Significantly reduces hours in breach**	Reduces maximum voltage levels	Highest net-benefit for one LV network due to extreme voltage rise, superseded by VR at higher PV penetration levels
3. LVR	**Increases PV penetration at first breach of six LV networks**	**Significantly reduces hours in breach**	Reduces maximum voltage levels	Highest net-benefit for one LV network at high PV penetration levels due to extreme voltage rise
4. Smart inverter	Increases PV penetration at first breach of two LV networks Very minor improvements in all other example networks	Slightly reduces hours in breach	**Significantly reduces maximum voltage levels**	**Highest net-benefit at low PV penetration levels due to low cost, but has limited benefits at high PV penetration levels due to a high level of curtailment**
5. Battery	No improvement in any of the example networks	Slightly reduces hours in breach	Slightly reduces maximum voltage levels	No benefit for any LV network under this study's assumptions

Key techno-economic performance assessment findings

PV penetration level and the PV penetration level when the first breach occurs: Network augmentation mitigation measures (transformer upgrade/reconductoring, OLTC and LVR) were most effective at increasing the PV penetration level when the first breach occurs. This is generally because they actively reduce voltage levels on the LV networks so that the LV network can withstand further PV penetration before voltage issues arise.

Annual average hours per day spent in breach: Like the first metric, network augmentation mitigation measures were the most effective at improving the average hours per day in breach.

Increase in annual maximum voltage level: By comparison, smart inverters were the most effective at reducing voltage rise for most of the LV networks. This is primarily achieved through the large amount of curtailment they enact at high PV penetration levels.

Across the three metrics for assessing technical performance, behind-the-meter batteries did not improve the ability for LV networks to accommodate increasing PV penetration levels. This was due to the way they were operated in this study, which was to maximise self-consumption.

Cost-benefit analysis: Smart inverters had the highest net-benefit at low PV penetration levels due to their comparatively lower cost. However, as PV penetration increased, transformer upgrade/reconductoring had the highest net-benefit for most of the LV networks. This was because as PV penetration increased, smart inverters began to curtail PV generation, whereas network upgrade/reconductoring enabled more PV generation.

Increasing the hosting capacity of LV networks with few customers is not cost-efficient because the benefit of additional PV generation is unlikely to outweigh the cost. This is evidenced by the example LV networks from the Low-density rural single-phase and Remote rural single-wire earth return (SWER) categories.

Importantly, modelling a small number of LV networks (10 out of 80,000) means that the results are unlikely to cover the diversity across CPPAL's entire distribution network. However, key findings from this study highlight typical issues faced by DNSPs when managing LV networks with increasing PV uptake.

Recommendations for government and industry stakeholders

Based on this study's results, 11 key recommendations were made — six recommendations to government and industry stakeholders and five recommendations for further investigation.

1. Allow for flexible export limits of PV generation

Governments could consider allowing for flexible export limits (also referred to as dynamic curtailment) in scenarios where it is appropriate.

Historically, DNSPs have applied a fixed (or static) export limit that caps PV exports to the grid. This blanket rule means that some customers are having their PV generation curtailed when it is not required. On the other hand, unlocking 100% of customers' PV exports across the entire distribution network would be economically inefficient and may create unnecessary upward pressure on electricity prices. Allowing customers to only be curtailed on the occasions when the grid requires it via flexible export limits is a more efficient alternative.

This study has shown that, in many cases, smart inverters achieve the highest net-benefit at low PV penetration levels by enabling dynamic export through Volt-Watt and Volt-VAR control. For some LV networks, mitigation measures that unlock 100% of customers' PV exports do not enable enough additional PV generation to offset their cost, even at very high PV penetration levels. In these cases, dynamic exports may be more cost-effective.

2. Promote and install smart inverters in jurisdictions that expect PV growth

Governments in jurisdictions with expected PV growth are encouraged to follow the example of the state of Victoria, by mandating the installation of smart inverters with Volt-Watt and Volt-VAR control enabled. DNSPs should include smart inverters as part of their connection agreements with customers installing PV.

Smart inverters with Volt-Watt and Volt-VAR response modes can progressively curtail PV generation and can act as a 'safety net' to ensure that voltage does not reach excessive levels. This can be achieved at a negligible additional cost for customers compared to standard inverters.

This study has shown that, through dynamic export, smart inverters can mitigate extreme voltage rise levels efficiently, even up to 100% PV saturation. While CPPAL's smart inverter settings have been shown to be effective, other DNSPs should determine optimal settings based on their context and local network conditions.

3. Consider other mitigation measures to complement smart inverters

While smart inverters mitigate voltage rise efficiently, they do so by curtailing a significant amount of PV exports at high PV penetration

DNSPs should expect to deploy a range of mitigation measures in conjunction with smart inverters. These will differ depending on the local network context.

Although smart inverters should be encouraged alongside all PV system installations, they should not be considered a 'silver-bullet' to solve all issues. While smart inverters can mitigate voltage rise, this study has shown they will not achieve optimal outcomes for the customer at high levels of PV penetration on many LV networks. This is due to high levels of curtailment.

Investment in targeted network upgrades should be expected, even after the widespread deployment of smart inverters.

4. Upgrade transformers during replacement activities

During a DNSP's normal transformer replacement activities, additional negative taps and transformers targeting the updated regulated voltage levels should be installed in all cases.

This study showed that an increased 'buck' tap range of an off-load tap changer had a much more beneficial impact on voltage than an increase of the transformer's rating and/or reconductoring of the LV network. So does the installation of a transformer targeting the updated regulated voltage range.

Many older transformers on CPPAL's network still target voltages that are 10 V above the regulated nominal voltage level. This is due to a regulatory change which moved the nominal value from 240 to 230 V in Australia. Because the transformer's transformation ratio is a fixed parameter of its make and model, full replacements are required to alter that characteristic.

5. Build power flow models for a wide range of LV networks

DNSPs are encouraged to invest in building a wide range LV network power flow models, either manually or through an automated process.

Although the 10 LV network examples were chosen through categorising CPPAL's LV networks, analysis has shown that they are not fully representative of the full population of LV networks. This is largely due to the diversity of LV arrangements.

The creation of an expanded set of example LV networks would allow a more accurate extrapolation to the entire distribution network.

6. Explore the potential of a fleet of behind-the-meter batteries

The grid-servicing potential of a fleet of behind-the-meter batteries (further detailed in recommendations 7 and 8) could be investigated by DNSPs and governments.

This study has shown that batteries will not contribute to increasing PV hosting capacity without coordinated management. Operating behind-the-meter batteries to simply maximise customer self-consumption did not improve LV power quality in any meaningful way. However, alternative battery operation modes that target grid services may achieve greater voltage regulation benefits.

This finding can inform future policies, particularly in Victoria, where Solar Victoria is currently piloting a battery rebate scheme. Although eligible customers must agree to receive information from DNSPs about taking part in battery trials, there are no guidelines around how customers should operate their battery[8].

> **This study has shown that batteries will not contribute to increasing PV hosting capacity without coordinated management**

Recommended topics for further study

Additional recommendations have been made for further analyses that were outside of the scope of this study.

7. Behind-the-meter battery operation

The operation of behind-the-meter batteries could be further explored as a mitigation measure against LV voltage rise.

Specifically, the optimal operating procedure of a fleet of batteries for mitigating power quality issues should be identified and quantified. In addition, further operating modes should be explored with the aim of identifying the alternate effects of batteries on different outcomes. An example could be the effect of reactive power absorption.

Reflected through the OpEN's project consultation, behind-the-meter batteries could be operated to target different (and sometimes conflicting) outcomes, such as arbitrage for customer profit or LV voltage management. These outcomes must be identified, valued, and compared. Opportunities for 'win-win' scenarios must be sought, wherein customers could be paid for providing grid services, potentially through an aggregator.

8. Behind-the-meter battery governance

Beyond the question of operation, the impact of different organisational structures could be investigated.

The potential roles and responsibilities of DNSPs, DSOs, VPPs and others could be explored, with the aim of establishing the maximum customer benefit. This would support the OpEN project's key objective of understanding the future role of DNSPs in managing an increasingly decentralised system[9].

These organisational scenarios should be compared with other grid-servicing options via a cost-benefit analysis, and they should be tested further through pilot studies. Lessons learned from this study and other ongoing projects, such as SA Power Network's Advanced VPP Grid Integration project, should be integrated into the design of further investigations.

[8] Solar Victoria, "Solar battery rebate", 2019.

[9] AEMO and Energy Networks Australia, "Open Energy Networks, Required capabilities and recommended actions (interim report)," July 2019.

9. Electric vehicles (EVs)

The potential positive and negative impacts of EVs could be explored.

EVs can be considered large flexible loads that are intermittently connected to the grid. Therefore, their potential as a mitigation measure should be assessed. As with behind-the-meter batteries, a properly managed EV fleet could provide LV voltage management services. Fleet management strategies could be explored, as well as identifications of customer usage patterns, and potential incentive programs to guide customers' charging behaviour.

Without proper management, EVs could contribute to voltage drop issues and maximum demand increase if allowed to charge during peak load periods. This could create local network congestion and contribute to widening the range of observed voltages on an LV network. The potential magnitude of both effects could be measured and explored across a range of uptake scenarios.

10. Additional mitigation measures and/or combinations of them

Further study could be undertaken to investigate the effects of combined mitigation measures on the metrics detailed in this report.

Throughout this study, mitigation measures were treated independently of each other. However, it is likely that the optimal LV voltage management solution uses a combination of more than one mitigation measure. Further, there may be other mitigation measures not explored in this study that can improve PV hosting capacity.

This study has shown that the mitigation measures assessed offer qualitatively different voltage-reduction effects — for example, the 'flattening off' of voltage rise offered by smart inverters compared to the discrete step-down of voltage levels offered by an OLTC. This difference suggests that no single measure will address all voltage issues as PV penetration increases and that, in some cases, more than one mitigation measure may be more effective.

It is also noteworthy that smart inverters will soon be regularly combined with other mitigation measures in Australia as they progressively become mandatory.

Further, HV-level measures could be assessed, such as HV regulators, OLTC functionality at ZSS, and traditional HV augmentation. Finally, additional mitigation measures could be considered, such as optimising controlled load dispatch (for example, hot water tanks) or additional network-side mitigation measures (for example, network-side batteries).

11. Management of both HV and LV voltages for long feeders

Further analyses could be undertaken that explore the use of HV and LV mitigation measures in combination.

DNSPs' voltage management strategy for long feeders must consider both HV and LV levels of the distribution network, because substantial voltage rise is expected in both network portions. Addressing both levels in a coordinated way will likely allow the best results on these long HV feeders.

Long HV feeders exhibit material voltage variation across DSSs. DNSPs are already mitigating this through HV voltage management (for example, with HV voltage regulators). It was observed that these variations would be amplified during times of export with widespread PV uptake. This reinforces the need for HV voltage management, independent of voltage effects within the LV networks.

It is also clear that voltage rise can be driven by effects purely within the bounds of an LV network, independent of voltage effects of the HV network. Therefore, addressing only one of these network portions (either HV or LV) will not suffice to mitigate customer voltage rise on these long feeders.

Contents

Abbreviations

Abbreviation	Definition
AC	Alternating current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced metering infrastructure
ARENA	Australian Renewable Energy Agency
C&I	Commercial and industrial
DC	Direct current
DER	Distributed energy resources
DNSP	Distribution network service provider
DSS	Distribution substation
DVC	Dynamic voltage control

Abbreviation	Definition
EV	Electric vehicle
HV	High voltage
kW	Kilowatt
LV	Low voltage
LVR	Low voltage regulator
OLTC	On-load tap changer
OpEN	Open Energy Networks
PV	Photovoltaic
SWER	Single wire earth return
V	Volts
VPP	Virtual power plant
ZSS	Zone substation

Definitions

Term	Definition
Distributed energy resources	Small-scale, decentralised energy generation or management that is located behind-the-meter. Common examples include rooftop solar PV, batteries and electric vehicles.
Distribution transformer	Power transformer that steps down high voltage electricity to low voltage electricity at the distribution substation so that electricity can be supplied to customers.
Power quality	Electricity supply that is continuous and delivered at the required frequency and voltage without waveform distortion. Poor power quality can affect efficiency and damage electrical equipment. In the Electricity Distribution Code, power quality means the measure of the ability of the distribution system to provide supply that meets the voltage quality requirements.
Reactive power	Power that does not do any useful work and is either generated or absorbed to maintain a certain voltage level so that real power can move through the transmission and distribution networks. It is measured in volt ampere reactive (VAR).
Real power	Power that is consumed or used, measured in Watts. Also known as true or active power.
Reverse power flows	When electricity flows upstream through the network from the consumer to the distribution and zone substations.
Tap changer	A component of a transformer that enables the connection from one 'tap' to another and varies the turns ratio of the transformer to increase or decrease voltage.
Thermal constraints	Limits on the maximum allowable temperature and power flow in a conductor or other asset on the distribution network to protect electricity infrastructure against thermal variation and overheating.
Topology	For the purpose of this report, data-driven structure of an LV network, which includes detailed technical and geographical information including the number of customers, customer and asset locations, asset types and asset connection graphs.

1 Study overview

This chapter provides an overview of this Australian Renewable Energy Agency (ARENA) funded Distributed Energy Resources (DER) Hosting Capacity Study. This study was undertaken in the context of PV penetration creating power quality issues on the low voltage (LV) portions of electricity distribution networks. It was led by CitiPower and Powercor (CPPAL).

CPPAL commissioned ENEA Consulting to use its distribution networks as a case study to:

1. Establish a replicable methodology to determine the hosting capacity of LV networks
2. Assess the techno-economic performance of LV mitigation measures to increase the hosting capacity of LV networks.

Key themes

Growing DER penetration is increasing the amount of electricity generated on LV networks, creating a new operating environment for managing distribution networks. Large exports of PV generation can increase voltage levels above the regulatory limit on the LV networks. Also, two-way electricity flows risk exceeding the thermal limits of distribution network assets.

Traditionally, electricity infrastructure was designed to deliver electricity from centralised, utility-scale power plants to downstream customers. Accordingly, distribution network service providers (DNSPs) have undertaken little monitoring of LV networks because most of the action was happening upstream.

The shift to a more distributed energy mix requires DNSPs to develop new knowledge and capabilities to improve the visibility of LV networks.

Chapter sections

- Section 1.1 — Challenges of growing distributed energy resources
- Section 1.2 — CPPAL's LV hosting capacity and measures for increasing it.

1.1 Challenges of growing distributed energy resources

DER is increasing globally

Globally, there is an energy transition underway from a system dominated by fossil fuels to a low-emissions future. One aspect of this transition is the rise of the 'prosumer[10]', a customer that both consumes and produces electricity. These customers are generating power in a distributed manner and causing energy systems to become more decentralised. Customers are increasingly taking advantage of DER, including rooftop solar photovoltaic (PV), behind-the-meter batteries and electric vehicles (EVs), to generate and store electricity on-site.

Australia is a global leader in rooftop photovoltaic (PV) uptake, with over 20% of households having a rooftop PV system installed [1]. Australians have installed over two million rooftop PV systems. In some areas of Australia, PV uptake is significantly higher than the national average, such as Mallala in South Australia, where 48% of customers had installations as of September 2019 [2].

The amount of DER is set to grow. CSIRO forecasts that over 40% of customers in Australia will use on-site DER by 2027, including 29 gigawatts of PV and 34 gigawatt hours of behind-the-meter batteries [3]. The Australian Energy Market Operator (AEMO) forecasts that DER could provide 13% to 22% of total underlying annual National Electricity Market (NEM) energy consumption by 2040. EVs are also expected to increase and make up 20% of light vehicle road transport by 2035 [3].

The growing penetration of DER is increasing the share of electricity generated and managed at the customer level. Historically, electricity infrastructure was designed to deliver electricity from centralised, utility-scale power plants to customers on the distribution networks. Therefore, this shift to a more distributed energy mix is creating a new operating environment for managing the distribution networks.

Role of DNSPs in accommodating growing PV penetration

DNSPs are responsible for managing and operating electricity distribution networks to maintain power quality and safe supply.

The Victorian Electricity Distribution Code sets out the obligations of DNSPs regarding quality of supply, including voltage. In Australia, DNSPs must deliver electricity at a voltage within -6 / +10% of the nominal voltage level of 230 V [4].

Increasing decentralisation is creating a new operating environment as prosumers are causing one-way flows (from generators upstream to customers downstream) to become bi-directional. This is a mode of operation for which distribution networks were not originally designed.

Increasing PV penetration can cause a range of issues, from safety issues linked with the inadequacy of traditional protection schemes, to power quality and thermal breach issues. Among these, maintaining voltage levels within the allowed range is usually the most constraining and priority problem to address, especially at LV network level[11]. Indeed, large exports of behind-the-meter PV to the LV networks during a period of low customer demand, such as during the middle of the day, can increase voltage on the LV networks above the regulatory limit.

Also, large exports of PV generation at the customer level can cause power to flow upstream, which can risk exceeding the thermal limits of some assets on the distribution network. In Australia, due to the high uptake of PV systems, these issues are resulting in increased customer complaints, involuntarily reduced PV generation (also known as 'curtailment') and distribution businesses sometimes delaying or refusing prospective PV connections.

PV is currently the primary focus in Australia among DER. However, Australians are increasingly showing interest in behind-the-meter batteries. In Victoria, this is supported by policy incentives. For example, Solar Victoria is currently piloting a Solar Battery Rebate scheme to help identify demand and battery usage in Victoria (1,000 rebates across 2019–20). The program is targeting locations with high PV penetration and population growth. As the economics improve and supporting policies are implemented, Australians are increasingly installing behind-the-meter batteries.

EVs can also create local network problems and are the primary concern in other jurisdictions experiencing rapid EV uptake. AEMO forecasts, in its step change scenario [4], that EVs will comprise only 8% of total National Electricity Market consumption by 2040.

Historically, DNSPs have undertaken little monitoring of the LV networks because most of the action was happening upstream. It is worth noting that Victorian DNSPs are in a favourable position in terms of LV network monitoring due to the deployment of advanced metering infrastructure (AMI) across the state. This means the ability of LV networks to accommodate growing PV penetration — their 'hosting capacity' — is relatively unknown and requires new knowledge and capabilities. Improving the visibility of LV networks to establish their hosting capacity will enable DNSPs to make more informed investment decisions to enable distributed PV generation by their customers in a cost-efficient way, while maintaining power quality and safe supply.

[10]A prosumer is a customer that both consumes and produces electricity. Electricity production may be consumed by the customer first and the excess fed back into the energy system in exchange for a feed-in-tariff.

[11]In this study 'LV networks' are the low voltage portions of the distribution network, downstream of distribution substations. Residential and small C&I customers are connected to the LV network, while larger C&I customers are directly connected to the high voltage (HV) network.

Understanding hosting capacity

The ability of a distribution network to accommodate DER penetration (or in this study PV penetration) without compromising power quality is known as its 'hosting capacity'. Several metrics have been used to assess the hosting capacity of the LV networks. These include:

1. The PV penetration level[12] when power quality issues first arise (or thermal limits are first breached, whichever happens first)
2. The average number of hours per day spent in breach of power quality limits as PV penetration increases
3. The rise of the annual maximum voltage level as PV penetration increases.

LV network management has historically been a low priority for DNSPs. It is only since DER have started to be used more widely that LV networks have begun presenting issues. As DER penetration increases, DNSPs are focusing more closely on the LV portions of distribution networks. However, it can still be challenging to gain a clear view on older LV networks without physical inspection. For this reason, LV hosting capacity is often unknown before voltage limits are breached, presenting challenges when planning for a future with such a large penetration of PV systems.

Characteristics of the LV portions of distribution networks can vary drastically, including the number of customers served, network topology, location on the HV feeder, conductor types and transformer attributes. These characteristics can have a large impact on voltage behaviour and subsequently each individual network's hosting capacity. The high variability between LV networks thus makes it difficult to apply a single solution to increase hosting capacity across the entire distribution network. It is likely that numerous measures are required, depending on the LV networks in question.

Other work contributing to DER integration

Australia's energy governance bodies are cognisant of these network challenges and a large body of work is already underway to improve network visibility and manage growing DER penetration. For example:

- AEMO forecasts that DER could provide 13% to 22% of total underlying annual National Electricity Market (NEM) energy consumption by 2040 [5]. Growth is driven mainly by PV, however storage will start to play a bigger role. AEMO has highlighted that the technical integration of DER requires updating DER inverter standards, ensuring visibility of LV networks to support decision-making and improving understanding of DER behaviour during power quality disturbances [6]
- Similarly, a joint Energy Networks Australia and AEMO project, Open Energy Networks (OpEN), is incorporating stakeholders' feedback on how to best integrate DER. This work has highlighted a primary focus on local network challenges, particularly LV voltage limits. The interim report identified improving network visibility, particularly through real-time monitoring — as well as establishing Australian standards or guidelines for DER operating envelopes for DER import/export — as required capabilities to support DER integration [7]
- The Australian Energy Market Commission (AEMC)'s work to transition to the 'grid of the future' highlighted that the lack of visibility of LV networks, inadequate technical standards and compliance, and an industry-wide lack of cost-reflective pricing are reducing efficiencies and causing power quality issues as DER penetration increases. In 2019, AEMC made recommendations regarding network challenges of integrating DER, some of which centred around DNSPs improving visibility of loads and voltages [8]
- Other studies are assessing options for LV voltage management as DER penetration increases. For example, the ARENA Networks Renewed project investigated the potential of smart inverters and battery storage to increase electricity supply quality and reliability [9]. In addition, there are multiple virtual power plant (VPP) pilots and trials occurring, which include assessing VPPs' potential for network management.

[12] PV penetration level is the percentage of the reference theoretical maximum penetration level (kW). The reference maximum PV penetration level (in kW) is reached when every residential and commercial and industrial (C&I) customer on an LV network has a 5 kW and 25 kW PV system installed respectively. This is also referred to as '100% PV penetration' or 'saturation' and is discussed in chapter 2.

1.2 CPPAL's LV hosting capacity and measures for increasing it

Given the above context, this study was designed to improve the understanding of LV networks and assess mitigation measures to enable further PV penetration while maintaining power quality. This study is an ARENA-funded project in the Advancing Renewables Program, led by CPPAL, a Victorian DNSP. CPPAL commissioned ENEA Consulting to:

1. Establish a replicable methodology to assess the hosting capacity of LV networks
2. Assess the techno-economic performance of LV mitigation measures to increase hosting capacity.

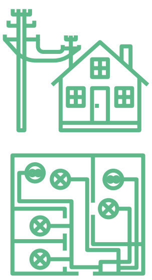
140k

PV systems installed on Powercor network in 2019

This study shares knowledge and insights gained with other participants in the ARENA Advancing Renewables Program and the broader energy industry, including other DNSPs and government agencies.

CPPAL manages over 80,000 LV networks across Melbourne and the western part of the state of Victoria, covering a 150,000 km^2 network area and serving approximately 1.1 million customers. Installed PV capacity on CPPAL's distribution networks has increased significantly. In 2019, Powercor experienced a 16% increase in rooftop PV, resulting in more than 142,449 additional installations.

Given growing PV penetration, improving the visibility of the hosting capacity of its LV networks will help CPPAL facilitate further PV connections and make more informed investment decisions to maintain power quality. This study will also help other DNSPs who are dealing with increasing DER uptake.



over

80k

LV networks managed by CPPAL

Establishing a replicable methodology to assess the hosting capacity of LV networks

The first aim of the study was to establish a methodology to assess the hosting capacity of LV networks, considering voltage levels and equipment thermal ratings constraints[13], using CPPAL's distribution network as a case study. This methodology is intended to be replicated by industry and public stakeholders wishing to investigate LV hosting capacity on other LV networks.

This study assessed the ability of LV networks to accommodate PV through the assessment of voltage levels under growing PV penetration. Advanced metering infrastructure (AMI) data from CPPAL customers was used, enabling voltage simulations of a high level of granularity. Modelling was undertaken using publicly available open source analysis software, which enables the methodology to be replicated by other industry stakeholders without reliance on proprietary software. The methodology is discussed in chapter 2 and the results are discussed in chapter 3.

Assessing the techno-economic performance of LV mitigation measures to increase hosting capacity

The second aim of this study was to assess the techno-economic performance of measures to increase the level of PV penetration without experiencing power quality issues. Traditionally, network augmentation has been used to manage increasing customer loads on distribution networks. In addition to network augmentation approaches, there are newly emerging customer-side options for improving hosting capacity.

