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Distributed Energy Resources Enablement Project – Discussion and Options Paper

Prepared for Renew

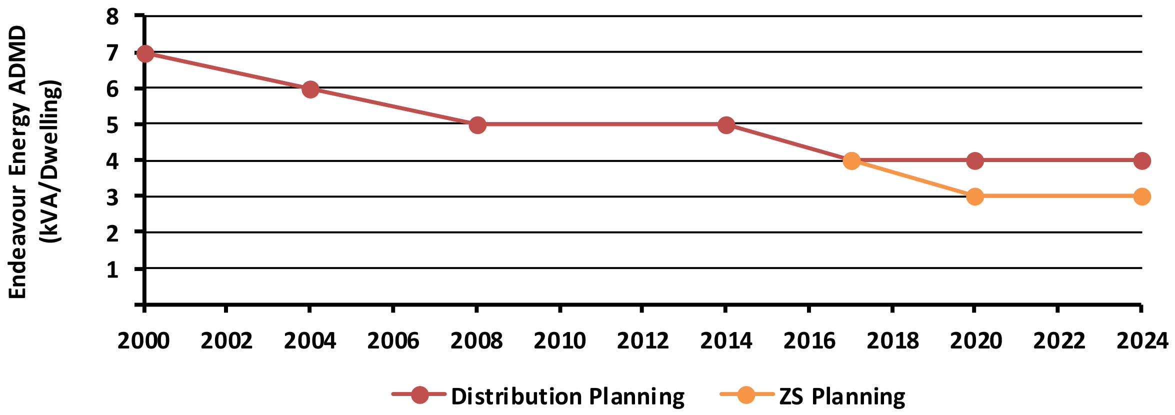
22 May 2020

ENERGEIA

Executive Summary

Electricity distribution networks in the immediate post-WWII period were originally designed and built to accommodate around 1 kW of After Diversity Maximum Demand (ADMD)[1] per residential premise. Over the past 50 years or so, an increase in the number and nature of loads in the home, particularly air-conditioners (ACs), has resulted in distribution network planners assuming up to 7 kW ADMD for new residential premises[2] in the early 2000s. However, over the past two decades, improvements in building standards, decreases in average building size, solar penetration and increasingly efficient home appliances have brought the ADMD back down to 4 kW, as shown below.

Endeavour's Historic ADMD



Source: Endeavour[2]

ACs are widely believed to be a key driver of the increase in ADMD and associated power quality issues, however the higher costs have not been specifically allocated to those with these devices. The lack of an effective 'cost-reflective' pricing system, at least not for existing premises, has led to an uneconomic increase in network capital expenditure over the past 10-15 years. While those with ACs do pay more due to the higher energy consumption of these devices, non-cost reflective pricing resulted in significant cross-subsidies[3].

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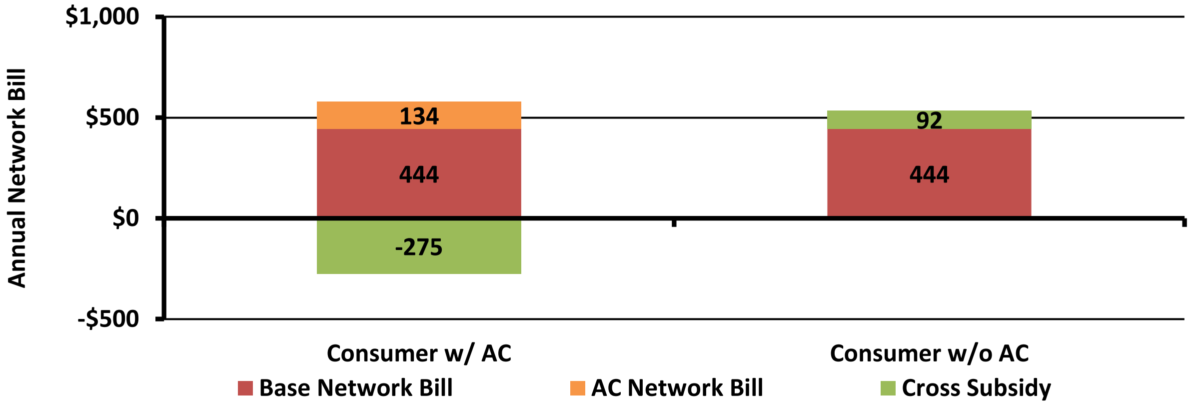
[1] ADMD is the highest coincident peak consumption anticipated by network planners per premises, after correcting for the expected variation and diversity in consumer behaviours.

[2] Endeavour (2018), '*Regulatory Proposal*', https://www.aer.gov.au/system/files/Endeavour%20Energy%20-%200.01%20Regulatory%20Proposal%20-%20April%202018%20-%20Public.pdf; Note: The above figures are for a single DNSP and are not perfectly reflective of either the current ADMD for other DNSPs in the NEM, or the pathway taken by them over time. Endeavour has been chosen as an indicative DNSP to show the trend of recent declines in the ADMD per connection.

[3] It is worth noting that cross-subsidies are an inherent part of the energy system, and that this is by design (e.g. urban customers cross-subsidising rural ones). The key issue is ensuring that the cross-subsidy is equitable. Some level of cross subsidy is accepted due to the transaction cost of unwinding them. For example, charging every dwelling based on their exact cost-to-serve would result in no cross-subsidies, but would be extremely complex and costly to calculate, uniformly increasing customer bills.

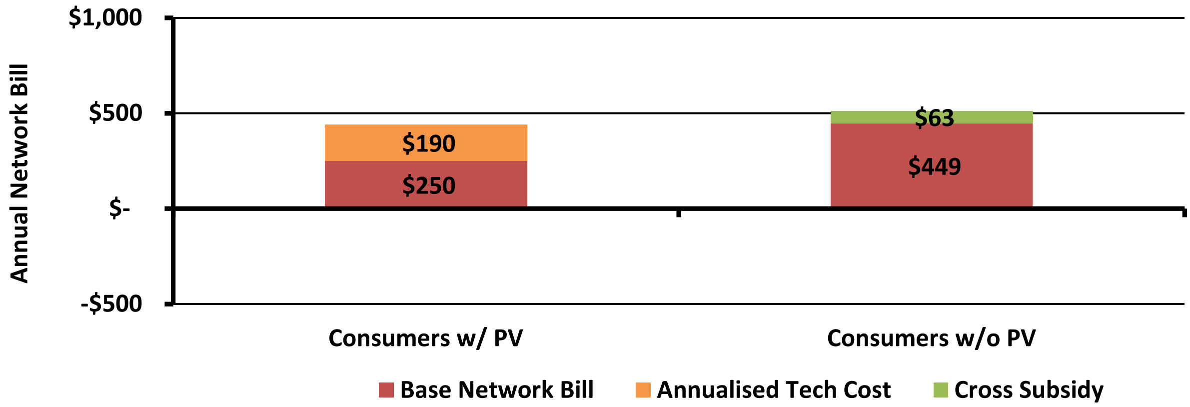
Illustration of Residential Bill Impacts from AC Adoption by AC Adoption Status (Annualised Basis)



Source: Energeia; Note: AC = Air-Conditioners; Note: Costs shown on an annual basis.

Rooftop solar photovoltaic (PV) systems are the latest change in customers' use of the electricity distribution network. Their penetration has risen rapidly over the past 5-10 years, and Australia now has among the highest penetration of rooftop solar PV in the world. Solar PV, as was the case with AC before it, is widely believed to be a key driver of emerging voltage rise and other power quality issues, and probably leads to some level of cross-subsidies between those able to install a solar PV system and those that can't, typically those renting and/or living in apartments.

Illustration of Residential Bill Impacts from PV Adoption by PV Adoption Status (Annualised Basis)



Source: Energeia

Distribution Network Service Providers (DNSP) responses to rising solar PV penetration and associated grid and inverter impacts have included limiting the amount of solar generation that can be fed into the network, limiting the size of new solar PV systems connecting to their network, and in some cases disallowing new solar PV system connections altogether.

Importantly, Australian DNSPs have started to look at better options[4] for integrating Distributed Energy Resources (DER) at lower cost, including solar PV, battery storage and electric vehicles. The approaches being proposed by DNSPs in their submissions to the Australian Energy Regulator (AER) come at a significant cost[5], and it is therefore critical that the approach ultimately adopted is in the best interest of all Australians. It is also important that the associated costs and benefits be equitably distributed among stakeholders.

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[4] See Energex (2018), 'Distribution Annual Planning Report', https://www.energex.com.au/__data/assets/pdf_file/0016/720223/Distribution-Annual-Planning-Report-2018.pdf and Ergon (2018), 'Distribution Annual Planning Report', https://www.ergon.com.au/__data/assets/pdf_file/0018/720234/DAPR-2018-2023.pdf

[5] Ibid.

Scope and Approach

As a community organisation interested in the fair treatment of solar PV and other DER technologies, Renew engaged Energeia to help inform the national debate regarding rooftop solar PV and other DER by:

- Identifying the key issues related to rising solar PV and DER and who they impact;
- Identifying the potential solutions to these issues and their associated cost; and
- Developing an analytical framework for identifying the optimal approach in a given situation.

Energeia developed the following approach to address Renew's key objectives and scope of work based on our experience modelling and optimising DER net benefits over the past ten years:

- **Comprehensive desktop review of key industry and academic reports** – The desktop review focused on reported issues and solutions. It included submissions to the Australian Energy Regulator (AER) and Distribution Annual Planning Reports (DAPR), as well as major international studies.
- **Short listing of the key issues, solutions and development of an optimisation framework** – Energeia engaged with the stakeholder represented Steering Committee to validate the key issues, solutions and optimisation framework; however, the final list and approach is ultimately our own view.
- **Documentation of our research findings and draft optimisation framework** – Energeia developed a Problem Statement Report for wider consultation with key stakeholders. The feedback from this report was used to refine the optimisation framework applied in the modelling stage.
- **Modelling potential solutions under different scenarios and scales** – The final step in the project involves the finalisation and implementation of the optimisation framework, and documentation of the results in a subsequent Options and Discussion Paper Report (i.e. this report).

Stage 1 – Research Key Findings

Key DER Integration Issues

Energeia completed a comprehensive desktop research process, including the low voltage (LV) network management and DER connection practices of all 13 DNSPs in the National Electricity Market (NEM), and major international studies in Europe and North America. Our research totalled tens of thousands of pages over 130 key documents, which are summarised in the bibliography (Appendix A – Bibliography).

Energeia's comprehensive review of the issues reported to be associated with increasing rooftop solar PV adoption identified 21 key issues, 11 of which were distribution network impacts as shown in the table below. Issues were selected based on their expected total cost over time.

Summary of Issues Associated with Rising DER Penetration

Stakeholder	Category	Issue	Impacts
Customers with Solar PV	Investment	Connection Limits	Connection standards can limit efficient investment choices in DER
		Export Limits	Connection standards can limit efficient operation of DER
		Inverter Curtailment	Inverter standards can reduce output and investment certainty
		Increased Energy Losses	Inverter standards can increase reactive power losses, reducing investment certainty
		Reduced Capacity	Inverter standards can increase reactive power, reducing inverter capacity and lifetime and investment certainty
		Reduced Lifetime	
Distribution Networks	Power Quality	Over-Voltage	Excess generation can increase voltage above allowed thresholds
		Under-Voltage	Generation can increase voltage range, leading to under-voltage
		Flicker	Intermittent generation can lead to voltage flicker
		Harmonics (THD)	Inverters can inject additional harmonics
	Reliability	Thermal Overload	Generation levels can exceed thermal rating limit
	Safety	Protection Maloperation	Changes in generation and load patterns can break some schemes
		Islanding	Inverters can fail to disconnect, creating safety issue
	System Security	Disturbance Ride-through	Inverters disconnect during disturbance, worsening the disturbance
		Under Frequency Shedding	Load shedding inverters can increase net load, worsening frequency
	Cost / Efficiency	Phase Imbalance	Inverters can be unevenly distributed, unbalancing the g rid
		Forecasting Error	Stochastic inverter uptake and output can reduce forecast accuracy
Generation, Transmission and Market Operations	Operability	Ramp Rate	Inverters can increase rate of change above system capabilities
	Reliability	Thermal Constraints	Large DER resources can overload thermal limits
	Safety	Fault Levels	Inverters can reduce fault current
	Cost / Efficiency	Forecasting Error	Uptake and operation can increase forecasting error
		Generation Curtailment	Curtailment of DER generation can increase wholesale market prices

Source: Energeia; Note: THD = Total Harmonic Distortion, 1. Grey indicates that issue is addressed by current inverter standards. 2. The lack of LV network monitoring means that there is limited visibility of the nature, scale and extent of LV network issues.

Key DER Integration Solutions

Energeia's comprehensive review of the potential solutions to the identified key issues identified 22 key options, grouped into six categories:

- **Customers** – Customer-side solutions include load change, and/or DER investment and/or DER operation
- **Pricing Signals** – Improved cost and value signalling, from moving to basic Time-of-Use pricing to establishing the most sophisticated, real-time and locational signals possible
- **Technical Standards** – Changes to both inverter (i.e. so-called 'smart' inverter standards and remotely configurable inverters) and connection limits standards (dynamic limits replacing static limits)
- **Reconfiguration** – Changing existing settings, topology, schemes and operation of the LV network to remediate identified issues (excludes investment in new methods or assets)
- **New Methods** – New methods or techniques for resolving issues, such as improved forecasting methods and use of non-traditional data sources including third party inverters and smart meters
- **New Assets** – New monitoring, control, voltage regulation, transformer or conductor assets to remediate identified issues

Solution to Issue Mapping

Each solution can potentially remediate multiple issues. Based on our research, Energeia mapped each solution to each identified issue, with the resulting impact assessment reported in the table below.

Summary Mapping of Remediation Options to DER Issues

Issue Stakeholder	Key Issue	Potential Solutions					
		Customers	Pricing Signals	Technical Standards	Re-configuration	New Methods	New Assets
Prosumer	Investment	✓	✓	✓*	✓*	✓*	✓*
Distribution Network Service Providers	Power Quality	✓	✓	✓*	✓*	✓*	✓*
	Reliability	✓	✓	✓*	✓*	✗	✓*
	Safety	✗	✗	✓*	✓*	✗	✓*
	System Security	✓*	✗	✓*	✓*	✓*	✓*
	Cost / Efficiency	✓	✓	✓*	✓*	✓*	✓*
Gen, Tx and Mkt Ops	Various	✓*	✓*	✓*	✓*	✓*	✓*

Source: Energeia; Note: Gen = Generation; Tx = Transmission; Mkt Ops = Market Operations; ✓ = Full Match (i.e. all of the potential solutions match all of the identified issues in these categories); ✓* = Partial Match (i.e. some potential solutions match some of the identified issues in these categories); ✗ = No Matches (i.e. none of the potential solutions match any of the identified issues).

Solution Costs

Energeia used desktop research, consultation with the Steering Committee, and our industry network to develop indicative cost estimates for each of the key solutions, as shown in the table overleaf.

The indicative costs below were taken forward into the indicative cost-benefit and optimisation analysis conducted in Stage 2. Energeia recognises that solution costs can vary widely according to numerous factors including network density and topography. These costs are intended to be indicative, high level estimates, and do not necessarily reflect the views of all Steering Committee members.

Summary of Key Solution Cost Estimates by Category

Category	Solution		Capex	Opex	Units
Consumer	Water Heater Management – Retrofit Control		$150	$15	kW
	Level 2 Charger Management – Retrofit Control		$150	$15	kW
	Storage Management – Install New Controllable		$1k	$15	kW
Pricing	Coarse (e.g. ToU pricing), excl. smart meter		Negligible	$0	Customer
Signals	Granular (e.g. real-time pricing), excl. smart meter		$12m	$250k	DNSP
Technical Standards	Inverter Standards		Negligible	$0	DNSP
	Remote Inverter Configuration		Negligible	$0	Country
	Static Limitations		Negligible	$0	DSNP
	Dynamic Limitations		$6m	$250k	DNSP
Reconfiguration	Change Taps		Negligible	$1-2k	Trip
	Change Topology		$200k-$660k	$0	Feeder
	Change UFLS		$100k-$150k	$0	Feeder
	Change Protection		$1k	$0	Feeder
	Balance Phases		Negligible	$1.5-$2k	Trip
New Methods	Third Party Data	New Install	$500	$5	Customer
		Previous Install	Negligible	$5	Customer
	Better Long – Term Forecasts		$8m	$250k	DSNP
New Assets	LV Metering		$3,500	$30	Transformer
	Voltage Regulators		$300k	2.5% of capex	Regulator
	Larger Assets		$100k-$400k	2.5% of capex	Asset
	On-Load Tap Changer	Vault	$120k	$7k	Transformer
		Pole-Mounted	$60k	$7k	Transformer
	Harmonic Filters		$500k	$0	Substation
	Statcom (Single-Phase)		$5-8k	2.5% of capex	LV Phase
	Network Storage		$1.2k	2.5% of capex	kWh

Source: Energeia; Notes: 1. Changes deemed to be part of existing operations excluded, e.g. introduction of new price structures. 2. In-depth consultation with DNSPs would be required on to better understand costs on a jurisdictional basis. 3. Solutions are not mutually exclusive; the application of certain solutions may be limited by the absence of others i.e. electric water heaters must be in place to control their load.

Stage 2 – DER Integration Optimisation

Energeia developed a high level, best practice DER-integration optimisation framework based on our research of best practice approaches to DER integration solution optimisation and our experience modelling the costs and benefits of DER across consumers, prosumers, DNSPs and the wholesale market.

Energeia's solution optimisation approach modelled the costs and benefits of various solutions, for a given category of LV network, to identify the set of solutions that is expected to deliver the highest net benefits. The modelling approach for Stage 2 focused on optimising the costs for addressing over-voltage issues due to over-generation, mainly by rooftop solar PV systems.[6] Over-voltage was chosen as the area of focus given the level of reported incidence of this issue by DNSPs with relatively high levels of rooftop solar PV penetration.

[6] Energeia was unable to implement our originally proposed DER-integration cost analysis due to a lack of sufficient data on: peak demand or utilisation by LV transformer; hosting capacity functions or estimates for phase imbalance, under-voltage and under-frequency load shedding, and; solution costs for under-frequency load shedding.

Network Segmentation

Energeia redesigned our LV classification approach for Stage 2 to reflect the data available in the AER's Regulatory Information Notices (RINs). The revised approach segments all LV networks into 50 kW, 250 kW and 1,000 kW, representing rough mid-way points between the AER RIN categories. These segments are also reflective of different customer densities and reliability types (i.e. Urban, Suburban and Rural).

Key LV Network Segments

Name	No. of Transformers	Reliability Type	RIN Categorisation	Construction
50 kVA	350,653	Rural	< 60 kW	Overhead
250 kVA	230,988	Suburban	60 -1,000 kW	Underground
1,000 kVA	34,024	Urban	> 1,000 kW	Underground

Source: Energeia Analysis

The key difference between each type of LV network was the assumed contribution of customers to coincident peak demand, with the denser urban areas assuming 5 kWs compared to 6 for suburban and 7 for rural. This mainly drives a different cost structure for network solutions, and in particular new network assets.

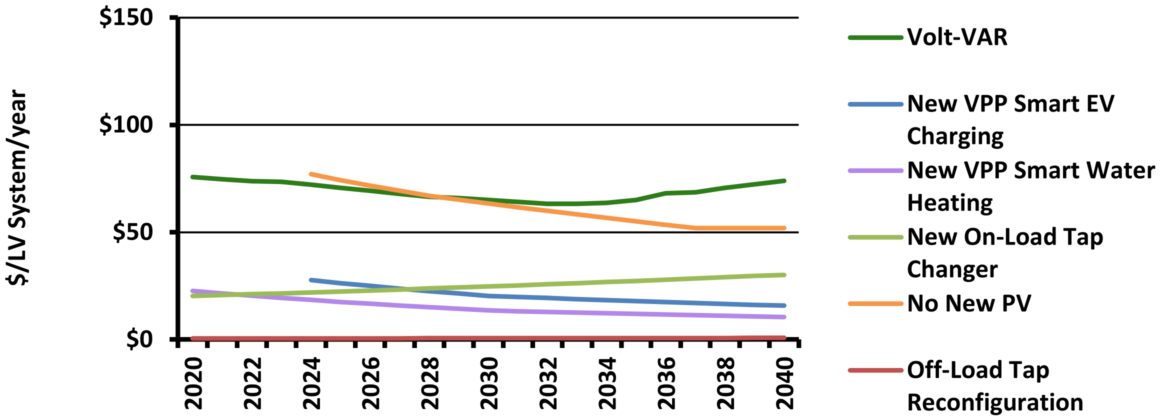
Most distribution networks are comprised of a mix of the above types of network segments.

Solution Availability and Marginal Cost Over Time by Network Type

Energeia's modelling of the optimal DER-integration solution over time focused on addressing the voltage rise issue, given the prominence of this problem, and the limitations of data availability. The redesigned approach was based on our research in Stage 1 of this project on the marginal cost and availability of selected network and prosumer solutions[7].

Energeia's modelling of the optimal DER-integration solution over time was based on the marginal cost and availability of selected network and prosumer solutions. The results of our modelling of the marginal costs and availability of selected network and prosumer solutions are shown below for the Neutral Scenario[8].

Urban LV System: Least Cost Annual Expenditure by Solution – Neutral Scenario



Source: Energeia*;* Note: Off-load or manual tap changes, are shown but difficult to see due to their very low cost (<$1 per PV kW p.a.) and are between 20x and 30x cheaper than on-load or dynamic tap changer installations (between $20 and $30 per PV kW pa).

Our modelling of the Urban LV network segment shows offline tap changers as providing the lowest cost additional hosting capacity sufficient to meet forecast requirements over the modelling period.[9] The cheapest

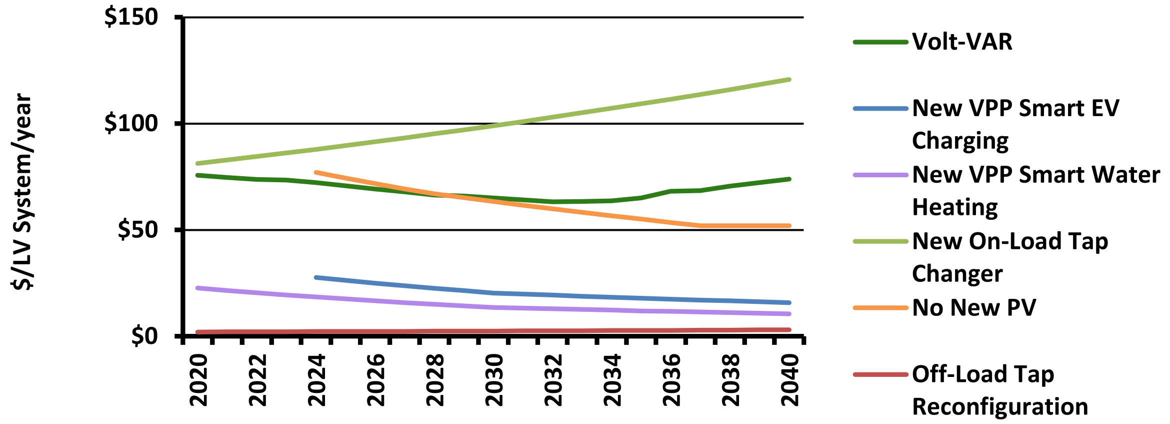
[7] The modelling excludes analysis of existing VPP resources due to the complexity of opportunity cost analysis, a subject for Phase II.

[8] See Appendix F – Optimisation Results by Scenario for all scenario results.

[9] Under the high DER scenario, reconfiguration of fixed tap settings is insufficient and online tap changers are required.

consumer solution[10] in this scenario is a new, VPP connected electric water heater, but it is significantly more expensive.

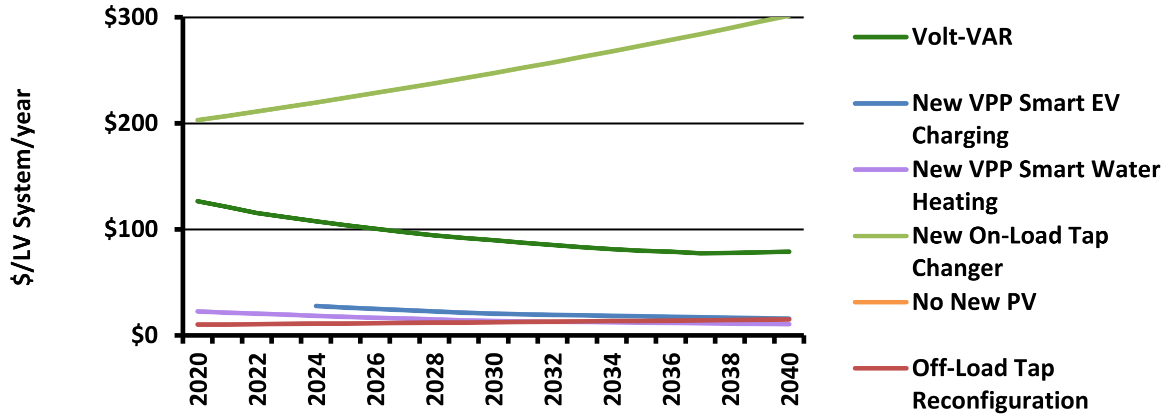
Suburban LV System: Least Cost Annual Expenditure by Solution – Neutral Scenario



Source: Energeia

For the Suburban LV network segment, offline tap changes are also the lowest cost solution over the modelling period. It is worth mentioning that the identified network solutions are much cheaper than the curtailment options including static network limitations (i.e. No New PV) and Volt-VAR inverter settings, mainly due to the forecast value of solar PV generation[11].

Rural LV System: Least Cost Annual Expenditure by Solution – Neutral Scenario



Source: Energeia

For the Rural LV network segment, the relatively low customer density leads to relatively high cost per customer for network solutions. This results in a new VPP enabled electric water heating solution being the lowest cost consumer solution, until the resource is exhausted in 2036. By that time, a new, VPP-enabled smart EV charging solution is available and forecast to offer the lowest cost per unit of increased hosting capacity in this network segment.

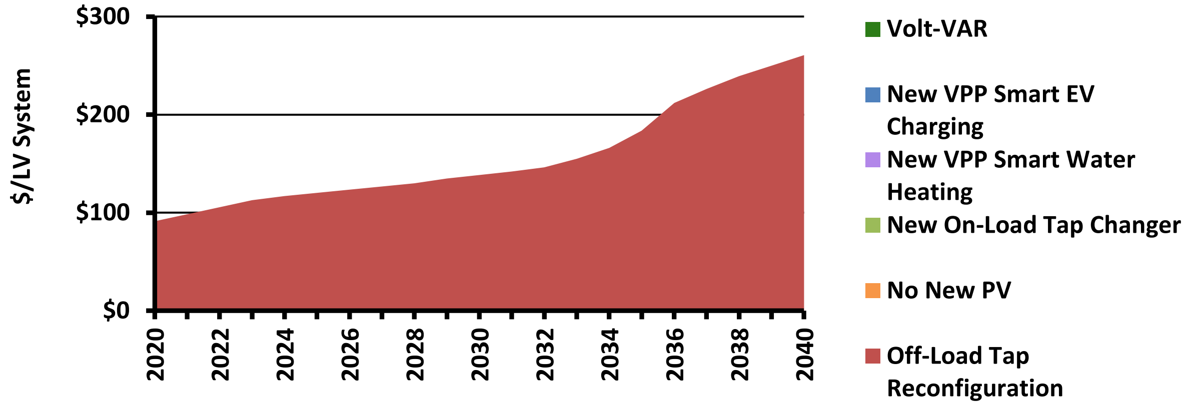
[10] Smart water hot heating is an immediately actionable potential solar "sink" for networks to access given existing technologies, network prices and consumer appliance installations. Electric vehicle charging will increasingly be an important household load, and over the next 10 years has the potential to grow to be a similarly priced, but larger and more significant solar "sponge".

[11] Energeia has calculated the value of solar PV on the basis of electricity from the wholesale market that it replaces, rather than the value of the feed-in-tariff.

Solution Costs Over Time by Network Type

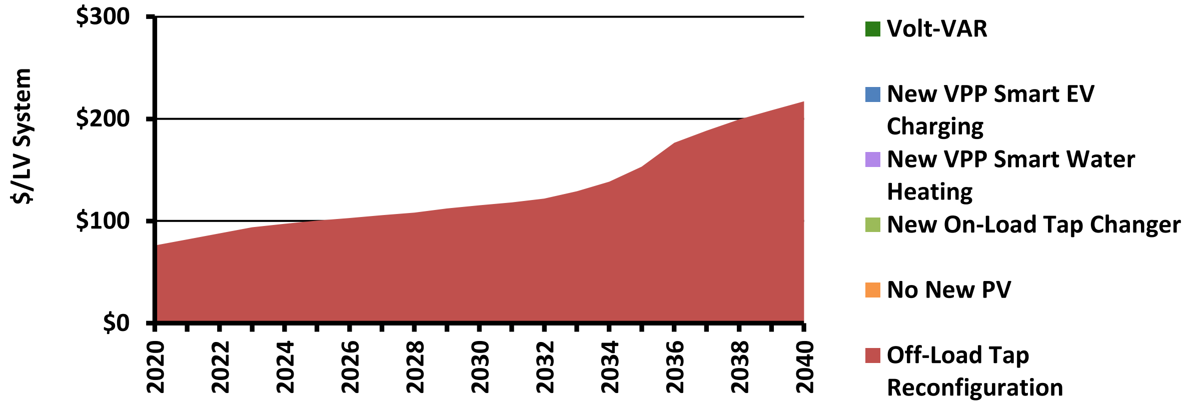
The results of Energeia's modelling of the costs of the lowest cost solutions needed to address forecast DER-integration issues over the next 20 years are shown for the Neutral (i.e. expected rate of technology adoption) scenario[12] below per LV network by LV network type.

Urban LV System: Least Cost Cumulative Expenditure by Solution – Neutral Scenario



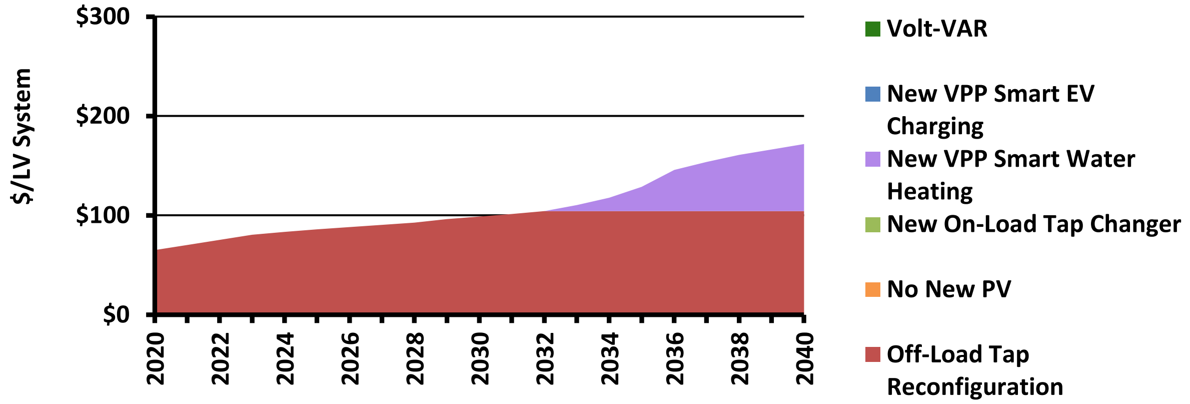
Source: Energeia

Suburban LV System: Least Cost Cumulative Expenditure by Solution – Neutral Scenario



Source: Energeia

Rural LV System: Least Cost Cumulative Expenditure by Solution – Neutral Scenario



Source: Energeia

[12] Solutions were limited by data availability and to the most prospective options based on stakeholder feedback.

Our high-level analysis suggests that most expenditure should go to off-load tap reconfigurations as the lowest cost solution for the level of DER forecast to 2040 for most low voltage systems. Expenditure on prosumer (behind-the-meter) solutions is suggested from 2033 onwards in rural (50 kVA) low voltage systems, where there are lower network economies of scale.

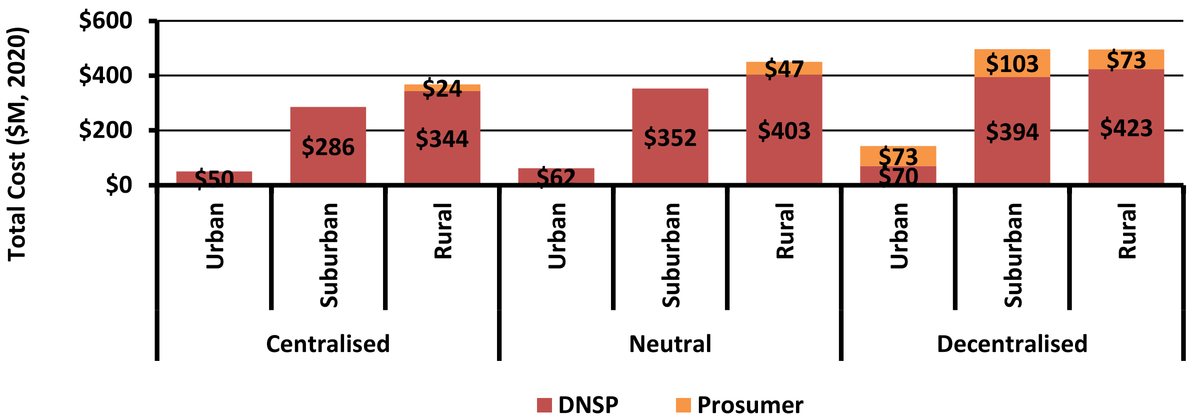
Overall, our analysis shows that, under the Neutral scenario, the optimal annualised cost of mitigating overvoltage due to solar PV adoption is expected to amount to around $260, $205 and $175 per LV network per annum (p.a.). by 2040 for Urban, Suburban and Rural LV systems, respectively. Due to economies of scale, driven by different customer densities, these costs per system type translate to $1.30, $4.90 and $25.00 p.a. per customer by 2040 for Urban, Suburban and Rural LV networks, respectively.

Total Solution Expenditures by Network Type, Solution Provider and Scenario

In order to provide a benchmark estimate against which future DER-integration optimisation studies can be compared, Energeia calculated total forecast expenditures by type of LV network, solution and scenario over the 20 year modelling period. The results of this analysis are shown below.

Energeia notes that most expenditure is in the 250 kVA (Suburban) and 50 kVA (Rural) LV networks, due to the marginal cost of their specific solutions but also the number of these systems across Australia in the case of the 50 kVA (or Rural) systems. Energeia also notes that network solution expenditure dominates spending in Urban and Suburban networks, while prosumer solution expenditure is mainly focused the Rural feeder type in the Centralised and Neutral scenarios.

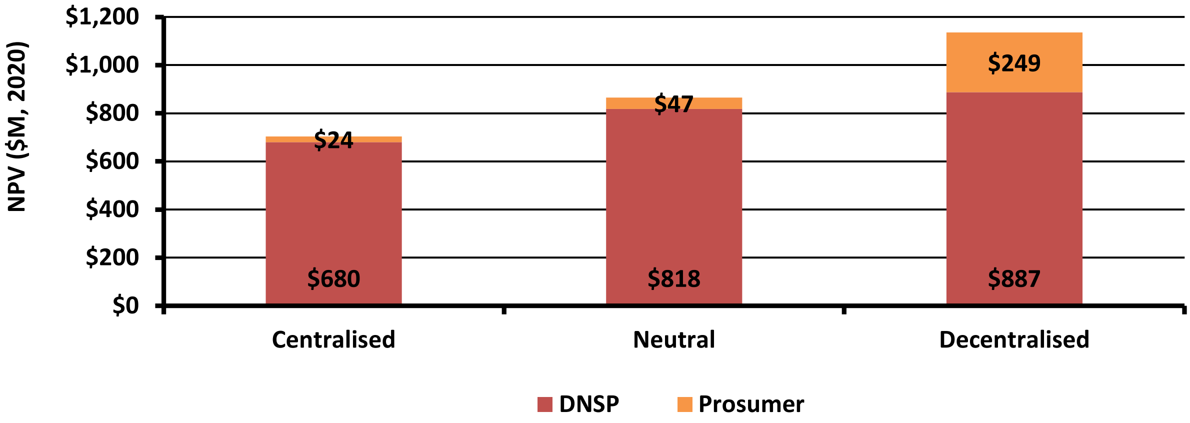
NPV of DER Integration Costs by Scenario and Voltage System (2021-40, 2020$s)



Source: Energeia

Based on this analysis, Energeia's modelling carried out for this project has found that Australia's overall cost of mitigating over-voltage due to solar PV installations over the next 20 years is forecast to range by from $0.7 to $1.1 Bn, depending on the level of DER-adoption. It also shows that $0.7 to $0.9 Bn revenues flowing to networks and $0.0 to $0.2 Bn flowing to prosumers or their agents for providing DER-integration services.

NPV of DER Integration Costs (2021-40, 2020$s)



Source: Energeia

Conclusions and Recommendations

Based on the above analysis, Energeia's key findings, conclusions and recommendations include:

- $0.7-$1.1 billion expenditure on optimal network and prosumer solutions will deliver greater net benefits to Australia than other sub-optimal solutions
- Solar PV curtailment is higher cost than network and prosumer side solutions
- Deploying prosumer water heating and EV load control solutions could provide lower cost options in suburban and rural networks in the future

It is important to note that the above analysis has been limited to over-voltage due to over-generation, and that the findings could change when the full range of potential issues are included in the modelling, including thermal overloads, phase balancing, under-frequency control, updating protection settings or applying more cost reflective pricing for prosumers. Furthermore, the optimal solution could also change if existing VPP enabled DER is included in the analysis.[13]

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[13] Energeia and Renew are planning to address these questions in a Phase II project.

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Disclaimer

While all due care has been taken in the preparation of this report, in reaching its conclusions Energeia has relied upon information and guidance from Alternative Technology Association (trading as Renew), and other publicly available information. To the extent these reliances have been made, Energeia does not guarantee nor warrant the accuracy of this report. Furthermore, neither Energeia nor its Directors or employees will accept liability for any losses related to this report arising from these reliances. While this report may be made available to the public, no third party should use or rely on the report for any purpose.

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1. Background to the Project

Customer applications for the electricity system (the grid) have evolved over time with the introduction and deployment of new technologies. In addition to whether and how to charge for connection and using new devices, there is typically a discussion regarding whether there are more efficient methods for its integration. The tradition to date has been socialisation of the cost across all system users, and industry effort to minimise costs.

The rapid rise of rooftop solar photovoltaic (PV) adoption over the last decade is the latest 'new' grid application, and there is debate regarding how and whether to regulate and price it. Also included in the current debate is the optimal approach to integrating solar PV and other inverter based, consumer-side devices, including battery storage and electric vehicles, into the distribution network and power system.

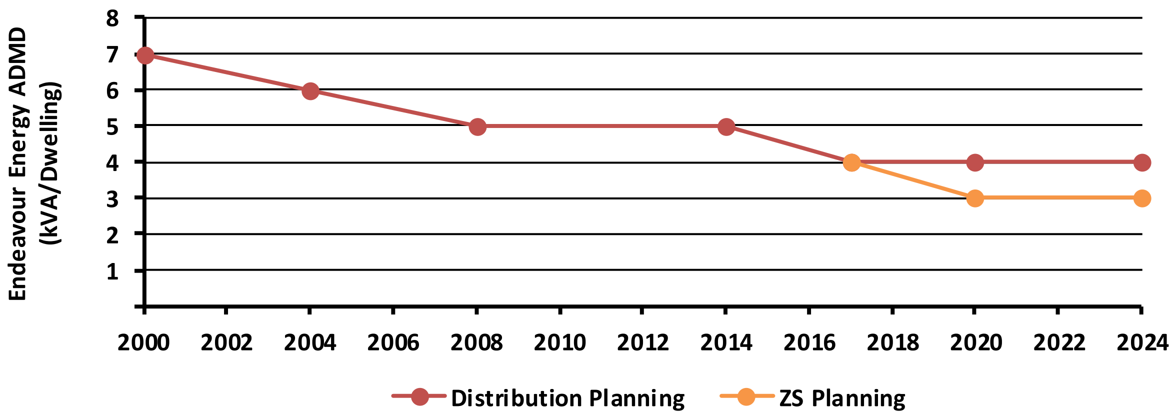
The following sections summarise:

- The historical debate regarding new applications like reverse cycle air-conditioners (ACs),
- The current state of solar PV adoption and estimated impacts, and
- The current industry initiatives underway to minimise system adaptation costs (technically called 'integration' costs) and to potentially allocate them to solar PV owners and adopters of other 'new' devices connected to the electricity distribution system.

1.1. Trends in Electricity System Applications

Electricity distribution networks in the immediate post-WWII period were originally designed and built to accommodate around 1 kW of After Diversity Maximum Demand (ADMD)[14] per residential premise. Over the past 50 years or so, an increase in the number and nature of loads in the home, particularly air-conditioners (ACs), has resulted in distribution network planners assuming up to 7 kW ADMD for new residential premises[15] in the early 2000s. However, over the past two decades, improvements in building standards, decreases in average building size, solar penetration and increasingly efficient home appliances have brought the ADMD back down to 4 kW, as shown in Figure 1.

Figure 1 – Endeavour's Historic ADMD



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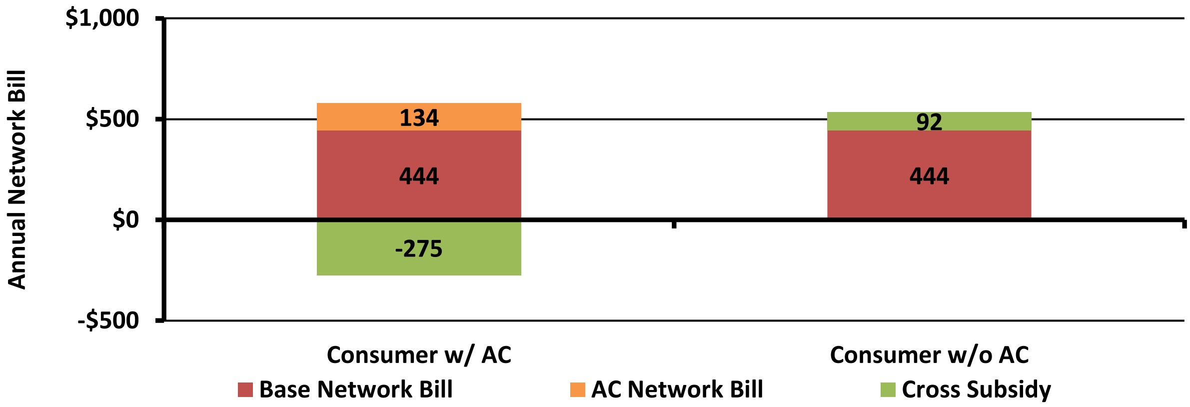
1.1.1. Air-Conditioners

ACs are widely believed to be a key driver of the increase in ADMD and associated power quality issues, the higher costs have not been specifically allocated to those with these devices. The lack of an effective 'cost-reflective' pricing system, at least not for existing premises, has led to an uneconomic increase in network capital expenditure over the past 10-15 years. While those with ACs do pay more due to the higher energy consumption of these devices, non-cost reflective pricing resulted in significant cross-subsidies[16], as shown in Figure 2.