This study assessed the techno-economic performance of five mitigation measures. This included a cost-benefit analysis that compared the value of additional PV generation enabled by each mitigation option with its costs for each of the example LV networks. The mitigation measures included a range of network augmentation[14] and customer-side solutions. These are listed in table 2.

The performance of the mitigation measures was assessed using key hosting capacity metrics (see 'Understanding hosting capacity' in section 1.1 on page 18). A cost-benefit analysis was undertaken to derive the net benefit of each mitigation measure under increasing PV penetration.

[13] The adequacy of protection schemes under high PV penetration is not explored in this study, nor are other aspects of power quality that are of lesser concern (for example, harmonics).

[14] Not all types of network augmentation mitigation measures are considered in this study. For example, the possibility of splitting an LV network over two transformers was not considered.

Table 2 • LV mitigation measures

Mitigation measure	Mitigation measure type	Summary
1. Transformer upgrade / reconductoring	Network augmentation	Replace the distribution transformer to include an off-load tap changer[15] with additional manual buck taps, increase the distribution transformer rating (where possible) and increase the quality of any connecting LV conductor (where possible).
2. On-load tap changer (OLTC)	Network augmentation	Replace existing transformer with a transformer fitted with an OLTC. An OLTC automatically adjusts voltage at the distribution substation (DSS) based on load characteristics on the LV network. This is also known as dynamic voltage control (DVC) and is more commonly installed at the zone substation (ZSS). Also increase the rating of the distribution transformer (where possible).
3. Low voltage regulator (LVR)	Network augmentation	Install LVR(s) on the LV network that use(s) a controllable transformer to increase or decrease voltage on the LV network.
4. Smart inverter	Customer-side	Enable an inverter (with associated Volt-VAR and Volt-Watt settings) alongside each PV system that has extended capabilities to sense and react to grid voltage by adjusting the real and reactive power exported from the PV system.
5. Behind-the-meter batteries	Customer-side	Install a battery behind-the-meter alongside each PV system. Batteries store and time-shift energy. In this study, they are assumed to be operated to maximise customer self-consumption.

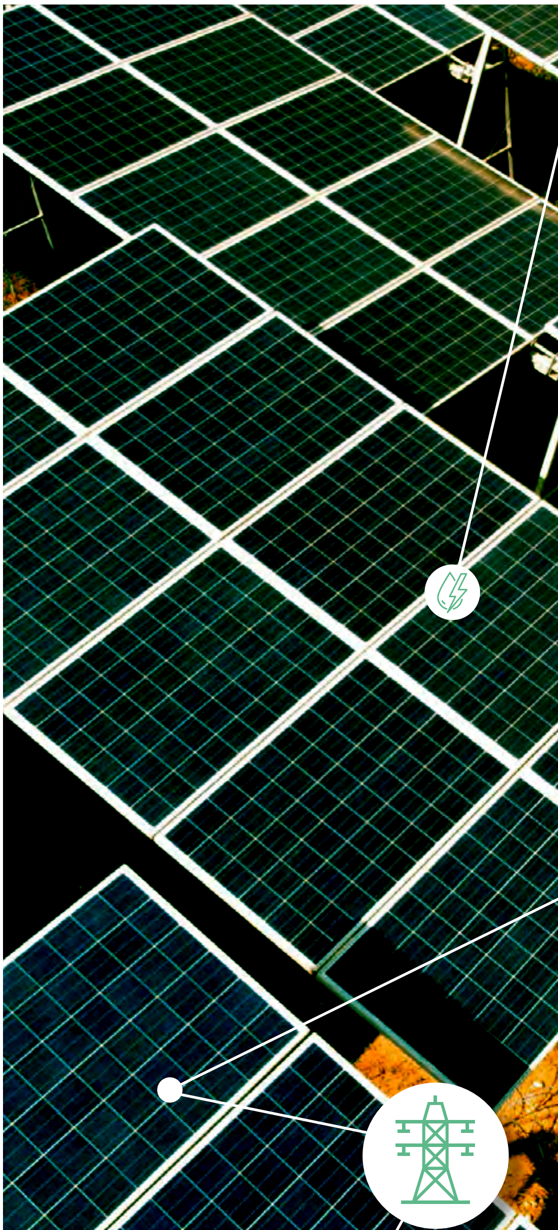
In Victoria, under the Victorian Government's Solar Homes Program, from 1 July 2019, customers installing PV systems are required to install smart inverters with Volt-Watt and Volt-VAR response modes to adjust the voltage level on LV networks. This means that smart inverters are becoming business-as-usual for CPPAL and other Victorian distribution networks. As part of the knowledge-sharing component of this ARENA-funded study, the techno-economic performance of smart inverters has been assessed to inform DNSPs operating in regions where they are not required.

Chapter 4 of this report includes a comparison of the different mitigation measures. The methodology for assessing the techno-economic performance of each measure and the results of that assessment are discussed in chapter 5.

[15] An off-load tap changer allows an operator to manually adjust the voltage ratio between the HV network and the LV network. Boost taps increase the output voltage and buck taps reduce the output voltage. The taps are manually adjusted based on network conditions. By comparison, an on-load tap changer automatically adjusts the output voltage in real-time based on load characteristics on the LV network.

2 Establishing hosting capacity

The first aim of this study was to establish a replicable methodology to determine the hosting capacity of CPPAL's LV networks. This chapter highlights the benefits and challenges of establishing hosting capacity and details the key parts of the methodology.



Key themes

Assessing the hosting capacity of the entire distribution network is a difficult task considering the high level of variability between individual LV networks. For this study, 10 categories were defined to represent common LV network topologies, enabling the selection of 10 diverse LV networks.

Using advanced metering infrastructure (AMI), a power flow model was built for each of the 10 example LV networks. The availability of AMI data allows for modelling real-world networks, avoids using oversimplified assumptions, and provides an opportunity to assess simulated voltage levels against historical voltage readings.

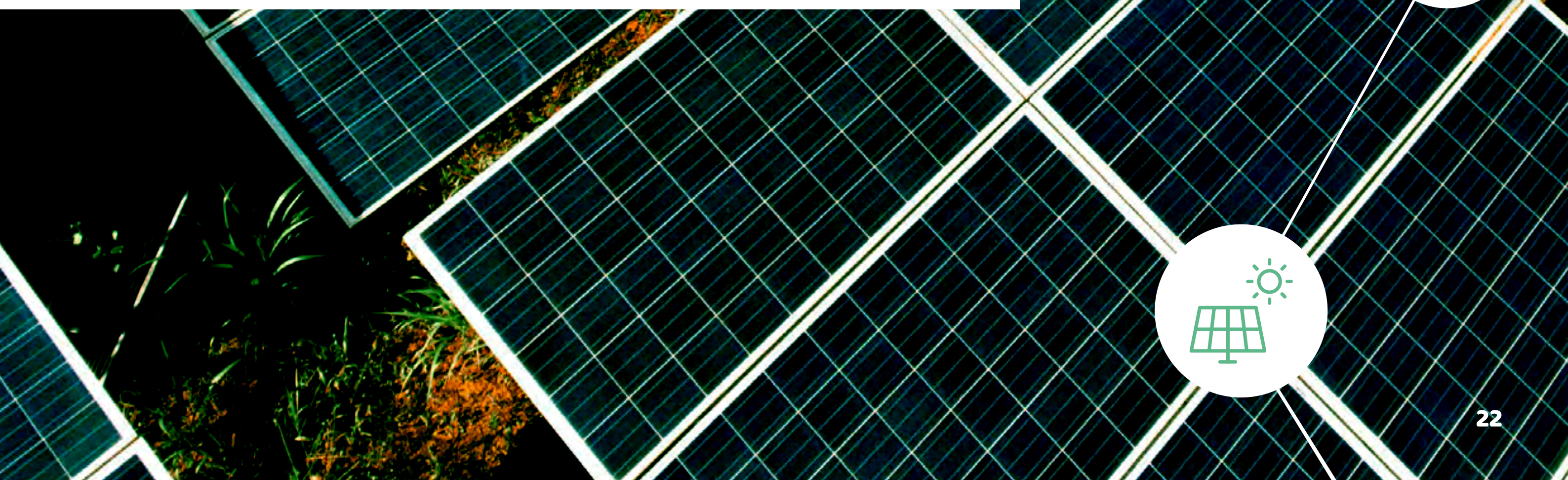
Overall, the methodology for establishing hosting capacity included defining hosting capacity, categorising the LV networks, building the power flow models, conducting a 'digital twin test' and power flow modelling under increasing PV penetration.

Anticipated challenges of establishing hosting capacity included:

1. Capturing the variability between CPPAL's LV networks
2. Representing the operation of certain network assets
3. Incorporating phase imbalance.

Chapter sections

- Section 2.1 — Overview of the modelling approach
- Section 2.2 — Hosting capacity methodology.



2.1 Overview of the modelling approach

This section provides an overview of the hosting capacity modelling approach, discusses some of the advantages and challenges and introduces limitations of the approach.

2.1.1 Key steps of the modelling approach

Assessing the hosting capacity of LV networks involved the following key steps:

1. Define 10 categories of LV network types based on common LV network topologies and map CPPAL's 80,000 LV networks to the 10 categories
2. Select a real-world LV network[16] as an example of each category and build a power flow model of each of the 10 LV networks (along with their HV feeder)
3. Characterise the LV hosting capacity of each specific LV network using three key metrics.

2.1.2 Advantages and anticipated challenges of the modelling approach

CPPAL previously investigated hosting capacity at the HV level. This previous study aimed to establish hosting capacity by investigating HV feeder voltages under increasing PV penetration. It found that further investigation at the LV level was important to establishing hosting capacity, because most issues were concentrated on the LV networks.

Undertaking power flow assessments of PV connections that reflect customer behaviour across all times of the year is time-consuming. As such, standard industry practice has instead focused on worst-case conditions to predict network constraints. Thanks to the roll-out of AMI across CPPAL networks, data for most customers at 30-minute intervals is available, meaning that a highly granular understanding of network conditions is possible for a given LV network.

To capture the high level of variability between CPPAL's 80,000 LV networks, 10 network categories were defined, each representing common LV network topologies. Categorising the population of LV networks is inherently challenging due to the highly variable nature of the network at the low voltage level and the large impact small differences between networks can have on voltage behaviour. Categorising LV networks by representing common network topologies enabled the selection of real-world LV networks as examples for each category, resulting in 10 highly diverse real-world LV networks.

A power flow model was built to represent each of the 10 LV networks using AMI, geospatial and topological data. Power flow modelling was performed over a 12-month historical period, meaning that actual historical customer load from this period could be aligned with historical network and weather data as modelling inputs. The availability of AMI data has the added benefit of avoiding the need to oversimplify assumptions about customer load[17], while giving a realistic view of the variety of loads within the LV networks, their diversification and relationship with changing weather patterns, and historical voltage readings.

Another benefit of modelling real-world networks as opposed to pseudo LV networks is that modelling outputs can be validated against historical voltage readings. When all inputs are aligned as described above, it is expected that power flow voltages are very similar to the historically observed AMI voltages, where discrepancies between the two are easily identified. Model design progressively moves closer to an accurate representation of reality by iteratively addressing the discrepancies, which could come from a range of sources. It was anticipated that two key sources of discrepancies during this 'digital twin' test would be:

1. Accounting for the operation of certain network assets, such as zone and distribution substations
2. Incorporating phase imbalance (see 'Phase imbalance amplifies voltage variability on the LV network' in section 2.2.4), considering that phase imbalance influences voltage levels but each customer's phase allocation is for the most part unknown.

Section 2.2.4 outlines how the modelling approach was adapted to ensure that the modelling output reflects the impact of network asset operation and phase imbalance on voltage levels as accurately as possible.

2.1.3 Limitations of this study

Categorising LV networks

Currently, creating real-world LV network power flow models is a time-consuming process when compared to the creation of HV network power flow models. This means that the study was limited to the inclusion of 10 LV network examples. Although these 10 examples were intended to capture a wide variety of network types, it is difficult to confidently make network-wide inferences based on the limited sample size.

[16] A 'real-world' LV network refers to an LV network that exists in CPPAL's distribution networks.

[17] As AMI data does not provide information about a customer's power factor in all cases, an assumption was taken that unknown power factors were 0.9, which is the middle of the DNSP's regulated operating range. In most cases, power factor was available for commercial and industry customers, and was used when available.

LV networks are far more variable than other portions of the distribution network. A large number of known characteristics (e.g. conductor impedance, customer density) and unknown factors (e.g. phase imbalance) impact voltage behaviour. The study initially intended to extrapolate the example results across CPPAL's distribution network, but due to variability of LV network characteristics even within each category, this extrapolation would have been potentially misleading without significant further work. For that reason, network-wide extrapolation was largely removed from the study.

LV network management has historically been of low priority for DNSPs, because it is only since DER began to be widely used that LV networks have begun presenting issues. For this reason, geospatial and topological information has not always been readily available or of the highest quality, meaning the geospatial data used to build the power flow models for this study could include inaccuracies or be out of date. This could result in power flow outputs that are slightly altered under additional PV penetration, but is unavoidable within the scope of this study.

HV voltage management

Further, HV voltage management was not considered in this study. HV regulators were actively removed from HV feeder models during power flow modelling, and other HV voltage management capabilities (for example, ZSS tapping) were not leveraged. This makes modelling results conservative in terms of voltage rise, since the real-world HV network is regulating voltage in a way that is not reflected in the power flow analysis. Removing HV regulators impacts two of the 10 example LV networks (downstream of the HV regulator) and slightly amplifies voltage variations.

In most cases, historical ZSS voltage is used to represent ZSS behaviour for a given time and date, aligning with historical weather and customer load at that time. As part of the modelling pipeline, this simulation is rerun many times with gradually increasing PV uptake. Using the historical ZSS voltage is a conservative approach, as in reality, the ZSS line drop compensation would reduce voltage as demand decreases due to PV generation. However, at very high PV penetration levels, it is expected that the voltage regulation would reach its range limits, reducing its efficiency. These HV regulation aspects are outside the scope of this study.

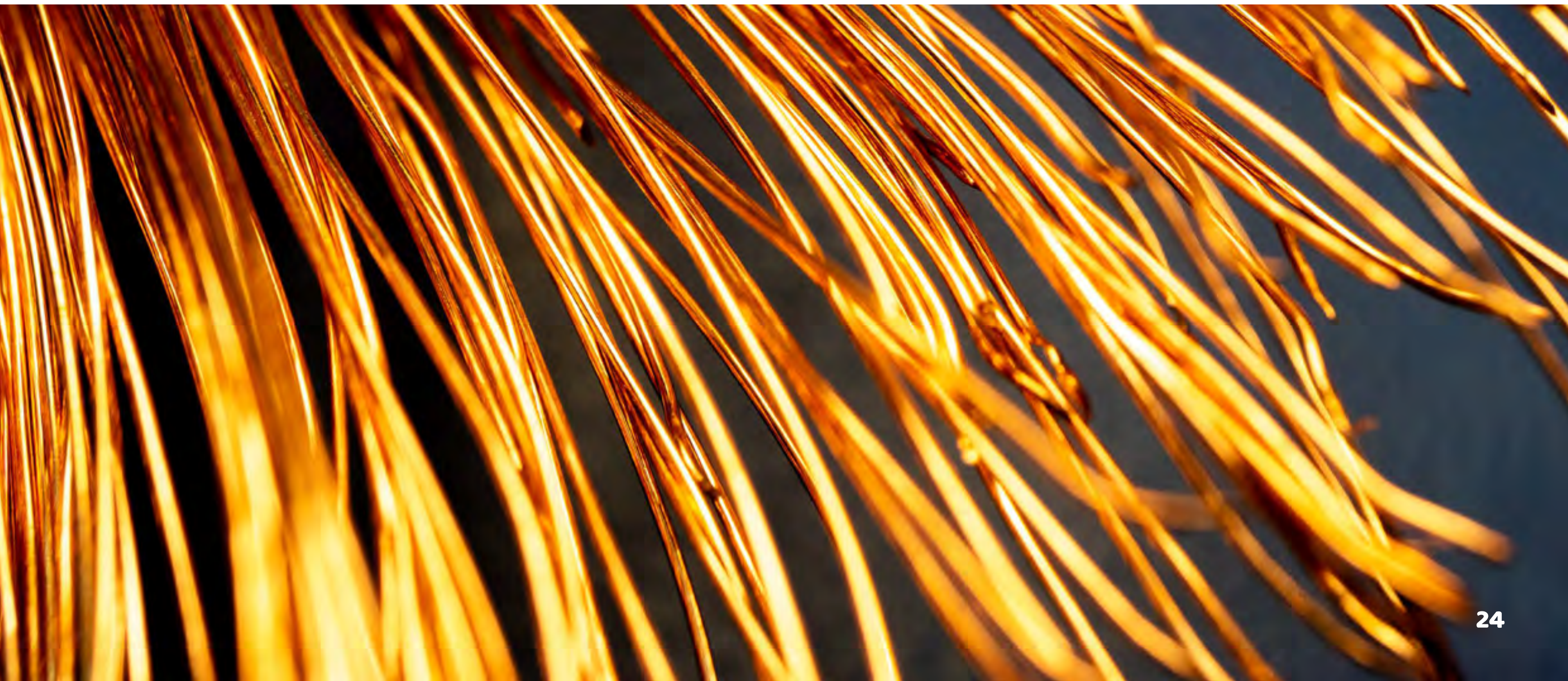
By design, this study focuses only on LV mitigation measures (detailed in appendix 5) and LV voltages. This focus stems from the fact that voltage issues are primarily being observed at the LV level. That said, key learnings from this study (see chapter 3) indicate that HV voltage management will be key to addressing LV voltage issues in the future despite HV measures being out of the study's scope.

Phase imbalance

In a three-phase network, 'phase imbalance' occurs if customer load is unevenly distributed across phases. Phase imbalance can amplify or dampen voltage rise and voltage drop. However, an individual customer's phase allocation is not currently known on CPPAL's distribution network.

This means that modelling phase imbalance directly cannot be achieved, and each customer is treated as a balanced three-phase load in the power flow model. This creates a highly optimistic view in terms of the LV network's ability for voltage regulation. To mitigate this effect, phase imbalance was captured separately as a post-processing step. This is discussed further in section 2.2.4.

The methodology for establishing hosting capacity is detailed in section 2.2.



2.2 Hosting capacity methodology

This section details the key elements of establishing a methodology to determine LV networks' ability to accommodate increasing PV penetration.

2.2.1 Defining hosting capacity

Despite being a topic of discussion among industry stakeholders, there is no official or agreed-upon definition for hosting capacity. In this study, we assessed the three metrics listed below when considering LV networks' ability to accommodate increasing PV penetration levels. These metrics aim to capture the multifaceted nature of the term 'hosting capacity':

1. The PV penetration level when the first breach of either the voltage limit or thermal constraint occurs on the LV network
2. The amount of time spent in breach
3. Voltage rise.

Throughout this report, PV penetration levels are presented in plots and charts. These figures assume no network augmentation (besides those explicitly included as mitigation measures) or HV voltage management. Realistically, DNSPs would invest in augmenting the HV network, because PV penetration causes HV voltage rise. However, these activities (such as installing HV voltage regulators or reconductoring) are not included in the modelling. This allows a focus on the specific LV mitigation measures and their independent effectiveness in an otherwise unmanaged network. In this study, the LV networks are thus theoretical given their isolation from any HV mitigations.

Metric one: PV penetration level when the first breach occurs

This metric assesses the percentage of the reference maximum penetration of PV (in kilowatt peak (kWp)) when either voltage issues are first observed on the LV network or the thermal constraints of the LV network are breached. This assumes:

1. The reference maximum penetration is reached when every residential customer and commercial and industrial (C&I) customer on an LV network has a 5 kW and a 25 kW PV system installed respectively. These system sizes are taken from current average installation sizes and are larger than historical averages
2. Voltage issues are voltage readings above the maximum voltage limit of +10% of the nominal voltage level of 230 V (or under -6% below)
3. Thermal constraints depend on the rating of the assets on that LV network and occur when network assets are overloaded. Note that this can occur in either direction, where a large amount of PV generation could cause reverse power flow that is greater than a distribution asset's rated capacity.

Metrics two and three: The amount of time spent in breach, and voltage rise

Metric one indicates the level of PV penetration that the LV network can handle before first issues arise. However, assessing this metric alone does not capture the multifaceted nature of voltage management.

Specifically, this study assesses the amount of time spent in breach and the magnitude of voltage rise experienced as PV penetration increases beyond the first breach, as a measure of the gravity of the non-compliance. These metrics are further detailed below:

1. Amount of time spent in breach: The LV network's annual average number of hours per day, with at least one customer in breach of the maximum voltage limit as the PV penetration level increases. This metric is sensitive to situations where a single customer within an LV network has issues, or networks with a very large number of customers
2. Voltage rise: The increase in annual maximum observed voltage at customer's premises as PV penetration increases. This captures the magnitude of power quality issues by measuring voltage rise on the LV network under increasing PV penetration.

Defining hosting capacity using these metrics is a theoretical exercise that aims to assess network voltage as PV uptake increases, with no investment in mitigation measures. The metrics are calculated in a scenario where all customer connections are accepted, and PV generation is not curtailed. This means that, for example, a voltage rise value at 50% PV penetration would assume that 50% of customers have an uncurtailed PV system operating at full output, regardless of observed voltage.

2.2.2 Categorising the LV networks

To capture the variability of CPPAL's 80,000 LV networks, 10 LV network categories were defined, based on common LV network topologies and features that influence hosting capacity. These included the distribution transformer rating, number of customers on the LV network, HV feeder type and conductor type.

Considering these four features, the 10 LV network categories listed in table 3 were identified, based on common arrangements. Each of CPPAL's 80,000 LV networks were allocated into one of these 10 categories.

Table 3 • LV network categories

Category name	Description	Transformer kVA rating	Number of customers	Feeder type	Conductor type	Number of customers mapped to this category
1. High-density indoor	High density commercial and urban	1000	Any[18] (~ 1–100)	Any	159mm (0.25 in) 3/c cu plysws	~150k
2. URD kiosk	Residential estates, underground cabling	315	>50	Any	185mm 4/c lv.sa.x	~140k
3. Mid-density pole	Mid-density commercial and urban	500	>10	Urban, Rural Short	4-19/3.25 AAC	~180k
4. C&I pole	Commercial and industrial	500	<10	Any	4-19/3.25 AAC	~15k
5. Urban pole	Metro urban	315	>50	Urban	150mm LV ABC	~390k
6. Urban C&I pole A	Commercial and industrial	315	<50	Urban	150mm LV ABC	~15k
7. Urban C&I pole B	Commercial and industrial, with a modified conductor type	315	<50	Urban	4-6/.186,7/062 ACSR	~15k
8. Mid-density rural pole	Mid density rural setting — small properties (in town)	100	Any[18] (~1–10)	Rural Long, Rural Short	4-6/1/114 ACSR	~90k
9. Low-density rural single phase	Lower density rural — large properties	50	Any[18] (~1–10)	Rural Long	3-7/.064 Cu	~90k
10. Remote rural SWER	Single rural customer — farming/ remote	10	Any[18] (~1)	Rural Long	2-7/.064 Cu	~30k

[18] 'Any' means that the number of customers did not impact categorisation into that LV network category.

2.2.3 Building the power flow models

To ensure a wide variety of LV networks were included in the study, a real-world LV network was selected as an example of each category. The features of each real-world LV network are detailed in the appendix 3. The topology of each LV network was built manually using:

1. Geospatial and topological Geographic Information System (GIS) data, including customer and asset locations, conductor types and asset connection graphs
2. CPPAL customer AMI data for historical customer load profiles and historical voltage levels for the 12-month modelling period.

Figure 2 shows the general structure of each power flow model. Each model has an HV feeder with the single selected LV network attached at its real-world location. The loads of all other LV networks on that HV feeder are aggregated at the DSS . A 12-month period spanning calendar year 2017–18 was used for the power flow modelling.

This study takes a conservative approach to assess hosting capacity by not modelling HV voltage regulation.