Figure 2 – Illustration of Residential Bill Impacts from AC Adoption by AC Adoption Status (Annualised Basis)

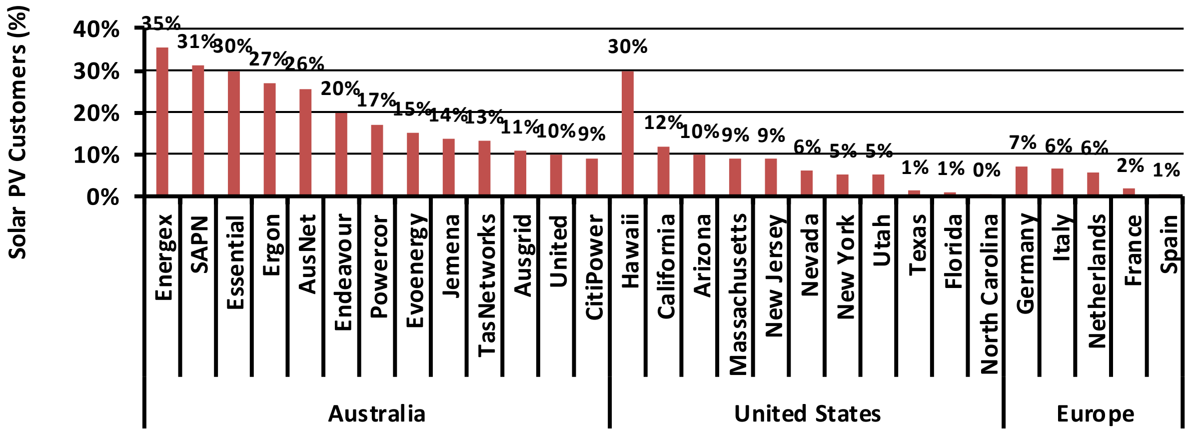


Source: Energeia; Note: AC = Air-Conditioners; Note: Costs shown on an annual basis.

1.1.2. Rooftop Solar PV

Rooftop solar photovoltaic (PV) systems are the latest change in customers' use of the electricity distribution network. Their penetration has risen rapidly over the past 5-10 years, and Australia now has among the highest penetration of rooftop solar PV in the world, as shown in Figure 3.

Figure 3 – Percentage of Solar PV Customers by DNSP



Source: Clean Energy Regulator, DNSP RINs, Energeia

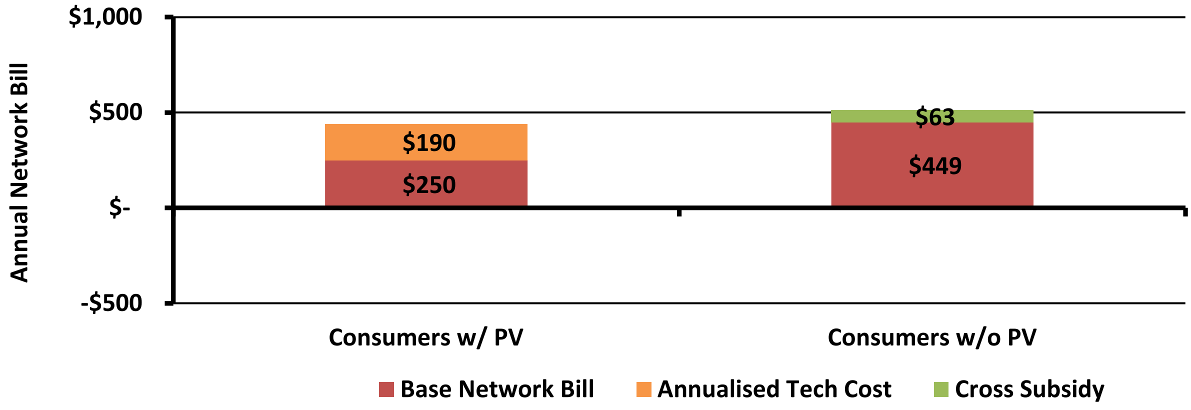
Solar PV, as was the case with AC before it, is widely believed to be a key driver of emerging voltage rise and other power quality issues, and probably leads to some level of cross-subsidies between those able to install a

[16] It is worth noting that cross-subsidies are an inherent part of the energy system, and that is by design (e.g. urban customers cross-subsidising rural ones). The key issue is ensuring that the cross-subsidy is equitable. Some level of cross subsidy is accepted due to the transaction cost of unwinding them. For example, charging every dwelling based on their exact cost-to-serve would result in no cross-subsidies, but would be extremely complex and costly to calculate, uniformly increasing customer bills.

solar PV system and those that can't, typically those renting and/or living in apartments. However, recent work[17] by AEMO based on Solar Analytics data has demonstrated that this belief is often misplaced: based on these real-world data sets AEMO has found that power quality issues are widespread across the low-voltage network, independent of the degree of DER installed on any given network feeder or segment.

Figure 4 illustrates the typical level of annual cross-subsidy between a customer with solar PV and one without solar PV under current, flat or inclining block tariffs.

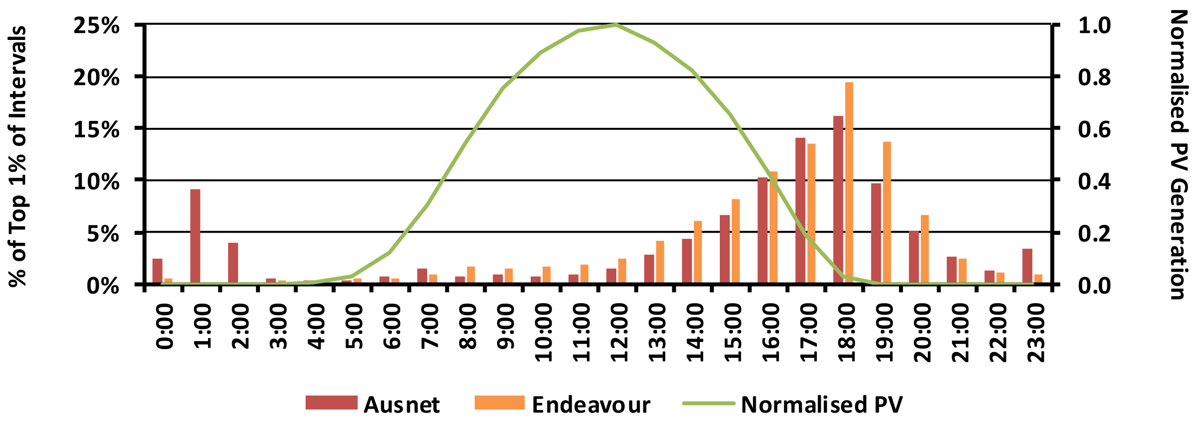
Figure 4 – Illustration of Residential Bill Impacts from PV Adoption by PV Adoption Status (Annualised Basis)



Source: Energeia

As is the case with ACs via demand-side participation, solar PV systems can also potentially provide electricity system benefits, including lower wholesale prices, lower peak demand[18] and improved power quality. An example of how solar PV systems may be reducing peak demand on AusNet[19] and Endeavour Energy[20] zone substations is shown is Figure 5. Energeia notes the lack of a comprehensive assessment of solar PV net benefits to date.

Figure 5 – Time-Distribution of Top 1% Zone-Sub Load Intervals vs. Solar PV Generation Curve



Source: Energeia

[17] AEMO (2020), '*Renewable Integration Study*': https://aemo.com.au/energy-systems/major-publications/renewable-integration-study-ris

[18] Where peak demand coincides with PV generation.

[19] Ausnet zone-sub load profiles sourced from CSIRO EUDM.

[20] Endeavour zone-sub load profiles sourced from Endeavour (2019), '*2018-19 Distribution zone substation data*', http://www.endeavourenergy.com.au/wps/wcm/connect/1875dfe1-6a62-4791-8eca-8dd1ada1a7b8/FY2018-19_CSV_2.zip?MOD=AJPERES&ContentCache=NONE

Distribution Network Service Provider (DNSP) responses to rising solar PV penetration and associated grid and inverter impacts have included limiting the amount of solar generation that can be fed into the network, limiting the size of new solar PV systems connecting to their network, and in some cases disallowing new solar PV system connections altogether. It is important to note that a DNSP's current approach is at least partly due to the current National Electricity Rules that govern DSNP investment cost recovery, as they do not provide cost-recovery certainty for connecting generation to the distribution network.

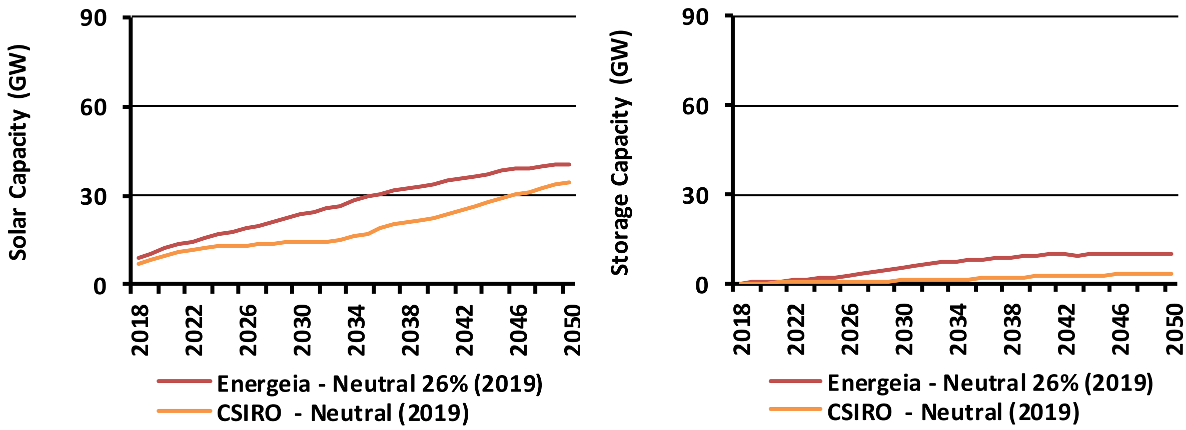
Importantly, Australian DNSPs have started to look at better options[21] for integrating Distributed Energy Resources (DER) at lower cost, including solar PV, battery storage and electric vehicles. The approaches being proposed by DNSPs in their submissions to the Australian Energy Regulator (AER) come at a significant cost[22], and it is therefore critical that the community welfare-maximising approach is ultimately adopted. It is also important that the associated costs and benefits be equitably distributed among stakeholders.

1.1.3. Major New Device Outlook

While Australia is largely saturated in terms of ACs, rooftop solar PV growth remains strong, and behind-the-meter (BTM) storage and EV adoption is expected to soar in the next 10-20 years.

Solar and BTM storage forecasts commissioned by the market operator in 2019, as shown in Figure 6, expect a three to four fold increase in rooftop solar PV inverter capacity over the next 30 years. BTM storage is expected to rise between five to 20-fold over the same period in nameplate capacity terms.

Figure 6 – Rooftop Solar PV (Left) and Behind the Meter Storage (Right) Uptake (GW) Forecasts



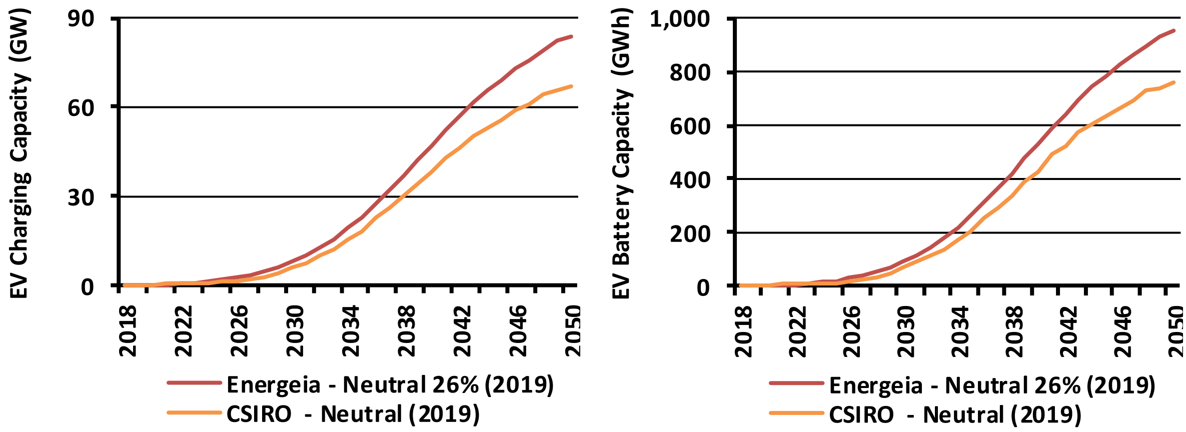
Source: Energeia, CSIRO; Note: Assumed 4-hour storage capacity.

Although EV adoption is expected to remain largely flat until around 2025, it is expected to rise rapidly from that point onward, reaching 9-11 million vehicles by 2050, or 80 GW in potential charging load and 950 GWh in total battery storage potential, dwarfing the stationary battery estimate as shown in Figure 7.

[21] See Energex (2018), 'Distribution Annual Planning Report', https://www.energex.com.au/__data/assets/pdf_file/0016/720223/Distribution-Annual-Planning-Report-2018.pdf and Ergon (2018), 'Distribution Annual Planning Report', https://www.ergon.com.au/__data/assets/pdf_file/0018/720234/DAPR-2018-2023.pdf

[22] Ibid.

Figure 7 – Electric Vehicle Level 2 Charging Capacity (Left) and Battery Capacity (Right) Forecasts



Source: Energeia, CSIRO; Note: EV charging assumes avg. charger rating of 7.5kW. EV battery capacity assumes 85 kWh avg. battery.

Energeia estimates that each of the inverter based DER technologies discussed is expected to add the following level of nameplate capacity to each residential premises:

- 5-8 kW of solar PV,
- 15-22.5 kW of Level 2 EV charging, and;
- 5-10 kW of battery storage.

Magnitude at commercial premises is likely to be significantly larger.

As inverter-based equipment becomes the dominant type of grid connected technology at customer premises, it is critical that the proposed approach to pricing and managing them is fit-for-purpose.

1.2. Trends in LV Network Management

DNSPs have historically managed low voltage (LV) networks differently to the rest of the distribution network due to the sheer number of assets, and the relatively high cost of adding remote monitoring and control. They have typically been operated on a 'run-to-failure' basis, and reliant on customer reports of outages or voltage issues.

The rise of solar PV in the LV network is leading to a significant increase in customer reported issues, demonstrated by Energeia's research detailed in Section 3.3, and an associated increase in the rate of LV network investment in DER solutions, as reported in Section 3.5. As a result, DNSPs are re-assessing their LV management approaches, including limiting new connections and curtailing existing ones.

Key questions include whether the current or proposed future approaches will best serve Australians' overall interests, and whether there are any distributional effects that need to be considered to ensure fairness.

1.2.1. Changes in Key Connection and Technical Standards

The Australian electricity distribution and inverter industries, like their overseas peers, have implemented a number of key reforms over the past 3-5 years to their connection and other technical standards to address potential issues from rising rooftop solar PV capacity across their network.

New Static Solar PV Connection and Export Limits

A key DNSP response to date to potential issues related to solar PV penetration has been to set limits on solar PV exports as shown in Table 1[23]. Across the majority of DNSPs, the connection limit has been set to either 5 or

[23] These are limits on automatic connections, systems larger than the size specified would have to go through an assessment process before they can be connected. In the assessment process it is possible (but not always) that an export limit may be imposed. The issue DNSPs are addressing is grid exports, so they generally approve output from larger PV systems if self-consumed by consumers.

10 kW/kVA for a single-phase connection and up to 30 kW/kVA for a three-phase connection. Some DNSPs have stated explicit export limits lower than the connection limit.

Table 1 – Connection and Export Limits by DNSP and Phase

State	Network	Connection Limit		Export Limit	
		Single Phase	Three Phase	Single Phase	Three Phase
ACT	EvoEnergy	5kW	30kW	✓	✓
NSW	Ausgrid	10 kVA	30 kVA	N/S	N/S
	Essential	3 kW / 5 kW	30 kW	N/S	N/S
	Endeavour	8 kW	40 kW	5 kW	30 kW
QLD	Energex	10 kVA	30 kVA	5 kVA	30 kVA
	Ergon	10 kVA	30 kVA	5 kVA	30 kVA
SA	SAPN	10 kW	30 kW	5 kW	15 kW
TAS	TasNetworks	10 KW	30 kW	✓	✓
VIC	United	10 kW	30 kW	N/S	N/S
	CitiPower	5 kW	30 kW	N/S	N/S
	PowerCor	5 kW	30 kW	N/S	N/S
	Jemena	10 kVA	30 kVA	5 kVA	15 kVA
	Ausnet	10 kW	30 kW	3.5 kW / 5 kW	15 KW

Source: DNSP Technical Standards; Notes: ✓ = explicitly stated that exports may be limited, N/S = not stated; DNSPs use connection and export limits as conditions for automatic approval of new DER connections, and almost all DNSPs allow, on a case-by-case basis, both or either connections or exports larger than these limits.

Energeia has been unable to identify the original basis for the above limits, and recent work completed by SA Power Networks suggests that the actual solar PV hosting capacity varies widely by LV network type.

Modernised Inverter Standards

Australian industry stakeholders approved updates to AS4777 in 2015 that require inverters to curtail exports in response to voltage exceedances and grid outages. This is commonly known as the Volt-Watt standard, and Australia's current Volt-Watt setting is shown in Figure 8, along with the optional Volt-VAR setting.

Ensuring standardised Volt-VAR settings on inverters is complicated by the unique power quality requirements many DNSPs have. Installer intervention is currently relied upon, with the potential need for a single set of fixed power quality settings set by manufacturers.

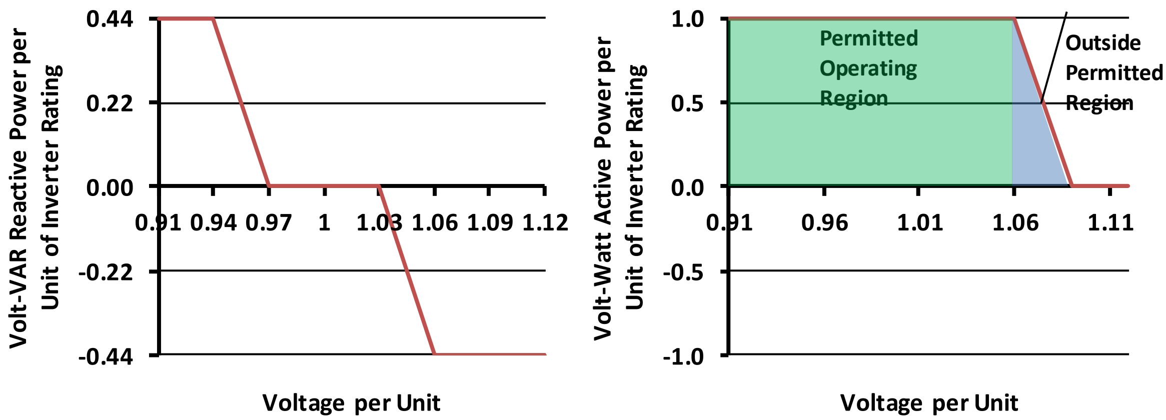
Research has shown the Volt-VAR operating mode can enable up to around 60% penetration of solar PV systems without curtailment. However, it does not solve thermal issues, and inverter capacity is lost in proportion to reactive power generation[24]. Industry contacts report ~10% of current solar PV installations comply with Volt-VAR standards, indicating there may be an enforcement issue.[25]

More detail on current Australian standards for smart inverters and LV management are provided in Appendix B – Updated Australian Standards.

[24] L. Ochoa, A. Procopiou, University of Melbourne (2019), *'Increasing PV Hosting Capacity: Smart Inverters and Storage'*: https://resourcecenter.ieee-pes.org/education/webinars/PESVIDWEBGPS0010.html

[25] Inverter standards compliance enforcement is a shared activity between DNSPs, jurisdictional regulators and industry bodies (e.g. CEC), which run a voluntary industry scheme. Although voluntary, the CEC's Approved Product List initiative is a key tool used to assess eligibility for some renewable energy programs and by most DNSPs as a requirement for grid connection approval.