Using historical weather data, PV generation was calculated for the full 12-month simulation period for each customer using the open-source Python library 'pvlib', using:

1. Assumptions regarding PV system size for residential and C&I customers
2. The LV network's local historical irradiance and temperature data across the selected 12-month period
3. Location of smart meters
4. Assumptions regarding solar panel tilt and orientation, detailed in appendix 1.

Power flow modelling was performed with Pandapower, an open-source Python library developed by The Fraunhofer Institute. Pandapower's open-source nature allows thousands of simulations to be run in parallel and for the methodology to be reproduced by stakeholders across the industry.

Figure 2 • Illustration of an LV network model

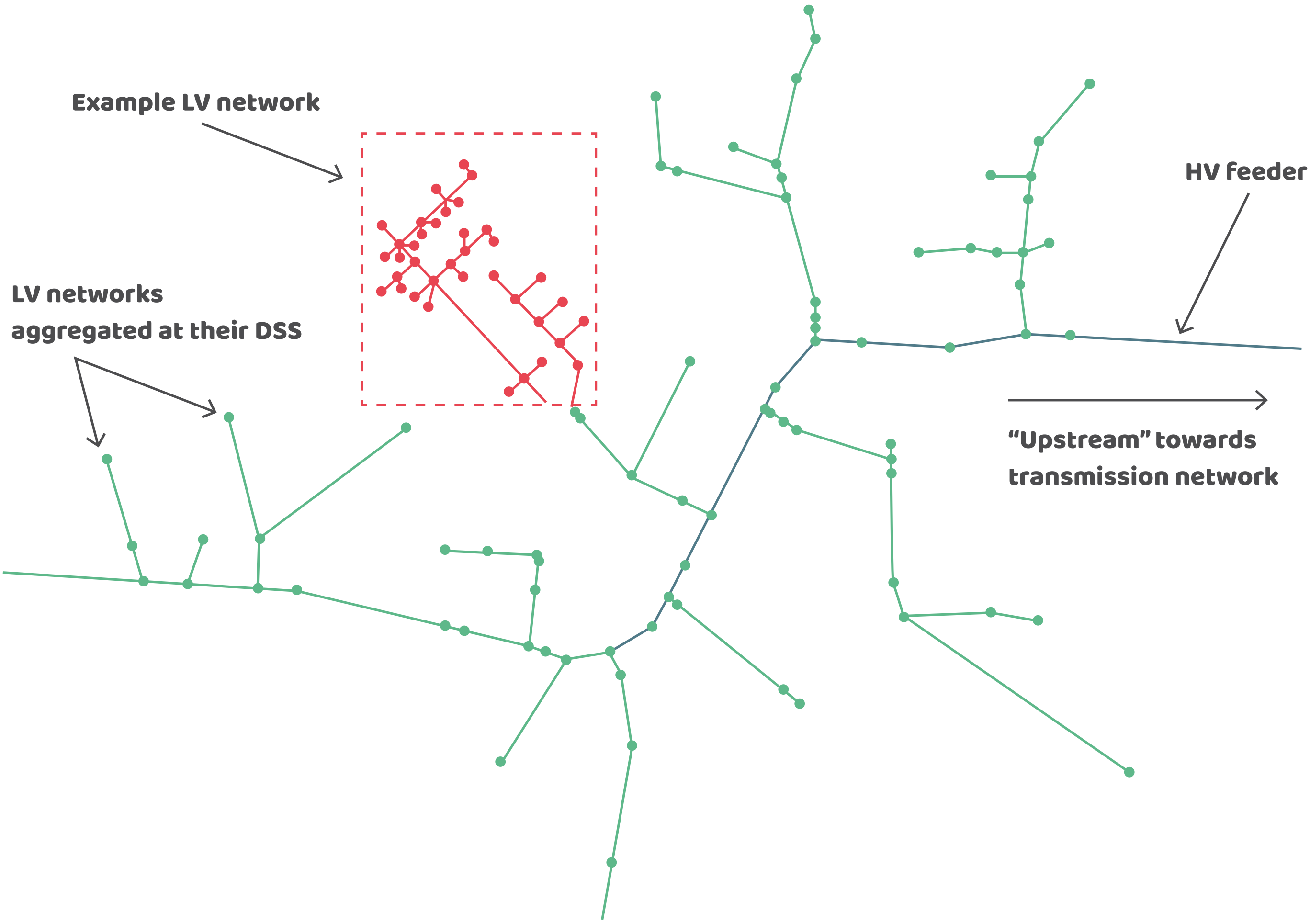
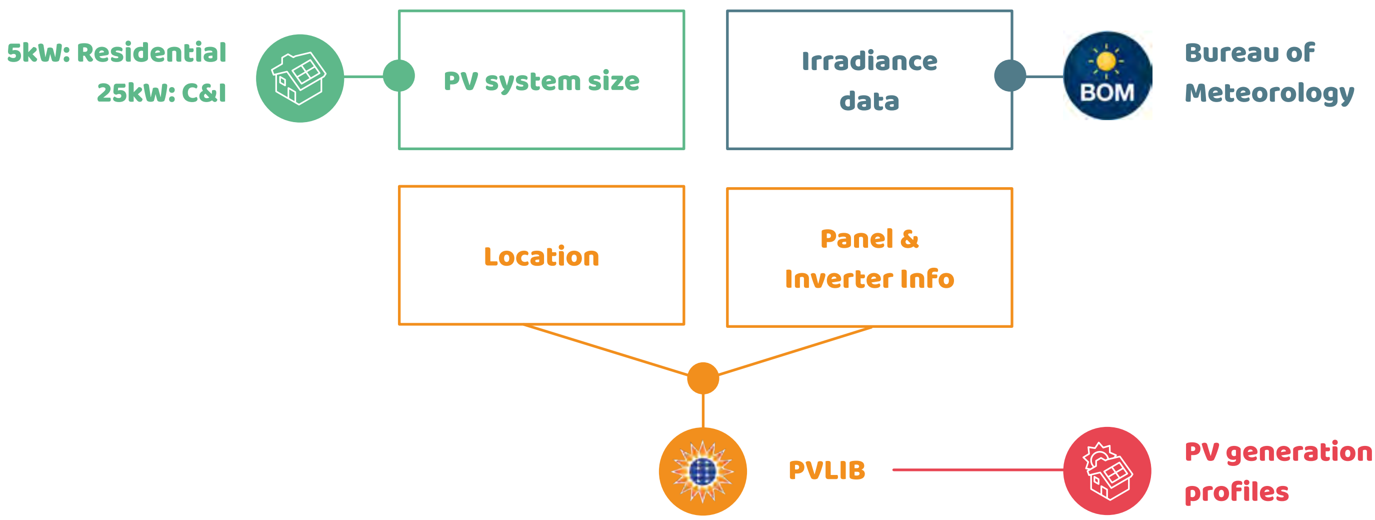


Figure 3 • Illustration of simulating PV generation profiles



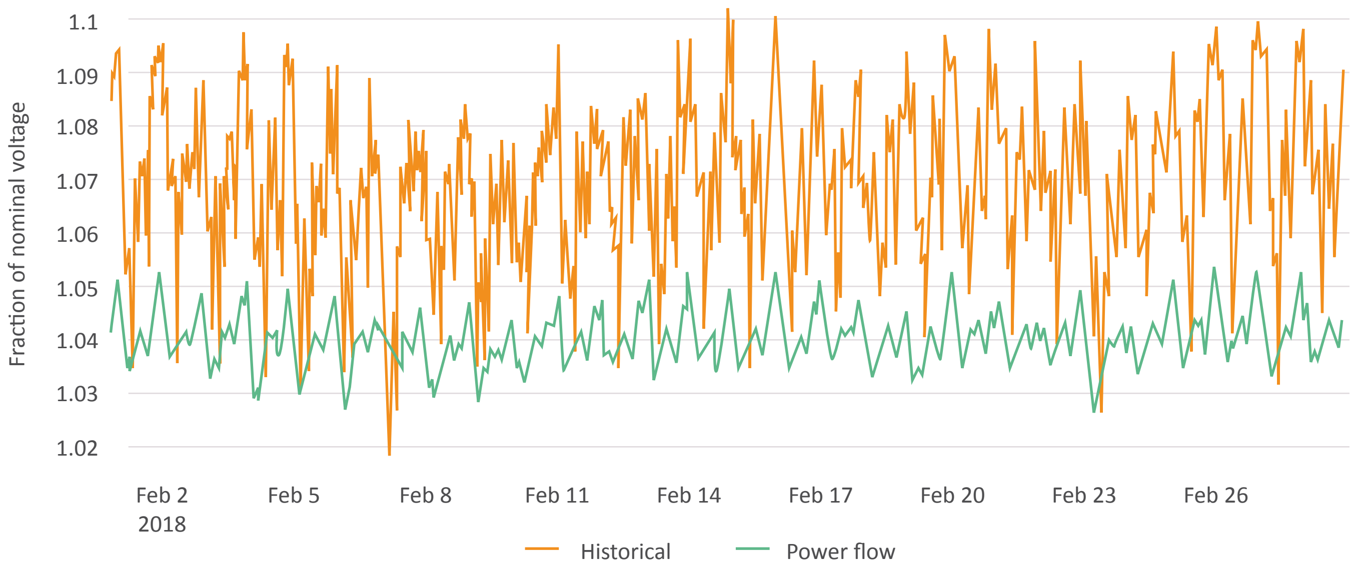
2.2.4 Advanced metering infrastructure (AMI) and conducting a 'digital twin test'

As previously mentioned, one advantage of using AMI data in this study was that it enabled validation of modelling results against real-world behaviour. AMI provides historical voltage readings, which can be compared to power flow outputs in a 'digital twin test'. Adjustments can then be made to the methodology to improve the modelling accuracy.

In this study, baseline power flow modelling outputs were generated for every 30-minute period over one month, using historical load data and no additional PV. These results were compared to historical AMI readings for each customer during the same period.

It was anticipated that the operation of network assets and phase imbalance would cause differences between simulated and historical voltages. The digital twin test highlighted that the magnitude of these two effects was larger than expected. A comparison of the baseline simulated voltages and historical voltages showed that the power flow modelling produced voltages that were lower and less varied than what occurred historically. See figure 4 as an example.

Figure 4 • Mean customer voltages for an example LV network



Network asset operation influences LV network voltage

The operation of certain assets at the ZSS or DSS levels influences voltage levels on the LV network. For example:

1. ZSSs are equipped with on-load tap changers, which adjust the turns ratio of a transformer to raise or lower voltage based on changes in demand on the network. This operation cannot be recreated perfectly given new steady-state modelling conditions, because tap position depends on recent events at the ZSS.
2. In addition, many DSSs are equipped with off-load tap changers, which are manually set to a position that modifies their voltage output. That position is unknown.

It was critical to represent these behaviours accurately, to ensure confidence in modelling outputs when additional PV installations are simulated. As such, baseline power flow modelling was initially performed with ZSS voltage set at 100% nominal (22 kV in most cases) and tap changers set at neutral at the DSS. As expected, these initial simulated LV voltages were lower than those historically observed, which was attributed to the ZSS and DSS behaviour that was not initially represented in the modelling.

Behaviour such as line drop compensation at the ZSS, HV regulators and manual DSS tap settings also needed to be represented, because they all influence individual customer voltage downstream. The following approach was taken to account for their effect:

1. For most models, the ZSS was set to its historical voltage at the timestamp of the simulation, which matches the timestamp of the historical load and PV generation. Using the historical ZSS voltage amounts to a conservative view, as in reality, the ZSS line drop compensation would reduce voltage as demand decreases due to PV generation. However, at very high PV penetration

levels, it is expected that the voltage regulation would reach its range limits, reducing its efficiency. These HV regulation aspects are outside the scope of this study.

2. For other models that did not experience substantial HV voltage rise, the 100% nominal assumption sufficed to match simulated with historical voltages.
3. To account for unknown DSS tap settings, a correction was applied to each of the 10 example LV networks, inferring the unknown DSS transformer's tap position from historical voltage readings.

Phase imbalance amplifies voltage variability on the LV network

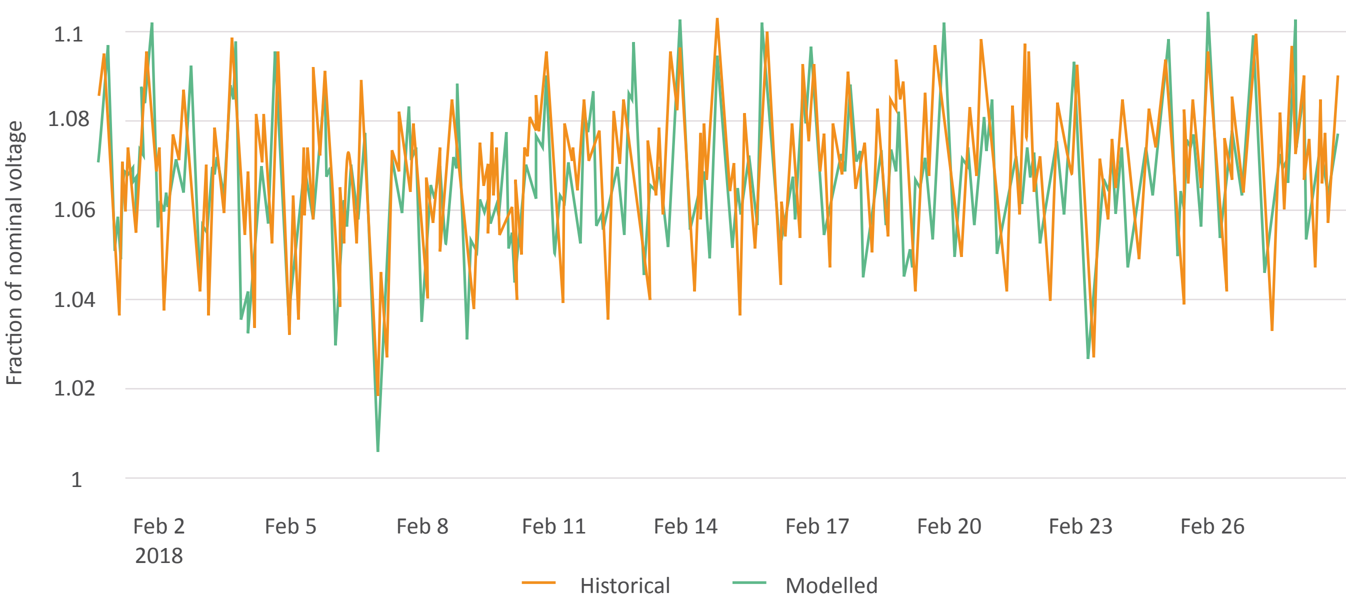
In a three-phase network, if customer load is unevenly distributed across the three phases, both voltage rise and voltage drop are amplified or dampened by an effect known as 'phase imbalance'. Currently, individual CPPAL customer's phase allocation is not known, despite ongoing efforts to build an inference algorithm using AMI data sources. Because of this, a balanced modelling approach has been used, which treats each customer as a balanced three-phase load. This is a highly optimistic view of the LV network's ability to regulate voltages, so the effect of phase imbalance was captured separately.

A linear relationship was observed between unbalanced historical AMI voltage readings and the initial balanced power flow model's output. As expected, historical voltage readings swung more extremely from their mean value than the initial balanced power flow modelling results. A linear model was fit separately for each customer and used to correct their power flow voltages, by increasing the amount of voltage swing to the level observed in historical readings.

A caveat of this approach is that as PV penetration increases, the character of each customer's phase imbalance is likely to change, especially due to PV generation lacking diversity. The modelling in this study assumes that each customer's phase imbalance correction does not change with additional PV. The implicit assumption is that the distribution of phase imbalance across an LV network's customers remains relatively stable.

After network asset operation and phase correction, modelling results align much more closely with historically observed voltages, as shown in figure 5.

Figure 5 • Mean customer voltages for an example LV network



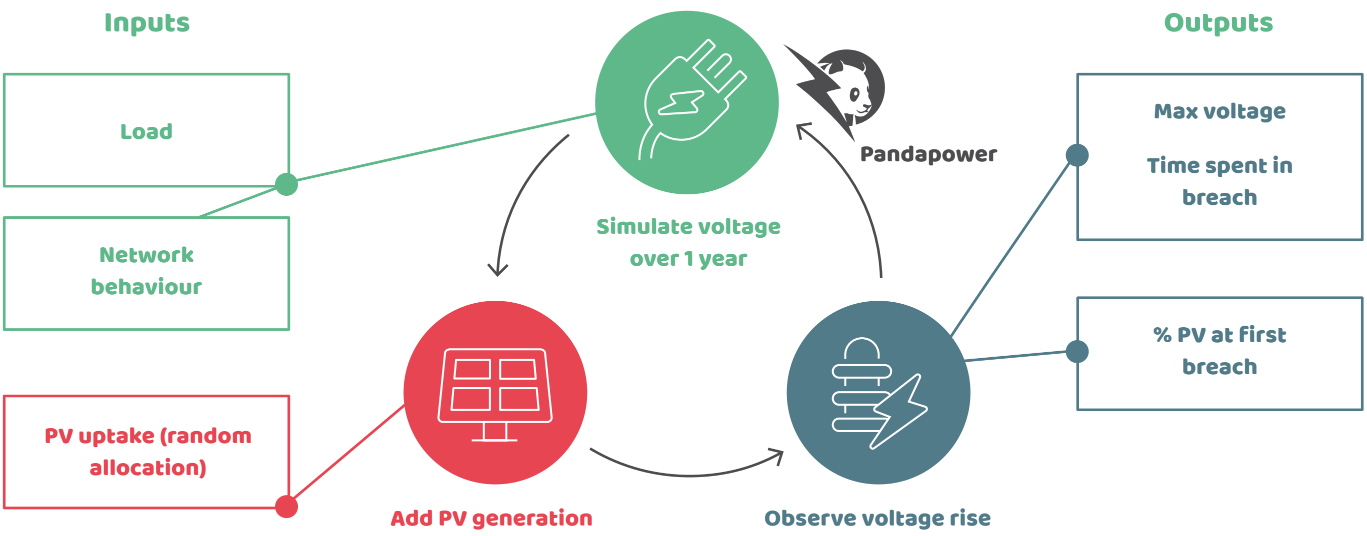
2.2.5 Power flow modelling under increasing PV penetration

PV installations were incrementally added until the reference maximum penetration was achieved, starting from the existing PV penetration level. After a PV system has been installed, the generation profile for that system's location was subtracted from the customer's historical load to give its new load profile.

PV systems were installed across the entire feeder as well as inside the LV network of interest. Five random scenarios were undertaken to allow for the exploration of uneven distributions of PV both within the LV network and across the entire HV feeder. In all cases, the worst-case (highest voltage) random allocation was reported, although generally this did not account for more than a 2–3 V difference in terms of maximum observed voltage. Taking the highest voltage scenario is a conservative assumption, wherein the 'worst-case' random allocation is taken, which may (for example) have seen an allocation of PV systems skewed towards the ends of a radial LV network.

For every daylight hour over a 12-month period, power flow simulations were run on a 30-minute basis. The full set of approximately 8,000 power flow simulations were performed for each incremental increase of PV penetration. The results were investigated and assessed according to the three metrics detailed in section 2.2.1.

Figure 6 • Illustration of hosting capacity modelling pipeline process



3 Hosting capacity results

This chapter discusses the results of CPPAL's hosting capacity for the example LV networks. Using the methodology detailed in chapter 2, the PV penetration level when the first breach of either the maximum voltage limit or thermal constraint occurred, the amount of time spent in breach, and voltage rise as PV penetration increased were investigated.

Key results

The results establish the baseline hosting capacity for this study. Key findings include:

1. The **results of all three metrics were highly variable** across the 10 example LV networks, with the PV penetration at first breach ranging from 0 to 100%. Three out of the 10 example LV networks experienced at least one breach of the maximum voltage limit without additional PV installations
2. **Given unregulated, unmanaged PV uptake, theoretical voltage rise was extreme** (up to 200% nominal). Importantly, CPPAL's current safety procedures would not allow this to occur. Nevertheless, the **voltage-management task is a substantial one**
3. **Older distribution transformers** (commissioned when nominal voltage was regulated to 240 V) **increased nominal voltage** at the **LV level**
4. On the **one long HV feeder** considered in this study, simulated **increases in PV** penetration further **reinforced the need for HV voltage regulation** (already present on this feeder but not accounted for in this study)
5. **Issues** faced by the **four short HV feeders** were **confined** to the **LV level**
6. On **all** of the example **LV networks**, a breach of the **voltage limit occurred before thermal issues** arose.

Chapter 5 details how different mitigation measures were applied to assess their ability to enable additional PV uptake.

Chapter sections

- Section 3.1 — PV penetration when the first breach occurs
- Section 3.2 — Amount of time spent in breach, and voltage rise
- Section 3.3 — HV network considerations
- Section 3.4 — Impact of distribution transformers.

3.1 PV penetration when the first breach occurs

Table 4 compares the current PV penetration level with the PV penetration when the first breach of the power quality limits occurs, for each of the 10 real-world LV networks. There were no breaches of thermal constraints in this part of the study. Table 4 shows that:

1. The PV penetration level at first breach varied widely between the LV networks, ranging from 0% to saturation
2. Two of the 10 LV networks (from the High-density indoor and C&I pole categories) never experienced a breach and were able to reach maximum penetration
3. Three of the 10 LV networks (from the Mid-density pole, URD kiosk and Urban pole categories) experienced a breach before reaching saturation
4. One of the LV networks (from the Mid-density pole category) could accommodate 80% PV penetration before there was a breach of the maximum voltage limit
5. The remaining five LV networks experienced a breach at their current PV penetration level. For these LV networks, power quality issues occur before the indicated PV penetration level.

Table 4 • Theoretical[19] PV penetration when first breach occurs for the 10 example LV networks

LV network model				PV Penetration	
Category	**Conductor**	**Transformer rating (kVA)**	**Number of customers**	**Current PV penetration level**	**PV penetration level when first breach occurs**
1. High-density indoor	159mm² (0.25 in) 3.5/c Cu	1000	9	0%	>100%[20]
2. URD kiosk	185mm² 4/c lv.sa.x	315	125	13%	24%
3. Mid-density pole	500kVA - 4-19/3.25 AAC	5000	23	6%	80%
4. C&I pole	4-19/3.25 AAC	500	9	4%	>100%[20]
5. Urban pole	150mm² LV ABC	150	57	2%	9%
6. Urban C&I pole A	150mm² LV ABC	315	15	1%	1%
7. Urban C&I pole B	4-6/.186,7/062 ACSR	315	16	1%	1%
8. Mid-density rural pole	4-6/1/114 ACSR	100	24	13%	13%
9. Low-density rural single-phase	3-7/.064 Cu	50	6	17%	17%
10. Remote rural SWER	2-7/.064 Cu (customer connected directly to substation)	20	1	0%	0% (13% across HV feeder)[21]

[19]PV penetration is unmanaged, without additional augmentation or voltage management. For this reason, realistically, the distribution network would never allow voltages to reach such problematic levels. Values shown are those of an unmanaged network and, as such, should be considered 'theoretical'.

[20]In these examples, no breach was observed after reaching (what is defined in this study as) 100% PV penetration. See chapter 2 for details.

[21]There is only one customer in this LV network, meaning that PV penetration is either 0% or 100%. This shows that there is a breach of the maximum voltage limit when PV penetration reaches 13% across the HV feeder.

Penetration at first voltage breach extrapolated to other category members

In figure 7, the penetration at first voltage breach is extrapolated from the example network to all other category members, in a map that is indicative only.