Figure 8 – Volt-VAR and Volt-Watt Curves



Source: NREL, HECO[26]

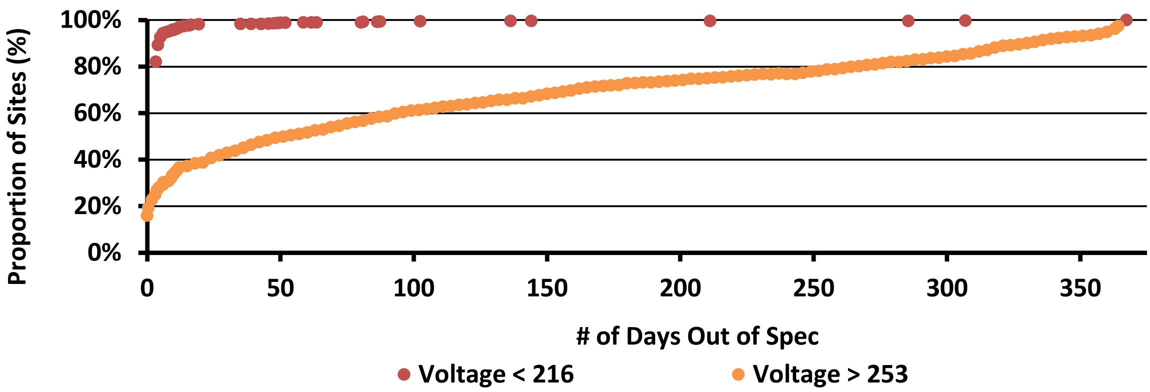
1.2.2. Emerging LV Management Issues

The two key issues that have emerged recently as rooftop solar PV penetration has risen are an increase in reported voltage issues, and the associated impact on rising levels of rooftop solar PV inverter curtailment.

Network Power Quality

There are increasing reports of LV network voltages falling outside of their statutory limits, as shown in Figure 9. DNSPs are increasingly reporting customer enquiries and complaints related to solar PV voltage related issues, and indeed a range of networks (CitiPower, Powercor, SA Power Networks, AusNet and Jemena) have proposed developing the ability to monitor and control solar PV exports to manage voltage exceedance.

Figure 9 – Voltage Excursions (230V Standard)



Source: Solar Analytics[27]

Prosumer Curtailment

In Australia, there has been a limited range of either academic or industry work to define the DER hosting capacity of LV networks. Without this work being completed, DER capacity on a given network asset is unknown, but the existing limited work suggests that export curtailment will increase as DER penetration increases:

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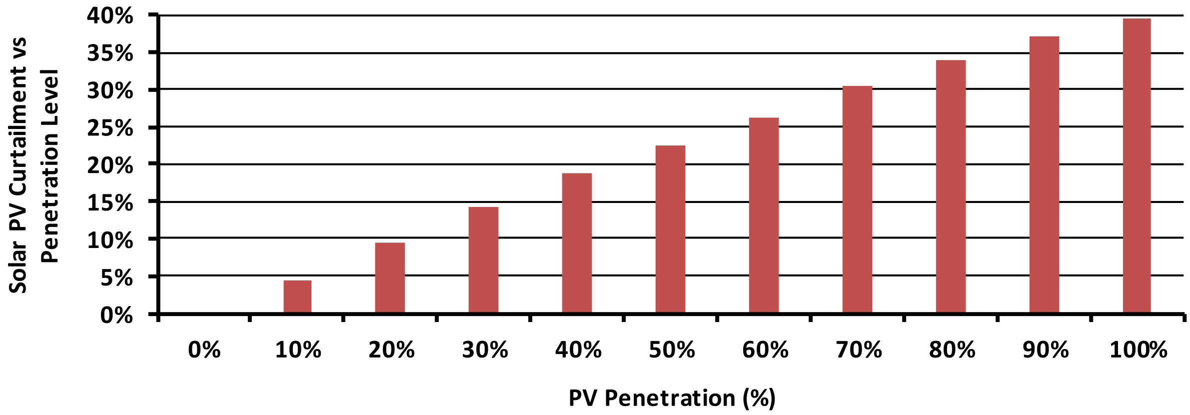
[26] NREL, HECO (2019), *'Impacts of Voltage-Based Grid-Support Functions on Energy Production of PV Customers'*: https://www.nrel.gov/docs/fy20osti/72701.pdf

[27] Smart Energy Council (2019), *'Special Webinar: High Voltage is Stopping Solar – 5 September 2019':* *https://vimeo.com/357975007?utm_source=High+Voltage+Webinar+September+5th+2019&utm_campaign=d730815347-ECAMPAIGN_BrkgNews8Jul19_COPY_01&utm_medium=email&utm_term=0_67fc466c8e-d730815347-89547021*

- **Smart Grid, Smart City (2014)**[28] – The Ausgrid managed project identified an increase in curtailment (i.e. the restriction of exports by DER investors) beyond 30% penetration.
- **University of Melbourne (2019)**[29] – Academics at the University of Melbourne have developed a stochastic approach that shows increasing curtailment from 10% penetration, based on a Monte Carlo analysis of a theoretical LV network in Australia, as shown in Figure 10.

The University of Melbourne's results appear to align with modelling results carried out by SA Power Networks[30] on the different areas in their network, which show some LV (but not all) network types experiencing voltage excursions (outside limits) at the 10% penetration limit.

Figure 10 – Solar PV Export Curtailment at Different Levels of Market Penetration



Source: IEEE / University of Melbourne[29]

1.2.3. Anticipated LV Management Costs

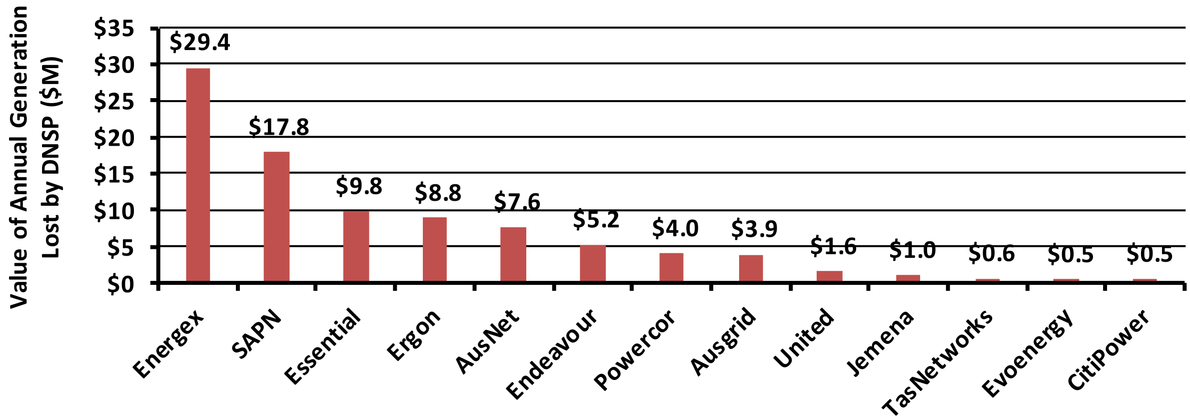
Energeia's analysis of the wholesale market value of annual curtailment losses to retailers are shown in Figure 11, based on current wholesale prices. This estimate does not consider any lost benefits from higher cost units setting the regional reference price in the National Electricity Market.

[28] Archived version of the following source: Department of Industry, Innovation and Science (2016) 'Smart Grid, Smart City', https://webarchive.nla.gov.au/awa/20160615043539/http://www.industry.gov.au/Energy/Programmes/SmartGridSmartCity/Pages/default.aspx

[29] L. Ochoa, A. Procopiou, University of Melbourne (2019), *'Increasing PV Hosting Capacity: Smart Inverters and Storage'*: https://resourcecenter.ieee-pes.org/education/webinars/PESVIDWEBGPS0010.html

[30] SA Power Networks (2019), '*LV Management Business Case: 2020-2025 Regulatory Proposal'*: https://www.aer.gov.au/system/files/Attachment%205%20Part%207%20-%20Future%20Network.zip, pg. 6

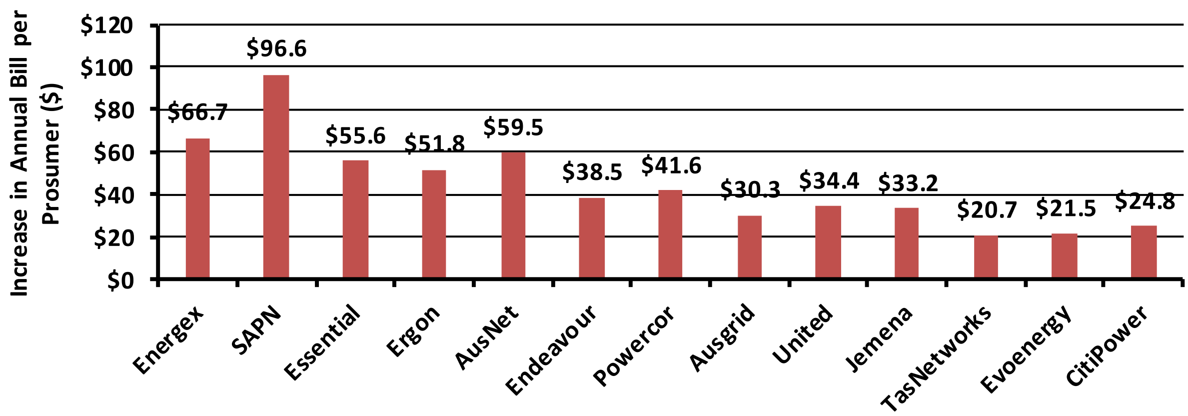
Figure 11 – Estimated ($M) NEM Value of Annual Generation Lost to Curtailment by DNSP



Source: Energeia; Note: SAPN = SA Power Networks

Energeia's estimate of annual losses to customers with solar PV due to losing feed-in tariff revenue from curtailment is shown by DNSP in Figure 12. The value of these losses will change over time as a result of changes in wholesale market regional reference prices, and changes to feed-in tariff policy.

Figure 12 – Estimated DER Feed-in Tariff Curtailment Costs per Customer with Solar PV

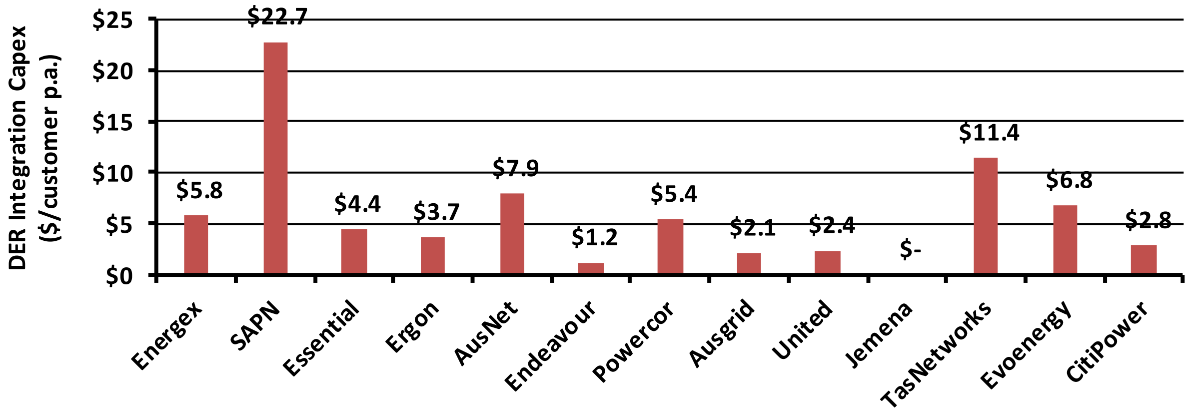


Source: Energeia; Notes: SAPN = SA Power Networks

The cost to DNSPs, and ultimately to Australian electricity consumers with and without solar PV, is also rising, with DNSPs putting forward DER[31] integration costs of up to $23 per customer per annum as shown in Figure 13. Energeia notes that the proposed investment is targeted at accommodating forecast growth and reducing uneconomic curtailment.

[31] Not all expenditure is necessarily related to solar PV specifically

Figure 13 – DNSP's Proposed DER Integration Expenditures ($/Customer/Year) per DNSP Customer



Source: DNSP Determinations; Note: PQ = Power Quality, SAPN = SA Power Networks

1.3. Key Distributed Energy Resource Integration Initiatives

A wide range of initiatives have been kicked off over the last 12 months to tackle the range of current issues associated with rising rooftop solar PV and other forms of DER, including the anticipated rise in related LV management and prosumer curtailment costs.

1.3.1. Key Regulatory and Industry-Led Initiatives

Australian stakeholder expectations regarding the impact of the rise of solar PV, storage and EV adoption over the next 20 years is triggering a number of industry initiatives to identify a range of DER integration solutions, from new technical standards, to new charges and new technical solutions, as listed in Table 2.

Table 2 – Current or Recent Distributed Energy Resources Management Initiatives

Initiative	Sponsor	Purpose and Objectives	Participants
Revision of AS 4777	Standards Australia	Sets out specifications, procedures and guidelines that aim to ensure products, services, and systems are safe, consistent, and reliable	Industry, consumers, and government
National Grid Connection Guidelines	ENA	Standardised guidelines for the connection of DER across the NEM (released September 2019)	Industry, consumers, and government
Distributed Energy Integration Program	ARENA	To maximize the value of customers' DER for all energy users	Industry, regulators, suppliers, government, customers and academia
Open Energy Networks	AEMO/ ENA	Consultation on how best to transition to a two-way grid that allows better integration of DER for the benefit of all customers	Industry, consumers, suppliers, government, and academia
Distributed Energy Resources Program	AEMO	To better utilise DER for the grid through developing and improving appropriate DER standards.	Industry, regulators, suppliers, government, and academia
Distribution Market Model	AEMC	To examine whether the economic regulatory framework is robust, flexible and continues to support the efficient operation of the energy market in the long-term interests of consumers	AER, ARENA, DNSPs, Standards Australia, and others
Assessing Distributed Energy Resources Integration Expenditure	AER	To review how the AER assesses DNSP's proposed expenditure to manage the increasing challenge of DER integration	Industry, regulators, suppliers, government, academia and consumers

Source: Clean Energy Regulator, DNSP Regulations; Note: AEMC = Australian Energy Market Commission, AEMO = Australian Energy Market Operator, ARENA = Australian Renewable Agency, DER = Distributed Energy Resources, DNSPs = Distributed Network Service Providers, ENA = Energy Networks Australia.

It is important to recognise that initiatives are being led by different National Electricity Market (NEM) bodies, such as the Australian Energy Market Operator (AEMO), the Australian Energy Market Commission (AEMC) and other prominent industry players, and therefore reflect incumbent agendas and perspectives. No consumer or prosumer led initiatives have been kicked off to date, nor are any currently being planned, limiting the voice of these stakeholders in the national debate to responding to others' initiatives.

Additional information regarding these initiatives is provided in Appendix C – Summary of DER Integration Initiatives.

1.3.2. Prosumer Focused, Collaborative Initiative Needed

Each of the above initiatives includes representatives from prosumer stakeholders, however, their role is limited to responding to the issues and questions determined by the sponsor. There is therefore a risk that the key issues and questions of greatest interest to prosumers have not yet been addressed. A prosumer led initiative may therefore be needed to ensure their perspective is truly represented in the national debate.

The types of issues and questions that a prosumer led initiative might ask (from a technical perspective) include:

- What is the fair and efficient level of curtailment and should there be compensation for curtailment?
- What is the fair and efficient level of DER connection capacity, and how might capacity rights be traded?
- Are the proposed DER integration solutions in the overall interest of Australians, and have all the options been considered, including those provided by consumers and prosumers?
- Have the benefits of DER been considered, with any shared benefits, for example from improvements in capex, opex or service level performance shared with prosumers and consumers?
- Are there any distributional effects from proposed DER integration solutions that need to be considered?

2. Scope and Approach

Renew engaged Energeia to review the range of issues related to solar PV, storage and EV adoption, the potential solutions for resolving them, including those potentially offered by consumer, prosumers and service providers, in order to identify the value maximising solution for Australia.

The project design envisioned:

- Identifying the key issues related to rising solar PV and DER and who they impact;
- Identifying the potential solutions to these issues and their associated costs;
- Developing an analytical framework for identifying the optimal approach in a given situation;
- Developing a report on the key issues and potential solutions (this report), for industry consultation;
- Developing an optimisation framework to model the cost of potential alternative responses to enabling increased DER connection and exports, and;
- Engaging with a stakeholder represented Steering Committee convened by Renew, comprised of energy retailers, electricity DNSPs and DER services providers.

While critical to the discussion related to potential 'extra' charges for solar PV exports, the determination of solar PV net benefits is out of scope for this project.

- **Comprehensive desktop review of key industry and academic reports** – The desktop review focused on reported issues and solutions. It included submissions to the Australian Energy Regulator (AER) and Distribution Annual Planning Reports (DAPR), as well as major international studies.
- **Short listing of the key issues, solutions and development of a draft optimisation framework** – Energeia engaged with the stakeholder represented Steering Committee to validate the key issues, solutions and optimisation framework; however, the final list and approach is ultimately our own view.
- **Documentation of our research findings and draft optimisation framework**[32] – Energeia developed a Problem Statement Report for wider consultation with key stakeholders. The feedback from this report was used to refine the key issue and solution inputs and the optimisation framework applied in the modelling stage.
- **Modelling potential solutions under different scenarios and scales** – The final step in the project involves the finalisation and implementation of the optimisation framework, and documentation of the results in a subsequent Options and Discussion Paper Report (i.e. this report).

The following sections summarise our technical approach to delivering the project.

2.1.1. Desktop Research

Key Issue Identification and Characterisation

Energeia undertook a comprehensive review of international industry reports related to solar PV integration, and Australian content, including:

- AER Proposals and Determinations
- DNSP DAPRs and other reports
- Industry Pilots and Trials[33]

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[32] Energeia (2020), *'Distributed Energy Resources Enablement Project – Problem Statement Paper'*: https://renew.org.au/wp-content/uploads/2020/01/RENEW-DER-Issues-Options-Approach-20200111v3.pdf

[33] Such as various projects funded by ARENA or via the DNSP Demand Management Innovation Allowance (DMIA).

We engaged with stakeholder and subject matter experts on the Steering Committee, as well as our own industry network, to identify key issues and potential sources of information.

With a short list of validated key issues in hand, Energeia applied the following analytical and research framework to identify and characterise the key issues arising from increasing DER penetration:

- Investigated the drivers of each key issue to identify alternative drivers to solar PV and to relate DER penetration levels with impacts and associated costs by stakeholder; and
- Assessed the current and projected future incidences of each issue to determine which are likely to be the most prevalent and costly across networks and how and why they may vary.

Key Solution Identification

After identifying DER export issues, Energeia then assessed the range of possible solutions with the following step process:

- Developed a database of potential solutions as reported by DNSPs and others in AER proposals, DAPRs, DMIAs, Australian Renewable Energy Agency (ARENA) proposals and industry and academic literature;
- Reviewed DNSP disclosures to understand the prevalence of these solutions;
- Mapped the solutions that addressed each of the identified issues, noting other potential beneficial applications for the solutions, to inform potential cost allocation decisions; and
- Investigated the cost and impact of each solution in terms of their effect on hosting capacity limitations, including the range of penetration over which the solution might operate effectively.

We also engaged with stakeholder and subject matter experts on the Steering Committee, as well as our own industry network, to validate our key solutions findings and conclusions.

2.1.2. Stakeholder Engagement

Energeia and Renew chaired a number of engagement sessions throughout the project, with the Steering Committee. This committee included representatives from distribution networks, retailers, consumer advocates and other parties, as shown in Table 3.

Table 3 – Steering Committee Composition

Segment	Name	Organisation
Network	Peter Wong	Jemena
	Justin Bethlehem	AusNet Services
	Brendon Hampton	SA Power Networks
	Therese Grace	Essential
Retailer	Travis Hughes	AGL
SME	Jonathon Dore	Solar Analytics
	Craig Chambers	Australian Renewable Energy Agency
	Robert Macmillan	Farrier Swier
Consumer Advocates	Rob Law	Central Victorian Greenhouse Alliance
	Gavin Dufty	St Vincent de Paul

Source: Renew

The Steering Committee reviewed the Problem Statement paper[34] before it was released publicly for open consultation. Consultation on the Problem Statement paper was extensive, with Renew and Energeia receiving over 100 comments from 16 different organisations or individuals, as shown in Table 4.

Table 4 – Open Consultation Respondees

Segment	Organisation
Network	Jemena
	AusNet Services
	SA Power Networks
	AusGrid
	Tas Networks
Retailer	AGL
Technology OEM	Redback
	Greensync
	WattWatchers
Peak Bodies	Smart Energy Council
	Clean Energy Council
	Energy Networks Australia
Government	Victorian Department of Energy, Land, Water and Planning
	Australian Renewable Energy Agency
	Australian Energy Regulator
Advocates	Brotherhood of St Lawrence
	Planet Ark
N/A	Individuals

Source: Renew

Energeia then classified the 100 comments of feedback received based on the type of issue raised, the subject matter involved, and Energeia's response, as summarised by Figure 14. Energeia's responses were reviewed and agreed with Renew, with Energeia ultimately bearing responsibility for the final actions determined.

[34] Energeia (2020), *'Distributed Energy Resources Enablement Project – Problem Statement Paper'*: https://renew.org.au/wp-content/uploads/2020/01/RENEW-DER-Issues-Options-Approach-20200111v3.pdf

Figure 14 – Approach to Categorisation and Response to Stakeholder Feedback

RENEW's CATEGORISATION OF FEEDBACK | **ENERGEIA'S ACTIONS**

Feedback Issues > **Subject Matter Area** > **Recommended Actions & Status**

Issue Type
Error
Omission
Clarification
Addition
Suggestion
Comment

Subject Matter Categories
Additional Sources
Additional Suggestions
Costs & Benefits
Cross-Subsidies
Data/Metering
Export Limits
General Clarification
Issues Table
Modelling Approach
N/A
Peer to Peer
Principles
Prosumer focus
Regulatory
Relevant Initiatives
Remediation Options
Standards
Storage
Terminology
Volt-VAR

Action Descriptions	Status
Actioned	Updated in Report
Addressed	Addressed in Feedback Register
Out-of-Scope	Potentially included in Next Phase
No Action	Resolved

Source: Energeia

Details regarding the feedback received, and Renew and Energeia's response to that feedback, are provided in Appendix E – Feedback Summary.

2.1.3. Optimisation Framework

Energeia developed a high level, best practice DER-integration optimisation framework based on our research of best practice approaches to DER integration solution optimisation and our experience modelling the costs and benefits of DER across consumers, prosumers, DNSPs and the wholesale market.

The proposed solution optimisation approach models the costs and benefits of various solutions, for a given category of LV network, to identify the set of solutions that is expected to deliver the highest net benefits. The modelling approach was focused on optimising the costs for addressing over-voltage issues due to over-generation, mainly by rooftop solar PV systems, given the paucity of data available to enable assessment of other issues.[35]

Our approach to modelling DER integration costs and their optimisation addresses:

- **Network Segment Assumptions** – Our approach segments all LV networks into 50 kW, 250 kW and 1,000 kW categories, representing roughly mid-way points between the AER RIN categories
- **Network Classification –** The key difference between the LV network segments is the assumed asset sizing per residential customer, driven by differences in assumed coincident maximum demand
- **Hosting Capacity Estimates** – Energeia modelled hosting capacity[36] for a given level of solar PV generation based on the results of our research
- **Solutions Costs** – Energeia developed unitised ($ per Incremental Solar PV kW) estimates based on a given solution cost, divided by the number of solar PV kWs it would enable
- **Scenario Assumptions –** Three scenarios were developed to cover high, expected and low levels of DER on the system, which also assume consistent levels forecast DER prices.

Further details regarding our approach is outlined in Section 4.1.

[35] Following our review of available industry data. Energeia was unable to implement our full DER-integration cost analysis due to a lack of sufficient data on: peak demand or utilisation by LV transformer; hosting capacity functions for phase imbalance, under-voltage and under-frequency load shedding, and; solution costs for under-frequency load shedding

[36] Hosting capacity typically refers to the level of DER inverter capacity, typically solar PV, which can be added before a network constraint is hit, typically over-voltage. For this study, we used reported relationships between additional solar PV capacity and curtailment as a proxy for an LV network's starting hosting capacity (i.e. prior to mitigation).

3. Stage 1 – Research Key Findings

Energeia's analytic framework shown in Table 5 used a comprehensive desktop research process to identify the key issues arising from increasing DER in the LV network and the potential range of solutions that might address these issues. Energeia's findings from our research into the issues and solutions are detailed in the following sections.

Table 5 – Analytical Framework

Item	Staged Assessment	Key Questions
Issues arising from increasing DER exports	1. Identified issues	What are the issues observed from public domain sources (for networks, prosumers and other stakeholders)?
	2. Costs associated with the issues	How are stakeholders impacted by each issue and how? What are the associated costs with these impacts?
	3. Prevalence of the identified issues	Does the frequency of the issues vary across different distribution networks in the NEM? How does this compare internationally?
Solutions to address the identified issues	4. Identified potential solutions	What are the measures that distribution networks apply to manage the LV network?
	5. Prevalence of the potential solutions	What is the response to DER issues by DNSPs? How does this compare to overseas utility experiences?
	6. Solutions mapped to issues	Which of these solutions directly address DER issues?
	7. Key solution costs	What are the costs of these solutions to DER issues?

Source: Energeia; Note: DER = Distributed Energy Resources, DNSPs = Distribution Network Service Providers, LV = Low Voltage, NEM = National Electricity Market

3.1. Identified Issues

Energeia has identified a range of issues impacting across three distinct groups of stakeholders, the drivers, the impacts and the costs, as outlined in Table 6.

Table 6 – Summary of Issues Associated with Rising DER Penetration

Stakeholder	Category	Issue	Impacts
Customers with Solar PV	Investment	Connection Limits	Connection standards can limit efficient investment choices in DER
		Export Limits	Connection standards can limit efficient operation of DER
		Inverter Curtailment	Inverter standards can reduce output and investment certainty
		Increased Energy Losses	Inverter standards can increase reactive power losses, reducing investment certainty
		Reduced Capacity	Inverter standards can increase reactive power, reducing inverter capacity, lifetime and investment certainty
		Reduced Lifetime	
Distribution Networks	Power Quality	Over-Voltage	Excess generation can increase voltage above allowed thresholds
		Under-Voltage	Generation can increase voltage range, leading to under-voltage
		Flicker	Intermittent generation can lead to voltage flicker
		Harmonics (THD)	Inverters can inject additional harmonics
	Reliability	Thermal Overload	Generation levels can exceed thermal rating limit
	Safety	Protection Maloperation	Changes in generation and load patterns can break some schemes
		Islanding	Inverters can fail to disconnect, creating safety issue
	System Security	Disturbance Ride-through	Inverters disconnect during disturbance, worsening the disturbance
		Under Frequency Shedding	Load shedding inverters can increase net load, worsening frequency
	Cost / Efficiency	Phase Imbalance	Inverters can be unevenly distributed, unbalancing the grid
		Forecasting Error	Stochastic inverter uptake and output can reduce forecast accuracy
Generation, Transmission and Market Operations	Operability	Ramp Rate	Inverters can increase rate of change above system capabilities
	Reliability	Thermal Constraints	Large DER resources can overload thermal limits
	Safety	Fault Levels	Inverters can reduce fault current
	Cost / Efficiency	Forecasting Error	Uptake and operation can increase forecasting error
		Generation Curtailment	Curtailment of DER generation can increase wholesale market prices

Source: Energeia; Note: 1. THD = Total Harmonic Distortion; Grey indicates that issue is addressed by current inverter standards. 2. The lack of low voltage monitoring means that there is limited visibility of the nature, scale and extent of issues impacting management of the low voltage network

3.2. Cost Associated with the Issues

Energeia identified the impacts and costs of the key issues associated with prosumers, distribution networks and other stakeholders, which are discussed in the following sections.

3.2.1. Customers with Solar PV

Table 7 details the key issues affecting customers with solar PV, namely limited connection limits, PV generation curtailment and increased energy losses.

Table 7 – Summary of Customers with Solar PV Issues

Category	Issue	Description	Impacts	Cost Type
Customers with Solar PV	Connection Limit	Connection limits size of system	Caps investment level	Reduced investment opportunity
	Export Limit	Limits amount of energy that can be injected at any time	Reduces investment level and revenues from generation	Reduced investment opportunity and/or certainty
	Curtailment	Over-voltage turns inverter off or DNSP export limits	Reduces revenues from generation	Reduced return on investment
	Increased Energy Losses	Higher reactive power increases inverter losses	Reduces bill savings and other benefits	Reduced return on investment
	Reduced Capacity	Higher reactive power reduces power capacity	Reduces peak demand payments	Reduced return on investment
	Reduced Lifetime	Higher reactive power reduces inverter lifetime	Shortens benefit stream	Reduced return on investment

Source: Energeia

Investment

Connection limits, generation curtailment, energy losses, power reductions and reduced lifetimes act to either restrict prosumer's investment opportunity or diminish the returns on an existing investment.

Connection Limit

All networks in Australia have a default connection limit restricting the size of inverters connecting to the grid to manage the risk of systematically breaching network constraints. Table 1 in Section 1.2.1 showed that most networks have a single-phase connection limit of 5 kW, with the exception of Ausgrid, TasNetworks, United Energy, Jemena and Western Power with a larger limit of 10 kW.[37]

The recent AEMC review of DER integration[38] has identified that the static limits are not a sustainable solution as they overly restrict customers' power generation potential and create inequities between early solar PV adopters and later solar PV adopters (whose connections are restricted).

Export Limit

Networks have recently begun to adjust their default export limits to reflect the increasing number of single-phase solar PV systems connected to the grid, as well as the differences in costs for a three-phase system. For example, SA Power Networks' static export limit is proposing to reduce from 5 kW to 3 kW in areas of high solar penetration to allow new solar PV connections without unduly impacting other customers.[39]

Static export limits restrict a prosumers' ability to invest in larger DER systems and increase their revenue for DER exports (either from feed-in tariffs or through participation in Virtual Power Plants (VPP) or demand

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[37] Customers can apply to install larger systems, with the outcome determined on a case-by-case basis by the DNSP.

[38] AEMC (2019), 'Economic Regulatory Framework Review: Integrating Distributed Energy Resources for the Grid of the Future': https://www.aemc.gov.au/sites/default/files/2019-09/Final%20report%20-%20ENERFR%202019%20-%20EPR0068.PDF

[39] AEMC (2019), 'Economic Regulatory Framework Review: Integrating Distributed Energy Resources for the Grid of the Future': https://www.aemc.gov.au/sites/default/files/2019-09/Final%20report%20-%20ENERFR%202019%20-%20EPR0068.PDF

response activities). They may also unfairly favour customers with relatively high daytime loads. Energy Networks Australia (ENA) is currently developing a unified national guideline[40] for DER export limits, which calls for a uniform "soft" export limit of 5 kVA for single-phase, and 5 kVA per phase with a balanced output for three-phase connections.

Generation Curtailment

The updated AS4777 (2015) inverter standard requires inverters to curtail exports in response to voltage exceedances[41] and grid outages[42]. Curtailment can also be driven by DNSP-specified export limits, as discussed above. Inverters can have several different curtailment mechanisms that work to reduce exports in the presence of high voltages, including:

- **Volt-Watt** – In this mode, the output power of the inverter is varied in response to changes in the terminal voltage. If this mode is available, AS4777 mandates that it shall be enabled by default
- **Volt-Ampere Reactive (Volt-VAR)** – In Volt-VAR mode, the reactive power output of the inverter is varied in response to the voltage at its grid connection. Some inverters include an optional Volt-VAR response capability which is typically disabled by default[43]
- **Binary** – In this mode, the inverter will simply turn on or off

The IEEE updated their standards in 2018 to include Volt-VAR response as a requirement. While Volt-VAR can lead to curtailment, we are seeking more information from stakeholders about the extent of this, and its impact on solar PV hosting capacity across different levels of solar PV penetration.

Curtailment affects prosumers through loss of benefits from solar generation. Curtailment frequency and the potential evolution of curtailment prevalence over time are unclear to consumers when they make their initial DER investment decision and are a significant source of dissatisfaction for prosumers with DNSPs.

Increased Inverter Energy Losses

When inverter power factor is not set to 1 it increases internal energy losses. Setting inverter power factor can occur where connection standards require it, or as part of the Volt-VAR inverter standard. It is worth noting that the National Energy Rules (NER) mandate that a market network service must have a lagging power factor of 0.9[44], limiting maximum exported generation to 90% of rated power. Higher inverter energy losses translate into higher electricity bills or lower feed-in tariff revenues for customers with solar PV, however, a key question is how significant these losses are, and what the net benefits of them are.

Reduced Inverter Maximum Power

When inverter power factor is not set to 1 it reduces its maximum power output[45].

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[40] ENA is currently running a process to develop national guidelines for DER grid connection. More details on the process, and the ongoing industry consultation is available here: https://www.energynetworks.com.au/assets/uploads/cmpj0127_technical_guideline_v6.0_basic_micro_eg_0.pdf

[41] AS4777 inverters limit grid exports during periods of high network voltages (over 253V). The voltage range limits, specified in the standard AS61000.3.100 Limits – Steady state voltage limits in public electricity systems, outline a nominal supply LV of 230V with limits of -6% to +10% (216V to 253V).

[42] The standard provides for compliant inverters to ensure the safety of distribution network technicians working on the network doing outage by preventing residential energisation during outages and provides mechanisms for residential solar to assist networks in managing network ramp up and ramp down periods either side of outages.

[43] Australian Standards require default disablement of Volt-VAR capability unless the distribution network service provider (DNSP) grid connection rules specify otherwise. As of Jan 2020, there were 10 DNSPs that required Volt-VAR response. Note it is unclear what compliance levels are across DNSPs.

[44] AEMC, NER Chapter 5, S5.3.a, https://www.aemc.gov.au/sites/default/files/content//NER-v82-Chapter-05.PDF

[45] GSES – Global Sustainable Energy Solutions (2015), '*Power Factor and Grid-Connected Photovoltaics*', https://www.gses.com.au/wp-content/uploads/2016/03/GSES_powerfactor-110316.pdf

As is the case for increased inverter losses, non-unity (i.e. 1) power factor can be required by connection standards or Volt-VAR inverter standards. This is typically done by DNSPs to improve the efficiency of electricity transfer, reducing the need for augmentation of the distribution network at the cost of the solar PV applicants.

Although helpful to the network for voltage management, non-unity standards can negatively impact the local grid where solar PV output is helping to reduce peak demand, for example. It can also negatively impact solar PV customers by resulting in curtailment or "clipping" whenever panel power reaches the inverter maximum power.

Reduced Inverter Lifetime

Higher levels of reactive power produced by solar PV systems has been shown to incrementally reduce inverter lifetime. Studies commissioned by NREL[46] and Sandia National Laboratories[47] found that as the power factor of an inverter moves away from unity, it increases the temperature of the power semiconductors, resulting in a marginal reduction in lifetime (approximately 4% reduction for a power factor of 0.9). We invite stakeholders to share any relevant research or data on this issue.

A shortened inverter lifetime reduces a solar PV customer's return on investment.

3.2.2. Distribution Networks

Table 8 details the key issues reported by distribution networks across a range of categories ranging from technical (power quality, reliability, system security), safety and cost issues.

Table 8 – Summary of Distribution Network Issues associated with DER Exports

Category	Issue	Description	Impacts	Costs
Power Quality	Over-Voltage	Increased injection of real power increases line voltage above upper limit	Can cause inverters to shut down, damage appliances	Complaints, Investigations, Remediation
	Under-Voltage	Curtailment of injections reduces line voltage below lower limit[48]	Can cause inverters to shut down, damage appliances	
	Flicker	Injection can vary widely and rapidly	Can increase voltage range, flicker	
	Harmonics (THD)	Inverters inject additional harmonics	Ran reduce transformer lifetimes	Remediation
Reliability	Thermal Overload	Injected power exceeds thermal rating	Can trigger over-current protection	Remediation
Safety	Protection Maloperation	Changes in current breaks some schemes	Can cause protection maloperation	
	Islanding	Inverter fails to disconnect	Can create a shock hazard	
System Security	Disturbance Ride-through	Inverters disconnect during disturbance	Can worsen frequency disturbance	Remediation
	Under Frequency Shedding	Load shedding inverters increases net load	Does not meet load shedding standard	
Cost / Efficiency	Phase Imbalance	Inverters grouped on single-phase	Can increase energy losses, reduces Tx capacity	Remediation
	Forecasting Error	Inverter uptake and output are stochastic	Increases forecasting error	

Source: Energeia; Notes: THD = Total Harmonic Distortion, Tx = Transmission, Grey indicates issue addressed by current inverter standards.

[46] R. Thiagarajan et al., NREL (2019), '*Effect of Reactive Power on Photovoltaic Inverter Reliability and Lifetime*', https://www.nrel.gov/docs/fy19osti/73648.pdf

[47] Gonzalez et al. (2014), '*Effect of non-unity power factor operation in photovoltaic inverters employing grid support functions*', https://ieeexplore.ieee.org/document/6925199

[48] Impacts of phase imbalance on the LV specifically can also include over-voltage on one phase and under-voltage on the other, in the case where a neutral phase shift occurs.

Power Quality

Increases in DER penetration can impact distribution network power quality. These issues can impact both consumer devices[49] and network operational efficiencies and include over and under-voltage, flicker, reverse flow and total harmonic distortion.

This is a salient issue for networks as they are required by regulation to provide the specified level of power quality to customers on their networks.

Over-Voltage

Over-voltage, defined as periods where the network voltage is higher than the allowed limit of 253 V, has been identified as the main issue currently facing networks in integrating residential solar uptake.

Over-voltage can cause inverters to shut down, and has the potential create excessive heat and strain on electrical components of appliances, reducing their lifetimes.

Key drivers of distribution network over-voltage include:

- **Network Management Practices –** Transformer tapping schemes can set the LV network voltage at too high of a level regardless of rooftop solar PV uptake. This can occur because of changes in loads and low to no LV power quality visibility[50]
- **Grid Export from Solar PV** – Inverter real power injection into the network can increase voltage, particularly on high impedance circuits, e.g. overhead lines with relatively small conductor sizes

DNSPs are required by their license conditions to keep voltage within Australian standards. With the nominal voltage recently being set to 230 V instead of 240 V, and the significant uptake of solar PV, many DNSPs are being required to re-tap their transformers to lower levels than their previous standard practices would dictate to prevent additional voltage excursions.

DNSPs deploy voltage monitoring equipment manually where needed in response to customer complaints. DNSPs with smart meters may be able to ping or read the customer meter to confirm the over-voltage situation.

Under-Voltage

The opposite of over-voltage, this condition occurs when the network voltage is lower than the allowed limit of 216 V. Although much less common than over-voltage, under-voltage can cause more significant consequences since in under-voltage conditions, appliances draw excessive current. Excessive current flows both increase the heat load of appliances and can trip network protection and outages. Hence, under-voltage induces costs for both the consumer, via appliance damage, and the network in outage-related costs.

Solar generation can sometimes contribute to under-voltage conditions arising in the LV network. Transient events, such as cloud cover, can cause a transient reduction in DER output resulting in a voltage drop. As distribution networks come to rely on more solar generation to meet their power needs, these effects will amplify. Current inverter settings can sometimes result in exaggerated voltage drop, as some inverters may switch off if they detect a voltage sag, exacerbating the original under-voltage condition.[51]

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[49] Appliances respond differently to over and under-voltages, the impact of voltage excursions depends on load type.

[50] DNSPs rely on customer complaints to identify issues.

[51] Future inverter capabilities and settings (so-called “smart inverters”) may have the opposite response and act to mitigate voltage sag. However, this technology has only recently been implemented.

Flicker

Power-line flicker is the visible change in brightness of a lamp due to rapid fluctuations in the voltage of the power supply.[52] Voltage fluctuations resulting in light bulb flicker have been a common problem with LV networks since their inception, however this is changing as incandescent lighting technologies are phased out.

Recently, rooftop solar PV generation has been raised as a possible source of flicker due to voltage fluctuations generated by passing cloud cover and inverter disconnection. Although this is an intuitive possibility, Energeia has not been able to identify evidence of a causal link between unacceptable flicker levels and residential solar generation.

A recent study[53] has demonstrated the absence of correlation between cloud cover (irradiance) and flicker levels. On the other hand, a CSIRO study[54] of the ramp rate of PV installations in Australia found that high ramp rate events occur more frequently at smaller timescales, with observed power output reductions exceeding 66% of PV rating within a ten second period. This level of variation can impact flicker.

The cost of flicker is borne by consumers' who lose amenity and networks through the loss of customer satisfaction and consequential brand-name damage.

Total Harmonic Distortion

Total harmonic distortion (THD) is a measure of the cumulative amount of power generated by frequencies other than the fundamental 50 Hz frequency of the network. In a network, THD is typically caused by asynchronous generators and loads.

THD can increase network losses and reduce electrical equipment lifetime as energy is lost through heat, and devices that use inductive loads, such as electric motors, draw more power to operate correctly. Network transformers are also adversely affected by THD through increased losses and decreased life expectancy.

Solar panels generate DC power which is converted to AC power by the inverter when exported to the grid. Inverters use high frequency switching to generate an approximate sine wave, but the switching itself also generates higher frequency components. This distortion can be significant if many of the same type of inverter are connected to a specific area of the network. The amount of THD generated by grid connected inverters is restricted by Australian Standards. In their 2019 economic regulatory framework review[55], AEMC found no recorded incidences of solar PV installations generating significant harmonic distortion. On the other hand, AusNet have observed that harmonics induced by solar PV can trip bush fire safety controls.[56]

Other sources of harmonics include modern air-conditioners with variable speed drive inverters and other switch mode power supplies, which basically includes any DC device that connects to the grid with a 'wall brick', including mobile phones, computers, audio visual devices, etc.

Energeia has marked THD as no longer a material issue related to rising DER adoption in light of modern inverter standards and performance. Unless we hear otherwise from the consultation feedback, we will not include any solution costs for it in the options and net benefits maximisation analysis.

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52 Flicker is a measure of human irritation, so it is difficult to measure and quantitatively quantify. It can cause adverse effects on human health including fatigue, lack of concentration, migraines and in extreme cases epileptic shocks. However, the subjective nature of the effect means that is difficult for either consumers or networks to attribute a cost to an effect that cannot be quantitatively measured.