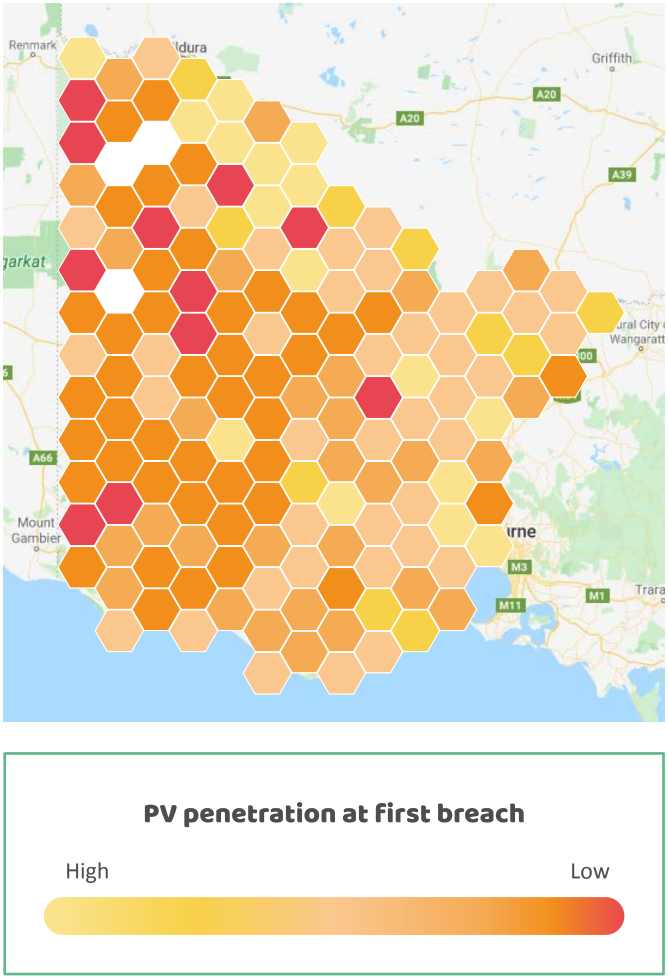
This map shows that hosting capacity is low across the CPPAL network, particularly in regional and remote areas. Also, by scaling this measure for population, the potentially challenging areas of CPPAL's distribution network have been highlighted. Some areas have high population density and low hosting capacity, meaning that a large number of customers may be affected by a modest increase in state-wide PV penetration.

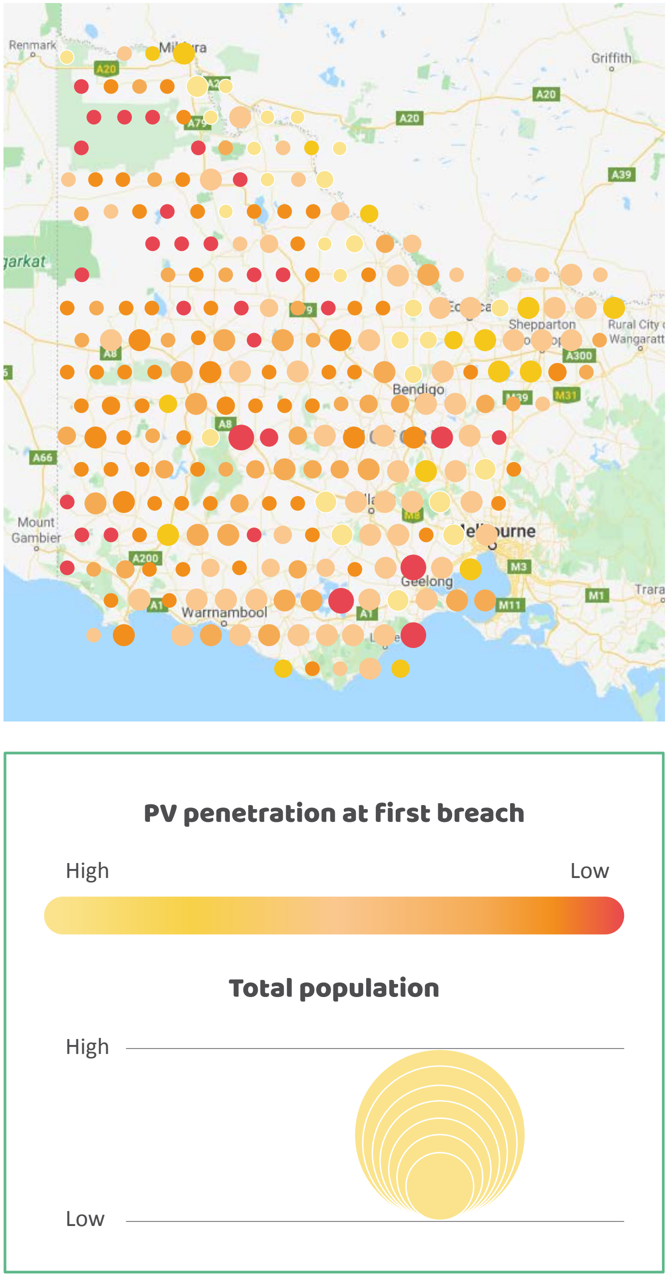
Limitations of extrapolating results

Each of CPPAL's 80,000 LV networks were mapped into one of the 10 categories. The intent was that a representative example would be taken from each category, the analysis of which would be extrapolated across the CPPAL network to all other members of the category.

However, this approach would assume that inferences of an entire category could be drawn based on a single example, which risks inferring too much from the example network's unique circumstances. For example, if the selected URD kiosk network happened to have abnormally imbalanced customer phase allocations, it should not then be inferred that all residential kiosk types had equally extreme voltage rises. For this reason, emphasis was instead placed on deeply examining the example networks through the techno-economic analysis. The maps displayed in figure 7 are indicative only.

Figure 7 • Indicative heatmap of PV penetration when first breach occurs across CPPAL's LV networks





3.2 Amount of time spent in breach and voltage rise

As part of evaluating each LV network's hosting capacity, this study assessed the LV networks' annual average hours per day spent in breach and the rise of maximum voltage levels under increasing PV penetration. These are presented in figure 8 and figure 9. These figures take PV penetration up to the reference maximum penetration, as defined in 2.2.1, Defining hosting capacity.

Figure 8 • Theoretical annual average hours per day spent in breach for each example LV network

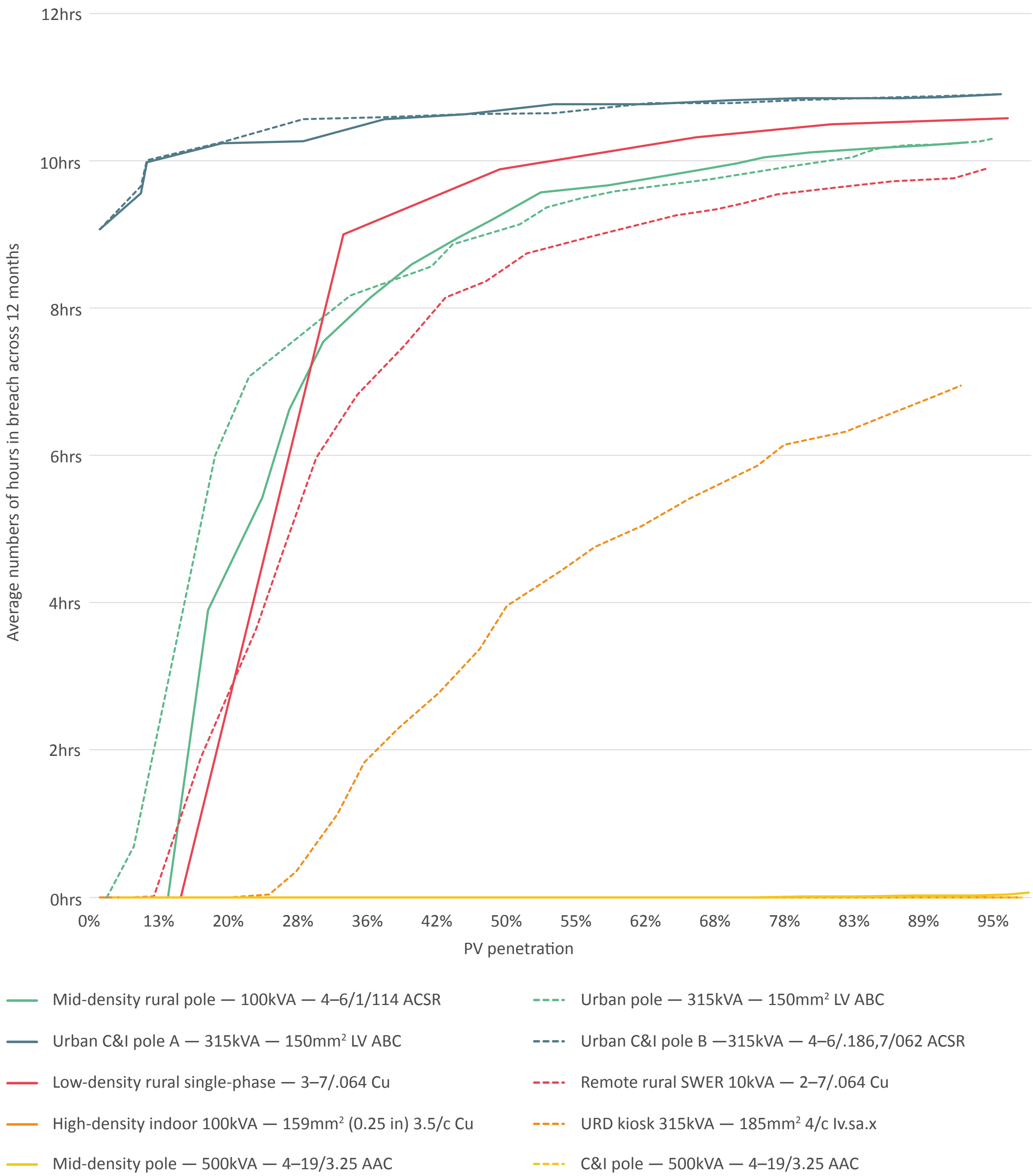
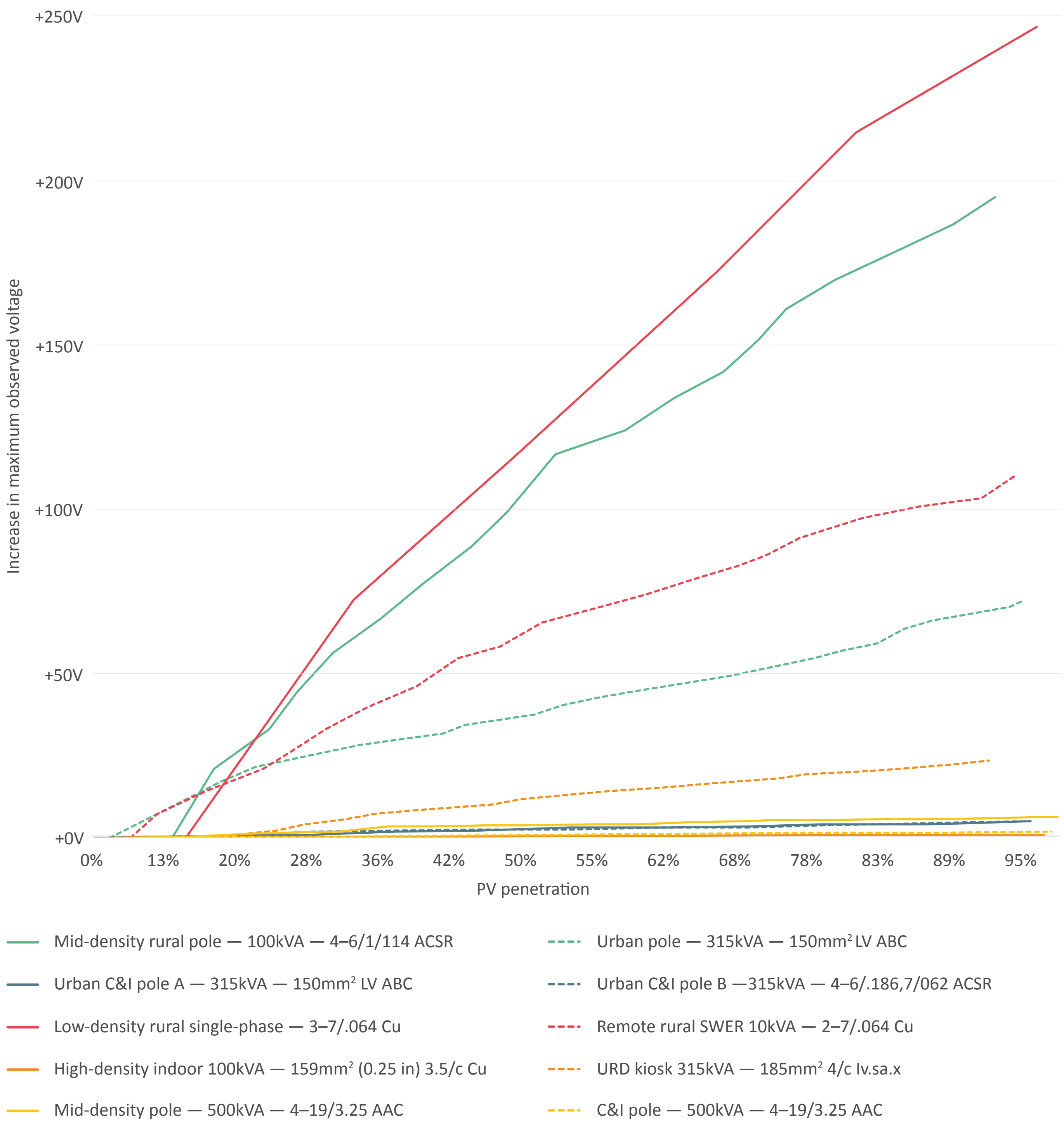


Figure 9 • Theoretical voltage rise of each example LV network with increased PV



The plots in figures 8 and 9 reflect a theoretical exercise, wherein PV penetration is increased to 100% without any regulation or management (including inverters that do not trip). This does not reflect real-world voltages, because Australian standards mandate network safety mechanisms that would not allow PV export under such high voltage conditions. Further, HV voltage regulation and network augmentation activities would likely occur alongside increased penetration.

Results indicate that at these PV penetration levels, DNSPs will need significant voltage regulation

Despite the theoretical nature of the modelling, there are still striking results. Particularly noteworthy is the magnitude of voltage rise from increased PV penetration, which reached 250 V in one case. This indicates that DNSPs will need to deploy significant voltage regulation should PV penetration ever reach these levels.

The variety of results is also noteworthy, with five of the 10 example LV networks not experiencing anything beyond a very minimal voltage rise. Further to this, three of the example LV networks spent close to no time in breach of the maximum voltage limit, even at 100% PV penetration. It should be noted that this was partly caused by the varying baseline voltage level across the example LV networks, some of which start closer to the voltage limit than others.

The URD kiosk LV model, however, indicates a potentially large return from minimal voltage regulation

An interesting case is the example LV network for the URD kiosk category. This model represents a highly populated residential area, with over 130 customers and a high-quality cable already supplying the network. There is minimal voltage rise on this model's HV feeder (because it is very short), so the maximum voltage increase can be taken as almost entirely from interactions within the LV network.

Although the maximum voltage increase is relatively modest, the amount of time in breach eventually reaches quite a high level (partially due to a higher voltage start-point for this network, because some customers had already historically installed PV). This, coupled with the fact that many customers are served by the network, indicates that a large return could be expected from a small amount of voltage regulation.

Note that the SWER network is comprised of a single customer, so figure 8 and figure 9 reflect the broader HV feeder PV penetration.

3.3 HV network considerations

As outlined in chapter 2, each assessed model in this study is an HV feeder with the selected LV network attached at its real-world DSS location. This means that the position of the particular LV network is fixed.

HV voltage rise is passed on to the LV networks

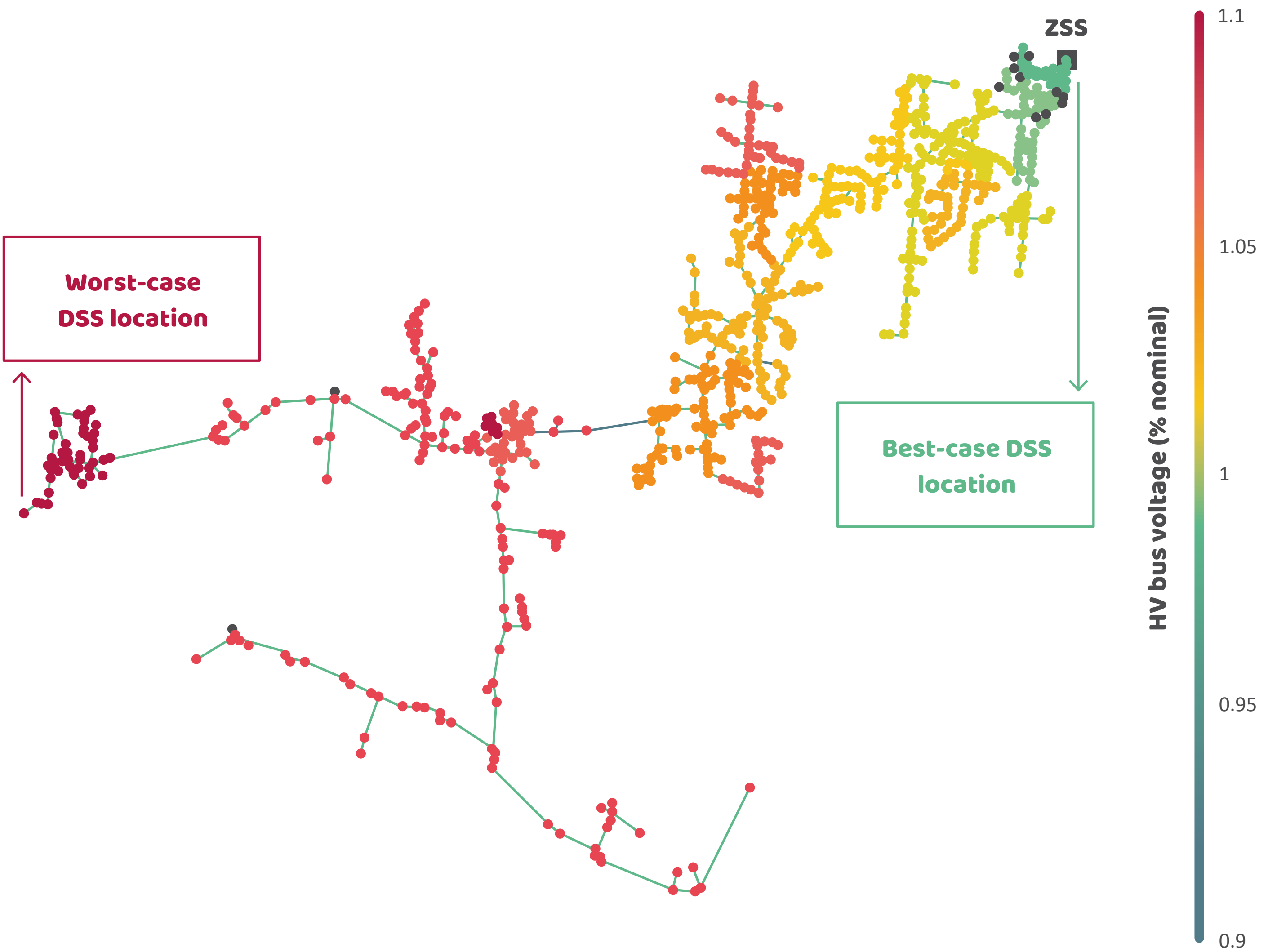
Distribution transformers step down voltage at a fixed ratio for delivery to customers on their associated LV network. This fixed ratio means that if voltage is high on the HV side of the transformer, the effect will be passed on to the LV networks.

For this reason, voltage behaviour on the HV feeder can have a significant impact on LV customers' voltage levels. It is therefore relevant to voltage management of LV customers.

A further consideration is that if a DSS is located further away from its ZSS, there is higher likelihood of voltage rise during periods of high generation across the feeder. As an example, figure 10 shows each DSS's HV bus voltage on a Rural long HV feeder with substantial HV voltage rise.

DNSPs are already taking steps to mitigate this HV voltage rise through HV voltage management (for example, with HV voltage regulators). As observed in this study, widespread PV uptake will create significant voltage rise along the feeder at times of export, reinforcing the need for HV voltage management, independent of voltage effects within the LV networks.

Figure 10 • Example of HV feeder voltage rise, 50% PV penetration (HV Regulators artificially removed)



DSS position and effect on HV bus voltage

As highlighted previously, there is a higher likelihood of HV voltage rise if the DSS is located further away from the ZSS. A comparison of the LV network examples showed that DSS position influenced HV bus voltage on Rural long HV feeder types, but not materially on shorter HV feeder types (for example, CBD and Urban).

Figure 11 shows the maximum HV voltage level as a function of PV penetration for three DSS locations on the Rural long HV feeder. The 'best' and 'worst' locations were selected as the locations with the most and least amount of voltage rise respectively. Figure 11 also shows that HV voltage management becomes increasingly necessary as PV penetration increases. In the extreme case of an unmanaged rural long HV network, the DSS position can result in a 20% voltage variation at PV saturation. Although this rise is substantial, at this high level of penetration, there is substantially more voltage rise occurring within the LV network.

It is notable that with moderate PV uptake, an unmanaged HV feeder can reach +10% nominal voltage before stepping down to the LV level. In these cases, voltage rise within an LV network compounds with the rise seen at HV level and could (without intervention) reach extremely high levels. To address this voltage rise, management is required both within the HV and LV network portions.

For comparison, figure 12 shows the same information across a shorter HV feeder. In this example, DSS location does not materially influence its HV bus voltage due to shorter feeder lengths and lower conductor impedance. This means that the voltage rise observed on those example LV networks is due only to factors occurring within the LV networks.

The following chapter introduces mitigation measures to improve power quality outcomes as PV penetration increases.

Unmanaged PV penetration

For one of the feeders modelled, an existing HV regulator's impact was not taken into account, meaning that PV penetration should be considered 'unmanaged' PV penetration.

This enables an understanding of the effects of theoretical PV uptake on distribution network voltage but does not reflect the network under its current operation, where voltage regulation may occur on an HV feeder regardless of PV penetration. This means that the effects of the mitigation measures can be understood independently of other voltage regulation efforts.

[22] PV penetration is unmanaged, without additional augmentation or voltage management. For this reason, realistically, the distribution network would never allow voltages to reach such problematic levels. Values shown are those of an unmanaged network, and as such, should be considered 'theoretical'.

Figure 11 • Maximum theoretical[22] HV voltage rise for three DSS locations on a Rural long HV feeder. The 'selected' DSS was one of five LV networks that were modelled on this HV feeder.