53 Spring et al., European Photovoltaic Solar Energy Conference (2013), *'Effects of Flicker in a Distribution Grid with high PV Penetration (2013)'*: https://pdfs.semanticscholar.org/9717/403435d7efb4b760984c0660ace41f51cde9.pdf

54 CSIRO (2012), *'Solar intermittency: Australia's clean energy challenge'*: https://publications.csiro.au/rpr/download?pid=csiro:EP121914&dsid=DS1

55 AEMC (2019), *'Economic Regulatory Framework Review: Integrating Distributed Energy Resources For The Grid Of The Future'*: https://www.aemc.gov.au/sites/default/files/2019-09/Final%20report%20-%20ENERFR%202019%20-%20EPR0068.PDF

56 As was stated by an AusNet representative during the stakeholder workshop as part of the documentation process.

Reliability

Solar PV and other types of DER inverters can reduce network reliability by breaching asset thermal limits, however this only occurs during reverse power flow conditions.

Thermal Overload

Thermal overload occurs when current levels exceed rated limits causing excessive heat and resulting in accelerated asset aging, damage to network equipment and outages from tripped fuses.

Network voltage limits are usually reached well before thermal limits. However, as voltage remediations are implemented, it can lead to reverse power flow levels reaching thermal limits.

The cost of thermal overload impacts networks and consumers:

- Reduction in asset lifetimes leads to early asset replacement and thus network expenditure;
- Upgrades to assets to increase their thermal rating increases network expenditure; and
- Outages due to thermal overloads increase network expenditure and negatively impact customers.

Traditionally, thermal overload is caused by load. However, reverse power flow can also result in thermal overload due to reverse current.[57]

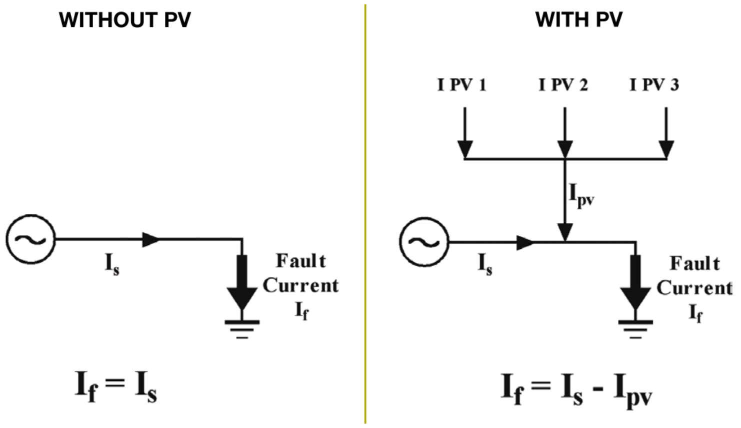
Safety

Network safety can be impacted by DER via its effect on fault levels, protection mechanisms and islanding.

Protection Maloperation

Figure 15 illustrates how DER can alter the fault current needed for protection to operate effectively. Protection maloperation can occur due to rising DER penetration changing fault levels and/or reverse flows confusing protection mechanisms (i.e. the systems networks have in place to mitigate damage to their assets and potential loss of life). The addition of PV can also serve to desensitise the fault relay[58].

Figure 15 – How High Penetration of Solar PV Systems may Reduce Fault Currents



Source: Endeavour Energy[59]

[57] There are circumstances under which the uptake of solar PV may also benefit thermal overload problems. One notable example is the potential for solar PV to reduce the duration of peak demand on days of high solar generation.

[58] NREL (2016), '*High-Penetration PV Integration Handbook for Distribution Engineers*', https://www.nrel.gov/docs/fy16osti/63114.pdf

[59] Endeavour (2011), '*Small Scale Domestic Rooftop Solar Photovoltaic Systems'*: https://www.elec.uow.edu.au/apqrc/content/technotes/UOW009_Tech%20Note%2010_AW_screen.pdf

Maloperation of protection due to DER can therefore arise because the protection schemes were not designed with DER in mind. This can lead to false tripping of protection schemes due to higher than expected current flows, or reverse current flows, depending on the protection equipment.

To resolve protection maloperation, the remediation will generally require networks to upgrade their protection systems to systems compatible with high levels of DER; e.g. installing a fuse with a higher interruption rating, and/or extra breakers closer to the PV load.

While protection maloperation can occur for a variety of reasons, the type of maloperations due to local changes in injection and load patterns are unique to DER.

Islanding

Islanding refers to DER systems supplying power to a grid when the grid power falls or fails, forming an island. The AS/NZS 4777.2 update in 2015 included requirements for inverter anti-islanding and disconnection functions to prevent islanding. Anti-islanding protection systems are designed to include N-1 redundancy[60].

Energeia has marked islanding as no longer a material issue for DER in light of the effect of the changes in the standard. Unless we hear otherwise from the consultation feedback, we will not include any solution costs for it in the options and net benefits maximisation analysis.

System Security

Increasing DER penetration can lead to changes in network security, including under-frequency load shedding.

Disturbance Ride-Through

Disturbance ride-through is the ability of inverters to remain operational during system disturbances including network faults to help keep the system secure. This issue is limited to grid-connected inverters.

Traditionally, grid-connected PV systems were designed to be disconnected from the grid under-voltage rise and drop conditions to protect the inverter. However, as DER penetration in the LV network increases, mass disconnection of a large amount of rooftop solar PV can disturb the stability of the network. The AS/NZS 4777.2 update in 2015 included requirements for inverter disconnection functions to support disturbance ride through, and it is therefore not expected to be a major industry issue moving forward.[61]

Energeia has marked disturbance ride through as no longer a material issue for DER integration in light of the effect of the changes in the standard. Unless we hear otherwise from the consultation feedback, we will not include any solution costs for it in the options and net benefits maximisation analysis.

Under Frequency Load Shedding

Under frequency load shedding (UFLS) is implemented by DNSPs in cooperation with AEMO to restore power system frequency stability if system frequency drops below the operational set point during major disturbance.[62] It is an emergency response by the network to losing a large amount of generation, typically due to a power station or transmission line tripping off. UFLS arrests the system frequency drop which may otherwise lead to further grid separation and ultimately total frequency collapse and prolonged system outage.[63]

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[60] Ausgrid (2018), *'NS194 Secondary Systems Requirements for Embedded Generators'*: https://www.ausgrid.com.au/-/media/Documents/Technical-Documentation/NS/NS194.pdf

[61] Note that changes are currently being considered for AS/NZS 4777.2 that may affect this description of disturbance ride-through. Throughout the first-stage, Energeia has focused predominantly on standards currently in effect, for simplicity.

[62] Omar et al. (2010), *'Under frequency load shedding (UFLS): Principles and implementation'*: https://ieeexplore.ieee.org/document/5697619

[63] M. Lu et al. (2016), *'Under-Frequency Load Shedding (UFLS) Schemes – A Survey'*: https://pdfs.semanticscholar.org/1a02/af98d845f4e626665592b81c82551381ace8.pdf

Increasing DER penetration has a two-fold impact on network's UFLS schemes:

- **Reduced System Inertia** – In LV networks where DER penetration is high, the increased level of DER exports reduces system inertia. If inertia drops low enough, frequency can drop faster than the UFLS scheme can operate.[64]
- **Generation Requirements** – Conventional emergency load shedding schemes implemented by distributors operate by disconnecting whole feeders at the substation. These schemes now need to consider the level of generation occurring at the time on the feeders, otherwise disconnecting the feeder to shed load could remove significant generation, further amplifying the under-supply issue.

UFLS settings are periodically changed to keep load shedding within the required standard. The cost of UFLS failure is set by the Value of Customer Reliability (VCR) for a prolonged system outage.

Cost / Efficiency

Increase in DER penetration can lead to several issues around the cost and efficiency of distribution networks including phase imbalance and forecasting errors.

Phase Imbalance

Phase imbalance exists when one or more of the line-to-line voltages in a three-phase system are mismatched. Line-to-line voltages in a three-phase circuit typically vary by a few volts, but a difference that exceeds 1% can damage motors and equipment.[65]

Phase imbalance can arise in the LV network where customers on one phase adopt more solar PV generation than on another phase, causing the load to become unbalanced resulting in negative sequence voltage[66].

However, it can and does occur due to organic changes in load composition, for example, due to customers on one phase adopting more reverse cycle AC than on another phase. Phase balancing is a typical LV maintenance task as load patterns change over time.

Forecasting Error

Forecasting error in this context can be described as the difference between predicted and actual values of solar PV output and generation. As the prevalence of solar PV increases, networks must be able to accurately forecast their impact in the short and long-run in order to produce accurate forecasting methods.

The inability to accurately predict both the magnitude and spatial locality of DER could result in uninformed network planning leading to inefficient investment outcomes for customers, either through higher network costs, and/or increased power quality and reliability issues.

Other sources of forecasting error include any significant changes in load drivers, e.g. reverse cycle AC adoption, which led to significant increases in medium term forecasting errors in the NEM in the early 2000s.

3.2.3. Generation, Transmission and Market Operation

Energeia's research found that increases in DER penetration could potentially impact generation, transmission and operation of the market, as detailed in Table 9.

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[64] AEMO (2017), *'Power System Frequency Risk Review Report Non-Credible Loss of Multiple Generating Units in South Australia'*: https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/Electricity_Consultations/2017/Power-System-Frequency-Risk-Report---Multiple-Generator-Trips---FINAL.pdf

[65] Enertiv (2019), '*What is Phase Imbalance?*', https://www.enertiv.com/resources/faq/what-isphase-imbalancec (Accessed 8/11/2019)

[66] AusNet (2017), '*Solar PV generator – Power Quality Compliance Requirements*', https://www.ausnetservices.com.au/-/media/Files/AusNet/New-Connections/Solar-Connections/Large-Solar/SOP-33-08---Power-Quality-Compliance-Requirements.ashx?la=en

Table 9 – Summary of Generation, Transmission and Market Operation Issues associated with DER Exports

Category	Issue	Description	Impacts	Costs
Operability	Ramp Rate	Inverter rates of change are much higher	Increases ramping requirement	Remediation
Reliability	Thermal Constraints	Large DER resources overload thermal limits	Asset overloads and outages	Remediation
Safety	Fault Levels	Inverters reduce fault current	Transmission protection fails to operate	Remediation
Cost / Efficiency	Forecasting Error	Inverter output is stochastic	Increases forecasting error	Remediation
	Generation Curtailment	Curtailment of DER generation	Increased wholesale costs	Remediation

Source: Energeia

Operability

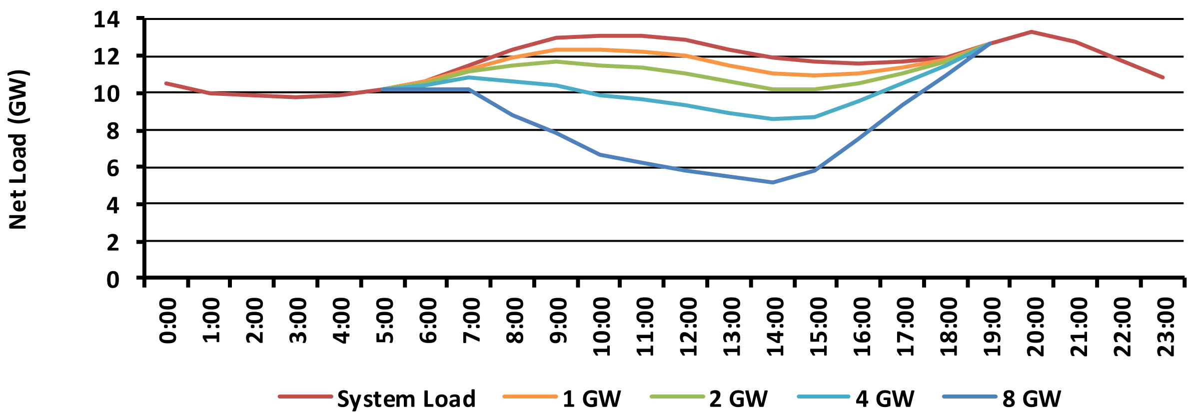
Increased DER can impact the operability of the system by increasing system ramp rate requirements.

Ramp Rate

Ramp rate refers to rate of change in system load or generation, which must be matched in real-time to maintain system stability. Historically, random and expected changes in load were matched in real-time by load following generation using automated governor controls (AGC). Changes in generator ancillary service (AS) requirements and associated changes in AS prices at least partially reflect the cost of increasing ramp-rate requirements.

High levels of DER penetration can increase the potential rate of change of the system, beyond the ability of conventional generation and load following systems. Solar PV only produces energy when the sun shines, however the demand for energy remains when solar energy is not being produced. The phenomenon is often referred to as the "duck curve", as shown in Figure 16. To ensure reliability under changing grid conditions, the system operator needs resources with ramping flexibility and the ability to start and stop multiple times per day. Utility scale solar PV and wind resources can also drive changes in ramp rate requirements.

Figure 16 – Example Duck Curve by BTM Solar PV Capacity



Source: GreenTechMedia (2018)[67]

Reliability

Increased DER can impact the reliability of the transmission system by overloading transmission network assets.

[67] GreenTechMedia (2018), "Massachusetts Is Staring Down a Duck Curve of Its Own. Storage Could Help", https://www.greentechmedia.com/articles/read/massachusetts-is-staring-down-a-duck-curve-of-its-own-storage-could-help

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Thermal Constraints

This issue is similar to the distribution network thermal limit issue but occurs at the transmission level. This issue is generally not expected to occur anytime soon due to the significant level of DER required to overload a transmission asset – however it could potentially occur as penetration rises to expected levels. Thermal limits have always been an issue, but new forms of generation, connected at different locations and voltage levels can cause flows on networks to change. This can lead to a change in the thermal constraints seen on transmission systems and a change in requirements for managing them.[68] As is the case with the distribution network, load is the alternative driver of transmission thermal overloads.

Safety

Rising DER penetration can impact transmission system safety by reducing fault levels which can impact transmission level protection schemes.

Fault Levels

The displacement of rotating plant from the generation fleet in lieu of inverter based generation is leading to a reduction in fault levels at the transmission system level. As such, protection devices installed may not recognise fault current and operate to protect transmission assets, creating a significant safety hazard as well as the potential to damage equipment. While high levels of DER penetration can displace rotating plant, they are also displaced by utility scale solar PV, wind and storage resources.

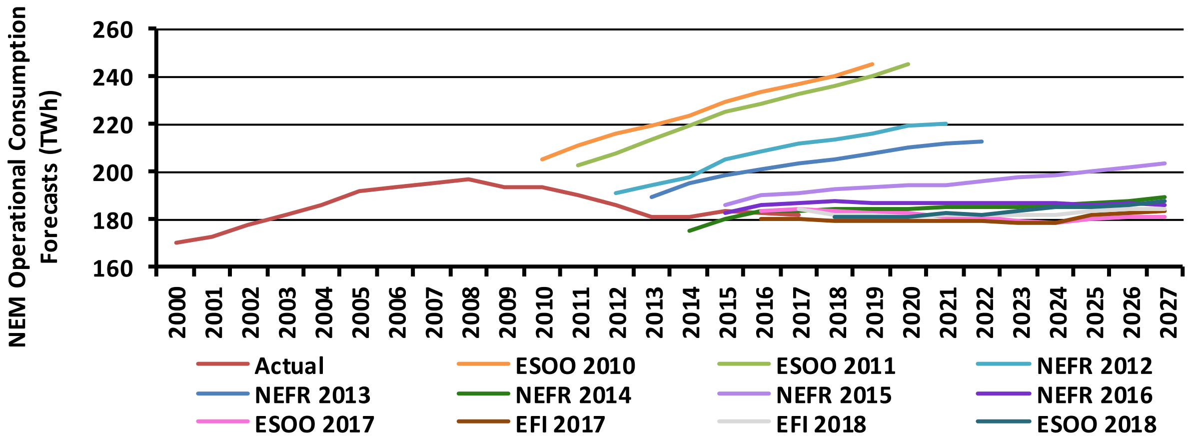
Cost / Efficiency

Cost and efficiency of the generation, transmission and market operation can be impacted through forecasting error and a lack of lower cost DER service due to curtailment.

Forecasting Error

Forecasting error in this context can be described as the difference between predicted and actual values of solar PV investment and output. Figure 17 provides the example of AEMO's forecasting errors.

Figure 17 – AEMO's Long-term Forecasting Errors



Source: AEMO Electricity Statement of Opportunities (2018)[69]

[68] National Grid (2016), '*Transmission Thermal Constraint Management*': https://www.nationalgrideso.com/sites/eso/files/documents/National%20Grid%20Transmission%20Thermal%20Constraint%20Management%20information%20note_July%202018.pdf

[69] AEMO (2018), *'2018 Electricity Statement of Opportunities':* https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

Increased levels of rooftop solar PV can increase forecasting errors in the short and longer-term, which can in turn lead to sub-optimal levels of generation and transmission investment, as operating reserves. Sub-optimal investment and resource allocation increases market costs.

PV generation is stochastic, and this can increase AEMO's short-term forecast error. For each five-minute dispatch interval, AEMO calculates the demand forecast error (DFE) for the period, that is, the percentage difference in the actual demand compared with forecast demand. AEMO has noted increases in the DFE in some regions at the times when solar generation is ramping up (increasing as the sun rises) and ramping down (decreasing as the sun sets)[70].

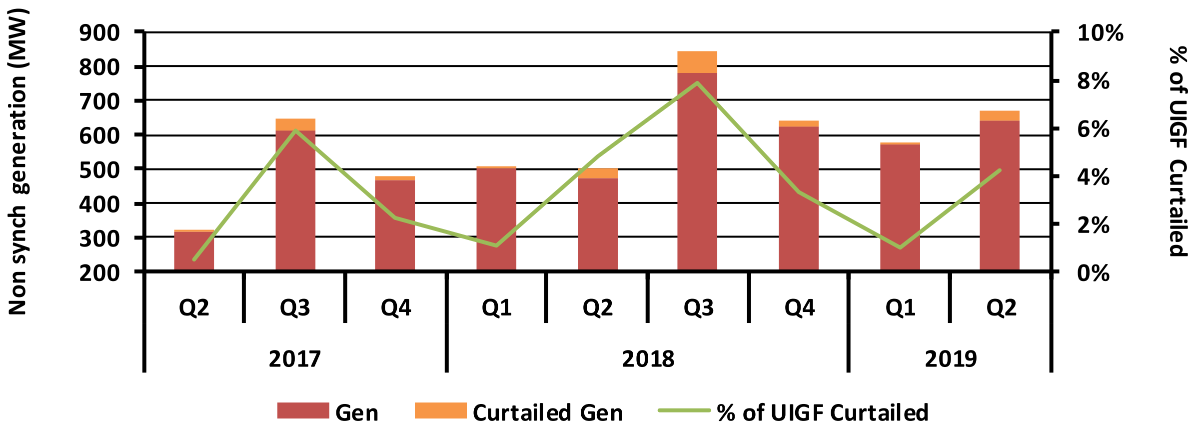
Large penetrations of DER, if not visible and predictable, could progressively decrease AEMO's ability to provide the level of accuracy needed to support market efficiency and/or reliability with asset under-utilisation, less informed investment decisions, and ultimately increased costs borne by consumers.

High levels of DER penetration can increase forecasting error, at least initially. However, intermittent, utility scale solar PV and wind resources can also drive increases in forecasting errors, due to the same stochastic factors.

Lack of Lower Cost DER Service due to Curtailment

Curtailment of lower cost DER resources can increase wholesale costs due to the dispatch of higher cost resources. This issue is increasing as additional utility scale solar PV installations are connected in the NEM. Figure 18 shows the non-synchronous generation curtailment in South Australia.

Figure 18 – Curtailment of Non-synchronous Generation



Source: AEMO[71]; Note: UGIF = Unconstrainted Intermittent Generation Forecast

This issue varies slightly from the prosumer use case, in that the former involves the loss from the reduced bill and/or feed-in tariff payments, while this issue relates to the impact of DER on the wholesale market merit order, leading to a higher clearing price than would otherwise be the case.

[70] AEMO (2017), *'Visibility of Distributed Energy Resources'*, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2016/AEMO-FPSS-program----Visibility-of-DER.pdf

[71] AEMO (2018), *'Quarterly Energy Dynamics Q2 2018':* https://www.aemo.com.au/-/media/Files/Media_Centre/2018/QED-Q2-2018.pdf (Accessed 8/11/2019)

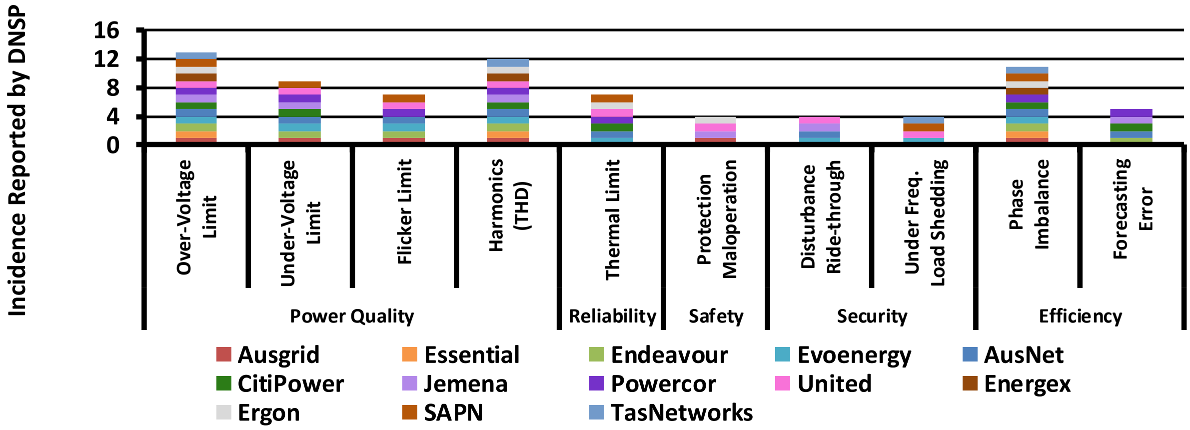
AEMO (2019), *'Quarterly Energy Dynamics Q2 2019':* https://www.aemo.com.au/-/media/Files/Media_Centre/2019/QED-Q2-2019.pdf (Accessed 8/11/2019)

3.3. Prevalence of the Identified Issues

Energeia looked at the incidences of each issue[72] to discover which are the most prevalent across networks and how they varied relative to international benchmarks, as shown in Figure 19 and Figure 20 respectively.

The most cited DNSP issues in Australia are over-voltage, harmonics and phase imbalance, with under-voltage and protection maloperation in the next tier of reported issues.

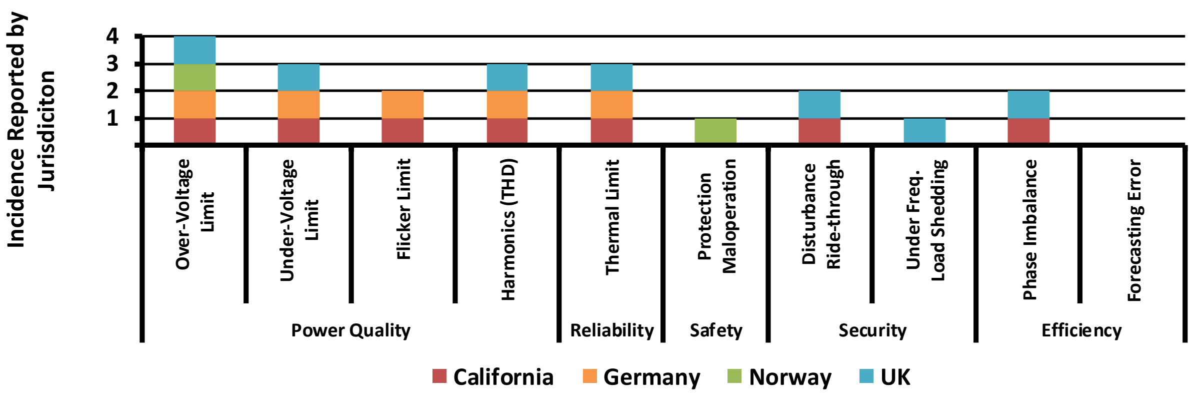
Figure 19 – Incidence of Key Distribution Network Issues Reported by DNSPs (Australia)



Source: Energeia

Overseas jurisdictions, such as Germany, the UK, Norway and California report a similar range of issues, with an increased experience of under-voltage issues than Australia.

Figure 20 – Incidence of Key Distribution Network Issues Reported by Overseas Benchmark Jurisdictions



Source: Energeia

3.4. Identified Solutions

Table 10 outlines the range of solutions that can be employed to remediate the range of key issues.

[72] Prosumer curtailment incidence was estimated in Section 1.2.2.

Table 10 – Key Options for Managing DER Export Issues

Category	Solution	Description
Consumers	Load Management	Shifting of water heating, pool pumping & under floor heating to soak up excess generation
	Storage Management	Use of storage to control Volt-VAR or to soak up excess generation
Pricing Signals	Coarse	Use of more cost-reflective pricing signals (e.g. tariff or rebates) that better reflect the value of marginal generation/consumption of real/reactive power, e.g. Time-of-Use
	Granular	Use of highly granular price signals that reflect the value of marginal generation/consumption of real/reactive power in real-time, e.g. Locational Marginal Price
Technical Standards	Inverter Standards	Changes to require DER inverter capabilities and settings at time of installation, including smart inverter capabilities, e.g. Volt-Var, Volt-Watt and Frequency-Watt
	Remote Inverter Configuration	Remotely configurable inverter capabilities, for managing voltage, frequency and other limitations by the network or service provider
	Static Limitations	Use of rating, rate-of-change or output limitations to ration available hosting capacity based on the worst-case scenario
	Dynamic Limitations	Dynamic setting of rating, rate-of-change or output limitations to make additional hosting capacity available as conditions warrant
Reconfiguration	Change Taps	Manual changes in transformer tap voltages to keep voltage profiles within limits
	Change Topology	Changes to MV and LV network topology to manage voltage and under-frequency load shedding issues
	Change UFLS	Changes to relay settings to maintain required load shedding and to avoid dropping circuits with reverse flow
	Change Protection	Changes to protection settings and schemes to resolve issues related to reverse flow
	Balance Phases	Manual changes in the allocation of single-phase connections to the three-phase system to maintain balance within standard
New Methods	Third Party Data	Customer side automation technologies that respond to market and network signal to improve efficiency and reliability of customer energy usage
	Better Forecasts	Improved analytical models to reduce or eliminate inverter related forecasting risk
New Assets	LV Metering	Installation of monitoring and control systems to monitor the LV network
	Voltage Regulators	Installation of transformer or line-drop voltage regulators to manage over or under-voltage conditions or to increase hosting capacity
	Larger Transformer and/or Conductor	Installation of larger transformers and/or conductors
	On Load Tap Changer	Installation of on load tap changers to enable real-time response to changing network conditions
	Harmonic Filters	Installation of harmonic filters
	STATCOMs	Installation of STATCOMs
	Network Storage	Installation of battery storage as a network asset

Source: Energeia; Note: The set of solutions available as well as the associated costs are changing rapidly, with the presentation of new solution sets. Energeia has provided a range of currently available solutions that address remediation of the key issues identified.

Each of the above solutions is discussed below in terms of the key issues it addresses, how it addresses them, any limits as to its application, who is using it, and key cost drivers.

3.4.1. Consumers

Consumers can use DER to shape their load profile and reduce their bill through:

- **Load Management** – Using behaviour change or controlled loads such as water heating and pool pumps to shift a portion of a customer's consumption to the solar peak hours, for example
- **Storage Management** – Incentivising demand response or VPP programs to either control Volt-VAR or ensure that batteries are charging during the solar peak hours

Load Management

By changing behaviour, installing time clocks, or modifying the designated controlled load tariff time period to the middle of the day instead of overnight, load management can be used to help reduce voltage rise and thermal limits. This solution is especially useful while consumer battery storage uptake is low. Water heaters, under floor heaters, pool pumps and electric vehicle charging are all examples of large, flexible residential loads, as shown in Figure 21.

Figure 21 – Example of Large, Flexible Customer Loads

Source: Energeia Research; Note: Shown are examples of a water heater, an electric vehicle charging and a pool pump.

Energeia identified a few examples of DNSPs in Australia using their load control systems to help reduce over-voltage issues[73], however, the practice does not yet appear to be widespread. Energeia has also been informed by industry contacts that some solar PV customers are taking their water heaters off controlled load and using time clocks to switch them on in the middle of day to use their excess solar PV generation.

The cost of implementing load management depends on whether existing solutions are in place, or new solutions have to be implemented. Retrofitting existing devices using a Demand Response Enabled Device (DRED) product is relatively expensive, while interfacing with an internet connected device will be relatively low cost.

Importantly, investments in load management to address DER driven issues could also be used for other network services, so it will be important to appropriately share costs where this solution is implemented.

Storage Management

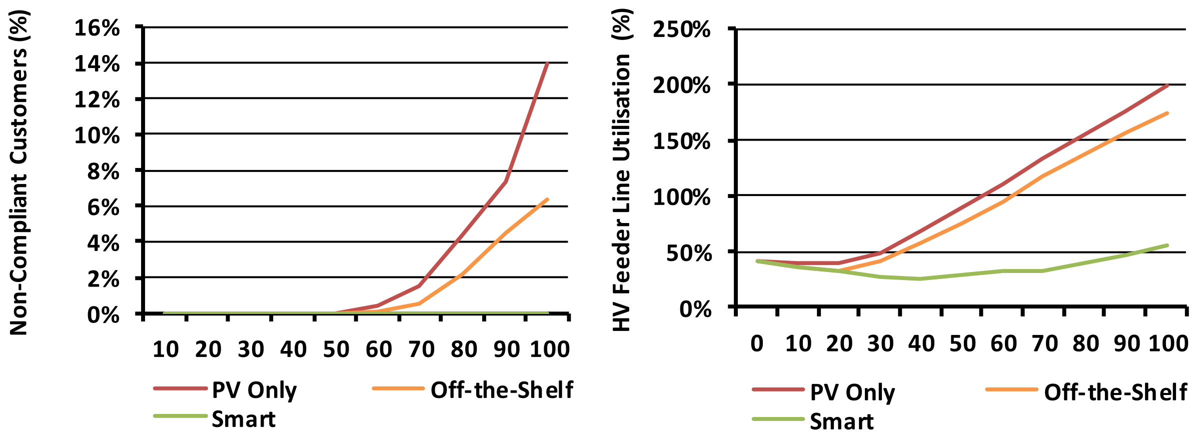
BTM battery energy storage systems are typically used to store a customer's own excess solar PV generation as shown Figure 22. Research by the University of Melbourne shows that behind the meter storage could be used during solar PV curtailment periods to avoid curtailment.[74] A wide range of studies sponsored by ARENA have shown batteries can be used to remediate a range of issues including voltage rise and thermal overload.

[73] Energex (2018), 'Distribution Annual Planning Report', https://www.energex.com.au/__data/assets/pdf_file/0016/720223/Distribution-Annual-Planning-Report-2018.pdf

Ergon (2018), 'Distribution Annual Planning Report', https://www.ergon.com.au/__data/assets/pdf_file/0018/720234/DAPR-2018-2023.pdf

[74] L. Ochoa, A. Procopiou, University of Melbourne (2019), *'Increasing PV Hosting Capacity: Smart Inverters and Storage'*: https://resourcecenter.ieee-pes.org/education/webinars/PESVIDWEBGPS0010.html pg. 14

Figure 22 – Using Storage to Eliminate Curtailment



Source: University of Melbourne[75]

VPPs in South Australia are reportedly using customer storage to address network issues including voltage rise.[76] Customers are receiving significant discounts or additional annual incentives to allow the VPP service provider to use their battery to provide network services.

Electric vehicle batteries could also be utilised as a solution in the future, as vehicle-to-home and vehicle-to-grid technologies continue to develop. As is the case for the load management solutions, the incremental cost of prosumer storage solutions will depend on whether the solution is already installed or not. If installed the cost will be at least the opportunity cost of using storage for other benefits, otherwise the cost will be the cost of a storage device and controls.

Again, investments in storage management to address DER driven issues could also be used for other network services, so it will be important to appropriately share costs where this solution is implemented.

3.4.2. Pricing Signals

As excess solar generation can cause power quality and reliability issues within the network, changing pricing signals to disincentivise DER output where it drives uneconomic costs is a potential solution to reduce the extent and frequency of these issues. There is a wide range of potential pricing and other incentive signals, the two categories below have been defined to provide pricing signal solution bookends:

- **Coarse** – Use of more cost-reflective pricing signals that better reflect the value of marginal generation or consumption of reactive power. These include tariffs, such as time-of-use tariffs, or rebates
- **Granular** – Use of highly reflective price signals that track the value of marginal generation or consumption of reactive power. These include locational pricing or real-time pricing tariffs

With these pricing signals, customers and/or their agents are incentivised to shift their energy usage including battery storage and EVs toward periods of excess solar PV output. Historically, take-up of optional cost-reflective tariffs has been poor. However, DNSPs have begun to mandate more cost-reflective pricing. For example, Ausgrid is reassigning customers on flat tariffs to more cost reflective tariffs when they receive a new smart meter (including customers with DER) from 1 July 2019[77].

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[75] L. Ochoa, A. Procopiou, University of Melbourne (2019), *'Increasing PV Hosting Capacity: Smart Inverters and Storage'*: https://resourcecenter.ieee-pes.org/education/webinars/PESVIDWEBGPS0010.html

[76] Tesla (2019) '*RE: SA Power Networks: 2020 – 2025 Regulatory Proposal*': https://www.aer.gov.au/system/files/TESLA%20-%20Submission%20on%20SA%20Power%20Networks%20Regulatory%20Proposal%202020-25%20-%2016%20May%202019.pdf

[77] Ausgrid (2019), 'Attachment 18 Tariff structure statement (2019 to 2024)', https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Ausgrid%20distribution%20determination%202019-24%20-%20Attachment%2018%20-%20Tariff%20structure%20statement%20-%20April%202019.pdf

Importantly, price signals need not be mandatory, and voluntary, 'prices to devices' are more likely to be acceptable to customers and the regulator.

Locational pricing signals are typically used as part of the DAPR process, which estimates the avoidable cost of planned projects. They only relate to the proposed project, and not the long-term-marginal-cost (LRMC) of the location. No spatially determined LRMCs have been identified by Energeia's research.

Real-time, locational pricing is a feature of the NEM, at least on a regional (state) basis. The Coordination of Generation and Transmission Investment (COGATI) reforms will introduce nodal pricing at the transmission level, which provide real-time, location-based pricing. Energeia also identified Distribution System Operator (DSO) platforms that provide this information at the distribution network level; however, they are limited to pilot projects at this stage.

The cost of implementing more cost reflective pricing signals includes the cost of a smart meter if tariffs are used, however, other forms of price signals including rebates and device measured performance, could be close to zero to implement, other than the cost of the incentive itself. The cost of DSO platforms needed to determine nodal market clearing prices in real-time are high; but they are expected to fall as they become commoditised.

Investments in pricing signals to address solar PV driven issues could also be used for other network services, so it will be important to appropriately share costs where this solution is implemented.

3.4.3. Technical Standards

Research in the US[78] and Australia[79] show improvements to technical standards can significantly reduce curtailment and voltage rise issues. Energeia research has identified the following potential technical standards based solutions for remediating identified voltage, curtailment and frequency related issues:

- **Inverter Standards** – Changes to DER inverter capabilities and settings at the time of installation, particularly changes to Volt-VAR and Frequency-Watt standards
- **Remote Inverter Configuration** – Capability for inverters to be remotely configured by networks or service providers, enabling dynamic reconfiguration and greater optimisation
- **Static Limitations** – Changes to connection limits, rate of change or output limitations of grid exports
- **Dynamic Limitations** – Dynamic setting of connection limits, rate of change or output limitations of grid export as conditions warrant

Importantly, any changes to standards will only be effective where there is effective enforcement of the standard.

Inverter Standards

The inverter standards outlined in AS/NZS 4777.1:2016 are available for implementation in Australia[80]. The most recent updates to this standard improved PV installation practices and configurations, including the use of smart inverters to provide power system support functions and alleviate network power quality, reliability and safety issues (such as reactive control, over and under-voltage, fault ride-through and harmonic compensation).

The frequency-Watt inverter standard has been shown to be an effective method for managing under-frequency events in the Hawaiian network and may be a solution for managing the UFLS issue in Australian networks. Both Hawaii and California have implemented mandatory Volt-VAR and Volt-Watt standards, as shown in Table 11 below.

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[78] NREL, HECO (2019), *'Impacts of Voltage-Based Grid-Support Functions on Energy Production of PV Customers'*: https://www.nrel.gov/docs/fy20osti/72701.pdf

[79] L. Ochoa, A. Procopiou, University of Melbourne (2019), *'Increasing PV Hosting Capacity: Smart Inverters and Storage'*: https://resourcecenter.ieee-pes.org/education/webinars/PESVIDWEBGPS0010.html

[80] As of 1 July 2019, smart inverters are mandatory for all solar PV system installations in Victoria that are supported by the Victorian Governments 'Solar Homes' program.

Table 11 – Summary of Key Inverter Standards from Selected Jurisdictions

Control Function Required	Australia General AS/NZS 4777.2	USA General IEEE 1547 Cat A	USA General IEEE 1547 Cat B	USA CA CA 21	USA HI HI 14	Europe General CLC/TS 50549	Europe Italy CEI 0-16	Europe Austria TOR D4	Europe Germany BDEW MV
Volt-Watt	✓	×	✓	✓ (Optional)	✓ (Optional)	✓ (Optional)			
Volt-Var	✓	✓	✓	✓	✓	✓	✓	✓	✓
cos φ (P)	✓	×	×	×	×	✓	✓	✓	✓
Fixed cos φ	✓	✓	✓	✓	✓	✓	✓	✓	✓

Source: University of Melbourne[79]; Note: ✓ = Yes, × = No, ✓ = Optional

Implementing new inverter standards will take time to address issues as older inverters fail or are replaced. It is also critical that new standards are enforced, or they will not have the expected impact.

The cost of implementing new standards includes the time and effort of agreeing them by industry stakeholders and implementing the new standards in devices. However, product development is a normal cost of doing business, and therefore not viewed as a significant incremental cost.

Remote Inverter Configuration

This standard would enable networks to remotely access smart inverters with internet connections and adjust their configuration to suit network conditions. Key settings that could be adjusted to manage power quality, reliability and network safety events include:

- Automatic disconnection of the inverter from the grid;
- Changing the power factor of the inverter;
- Limiting the ramp rate of the inverter; and/or
- Limiting the output of the inverter.

This added functionality would allow networks to effectively address location specific network issues. However, it brings with it a host of privacy and security challenges. Energeia research has identified this standard being implemented overseas in California[81] and Germany[82]; no Australian implementation examples were found.

Implementation cost of this solution will largely be driven by the back-office systems needed by DNSPs to manage device configuration management, which is not expected to be significant once off the shelf solutions are available. There will also be integration costs, but these are not expected to be material when completed as part of business as usual product development.

Static Connection Limitations

Static connection limitations are where distribution network limit the capacity of newly connected customer exports to ration available hosting capacity based on the worst-case scenario. In some instances, customers are not able to export any excess generation to the grid in regions of high DER penetration. In theory, if all additional exporting capabilities were removed, all network issues (power quality, reliability, safety, system security and efficiency) solely caused by excess generation exported to the grid would not reoccur with new DER installations.

[81] PGE (2018), 'EPIC Interim Report', https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.03a.pdf

[82] Bayer et al. (2018) 'The German experience with integrating photovoltaic systems into the low-voltage grids'; https://www.sciencedirect.com/science/article/pii/S0960148117311461

Although it may relieve the need to spend network expenditure to resolve additional network issues and improve hosting capacity for new DER installations, customers are no longer able to access feed-in tariffs or participate in demand response or VPP schemes and unlock the full suite of market benefits available for DER customers.

As mentioned in Section 1.2.1, most DNSPs are using this method currently, however, some are discussing reducing static limits in light of increasing voltage issues on their network.

Static connection limits are relatively inexpensive to implement, requiring mainly process changes, however, they increase the 'hidden' opportunity cost to prosumers of foregoing larger solar PV installations. In addition to this opportunity cost for consumers, limiting DER system sizes through static limits also reduces the potential emissions reduction and wholesale market price reduction benefits to all consumers.

Dynamic Export Limitations

Dynamic limitation setting involves applying limits to customer exports on a locational and/or time-varying basis reflecting network constraints. Under this approach, customers will not be limited in the capacity of their solar PV connection, but will be limited in their ability to export excess generation at certain times and at certain locations. This approach thereby addresses prosumer connection limitation and curtailment issues, and network voltage limit issues, and potentially other DNSP issues including UFLS, etc.

No Australian or overseas example has been identified of dynamic export limitation being implemented in practice, however, a number of Australian DNSPs are actively considering implementing it (i.e. via pilots like the Dynamic Limits DER Feasibility Study in NSW and South Australia[83]) and some, including SA Power Network, have included proposals in their latest AER submission.[84]

In contrast to static connection limitations, dynamic limitations are significantly more complex and costly to implement. Networks require greater visibility of network performance and DER on their LV network to identify regions and periods of constraint and the impact of applying a dynamic limitation framework before implementing dynamic limitations to customers. SA Power Networks assessed the cost of implementation in their 2019 LV Management Business Case report[84] as shown in Table 12.

Table 12 – SA Power Networks Cost Breakdown of Recommended Option

Work Package	2020-21 to 2024-25 Capex ($ '000)
LV Monitoring	$11,990
Build LV Hosting Capacity Model	$7,760
DER Database	$3,620
Dynamic Export Limit Calculation	$5,460
Transition and Program Management	$4,460
Total	$33,300

Source: SA Power Networks; Note: All costs are $2017 and include overhead costs.

3.4.4. Reconfiguration

Energeia research has identified a category of solutions that involve reconfiguring the existing network, assets, customer connections or secondary system settings to resolve network power quality, reliability, safety, system security and efficiency issues.