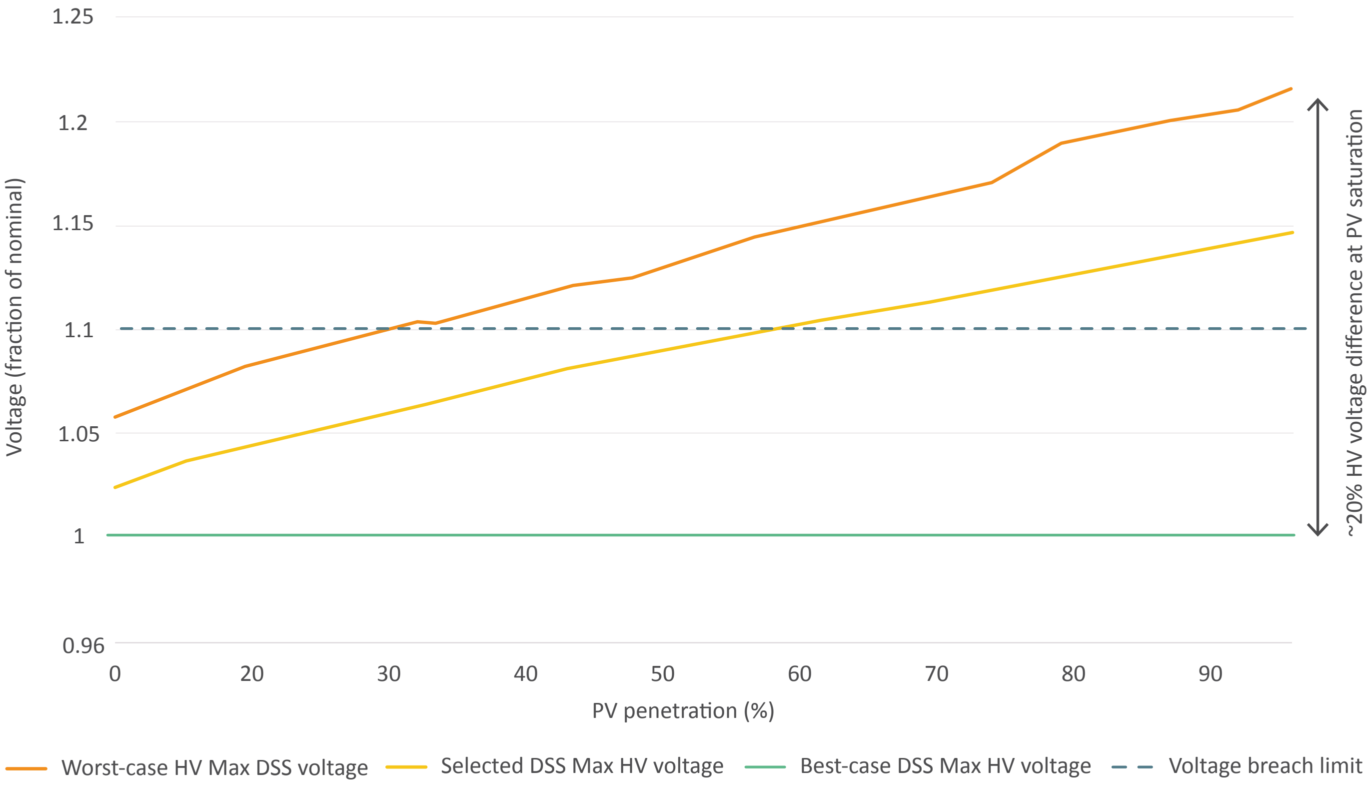
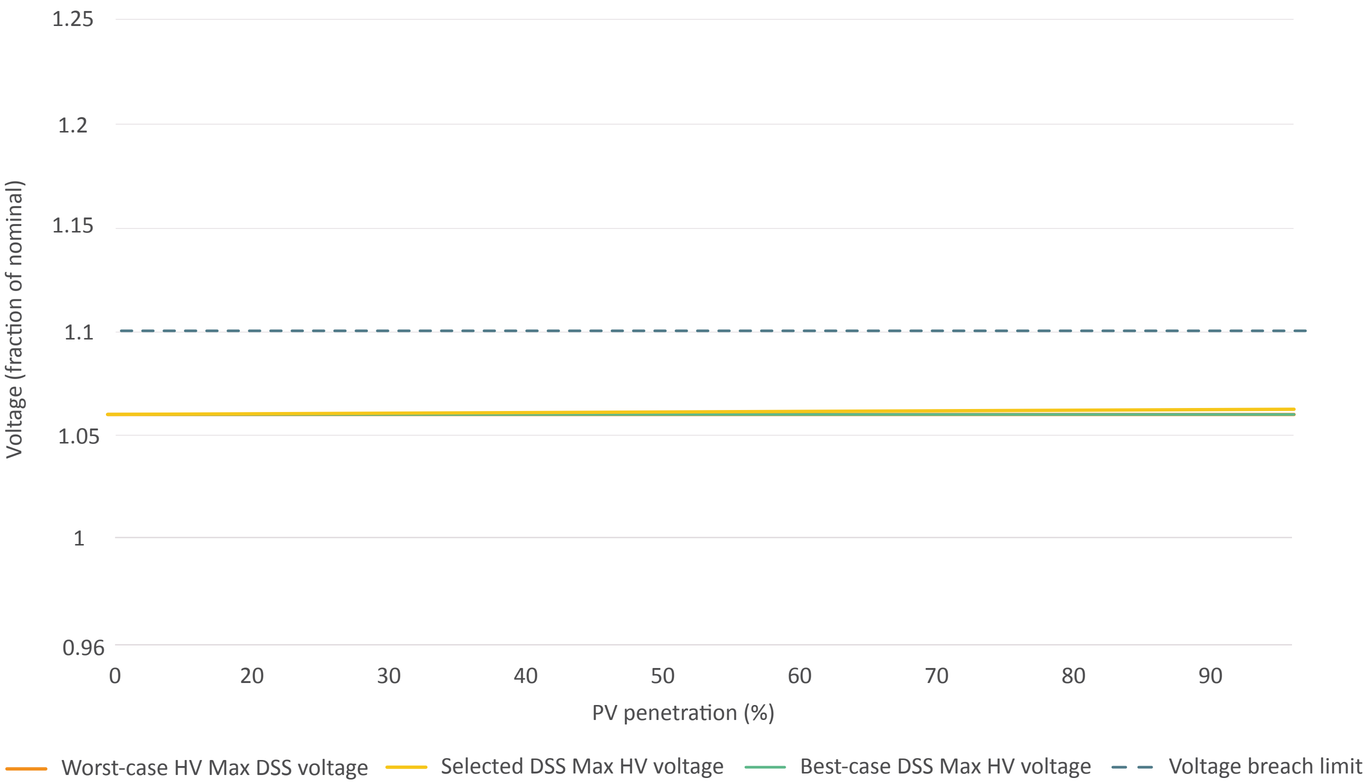


Figure 12 • Maximum theoretical HV voltage rise for three DSS locations on an Urban HV feeder



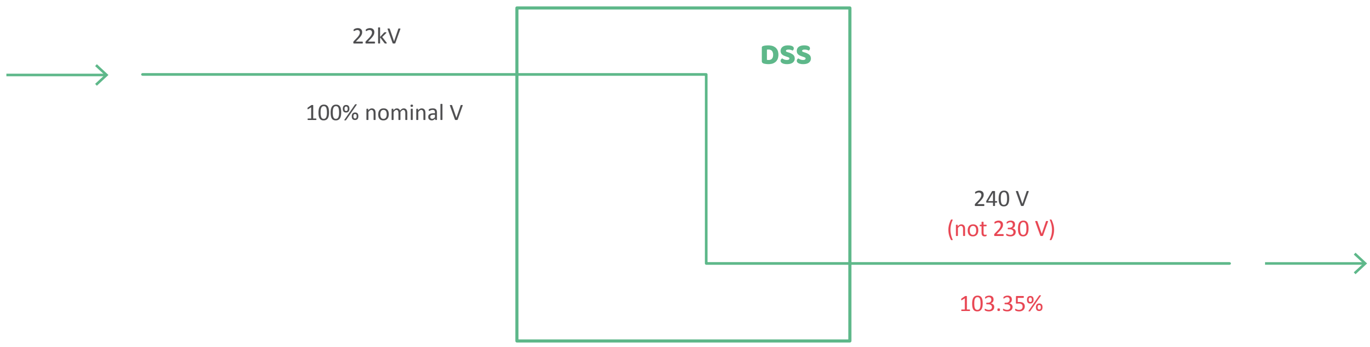
3.4 Impact of distribution transformers

Throughout the modelling, distribution transformers have been observed to cause increases in nominal voltage under normal operating conditions. Due to Australian Standard 60038 regarding standard voltages, the nominal low voltage level is now 230 V -6% / +10% for single-phase transformers and 400 V -6% / +10% for three-phase transformers.

Under the obsolete Australian Standard 2926, the nominal low voltage level was 240 V +/-16% for single-phase networks and 415 V +/-6% for three-phase networks. Many older transformers are still targeting the obsolete nominal low voltage, as unfortunately this is a fixed parameter of a transformer that cannot be modified without a full replacement (notwithstanding tap changers).

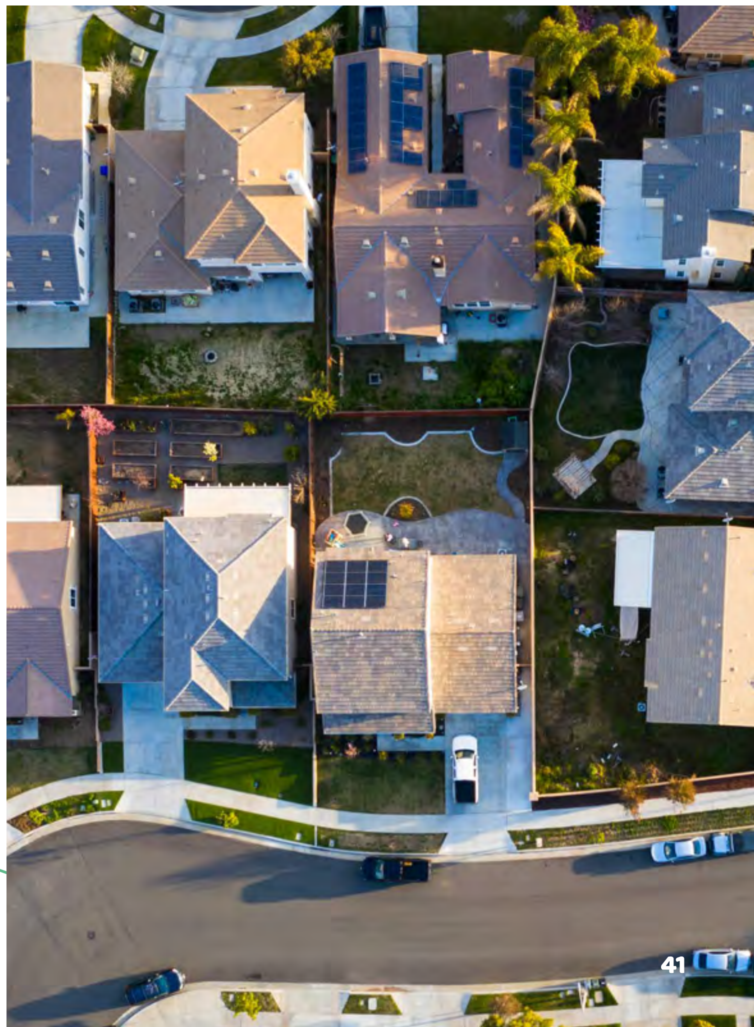
The upshot of this is that many DSS transformers' LV bus voltage is 3%–4% above their HV bus voltage (in percentage of nominal terms), an increase that compounds any voltage rise caused by an increasing PV penetration.

Figure 13 • Distribution transformers targeting previously regulated nominal voltage

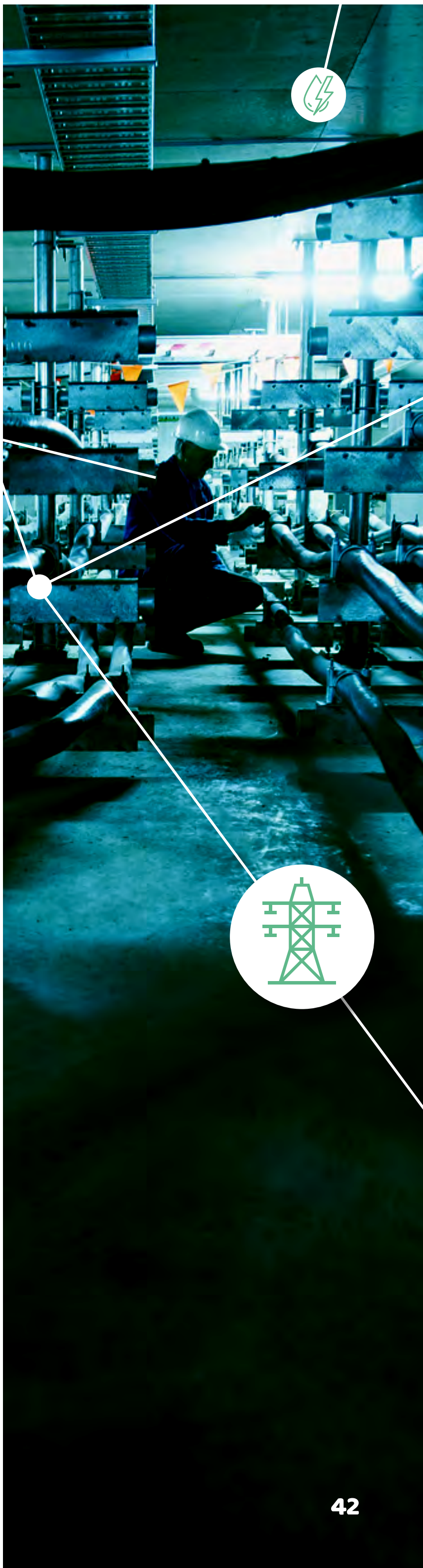


The result of this effect is equivalent to a loss of more than one 'buck' tap on the transformer in question, which can represent a considerable portion of the available +10% headroom. Of the 10 example LV networks, eight were equipped with transformers exhibiting this issue.

Clearly, the sample size is too small to make network-wide inferences, but it is anecdotally an issue that affects a substantial portion of the distribution transformers.



4 Measures to improve hosting capacity



As part of this study, five mitigation measures were assessed based on their techno-economic performance in improving the hosting capacity of the 10 example LV networks. This chapter compares these measures.

Key findings

The mitigation measures included:

Three network augmentation solutions:

1. **Transformer upgrade and/or reconductoring**, which, in this study, includes replacing a distribution transformer to include one with an off-load tap changer with two additional buck taps, increasing the distribution transformer rating and/or increasing the quality of the LV conductor
2. **OLTC (on-load tap changer)**, where a distribution transformer is replaced with a transformer that includes an OLTC so it can automatically adjust the voltage at the DSS based on load characteristics on the LV network
3. **LVR (low voltage regulator)**, which can be strategically placed on the LV network and uses a controllable transformer to increase or decrease the voltage on the LV network.

Two customer-side solutions:

4. **Smart inverters**, which can sense and react to grid voltage by adjusting the real and reactive power exported from the PV system
5. **Behind-the-meter batteries**, which can store and time-shift energy for self-consumption and correct PV output fluctuations on the LV network.

Off-load tap changers, OLTCs and LVRs all actively reduce voltage levels by their respective regulation ranges. While smart inverters and behind-the-meter batteries do not actively reduce voltage levels, they can also assist in voltage management.

Simply comparing capital expenditure of each mitigation measure does not provide a good criterion considering that each mitigation measure is used differently on the LV network. For example, smart inverters are installed on a per customer basis, while an OLTC is located at the distribution transformer.

Of all the mitigation measures, only smart inverters and network upgrade and/or reconductoring are at the commercial stage. OLTC, on the other hand, is still in the planning phase on CPPAL's distribution networks.

Chapter sections

- Section 4.1 — Location of mitigation measures on the LV networks
- Section 4.2 — Ability of mitigation measures to regulate voltage
- Section 4.3 — Capital expenditure
- Section 4.4 — Level of mitigation measure deployment on CPPAL's distribution network.

4.1 Location of mitigation measures on the LV networks

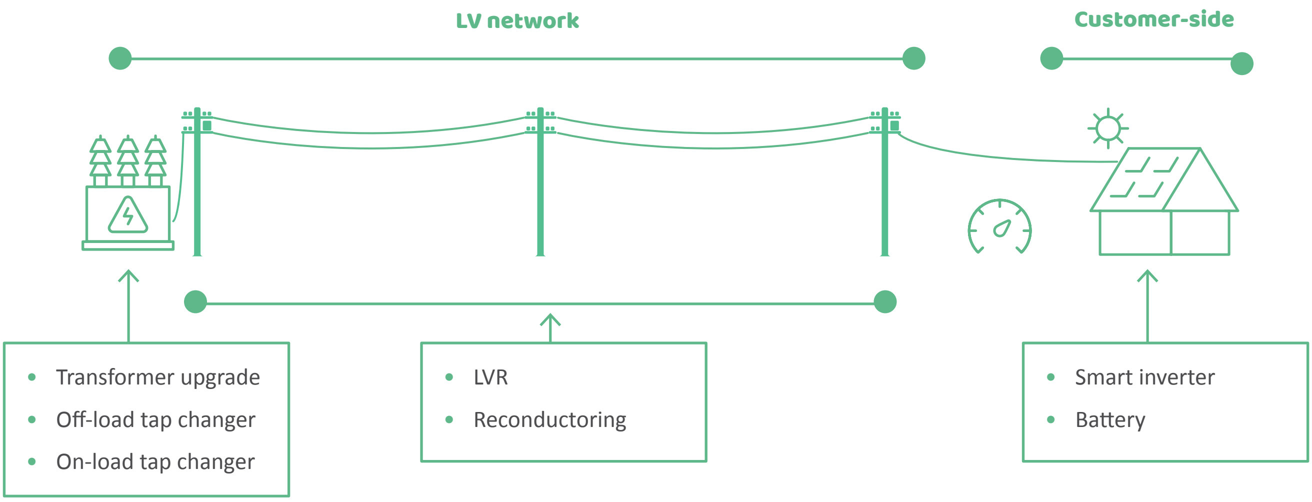
Upgrading the distribution transformer (increasing the rating, off-load tap changers and OLTCs), reconductoring and installing LVRs all are undertaken on LV network infrastructure.

Although LVRs can be strategically located on the LV network (provided the capacity of the LV network does not exceed the LVR rating), the distribution transformer is located at the DSS. One LVR is installed per phase and per LV street circuit.

Smart inverters and batteries are both located behind-the-meter within the customer's premises. The number of smart inverters and behind-meter batteries both increase with the number of customers on an LV network.

Figure 14 illustrates the location of mitigation measures on the LV network.

Figure 14 • Location of mitigation measures



4.2 Ability of mitigation measures to regulate voltage

The mitigation measures assessed in this study regulate voltage in different ways. Upgrading network assets (increasing the transformer rating and/or the quality of the LV conductor) improves voltage regulation by reducing losses, and off-load tap changers, OLTCs and LVRs actively reduce voltage levels.

The voltage regulation from an off-load tap changer and OLTC depends on the size and number of taps. This study assessed an off-load tap changer with two additional buck taps of 2.5%, so that the distribution transformer could reduce an input voltage by a further 5%. It also assessed an OLTC with an auto-tapping range of +/- 10% (nine taps of 2.5%).

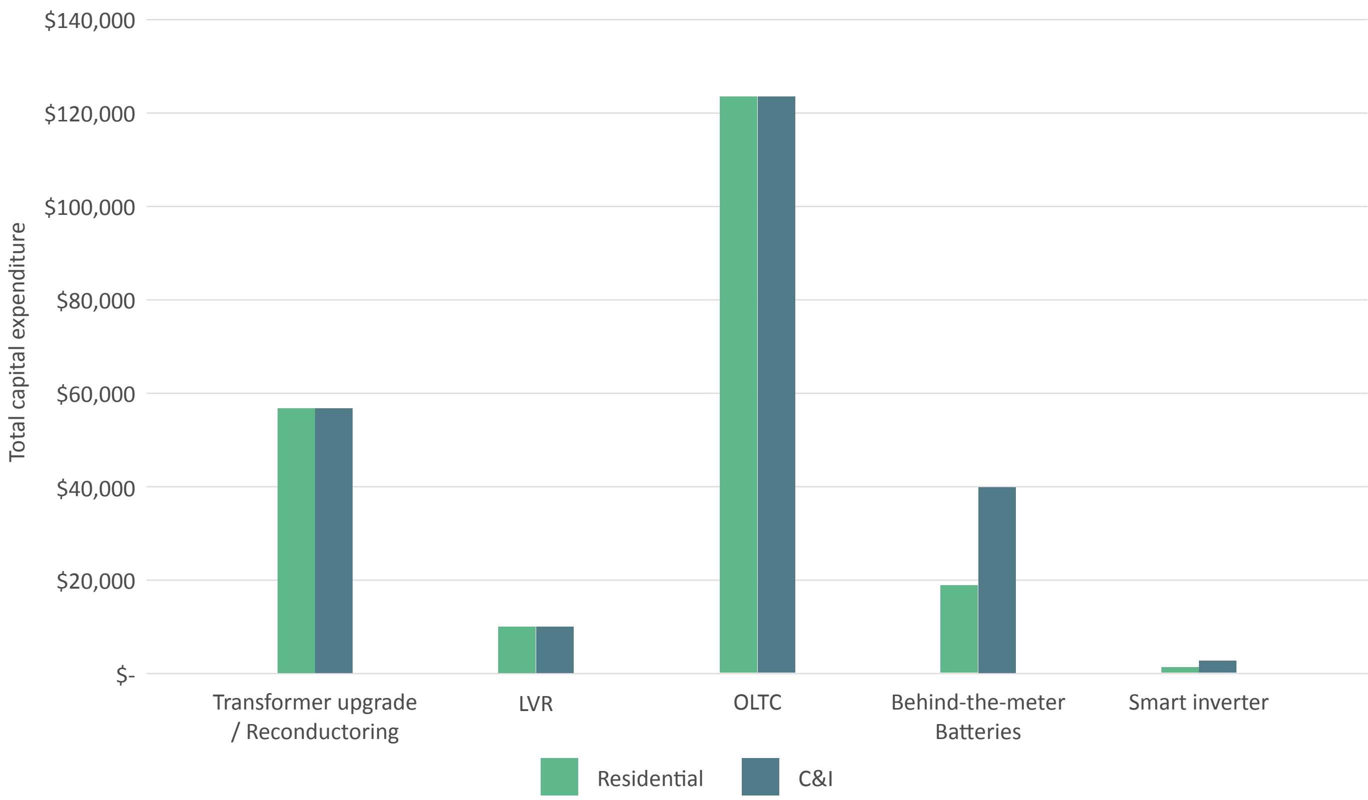
In comparison, the LVR considered in this study can maintain voltage at +/- 1V of the nominal voltage level if the incoming voltage is within its regulator range (+/- 13% in this study).

LV networks that experience extreme voltage rise from increasing PV penetration would benefit more from the greater voltage regulation range of OLTC and LVRs, provided these mitigation measures can support the LV network's capacity.

Smart inverters and behind-the-meter batteries do not actively reduce voltage levels via a transformer but can assist in reducing high voltage levels on the LV networks. A smart inverter adjusts the amount of real and reactive power being exported by a PV system in response to changes in grid voltage when compared to nominal voltage level of 230 V. Injecting reactive power can cause voltage to rise and absorbing reactive power can cause voltage to fall. Smart inverters can also curtail PV exported electricity if grid voltage is too high. These actions are known as the Volt-VAR and Volt-Watt response modes respectively. The charging and discharging of behind-the-meter batteries can time-shift load and reduce the negative impact of all PV systems exporting electricity at the same time, by reducing the level of peak generation.

4.3 Capital expenditure required for mitigation measures

Figure 15 • Capital expenditure per mitigation measure per unit[23]



An OLTC is the most expensive mitigation measure in terms of capital expenditure per unit, and smart inverters are the least expensive. However, simply comparing capital expenditure per unit is not sufficient, because each mitigation measure is used differently on the LV networks.

For example, although OLTC has a high capital cost, it is part of the distribution transformer, so only one OLTC is required per LV network. On the other hand, one LVR needs to installed for each phase of each LV street circuit on an LV network, so can be much more costly depending on network configuration. LVR installation is more expensive for a three-phase LV network than for a single-phase LV network, and the cost increases depending on the number of LV street circuits. Therefore, LVRs may be a comparatively better network augmentation mitigation measure for LV networks in the Remote rural single phase and SWER categories (which are both single-phase).

Batteries and smart inverters are installed on a per customer basis, and their capital expenditure will vary depending on the size of the customer's PV system. Therefore, smart inverters and behind-the-meter batteries would be a more expensive mitigation option for LV networks with larger numbers of customers. It is noted that smart inverters are funded by the customer as part of their PV system installation, and there is little difference in the cost of standard inverters and smart inverters. Further, in Victoria, smart inverters are required for PV systems installed under the Solar Homes Program, so there is no additional cost compared to business-as-usual for these customers.

Annualised marginal costs were used in the cost-benefit analysis. These are discussed in chapter 5.

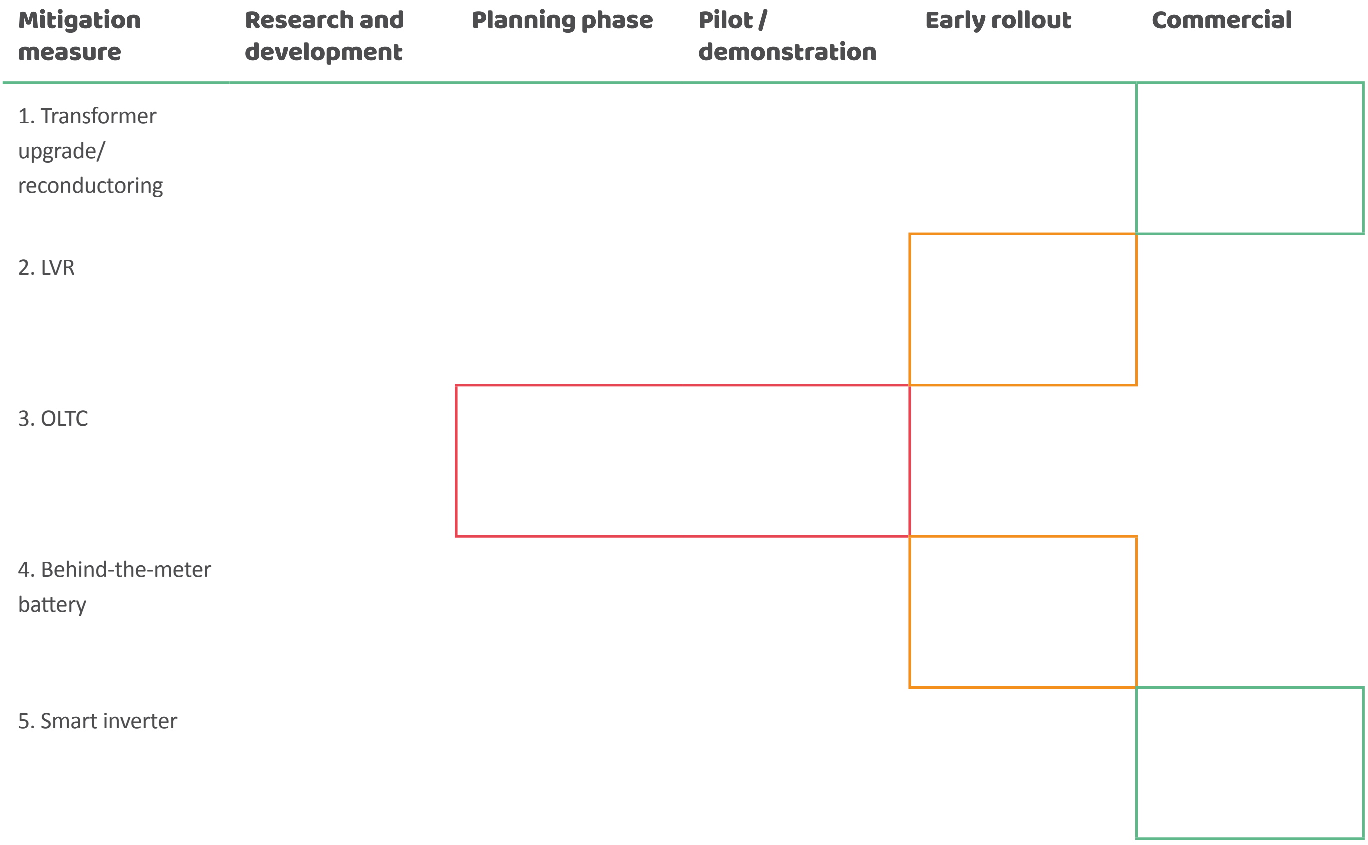
[23]Unit costs are taken as costs of specific examples of each technology. For example, the LVR costs was the cost of a specific LVR unit by a particular supplier, with details available in the appendix.

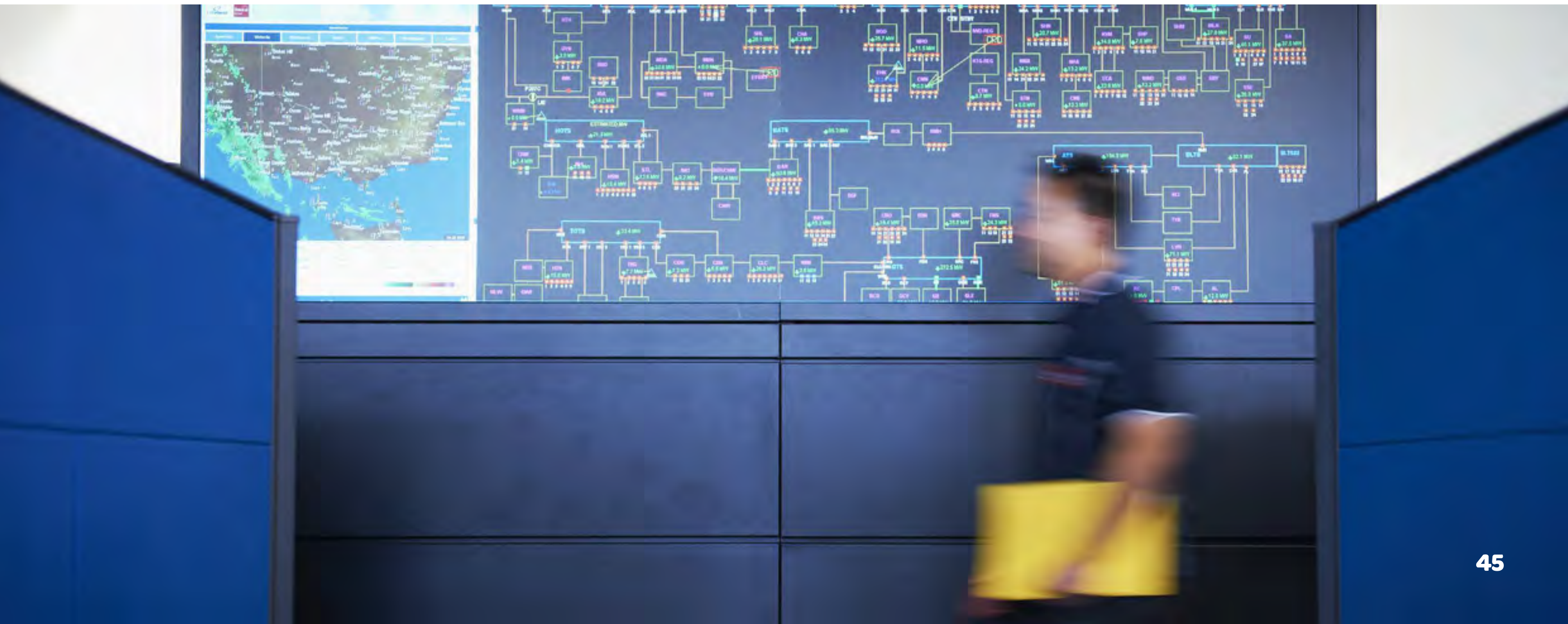
4.4 Level of mitigation measure deployment on CPPAL's distribution network

The mitigation measures discussed in this report are at varying levels of maturity in terms of implementation internationally, across Australia, and on CPPAL's distribution network.

Figure 16 compares the deployment of each mitigation option on CPPAL's distribution network.

Figure 16 • Current deployment of mitigation measures on CPPAL's distribution network





Transformer upgrade/reconductoring

Overall, transformer upgrade/reconductoring is the most implemented mitigation measure on CPPAL's networks (noting that manually adjusting tap settings using existing off-load tap changers is the first action taken before considering any upgrade).

The issue of LV voltage breaches is an emerging one, stemming from increased PV penetration. Currently, many manual tap changers on the network are set to positions that increase voltage to mitigate against low voltage levels, because low voltage levels have historically been the biggest issue facing the LV networks.

However, this setting can be changed. Decreasing the tap setting — or 'bucking' the distribution transformer — is often the first answer to high voltage levels. It can delay or solve high voltage issues, at the risk of creating low voltage issues.

LVRs and OLTCs

Due to their relative high capital costs, there are only approximately 40 LVRs currently installed on CPPAL's distribution networks. In recent years, LVRs have been used in rural areas, usually close to customer premises, to solve voltage-rise issues on long HV conductors that would otherwise incur high replacement costs.

Comparatively, OLTCs have never been installed at distribution substations on CPPAL's networks, although trials and pilots are being planned.

Behind-the-meter batteries

Due to high capital costs for customers, behind-the-meter batteries are in the early rollout stage across Australia. As capital costs decline, it is expected there will be wider uptake.

Further, orchestration of batteries is still in a trial stage, as several organisations explore the ideal operation and regulatory conditions to coordinate batteries for grid health and customer benefit. The influence of behind-the-meter battery orchestration on hosting capacity is, however, beyond the scope of this study.

Smart inverters

Smart inverters are also in the early rollout stage.

As previously stated, under the Solar Homes program in Victoria, all new PV systems are required to be installed with a smart inverter. CPPAL and all other Victorian DNSPs require that all new inverters are connected to their network by smart inverters with Volt-Watt and Volt-VAR response modes set as per the connection guidelines.

5 Techno-economic performance of mitigation measures

The second aim of this study was to assess the techno-economic performance of the five mitigation measures that were discussed in chapter 4. The technical performance of each mitigation measures was assessed in terms of their ability to improve the hosting capacity of the 10 selected LV networks across three key metrics. A cost-benefit analysis was used to assess the economic performance of each mitigation measure.

This chapter describes the approach for assessing the techno-economic performance of each mitigation measure and summarises the results.

Key findings

The key findings of the techno-economic assessment include:

1. **Network augmentation** mitigation measures were the **most effective** at improving the **PV penetration level** when the **first breach occurred**, and at **reducing the average hours per day in breach**. By comparison, **smart inverters were the most effective at reducing voltage rise** for most of the LV networks
2. **Smart inverters** had the **highest net-benefit** at **low PV penetration levels** due to their comparatively lower cost. However, **as PV penetration increased, transformer upgrade/reconductoring** had the **highest net-benefit** for most of the LV networks. This was because as PV penetration increased, smart inverters began to curtail PV generation, whereas network upgrade/reconductoring enabled more PV generation
3. **Increasing the hosting capacity** of LV networks with **few customers** is **not cost-efficient**, because the benefits of additional PV generation are unlikely to outweigh the cost
4. **Behind-the-meter batteries did not improve the ability for LV networks to accommodate increasing PV penetration levels**. This was due to the way they were operated in this study, which was to maximise self-consumption
5. **Thermal issues** were the **limiting factor in one case involving a Kiosk LV network** with a large number of customers.

Chapter sections

- Section 5.1 — Overview of the techno-economic assessment
- Section 5.2 — Mitigation measures modelling approach
- Section 5.3 — Results.

5.1 Overview of the techno-economic assessment

5.1.1 Overview of the technical assessment

The technical performance of each mitigation measure — that is, its ability to improve LV networks' hosting capacity — was assessed and compared using the same three hosting capacity metrics as the first part of this study:

1. PV penetration level when the first breach occurred
2. Annual average hours per day spent in breach
3. Maximum voltage level rise.

The results of the technical performance assessment are discussed in sections 5.3.1, 5.3.2 and 5.3.3.

5.1.2 Overview of the cost-benefit analysis

To complement the technical assessment, a cost-benefit analysis was performed to assess and compare the cost-effectiveness of each mitigation measure. The results of the cost-benefit analysis are discussed in 5.3.4. As stated in AER RIT-D guidelines, several classes of market benefits can be assessed as part of a cost-benefit analysis as specified under National Electricity Rules clause 5.17.1(c)(4), including:

1. Changes in voluntary load curtailment
2. Changes in involuntary load shedding and customer interruptions caused by network outages
3. Differences in the timing of expenditure
4. Changes in electrical energy losses.

This study focused on:

1. The value of the additional PV generation enabled by mitigation measures compared to a baseline scenario without mitigation measures
2. The marginal cost of mitigation measures.

Following the same approach as in the technical assessment, the cost-benefit analysis was performed from the current PV penetration level to saturation. The cost-benefit analysis therefore provides the cost-effectiveness of each mitigation option at different PV penetration levels. An advantage of this approach is that the results are independent from PV penetration forecasts.

Determining the baseline PV generation

To calculate the baseline PV generation, only non-breaching PV generation was considered, from the current PV penetration level to saturation. This assumed that new connections were not refused, but that PV generation for a customer in breach (in terms of voltage or thermal constraints) was excluded.

This approach does not reflect real inverter tripping conditions. Customers' solar inverters display differing tripping behaviour depending on the model's settings:

1. Inverter tripping can manifest as erratic voltage readings, as inverters trip off and on repeatedly, impacting voltage as they do so
2. In other cases, inverters trip off at a certain level of voltage, and must be reactivated manually.

However, the approach taken in this study allows an understanding of the network's performance under theoretical unconstrained PV penetration growth condition. An alternative approach would have been to stop when the first breach occurs, however this would not have captured network behaviour at higher PV penetration levels.

Determining additional PV generation enabled by each mitigation measure

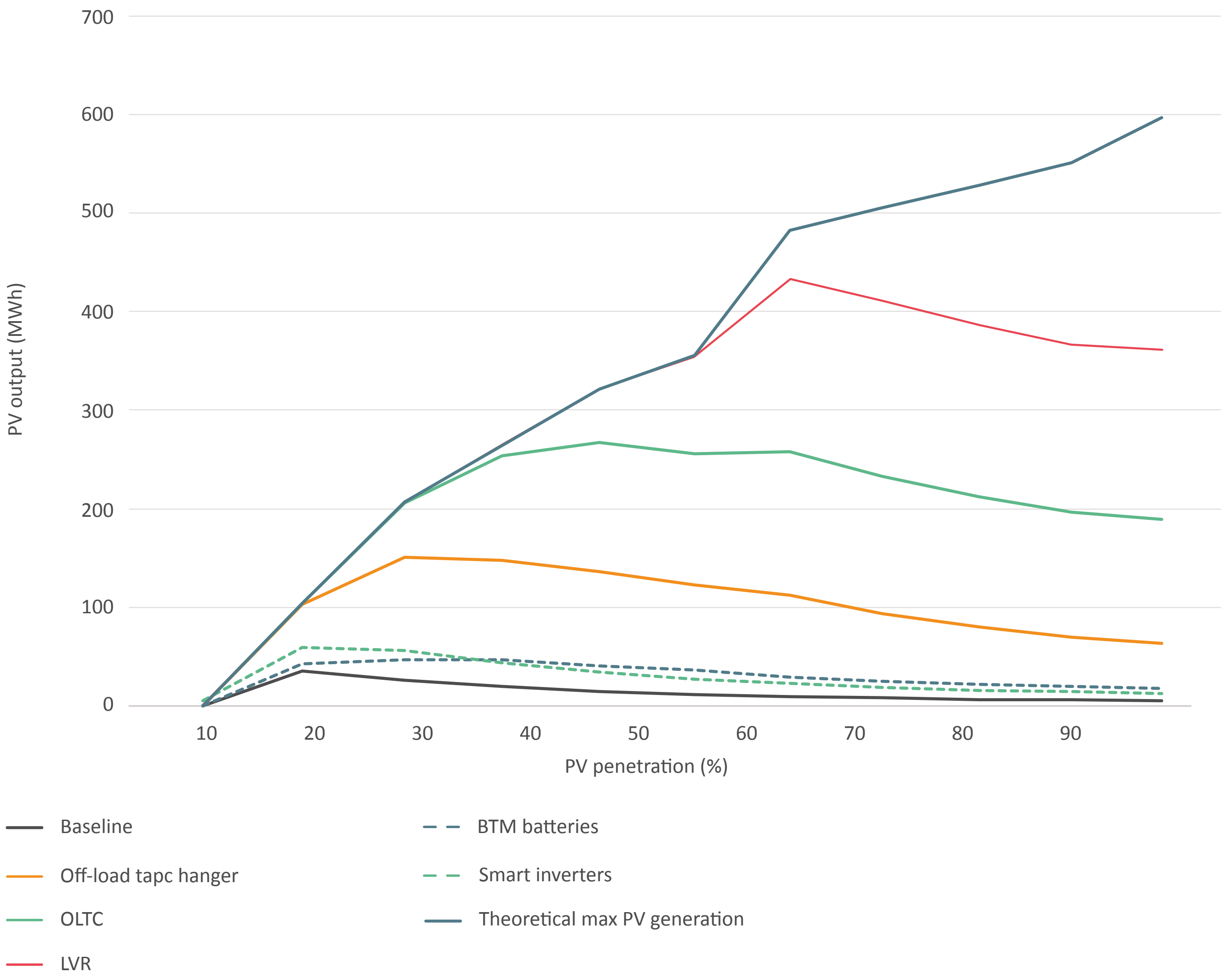
The modelling approaches that were used to assess the impact of each mitigation measure on the hosting capacity of the example LV networks are summarised in section 5.2.

Additional PV generation is the increase in PV generation with the mitigation measure applied, compared to non-breaching PV generation without any mitigation measures, which is referred to as the baseline. A limitation of this approach is that it treats every breach of either the voltage limit or thermal constraint the same regardless of the magnitude of the breach. However, this method allows to compare the relative economic merits of each mitigation measure.

As an example, figure 17 illustrates the non-breaching PV generation enabled by each mitigation measure for the example LV network in the Urban pole category, compared to the baseline, at different PV penetration levels. It shows that, in this example, LVRs improved PV generation the most, however as PV penetration increases, the amount of generation diverges from the theoretical maximum due to a growing number of breaches.

Figures of non-breaching PV generation enabled by each mitigation measure for each of the 10 LV networks are included appendix 3.

Figure 17 • PV generation (MWh) enabled by each mitigation for the example LV network of the Urban pole category



Assessing the value of the additional PV generation enabled by each mitigation measure

The wholesale price was used to value, on an annual basis, the additional PV generation enabled by each mitigation measure that was not in breach. Following the AER RIT-D guidelines, which require using market data where it is available and applicable, additional PV generation was combined with 2017–18 AEMO settlement price data for each 30-minute timestamp. This assumed that installing a PV system reduces the requirement to generate electricity from a utility-scale fossil fuel power station that would receive the wholesale price.

However, this approach does not consider the impact of PV generation on prices. At high PV penetration levels, prices are likely to be impacted by high PV export to the electricity grid. Therefore, using 2017–18 prices to value PV generation to saturation may overvalue PV generation at high PV penetration levels (every other market condition being held constant).

Given this study did not consider temporal changes, it is difficult to assess the market conditions at a particular penetration level. Market modelling to determine the impact of increasing PV penetration on wholesale prices was outside the scope of this study.

Assessing the cost of mitigation measures

Annualised marginal costs[24] were used to value the cost of each mitigation measure. Marginal costs were annualised over the lifetime of the assets using a weighted average cost of capital.

[24] In this study, 'marginal cost' has been used to refer to the additional cost compared to business-as-usual expenditure to manage the LV networks.

The following assumptions were made to calculate the marginal cost of each mitigation measure:

1. The cost of smart inverters was assumed to be zero. This is because there is a requirement to install smart inverters with PV systems in Victoria, so this mitigation measure does not incur any additional cost
2. The cost of LVRs and behind-the-meter batteries was assumed to be the absolute capital expenditure because these are new technologies being installed on the LV networks
3. The cost of replacing LV conductors and distribution transformers was based on the cost of bringing forward replacement expenditure. In this study, LV conductors and distribution transformers are assumed to have a 50-year lifetime and require a business-as-usual replacement in 25 years.

Assumptions for the cost-benefit analysis are further detailed in the appendix 1.

Comparing the cost and benefit of mitigation measures

The benefit and cost of each mitigation measure under increasing PV penetration levels were assessed. Figure 18 is an example and compares the benefit and cost of OLTC for the example LV network in the URD Kiosk category.

Figure 18 • Comparing the annualised benefit and cost of OLTC for example LV network URD kiosk

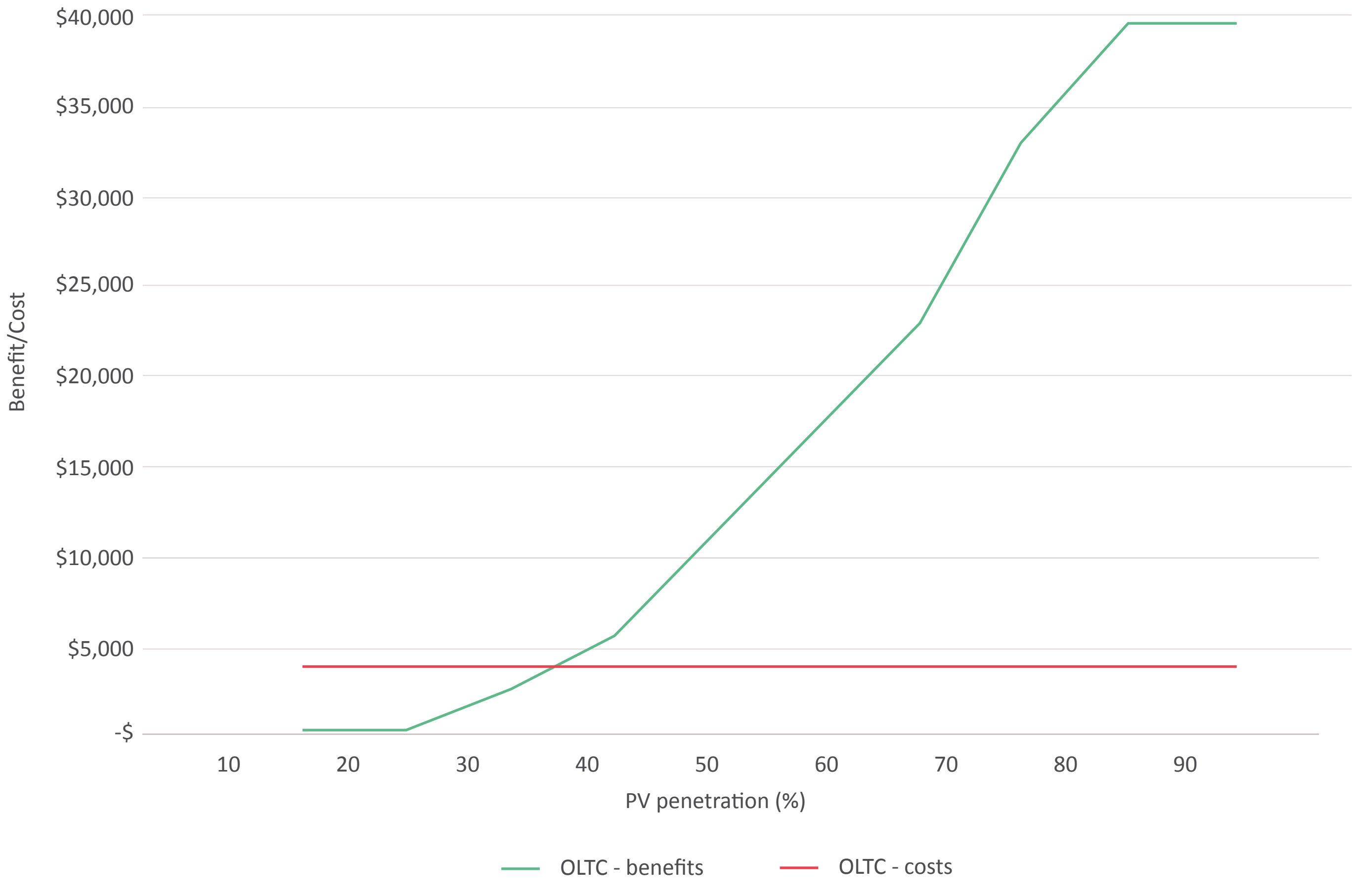
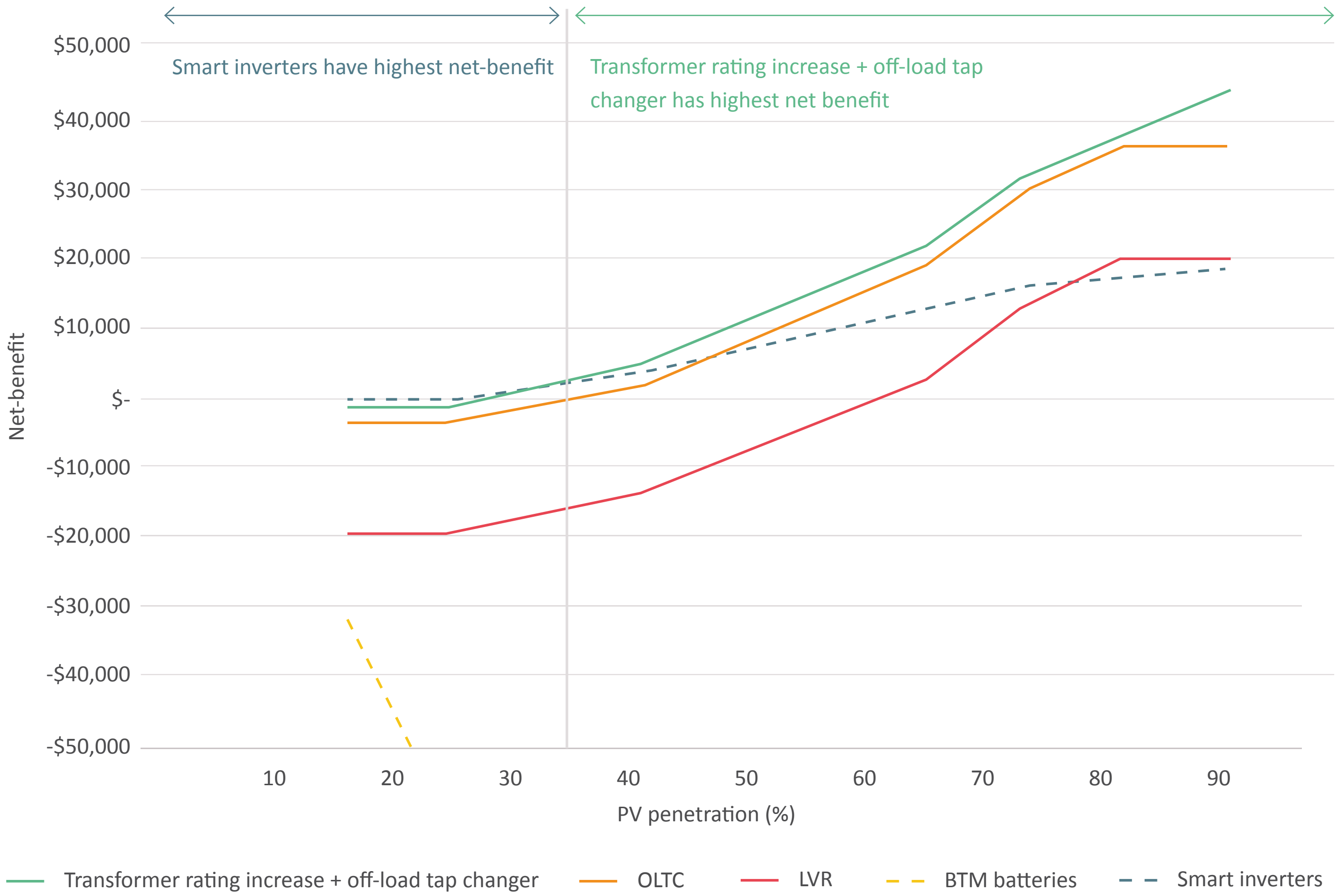


Figure 18 shows that the cost of OLTC is independent of the PV penetration so remains flat to saturation. This is different to customer-side measures such as behind-the-meter batteries and smart inverters, where the cost increases with PV penetration. As PV penetration increases, the benefit of additional PV generation eventually outweighs the costs at around 36% PV penetration, resulting in positive net-benefits.

The net-benefit of each mitigation measure was compared for each of the LV networks as PV penetration increases.

Section 5.3.4 discusses the results of the cost-benefit analysis in terms of the highest valued mitigation measure based on their net-benefits at different PV penetration levels. As an example, figure 19 illustrates how the mitigation measure with the highest net-benefit changes depending on the PV penetration level. Figures illustrating the net-benefit of each mitigation measure for each of the LV networks are in appendix 4.

Figure 19 • Net-benefit of mitigation measures for example LV network URD kiosk



5.2 Mitigation measures modelling approach

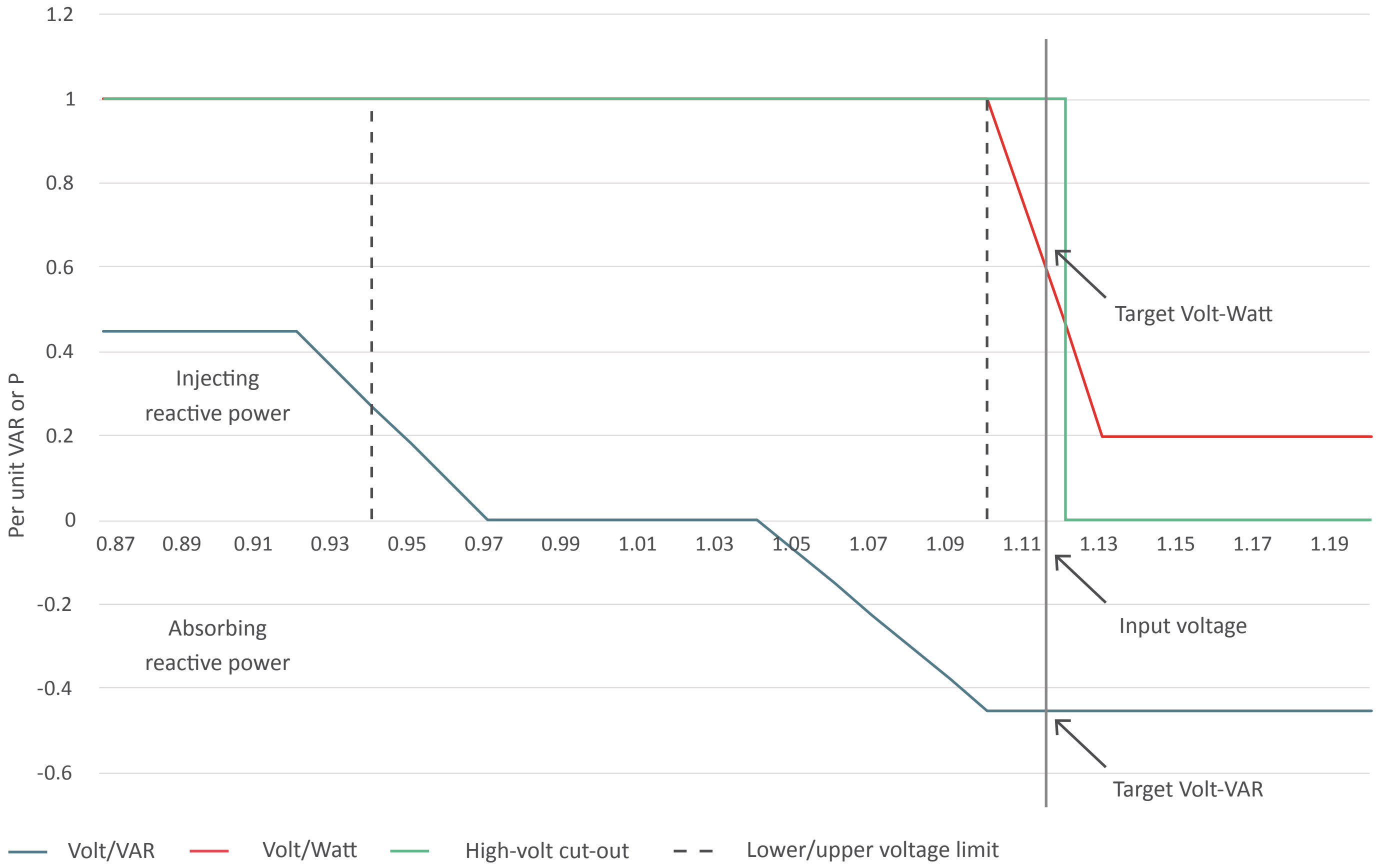
To assess the techno-economic performance of each mitigation measure, their impact on LV hosting capacity was modelled. This section summarises the different approaches for each mitigation measure based on how they operate on the LV networks. Assessing all the mitigation measures except for LVRs and OLTCs required additional power flow modelling.

It should be noted that all technologies represented in this study as 'mitigation measures' are representative of a particular model of that technology. For example, the 'OLTC' mitigation measure is represented by an SGrid transformer with OLTC capabilities. These choices reflect common technologies used by CPPAL, or in the case of customer-side technologies, common makes and models.

5.2.1 Smart inverters

Smart inverters are installed on a per customer basis, behind-the-meter, alongside a PV system. Smart inverters monitor the local voltage level at the terminals of the inverter and adjust the amount of reactive power that is injected or absorbed, while also curtailing the total amount of power as required. Settings are adjustable on smart inverter hardware. Figure 20 illustrates smart inverter settings as they are operated within Victoria [10].

Figure 20 • Illustration of smart inverter behaviour



To assess the impact of every PV system across the HV feeder having a smart inverter, the control scheme was applied to the single-point aggregated load at the DSS of each sibling LV network. This differs from reality, as each customer's load would in fact be operated on by a separate smart inverter, which would react to the voltage at their premises. The aggregated modelling approach was a good first approximation considering the relatively low diversification of customers' load and PV generation. Further, differences within sibling LV networks would have only a minor impact on the voltages in the LV network of interest, as the voltage at the HV level is largely governed by the wider balance between customer load and PV generation. Finally, the total amount of active power is calculated to compute the value of PV export.

5.2.2 Behind-the-meter batteries

A battery is co-located with the PV system at the customer's premises. Batteries store and time-shift energy for self-consumption, changing the load profile of the customer. New customer loads were simulated based on these assumptions:

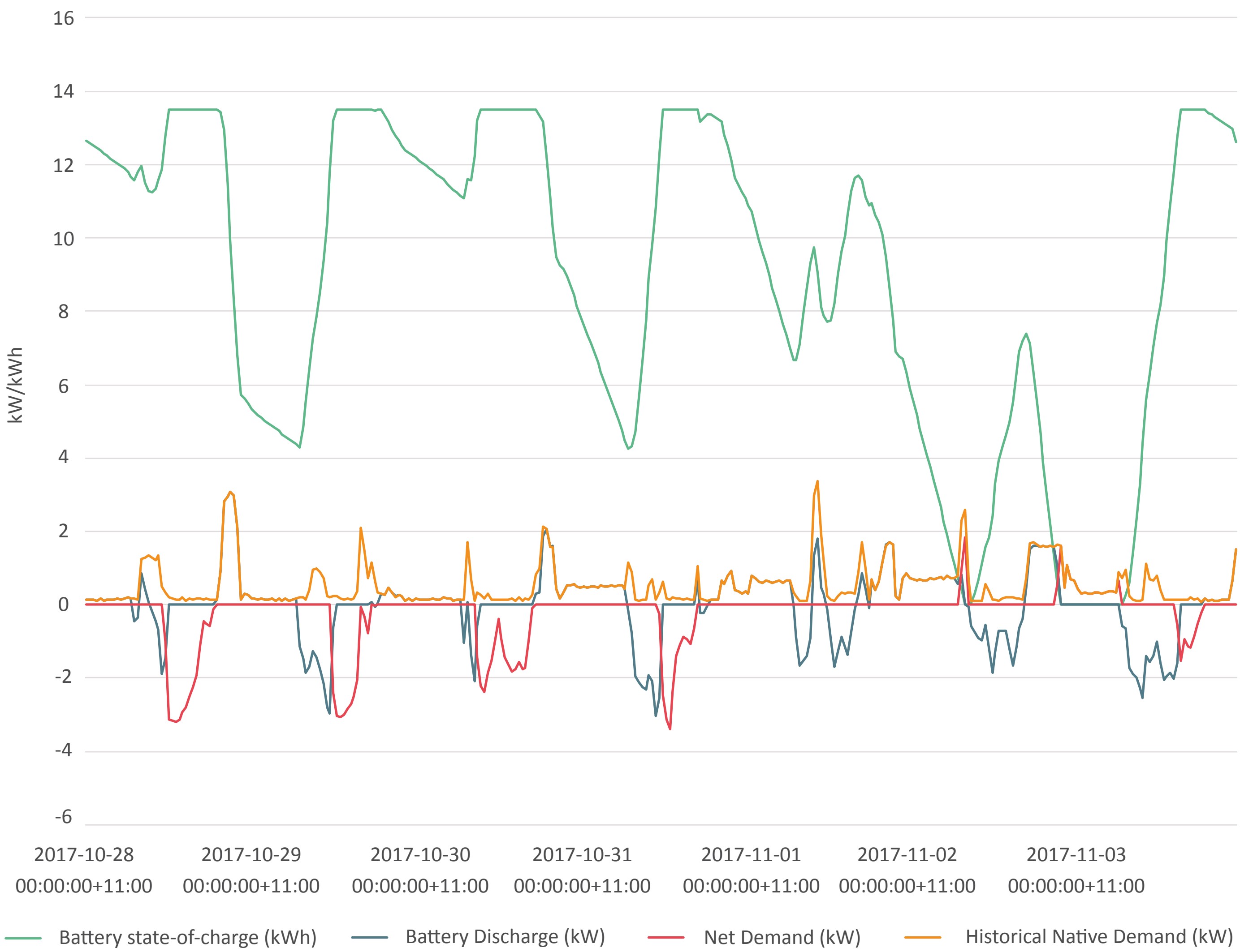
1. Customers use batteries to maximise self-consumption with no price consideration, where the customer will first consume electricity from the PV system, then the battery, then the grid. The battery is only charging when PV production outweighs electricity consumption. This reflects default battery operation without any interaction with a third-party aggregator or virtual power plant and is the most common battery operation scheme currently
2. The battery only charges from the PV system, not directly from the grid (no arbitrage)
3. Each residential customer gets a battery with a capacity of 13.5 kWh and a continuous output power of 5 kW[25]. Each C&I customer gets a battery with a capacity of 67.5 kWh, and a continuous power output of 25 kW
4. Batteries have a roundtrip efficiency of 92.5%.

Figure 21 shows the change in a customer's load with a PV system and battery installed. Historical customer load was used to simulate a new net load profile given a PV and battery system. Power flow modelling was performed where PV systems and batteries were incrementally added, so that a customer's historical load was replaced with their new simulated load.

Existing customers with PV installed did not receive a battery.

[25]This is similar to one Tesla Powerall system.

Figure 21 • Construction of new net customer load with PV system and battery



5.2.3 Low voltage regulators

The impact of an LVR depends on where it is located on the LV network. Analysis found that the variability of voltage levels between customers is low, meaning that voltage levels mostly rise and fall together on a particular LV network. An LVR steps down voltage, which results in reduced voltages for all customers downstream of its location. Therefore, the LVRs were placed just after the DSS in a location that results in a step-down in voltages for all customers on the LV network.

For this study, the Pacific Volt LVR-30 was modelled, which:

1. Can regulate an input voltage by 13%
2. Has a rating of 30 kVA (on a three-phase LV network, the capacity would be 90 kVA per LV street circuit).

The Pacific Volt LVR-30 can boost or buck an input voltage by at most 13%. This was represented in the modelling by assuming that voltages at the LVR location could be regulated up to a value of 13%. No additional power flow modelling was performed. Rather, if a voltage was observed anywhere on the LV network above +10% nominal after a step-down equalling the step-down applied at the LVR location, this was considered a voltage breach.

In this study, the Pacific Volt LVR-30 LVR assessed was only applicable on seven out of eight LV networks, since the maximum rating for this model was reached for the Mid-density pole example LV network. For this LV network, it was assumed that an LVR with a higher rating was installed with the same voltage regulation range (+/-13%). The cost of an LVR with a higher rating was assumed to be the same as the Pacific Volt LVR-30, since most of the cost is associated with installation rather than the actual equipment. Therefore, it is considered that this approach was a good first step to understanding the impact of installing LVRs on this LV network type.

5.2.4 On-load tap changers

OLTCs are not available for transformers below a certain rating. To assess the impact of OLTC functionality, some example LV networks' transformers were upgraded to a higher rated model with OLTC functionality. Table 5 lists the LV networks that received a distribution transformer rating increase alongside OLTC, and the LV networks that received an OLTC with their existing transformer.

Table 5 • Selected LV networks that received a transformer upgrade and OLTC

LV network	Transformer rating increase and OLTC	OLTC with current transformer rating
Urban C&I pole B — 315kVA — 4-6/.186,7/062 ACSR	✗	✓
Mid-density rural pole — 100kVA — 4-6/1/114 ACSR	✓	✗
Low-density rural single-phase — 50kVA — 3-7/.064 Cu	✗	✓
Remote rural SWER — 10kVA — 2-7/.064 Cu	✓	✗
URD kiosk — 315kVA — 185mm^2 4/c lv.sa.x	✓	✗
Mid-density pole — 500kVA — 4-19/3.25 AAC	✗	✓
Urban C&I pole A — 315kVA — 150mm^2 LV ABC	✗	✓
Urban pole — 315kVA — 150mm^2 LV ABC	✗	✓

An OLTC automatically steps the voltage up or down at the DSS using a discrete number of "taps" based on customer load downstream. In all cases, the OLTC was assumed to have 9 available tap settings, each with an effective voltage step of 2.5%. It was assumed that there were four taps both above and below the neutral setting, meaning that the tapping range of the DSS is +/- 10%

5.2.5 Transformer upgrade/reconductoring

In this study, the transformer upgrade and/or reconductoring mitigation measure included replacing the distribution transformer to include an off-load tap changer, increasing the transformer rating (where possible), and increasing the quality of the LV conductor (where possible). To assess the impact of upgrading the transformer and reconductoring, power flow modelling was performed with the new LV network configuration, where:

1. Distribution transformers were upgraded to the maximum reasonable rating that could be installed on their LV network type. This means that transformers are limited to ratings that are representative of real-world constraints, and that CPPAL would potentially install (see table 6)
2. LV conductors that have high impedance were replaced with higher quality conductors (lower impedance). LV networks which were already strung with high-quality conductors (such as those with underground or aerial bundled cables) were not modified. The remaining were upgraded to aluminium conductors (4-19/3.25 AAC).

Table 6 • Maximum distribution transformer kVA rating

DSS type	Maximum reasonable kVA rating (CitiPower)	Maximum reasonable kVA rating (Powercor)
Pole type (Three-phase)	500	315
Pole type (Single-phase)	N/A	50
SWER	N/A	25
Kiosk	2,000	2,000
Indoor	2,000	2,000

All the 10 example LV networks were eligible for replacing the distribution transformer with one that has an off-load tap changer. The off-load tap changer includes two additional manual buck taps (tap size of 2.5%), and tap settings were constrained based on the minimum historical voltage levels observed on the LV network. Table 7 lists the LV networks that were eligible for reconductoring or distribution transformer upgrade.

Table 7 • Selected LV networks eligible for network upgrade

LV network	Transformer rating increase	Conductor upgrade	Off-load tap changer
Urban C&I pole B — 315kVA — 4-6/.186,7/062 ACSR	✗	✓	✓
Mid-density rural pole — 100kVA — 4-6/1/114 ACSR	✓	✓	✓
Low-density rural single-phase — 50kVA — 3-7/.064 Cu	✗	✓	✓
Remote rural SWER — 10kVA — 2-7/.064 Cu	✓	✓	✓
URD kiosk — 315kVA — 185mm² 4/c lv.sa.x	✓	✗	✓
Mid-density pole — 500kVA — 4-19/3.25 AAC	✗	✗	✓
Urban C&I pole A — 315kVA — 150mm² LV ABC	✗	✗	✓
Urban pole — 315kVA — 150mm² LV ABC	✗	✗	✓

5.3 Results

Mitigation measures were applied to eight example LV networks to assess their techno-economic performance (two of the LV networks modelled can reach 100% PV penetration without experiencing a breach — in the High-density indoor and C&I pole categories).

This section discusses the results of the techno-economic assessment of mitigation measures, specifically their ability to facilitate higher PV penetration levels across the example LV networks. The technical performance was assessed according to three metrics:

1. PV penetration level when the first breach occurred
2. Annual average hours per day spent in breach
3. Maximum voltage level rise.

In addition, the net-benefit of each mitigation measure was assessed based on a cost-benefit analysis.

Table 8 summaries the results of the techno-economic performance of each mitigation measure. The results are discussed in more detail in the following sections. The results discussed in sections 5.3.1, 5.3.2 and 5.3.3 do not consider the cost of each mitigation measure.

Table 8 • Summary of the techno-economic performance of each mitigation measure

Mitigation measure	PV penetration at first breach	Average hours per day in breach	Maximum voltage levels (voltage rise)	Cost-benefit analysis
1. Transformer upgrade and /or reconductoring	Increases the PV penetration at first breach of six LV networks	Significantly reduces hours in breach	Reduces maximum voltage levels	The best option in many cases, but only on models with more than a few customers
2. OLTC	Increases the PV penetration at first breach of six LV networks	Significantly reduces hours in breach	Reduces maximum voltage levels	Highest net-benefit for one LV network due to extreme voltage rise, superseded by LVR at higher PV penetration levels
3. LVR	Increases PV penetration at first breach of six LV networks.	Significantly reduces hours in breach	Reduces maximum voltage levels	Highest net-benefit for one LV network at high PV penetration levels due to extreme voltage rise
4. Smart inverter	Increases PV penetration at first breach of two LV networks Very minor improvements in all other example networks	Slightly reduces hours in breach	Significantly reduces maximum voltage levels	Highest net-benefit at low PV penetration levels due to low cost, but has limited benefits at high PV penetration levels due to a high level of curtailment
5. Battery	No improvement in any of the example networks	Slightly reduces hours in breach	Slightly reduces maximum voltage levels	No benefit for all LV networks due to operating mode and high cost

5.3.1 PV penetration level when first breach occurs

Traditional network augmentation mitigation measures

The network augmentation mitigation measures assessed in this study were effective at increasing the PV penetration level when the first breach occurs. This is generally because they actively reduce voltage levels on the LV networks so that the LV network can withstand further PV penetration before voltage issues arise. In this study, an off-load tap changer (part of the transformer upgrade/reconductoring mitigation measure), an OLTC and an LVR can reduce an input voltage by up to 5%, 10% and 13% respectively.

Each of the three network augmentation mitigation measures enabled 100% PV penetration with no breaches on the example LV networks in the Urban C&I A and B categories. These example LV networks experienced relatively minor voltage breaches (in terms of magnitude) under their baseline scenario. These voltage breaches were fully addressed by transformer upgrade/ reconductoring and therefore by the other network augmentation mitigation measures with greater voltage regulation ability.

Example LV networks that experienced relatively higher voltage breaches under their baseline scenario (in the Mid-density rural pole and Urban pole categories) benefited more from greater voltage regulation ranges. For these LV networks, LVRs enabled the highest PV penetration level before a breach occurred.

No network augmentation mitigation measures improved the PV penetration level when first breach occurs for the example LV networks from the Remote rural SWER or Low-density rural single-phase categories. This reflects the dramatic voltage rise observed on these networks under their baseline scenarios, which rises very steeply with only a modest increase in PV penetration (see chapter 3). This result may not be applicable to all LV networks in those categories considering that CPPAL is currently using LVRs to moderate voltages on smaller LV networks.

Customer-side mitigation measures

Smart inverters did not greatly impact the PV penetration level when the first breach occurs across all example LV networks. However, they did enable a 'no breach' result for the example LV network from the Mid-density pole category. This LV network already had a relatively high hosting capacity before applying mitigation measures (80%) and experienced only minor breaches of the maximum voltage limit under its baseline scenario.

Smart inverters also improved the PV penetration level when the first breach occurs for the URD kiosk example network. This LV network had a high number of customers, so more smart inverters were being installed on the LV network and their broader effect was more impactful.

Installing behind-the-meter batteries did not improve the PV penetration level for any of the example LV networks. The assumed operation of behind-the-meter batteries was to maximise the customer's self-consumption, which reflects their usual operation setting without any coordination by a third party. Applying this assumption, batteries often reached storage capacity around midday, before voltage peaks were reached. As such, they were not effective at reducing voltage issues.

Similar to the network augmentation mitigation measures, no customer-side mitigation measures improved the PV penetration level when first breach occurs for the example LV networks from the Remote rural SWER or Low-density rural single-phase categories.

Table 9 lists the PV penetration when the first breach in the maximum voltage limit or thermal constraint was observed.

Table 9 • Theoretical PV penetration level when first breach occurs for each mitigation option

	PV penetration when first breach occurs					
LV network	**Baseline**	**Transformer upgrade/ reconductoring**	**OLTC**	**LVR**	**Smart inverter**	**Behind-the-meter battery**
Mid-density rural pole — 100kVA — 4-6/1/114 ACSR	13%	18%	22%	27%	13%	13%
Urban pole — 315kVA — 150mm² LV ABC	9%	19%	36%	54%	9%	9%
Urban C&I pole A — 315kVA — 150mm² LV ABC	1%	No breach	No breach	No breach	1%	1%
Urban C&I pole B — 315kVA — 4-6/.186,7/062 ACSR	1%	No breach	No breach	No breach	1%	1%
Low-density rural single-phase — 50kVA — 3-7/.064 Cu	17%	17%	17%	17%	17%	17%
Remote rural SWER — 10kVA — 2-7/.064 Cu	0%	0%	0%	0%	0%	0%
URD kiosk — 315kVA — 185mm² 4/c lv.sa.x	24%	80%	No breach	84%*	32%	24%
Mid-density pole — 500kVA — 4-19/3.25 AAC	80%	No breach	No breach	No breach	No breach	80%

*LVRs only achieved a percentage of 84% for the selected LV network for the URD kiosk category due to a breach of the thermal limit. No breach of the voltage limit occurred.

5.3.2 Annual average hours per day spent in breach

Same as the first metric, network augmentation mitigation measures were the most effective in terms of reducing the annual average hours per day spent in breach. Each of the three network augmentation mitigation measures reduced the annual average hours per day spent in breach to zero (or close to zero) for the example LV networks from the Urban C&I pole A and B and URD kiosk categories (although the URD kiosk example LV network was not eligible for LVRs). As discussed in section 5.3.1, these LV networks did not experience extreme voltage rise under their baseline scenario so that these mitigation measures were able to actively reduce voltage levels to below the maximum voltage limit.

LVRs were the most effective mitigation measure at reducing the annual average number of hours per day spent in breach, due to its higher voltage regulation ability compared with other network augmentation mitigation measures. This was most notable on LV networks that experienced high voltage rise as PV penetration increased under their baseline scenario.

Smart inverters had a significant impact on reducing the average annual hours per day spent in breach on the URD kiosk example network due to, as highlighted in section 5.3.1, the large number of inverters being installed.

Table 10 shows the annual average hours per day spent in breach across 12 months at 100% PV penetration.

Table 10 • Theoretical annual average hours per day in breach at 100% PV penetration

	Average hours in breach per day per customer					
LV network	**Baseline**	**Transformer upgrade/ reconductoring**	**OLTC**	**LVR**	**Smart inverter**	**Behind-the-meter battery**
Mid-density rural pole — 100kVA — 4-6/1/114 ACSR	10.25	9.54	8.56	7.65	9.99	10.15
Urban pole — 315kVA — 150mm² LV ABC	10.30	8.00	5.38	2.96	10.06	9.78
Urban C&I pole A — 315kVA — 150mm² LV ABC	10.90	0.00	0.00	0.00	10.85	10.79
Urban C&I pole B — 315kVA — 4-6/.186,7/062 ACSR	10.91	0.00	0.00	0.00	10.83	10.81
Low-density rural single-phase — 50kVA — 3-7/.064 Cu	10.58	10.06	9.48	8.65	10.42	10.26
Remote rural SWER — 10kVA — 2-7/.064 Cu	9.90	8.58	7.11	4.85	8.61	7.72
URD kiosk — 315kVA — 185mm² 4/c lv.sa.x	6.95	0.30	0.00	0.00	2.22	4.96
Mid-density pole — 500kVA — 4-19/3.25 AAC	0.07	0.00	0.00	0.00	0.00	0.05

5.3.3 Maximum voltage levels

In this study, smart inverters were the most effective mitigation measure at reducing maximum voltage levels on the example LV networks that experienced high voltage rise under their baseline scenario. This was primarily achieved through the large amount of curtailment they enact at high PV penetration levels, as illustrated in figure 22.

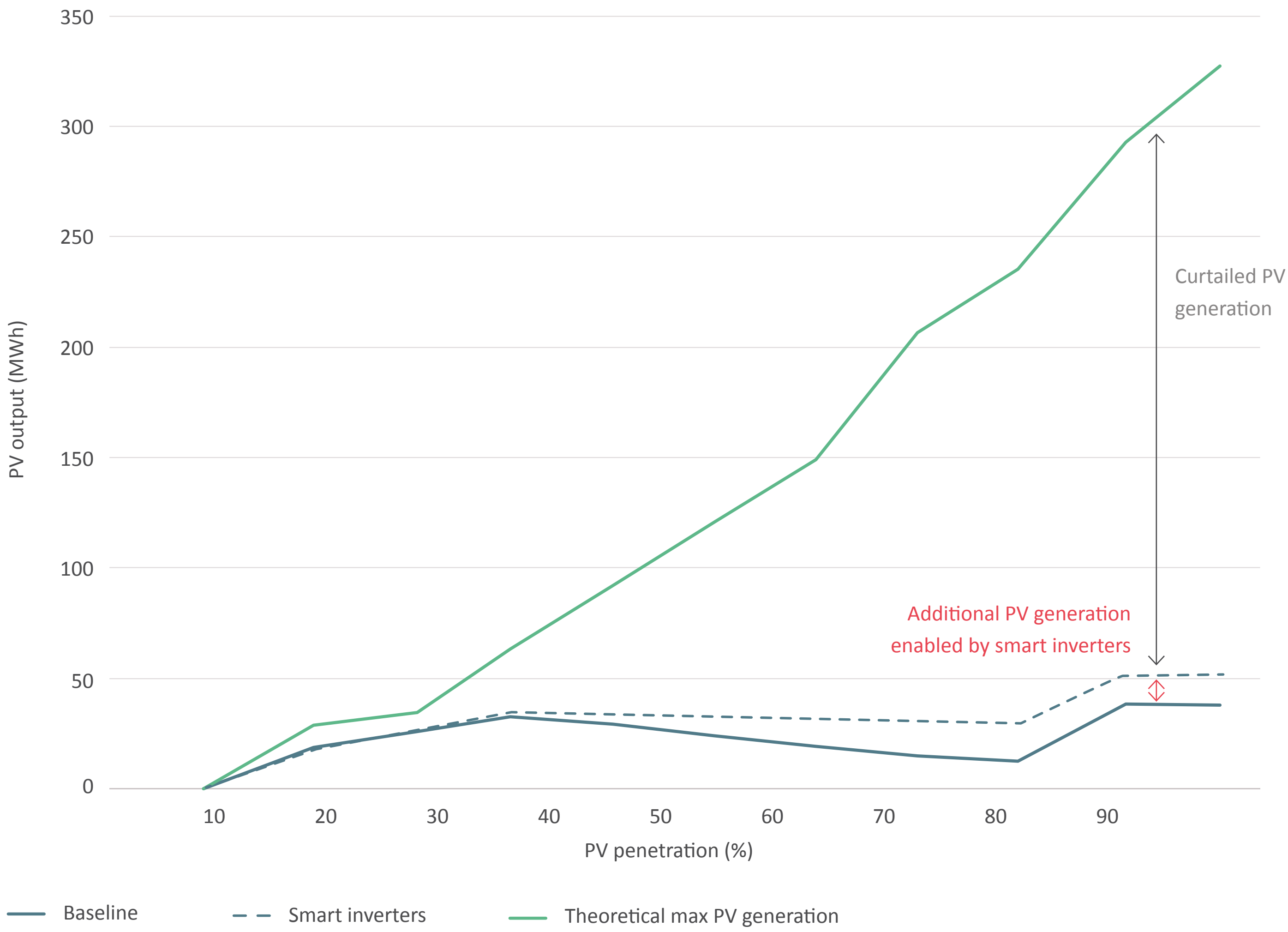
Increasing curtailment is central to why smart inverters should be considered as complementary to other mitigation measures. If relied on alone, they will curtail large amounts of generation as PV penetration increases, as shown in figure 22.

Table 11 shows the maximum voltage level across 12 months at 100% PV penetration for each of the selected LV networks.

Table 11 • Theoretical maximum voltage level across one year at 100% PV penetration

LV network	Maximum voltage level (fraction of nominal)					
	Baseline	Transformer upgrade/ reconductoring	OLTC	LVR	Smart inverter	Behind-the-meter battery
Mid-density rural pole - 100kVA - 4-6/1/114 ACSR	1.94	1.64	1.62	1.68	1.20	1.85
Urban pole - 315kVA - 150mm LV ABC	1.40	1.33	1.26	1.22	1.12	1.37
Urban C&I pole A - 315kVA - 150mm LV ABC	1.14	1.08	1.02	1.00	1.12	1.14
Urban C&I pole B - 315kVA - 4-6/.186,7/062 ACSR	1.14	1.08	1.03	1.00	1.12	1.14
Low-density rural single-phase - 50kVA - 3-7/.064 Cu	2.17	2.08	1.96	1.89	1.31	2.04
Remote rural SWER - 10kVA - 2-7/.064 Cu	1.55	1.47	1.41	1.35	1.15	1.37
URD kiosk - 315kVA - 185mm 4/c lv.sa.x	1.19	1.11	1.05	1.04	1.11	1.19
Mid-density pole - 500kVA - 4-19/3.25 AAC	1.11	1.05	1.00	1.00	1.10	1.10

Figure 22 • Example of PV generation modelling — Urban C&I pole A



5.3.4 Cost-benefit analysis results

Table 12 summarises the results of the cost-benefit analysis. For each example LV network, this table shows the PV penetration range where each mitigation measure is most applicable because it has the highest net-benefit.

Table 12 • PV penetration ranges where each mitigation measure is most relevant

LV network	Transformer upgrade/ reconductoring	OLTC	LVR	Smart inverter	Behind-the-meter battery
Mid-density rural pole — 100kVA — 4-6/1/114 ACSR	-	-	-	13% - 100%	-
Urban pole — 315kVA — 150mm^2 LV ABC	17% – 22%	22% – 56%, 84% – 100%	56% – 84%	-	-
Urban C&I pole A — 315kVA — 150mm^2 LV ABC	18% – 100%	-	-	1% – 18%	-
Urban C&I pole B — 315kVA — 4-6/.186,7/062 ACSR	24% – 100%	-	-	1% – 24%	-
Low-density rural single-phase — 50kVA — 3-7/.064 Cu	-	-	-	17% – 100%	-
Remote rural SWER — 10kVA — 2-7/.064 Cu	-	-	-	0% – 100%	-
URD kiosk — 315kVA — 185mm^2 4/c lv.sa.x	35% – 100%	-	-	24% – 35%	-
Mid-density pole — 500kVA — 4-19/3.25 AAC	-	-	-	6% - 100%*	-

*For this LV network, smart inverters were the best mitigation option despite having a negative net-benefit at saturation.

Table 12 highlights that network augmentation mitigation measures are the most applicable mitigation measure for high PV penetration levels on four of the eight example LV networks. The network augmentation mitigation measure that is most applicable is influenced by the magnitude of voltage breaches under the baseline scenario and the cost of the mitigation measure.

For example, replacing the distribution transformer to include an off-load tap changer with two additional manual buck taps was the most applicable mitigation measure for the selected LV networks in the Urban C&I pole A and B and URD kiosk categories. The maximum voltage levels observed on these LV networks were only slightly above the maximum voltage limit at 100% PV penetration. Therefore, the larger voltage regulation range of an LVR (+/- 13%) or OLTC (+/- 10%) did not result in additional PV generation. Because transformer upgrade/reconductoring is the least expensive network augmentation mitigation measure, it had the highest net-benefit for these LV networks.

As a comparison, LVRs were more applicable to the selected LV network in the Urban pole category. This selected LV network had a high maximum voltage level at 100% PV penetration, so the greater tapping range of an LVR enabled additional PV generation to offset the higher marginal cost (this LV network was three-phase with five LV street circuits). Notably, the transformer's thermal limit was breached at 84% PV penetration. After this point, the LVR is no longer viable (as it does not address any thermal issues). OLTC then becomes the best option, as the associated transformer rating upgrade addresses the thermal rating issue.

Due to their zero-marginal cost, smart inverters were the most applicable mitigation measure at low PV penetration levels for four of the selected LV networks. However, as PV penetration increases, the benefit of smart inverters declines due to increasing curtailment of PV generation. At a certain point, the additional PV generation enabled by the network augmentation mitigation measures (through their ability to actively reduce voltage levels) offset their cost for these LV networks.

The example LV network from the Mid-density rural pole category had high maximum voltage levels, and it benefitted from smart inverters preventing voltage level rise as PV penetration increased to saturation. Although LVRs were the most effective mitigation measure at enabling additional PV generation on this LV network, due to the low number of customers, additional PV generation was not high enough to offset the high marginal cost for a three-phase network with two LV street circuits.

Table 12 states that smart inverters were the most applicable mitigation measure for the example Remote rural SWER and Low-density rural single-phase LV networks, based on their net-benefit. Although smart inverters achieved a positive net-benefit, the additional PV generation enabled was insignificant. These LV networks have a low number of customers, meaning that additional PV generation enabled by other mitigation measures is so low that the benefits do not outweigh the costs.

No mitigation measures are relevant for the selected LV network from the Mid-density pole. This LV network was already able to reach a high level of PV penetration (80%) before a breach occurred under its baseline scenario. Beyond this point, additional PV generation enabled by the network augmentation mitigation measure was not high enough to offset the cost. Although smart inverters enabled 100% PV penetration, this was achieved through curtailment.

Recommendations based on the key findings of this study are outlined in the following chapter.

6 Recommendations

DER penetration will continue to grow as customer preferences change towards becoming energy independent and as efforts to reduce emissions also increase. Growing PV penetration is creating power quality issues on LV networks and future investment will be required to enable further PV installations.

This study was designed to help DNSPs improve their understanding of LV networks' ability to accommodate higher PV penetration levels. The two key aims of this study were to:

1. Establish a replicable methodology to determine the hosting capacity of LV networks
2. Assess the techno-economic performance of measures to increase hosting capacity.

Based on the results of this study, this chapter presents 11 key recommendations — six recommendations to governments and industry stakeholders and five recommendations for further study.

Key themes

Considering that this study found there is **no one definitive solution for improving hosting capacity**, the six recommendations to governments and industry stakeholders cover a range of topics. These include promoting and installing smart inverters for dynamic export, expanding the methodology established in this study to further improve LV network visibility, and continuing to explore the potential for behind-the-meter batteries.

In addition, the five recommendations for further study cover topics that were outside the scope of this study. These include behind-the-meter battery governance, electric vehicles and combining mitigation measures for LV and HV voltage management.

Chapter sections

- Section 6.1 — Recommendations for government and industry stakeholders
- Section 6.2 — Recommended topics for further study.

6.1 Recommendations for government and industry stakeholders

Based on the key findings of this study, the following recommendations are made.

1. **Allow for flexible/dynamic export limits of PV generation**
2. **Promote and install smart inverters in jurisdictions that expect PV growth**
3. **Consider other mitigation measures to complement smart inverters**
4. **Upgrade transformers during replacement activities**
5. **Build power flow models for a wide range of LV networks**
6. **Explore the potential of behind-the-meter batteries**

1. Allow for flexible export limits of PV generation

Governments could consider allowing for flexible export limits (also referred to as dynamic curtailment) in scenarios where it is appropriate.

Historically, DNSPs have applied a fixed (or static) export limit that caps PV exports to the grid. This blanket rule means that some customers are having their PV generation curtailed when it is not required. On the other hand, unlocking 100% of customers' PV exports across the entire distribution network would be economically inefficient and may create unnecessary upward pressure on electricity prices. Allowing customers to only be curtailed when the grid requires it via flexible export limits is a more efficient alternative.

This study has shown that, in many cases, smart inverters achieve the highest net-benefit at low PV penetration levels by enabling dynamic export through Volt-Watt and Volt-VAR control. For some LV networks, mitigation measures that unlock 100% of customers' PV exports do not enable enough additional PV generation to offset their cost, even at very high PV penetration levels. In these cases, dynamic exports may be more cost-effective.

These findings are in line with AEMC's recommendations, which identified dynamic export limits as a solution that DNSPs can implement to enable DER penetration [7].

2. Promote and install smart inverters in jurisdictions that expect PV growth

Governments in jurisdictions with expected PV growth are encouraged to follow the example of Victoria in mandating the installation of smart inverters with Volt-VAR and Volt-Watt control enabled. DNSPs should include them as part of their connection agreements with customers installing PV.

Smart inverters with Volt-Watt and Volt-VAR response modes can progressively curtail PV generation and can act as a 'safety net' to ensure that voltage does not reach excessive levels. This can be achieved at a negligible additional cost for customers compared to standard inverters. Through dynamic export, smart inverters have been shown to mitigate extreme theoretical voltage rise levels efficiently, even up to 100% PV saturation.

AEMO supports enhancing smart inverter standards (Australian Standard 4777.2) to improve device responsiveness to power quality issues occurring on LV networks. It is currently investigating best practice international standards regarding this [5].

CPPAL's smart inverter settings have been shown to be effective at mitigating voltage rise. However, DNSPs should determine optimal settings based on each DNSP's context and local network conditions.

Globally, DNSPs should look to Australia as a case study in managing high levels of PV penetration when increased behind-the-meter PV is expected in their network. As noted in the International Energy Agency's Renewables 2019 report, global capacity of distributed solar is set to increase by a further 320 GW in the next five years.

3. Consider other mitigation measures to complement smart inverters

DNSPs should expect to deploy a range of mitigation measures in conjunction with smart inverters, the details of which will differ depending on the customer's network context. Investment in targeted network upgrades should be expected, even after the widespread deployment of smart inverters with Volt-Watt and Volt-VAR control.

While smart inverters should be encouraged alongside all PV system installations by DNSPs, they should not be considered a 'silver-bullet' to solve all issues.

Smart inverters can mitigate many power quality issues. This study, however, has shown they will not achieve optimal customer outcomes at higher levels of penetration on many LV networks, where curtailment can reach very high levels without other mitigation measures in place.

4. Upgrade transformers during replacement activities

During a DNSP's normal transformer replacement activities, additional negative taps and transformers targeting the updated regulated voltage levels should be installed in all cases.

This study showed that an increased 'buck' tap range of an off-load tap changer and/or the installation of a transformer targeting the updated regulated voltage range had a much more beneficial impact on voltage than an increase of the transformer's rating and/or reconductoring of the LV network.

Many older transformers on CPPAL's network still target voltages that are 10 V above the regulated nominal voltage level. This is due to a regulatory change which moved the nominal value from 240 to 230 V in Australia. Because the transformer's transformation ratio is a fixed parameter of its make and model, full replacements are required to alter that characteristic.

5. Build power flow models for a wide range of LV networks

DNSPs are encouraged to invest in building a wide range of LV network power flow models, either manually or through an automated process.

Although the 10 LV network examples were chosen through categorising CPPAL's LV networks, analysis has shown that they are not fully representative of the full population of LV networks due to the sheer diversity of LV arrangements. Creation of an expanded set of example LV networks would allow a more accurate extrapolation to the entire distribution network.

To do so, the most populous categories would be subdivided to improve granularity, while multiple example networks would be taken from each category to represent variability within each category. Increasing the number of networks by one or two orders of magnitude would be highly beneficial, allowing more confident extrapolation of results.

Further, a comprehensive set of LV network models (one power flow model for each real-world LV network) would allow individual customer connections to be assessed in detail. However, short of a comprehensive set, a sampling approach across an increased number of categories and example networks will allow for more confidence when inferring LV networks' hosting capacity.

This aligns with the recent AEMC recommendation, which considers expenditure on improving the visibility of the LV networks to be an important step to integrating DER [7].

6. Explore the potential of behind-the-meter batteries

The grid-servicing potential of a fleet of behind-the-meter batteries (detailed in recommendations 7 and 8) could be investigated by DNSPs and governments.

Batteries will not contribute to increasing PV hosting capacity without active management. This study found that operating behind-the-meter batteries to simply maximise customer self-consumption did not improve LV power quality in any meaningful way. Under the assumptions used in this study, batteries are fully charged before the times of maximum PV export and are therefore unable to absorb PV export when most needed.

However, alternative battery operation modes that target grid services have the potential to positively impact voltage (not quantified in this study), by ensuring they are charging at times of maximum PV generation.

The critical observation in this study about the limitations of batteries that operate to maximise self-consumption could inform policies and programs. For example, it could assist in Victoria, where Solar Victoria is currently piloting a battery rebate scheme. Although eligible customers must agree to receive information from DNSPs about taking part in battery trials, there are no guidelines around how customers should operate their battery [11]. This finding also aligns with AEMO 's recommendation in its Draft 2020 Integrated System Plan that new DER installations will increasingly require some level of interoperability so that they can be controlled when required.

6.2 Recommended topics for further study

Five additional recommendations have been made for further analyses, relating to areas that were outside this study's scope.

7. **Behind-the-meter battery operation**
8. **Behind-the-meter battery governance**
9. **Electric vehicles (EVs)**
10. **Additional mitigation measures and/or combinations of them**
11. **Management of HV and LV voltages in conjunction on long feeders**

7. Behind-the-meter battery operation

As noted in recommendation 6, the operation of behind-the-meter batteries could be further explored as a mitigation measure against LV voltage rise.

Specifically, the optimal operating procedure of a fleet of batteries, in terms of mitigating power quality issues, could be identified and quantified. It is expected that peak-shaving[26] of PV generation would reduce voltage, but the magnitude of potential voltage reduction could also be measured.

Various operating modes could be explored, with the aim of identifying alternate effects batteries could have (such as reactive power absorption).

Reflected in OpEN's project consultation, behind-the-meter batteries could be operated to target different (and sometimes conflicting) outcomes, such as arbitrage for customer profit or LV voltage management. It is encouraged that these outcomes are identified, valued, and compared. Opportunities for 'win-win' scenarios are ideal, wherein customers could be paid for providing grid services, potentially through an aggregator.

In Victoria, the inclusion of battery systems under the Solar Homes program adds a further incentive to address this question. Similar programs in other jurisdictions are offsetting the cost of battery systems for customers, resulting in an increasing number of systems that are, by default, underutilised in terms of grid services.

8. Behind-the-meter battery governance

Beyond the question of operation, the impact of different organisational structures could be investigated, to weigh up the relative benefits of various battery fleet operation scenarios.

The potential roles and responsibilities of DNSPs, DSOs, VPPs and others could be explored, with the aim of establishing the maximum eventual customer benefit. This would support the OpEN project's key objective of understanding the future role of DNSPs in managing an increasingly decentralised system [6].

These scenarios may be compared with other grid-servicing options via a cost-benefit analysis, and they should be further tested through pilot studies. Lessons learned from this study and other ongoing projects, such as SA Power Network's Advanced VPP Grid Integration project, can inform the design of further investigations.

9. Electric vehicles (EVs)

The potential positive and negative impacts of EVs could be explored.

EVs can essentially be considered large flexible loads that are intermittently connected to the grid, and their potential as a mitigation measure of this form should be explored. However, without proper management and if allowed to charge during peak load periods, EVs could contribute to voltage drop issues and maximum demand increase. This could create local network congestion and contribute to widening the range of observed voltages on an LV network. The potential magnitude of both effects should be measured and explored across a range of uptake scenarios.

As with behind-the-meter batteries, a properly managed EV fleet could provide LV voltage management services while side-stepping the potential negative impacts of EV charging. Fleet management strategies should be explored, as well as identification of customer usage patterns and potential incentive programs to guide customers' charging behaviour.

[26]This is similar to one Tesla Powerall system

10. Additional mitigation measures and/or combinations of them

Further study could be undertaken to investigate the effects of combined mitigation measures on the metrics detailed in this report.

Throughout this study, mitigation measures were treated independently of each other. However, it is likely that the optimal LV voltage management solution could use a combination of more than one measure. Further, there may be other mitigation measures not explored within this study that can improve PV hosting capacity.

This study has shown that the mitigation measures offer qualitatively different voltage-reduction effects. For example, the 'flattening off' of voltage rise offered by smart inverters through dynamic export, is different to the discrete step-down offered by an OLTC. This difference suggests that no single measure will address all voltage rise issues. In some cases, combining more than one measure may provide the necessary voltage rise mitigation. It is also noteworthy that smart inverters will soon be regularly combined with other options in Australia, where smart inverters are now becoming mandatory.

As such, a study could investigate the effects of combined mitigation measures on the metrics detailed in this report. Further, HV-level measures should be assessed, such as HV regulators, OLTC functionality at ZSS, and traditional HV augmentation. Finally, additional mitigation measures could be considered, such as optimising controlled load dispatch (for example, hot water tanks).

11. Management of HV and LV voltages in conjunction on long feeders

Further analyses could be undertaken that explore the use of HV and LV mitigation measures in combination.

A DNSP's voltage management strategy for long feeders must consider both HV and LV levels of the distribution network, because substantial voltage rise is expected in both portions of the network.

Long HV feeders exhibit material voltage variation across distribution substations, an effect which DNSPs are already mitigating through HV voltage management (for example, with HV voltage regulators). As observed in this study, these variations will be amplified with a widespread PV uptake that will create significant voltage rise along the feeder at times of export, reinforcing the need for HV voltage management, independent of voltage effects within the LV networks.

It is also clear that voltage rise can be driven by effects purely within the bounds of an LV network, independent of voltage effects of the HV network. Therefore, addressing only one of these network portions (either HV or LV) will not suffice to mitigate customer voltage rise on these long feeders, because either one in isolation has the potential to cause voltage breaches. Addressing both levels in a coordinated way will likely allow the best results on these long feeders.

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