The main solutions within this category include:

[83] ARENA (2019), *'Dynamic Limits DER Feasibility Study'*: https://arena.gov.au/projects/dynamic-limits-der-feasibility-study/ (Accessed 8/11/2019)

[84] SA Power Networks (2019), 'LV Management Business Case: 2020-2025 Regulatory Proposal', https://www.aer.gov.au/system/files/Attachment%205%20Part%207%20-%20Future%20Network.zip

- **Manual Tap Changers** – Changing the transformer tap voltages to keep the voltage profiles within limits
- **Topology Changes** – Changing the LV and/or MV network topology to manage voltage, protection and/or UFLS issues
- **Change UFLS** – Changes to relay settings and/or UFLS schemes to maintain required load shedding and to avoid dropping circuits with reverse flow
- **Protection Changes** – Changes to protection settings and schemes to resolve protection related issues
- **Phase Balancing** – Changes in the allocation of single-phase connections to the three-phase system to resolve phase imbalance issues

These potential solutions are detailed further in the following sections.

Changing Transformer Tap Settings

This solution involves reconfiguring tap changers installed on transformers to change the voltage profile, bringing it back into tolerance.

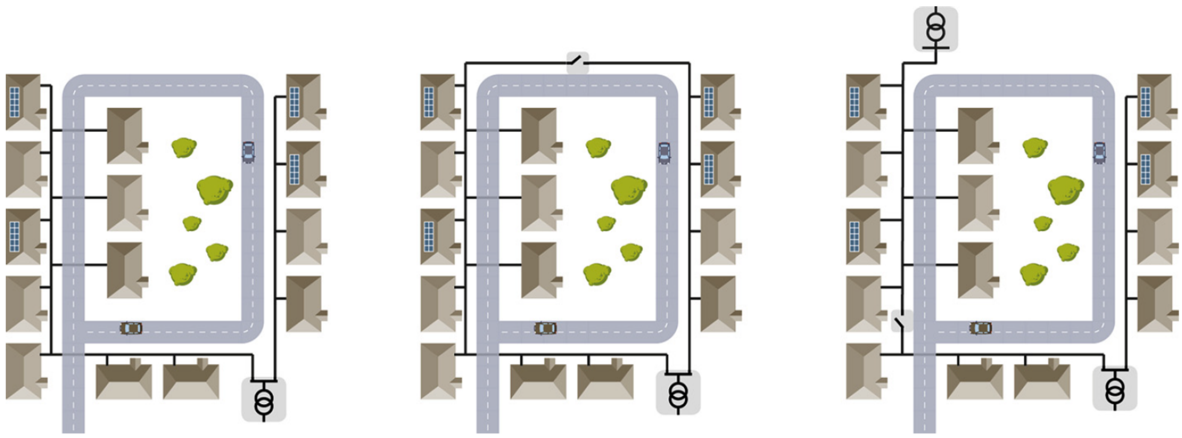
Changing tap settings is a very common solution to regulate voltage variations in the network. Offline taps typically operate over a limited band of voltage regulation, limiting their ability to effectively regulate wide or dynamic voltage profiles, which can be more common as DER penetration rises. Changing offline tap settings also requires an outage, which inconveniences customers.

The cost of implementing changes to offline taps includes notifying customers of the outage, sending out the team to reconfigure the tap settings, and any impacts to the customer. Taps may need to be changed multiple times depending on how frequently the load profile changes.

Changing Network Topology

And HV LV network topologies can be changed to manage network power quality, UFLS and protection issues. Examples of network topology changes include modifying a section of the network from a radial grid, as shown on the left in Figure 23, to one either a ring grid or adding a second local distribution transformer.

Figure 23 – Schematic of Radial Grid (left), Ring Grid (middle) and Second Local Dist. Transformer (right)



Source: Bayer et al. (2018) 'The German experience with integrating photovoltaic systems into the low-voltage grids'

The configuration changes shown above include both:

- **Ring grids** (as shown in the middle in Figure 23) – When closed, the ring grid can reduce grid resistance and therefore reduce voltage drops in the grid
- **Second local distribution transformer** (as shown on the right in Figure 23) – Can alleviate reverse flow as a portion of the exported generation is transferred to the second local distribution transformer

Energeia research has identified overseas networks using topology changes as a solution, and there are anecdotal reports of using this approach in Australia as well. However, it is not likely to be that common as it represents a significant cost and effort. The key costs involved in this solution include the engineering time, customer outage notification (where needed), and field operator time to implement the new topology, and any additional assets.

Changing UFLS Settings

Changing UFLS settings involve reconfiguring the set of relays in the field used to shed load during an UFLS event in order to deliver the required level of load reduction.

As there are only a few networks such as Hawaii, South Australia and Queensland with a high enough penetration of solar PV to potentially require a change in UFLS settings, Energeia was unable to identify examples of UFLS schemes being reconfigured.

One issue with changing the UFLS settings is that they may have to be adjusted multiple times, similarly to phase rebalancing. As mentioned in Section 3.4.3, Hawaii is investigating the use of the Frequency-Watt inverter standard to provide UFLS-like compensation for under-frequency events.

The cost associated with changing UFLS settings include the engineering resources required to design the solution and the field crew resources required to implement it. It may be required multiple times, and it may not be possible to use the current UFLS approach under high levels of DER penetration.

The cost associated with changing UFLS settings include the engineering resources required to design the solution and the field crew resources required to implement it. It may be required multiple times, and it may not be possible to use the current UFLS approach under high levels of DER penetration.

As the UFLS system is periodically maintained by DNSPs in response to changes in load patterns, changes to accommodate additional solar PV installations may not be significantly incremental. However, there are limits to the level of solar PV capacity that can be accommodated by changes to the existing protection method.

Changing Protection Settings

Distribution network protection schemes operate to keep assets and people safe in the event of a fault. This is mainly achieved using a combination of relays and circuit breakers in MV networks, and fuses in LV networks.

Changing the protection scheme involves replacing relays or changing their operational settings, to cater for changes in the distribution of load, injections, and fault levels.

Analysis by the US Department of Energy's NREL found that rising solar PV penetration could drive protection maloperation, and called for reengineering the protection scheme to accommodate the change in conditions.[85] However, as reported in Section 0, Energeia has not identified any Australian networks reconfiguring their protection schemes at this stage, other than AusNet, due to THD issues.

As for the UFLS solution, the cost associated with changing protection settings include the engineering resources required to design the solution and the field crew resources required to implement it. It may be required multiple times, and it may not be possible to use the current protection approach under high levels of DER penetration.

As protection systems are periodically maintained by DNSPs in response to changes in load patterns and scheme performance during faults, changes to accommodate additional solar PV installations may not be significantly incremental. However, there are limits to the level of solar PV capacity that can be accommodated by changes to the existing protection method.

[85] SunShot, U.S. Department of Energy, NREL (2016) *'High-Penetration PV Integration Handbook for Distribution Engineers'*: https://www.nrel.gov/docs/fy16osti/63114.pdf, pg. 13

Phase Rebalancing

Phase balancing involves the reallocation of customers on single-phase connections to a three-phase connection to maintain balance within standard limits and releases capacity headroom and losses on feeders in the network.

A 2015 UK study[86] found that rural overhead feeders have the most potential for phase rebalancing as it is easier to visually determine and adjust the customer's phase connection compared to underground feeders. Even so, the study found it was cost-effective to rebalance the phases of customers on only a few feeders[87], suggesting that phase balancing is only an effective solution for specific regions of the network.

The costs associated with phase rebalancing are mainly related to the field crew resources required to rebalance the system. Phase rebalancing may be required multiple times, as differences between connections evolves with changes in solar PV, BTM storage and EVs adoption.

Phase rebalancing is a common LV network maintenance activity, and it will be important to ensure that any costs allocate to DER are demonstrably incremental to business as usual.

3.4.5. New Methods

Energeia's research identified new forecasting methods and third party data sources as two new methods being used to address emerging issues at lower cost than the traditional methods.

New Forecasting Methods

The impact of changes in DER adoption and major end uses on forecasting accuracy is described in Section 3.2.2. This solution includes new forecasting methods such as machine learning, artificial intelligence and agent-based simulation, among others.

By improving forecasting techniques, networks can more accurately anticipate the adoption and operation of DER devices and use this information to more accurately estimate the expected impact on the network. With more accurate forecasts in hand, more efficient and prudent investment decisions can be made.

The costs of implementing new forecasting techniques are mainly related to changes in business processes and investments in new software and training. Costs for new forecasting systems can vary from under a million to over a million, depending on the software.

Improved forecasting methods adopted to address a DER driven issue could also provide additional benefits including more accurate load forecasts and/or improved unregulated business strategy, for example.

Third Party Data

This solution involves using third party provided data from smart meters, inverters and other electronic devices to provide network monitoring services instead of investment in network monitoring and control systems.

Third party data, such as the data provided by smart meters, will become increasingly available to networks and consumers over the next 5 to 10 years. Energeia's research has identified at least one DNSP that is actively looking at using smart meter and other third party data to inform their dynamic connection limit engine.

The cost of this solution depends on whether the devices are already installed, or need to be installed, with the later costs being much higher due to the need to visit and install the device, plus the cost of the device.

Once third-party data streams are in place, they could, depending on their frequency, latency, measurement unit and other key parameters, provide additional network services.

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[86] SP Energy Networks (2015) 'HV and LV Phase Imbalance Assessment', found here: https://www.spenergynetworks.co.uk/userfiles/file/HVandLVPhaseImbalanceAssessment16.pdf

[87] Ibid. The study found that phase rebalancing was only cost effective for 9% of LV feeders monitored compared to other network planning options.

3.4.6. Adoption of New Assets

Networks can install a wide range of new assets as the solution to remediating network issues that may arise due to increasing DER penetration, including:

- **LV Monitors** – Installation monitoring devices to monitor the LV network
- **Voltage Regulators** – Installation of line-drop voltage regulators to manage voltage fluctuations and keep them within standard operating bounds
- **Larger Assets** – Installation of new transformers or conductors, mainly to relieve thermal overloads, voltage issues
- **On Load Tap Changer (OLTC)** – Installation of OLTC devices on transformers for dynamic voltage regulation
- **Harmonic Filters** – Shunting and blocking harmonic currents to improve network power quality
- **Static Compensators (STATCOMs)** – Installing STATCOM devices for dynamic voltage regulation
- **Network Storage** – Installing battery storage systems for voltage regulation and remediation of thermal overloads

Each of these are described in more detail in the sections below.

LV Monitors

LV monitoring involves installing monitoring equipment on the LV network to provide a stream of network performance data, including real and reactive power, THD and wave form capture, among other types of data.

Installing monitoring systems to monitor the LV network can be used to proactively identify and address voltage issues, inform and drive dynamic export limit schemes, and inform and drive voltage management schemes.

Various DNSPs have identified additional monitoring as part of their regulatory proposals. For example, SA Power Networks[88] has proposed the use of LV monitoring through smart meters to develop a LV hosting capacity model and facilitate dynamic export limitations. Implementing the monitoring process would cost the network approximately $12 million ($2017) over a five-year period. Additionally, Evoenergy[89] have proposed installing 200 power quality monitors each year, equivalent to $700,000 in network capex over a five-year period, to identify LV issues.

LV monitoring can also be used for a range of business as usual engineering applications, including improving reliability, and reducing capex and opex.

Voltage Regulators

Transformers or line-drop voltage regulators on distribution poles are a commonly implemented solution to LV network voltage excursions.

United[90] spent $579,000 between 2011 and 2015 on LV regulators, with an additional $2.6 million of forecasted expenditure to be spent over the 2016-2020 period. Voltage regulators can require replacing every 7-10 years, which further increases the lifetime capital cost of this solution.

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[88] SA Power Networks (2019), 'LV Management Business Case: 2020-2025 Regulatory Proposal', https://www.aer.gov.au/system/files/Attachment%205%20Part%207%20-%20Future%20Network.zip

[89] Evoenergy (2018), *'Distribution Substation Monitoring and Supply Voltage Optimisation Program PJR'*: https://www.aer.gov.au/system/files/Evoenergy%20-%20Revised%20Proposal%20-%20Appendix%204.14%20-%20Distribution%20Substation%20monitoring%20PJR%20-%20November%202018.pdf

[90] United (2015), *'Expenditure Justification – Power Quality Maintained'*: https://www.aer.gov.au/system/files/United%20Energy%20-%20RRP%205-9%20-%20Power%20Quality%20Maintained%20CEES%20-%20Jan%202016.pdf

Voltage regulators can be used to address DER driven voltage issues, but they are also widely used for traditional voltage regulation as well. An example of a voltage regulator is shown in Figure 24.

Figure 24 – Example of an Overhead Voltage Regulator

Source: Eaton

Larger Assets

Traditionally, networks install larger assets, typically transformers or conductors, to remediate network issues, such as over-voltage or thermal overload, especially when continued growth was expected.

As reported in Section 0, most Australian and overseas DNSPs are using larger assets as a key solution to DNSP and prosumer issues arising from high penetration of DER.

Larger assets can also provide additional services beyond those needed to address any issue arising from rising DER penetration.

On Load Tap Changer (OLTC)

OLTCs are a special type of transformer-based voltage regulators that can provide real-time response to changing network conditions. Changes in tap settings occur automatically and without the need for taking the transformer offline, unlike off load tap changers.

OLTCs are traditionally used in special circumstances in MV networks, where the voltage profile is especially dynamic. Using them in the LV network is relatively new, and they are a relatively expensive additional cost. They also have a much shorter lifetime offline tap changers, and a higher maintenance cost.

Evoenergy's analysis[89] found that it was too expensive to deploy OLTCs to distribution transformers in the entire network, as opposed to those currently installed at the zone substation level. Additionally, a comparison of the costs of a voltage regulator and a OLTC by Eaton (2017)[91] is shown in Table 13, with an OLTC costing nearly twice as much as a voltage regulator over a 30-year period.

[91] Eaton (2017) '*Voltage Regulators vs. Load Tap Changers*': https://www.eaton.com/content/dam/eaton/products/medium-voltage-power-distribution-control-systems/voltage-regulators/voltage-regulators-vs-load-tap-changers-information-td225012en.pdf

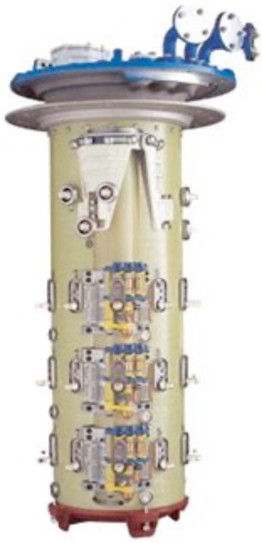
Table 13 – Comparison of Voltage Regulator Life Cycle Costs

	Regulator	Other Equipment	Initial Cost	Maintenance	30-year Cost
Voltage Regulator	$95,000	$2,500	$97,500	$10,000	$147,500
OLTC	$120,000	$0	$120,000	$35,000	$295,000

Source: Eaton (2017) 'Voltage Regulators vs. Load Tap Changers'; Note: Other equipment includes additional busywork and bypass switches, Maintenance costs are applied every five years, and thus would have five charges over the 30-year period.

As is the case with voltage regulators, OLTCs can be used to address DER driven voltage issues, but they are also widely used for business as usual voltage regulation as well. An example of an OLTC solution is shown in Figure 25.

Figure 25 – Example of an On Load Tap Changer



Source: Germes Online

Harmonic Filters

Harmonic filters are series or parallel resonant circuits designed to shunt or block harmonic currents, in other words, they provide a solution to THD related issues.

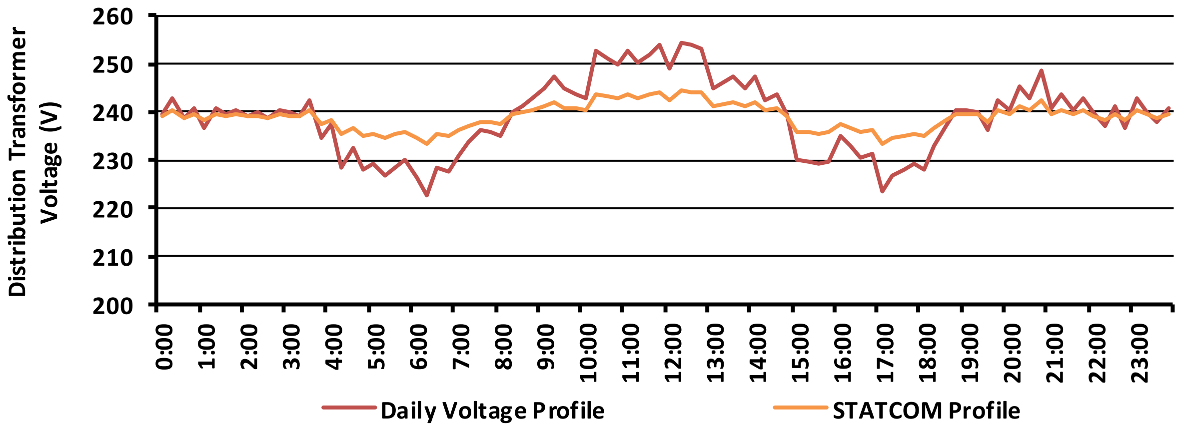
Other than AusNet, which is reporting solar PV inverters are driving increases in THD, Energeia's research has not identified this as a commonly implemented solution.

THD issues are relatively localised, and where they are needed, it is likely due to the behaviour of local devices on the network, which can include devices other than solar PV and other DER inverters.

Static Compensators

STATCOMs are an additional form of voltage regulators used to provide more dynamic voltage control than OLTC, as shown in Figure 26. The dynamic functionality of STATCOMs provides a highly flexible solution, the effectiveness of which may be limited in regions of the network with high impedance.

Figure 26 – Static Compensator (STATCOM) Voltage regulation capabilities



Source: Ecojoule Energy[92]

Ausgrid's latest Regulatory Proposal[93] stated the intention of piloting the use of advanced voltage control technology, including STATCOMs, within the LV and HV regions of the network. Total indicative capital expenditure over FY20-24 is forecast to be $3 million. Endeavour has undertaken a trial with Australian company Ecojoule Energy where they will trial the EcoVAR LV STATCOM to help Endeavour manage the voltage on LV Networks. The project initiated earlier this year will install 20 EcoVAR units on power poles throughout their network in the Illawarra and Western Sydney region.

STATCOMs can be used to address highly dynamic DER driven voltage issues, but they can also be used to address dynamic voltage conditions driven by variable speed drivers and other types of loads.

Network Storage

Network battery storage systems are similar to the consumer-side solution; however, they are installed on network assets and/or in network right of ways. They are also owned and operated by DNSPs.

Ausgrid recently trialled[94] a small number of grid battery pilots to assess the viability of network use cases including the deferral of network augmentation through peak shaving, improving power quality and reliability outcomes, particularly in locations with high PV penetration, and provision of other network support services.

In addition to addressing issues that can be caused by DER, network batteries can be used to provide a wide range of traditional network services. Non-network utility scale batteries can also provide similar network support services.

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[92] Ecojoule (2019), '*EcoVAR STATCOM*': https://ecojoule.com/wp-content/uploads/2019/06/EcoVAR_flyer-v3.pdf

[93] Ausgrid (2019) '*Revised Proposal, Justification for Operational Technology & Innovation Programs*': https://www.aer.gov.au/system/files/Ausgrid%20-%20Revised%20Proposal%20-%20Attachment%205.13.L%20-%20Justification%20for%20Operational%20Technology%20and%20Innovation%20Programs%20-%20%20January%202019.pdf

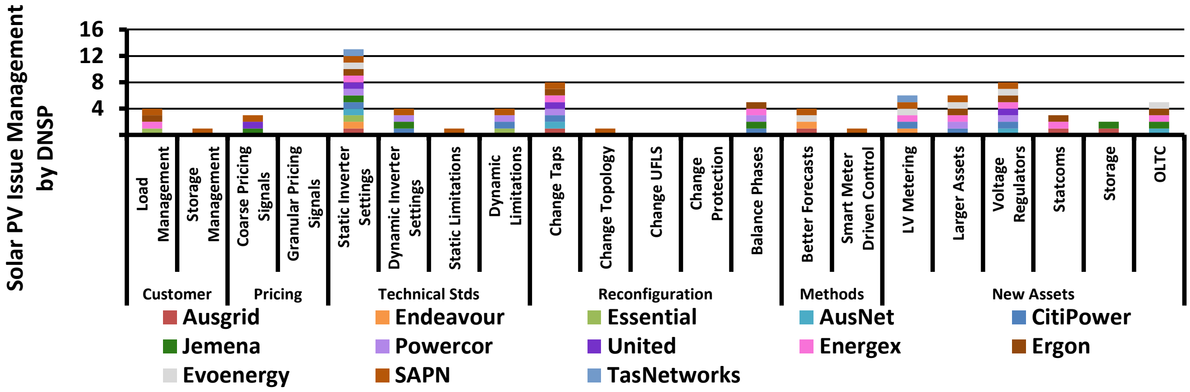
[94] Ausgrid (2019), '*Justification for Operational Technology & Innovation Programs*':https://www.aer.gov.au/system/files/Ausgrid%20-%20Revised%20Proposal%20-%20Attachment%205.13.L%20-%20Justification%20for%20Operational%20Technology%20and%20Innovation%20Programs%20-%20%20January%202019.pdf

3.5. Prevalence of Solutions

Energeia's research identified the prevalence of the identified solutions across Australian networks and how they varied relative to international benchmarks, as shown in Figure 27 and Figure 28.

The most commonly cited solution in Australia is static inverter settings, with all networks implementing this in some form of a standard. The next most commonly cited solutions are voltage regulators and changing taps.

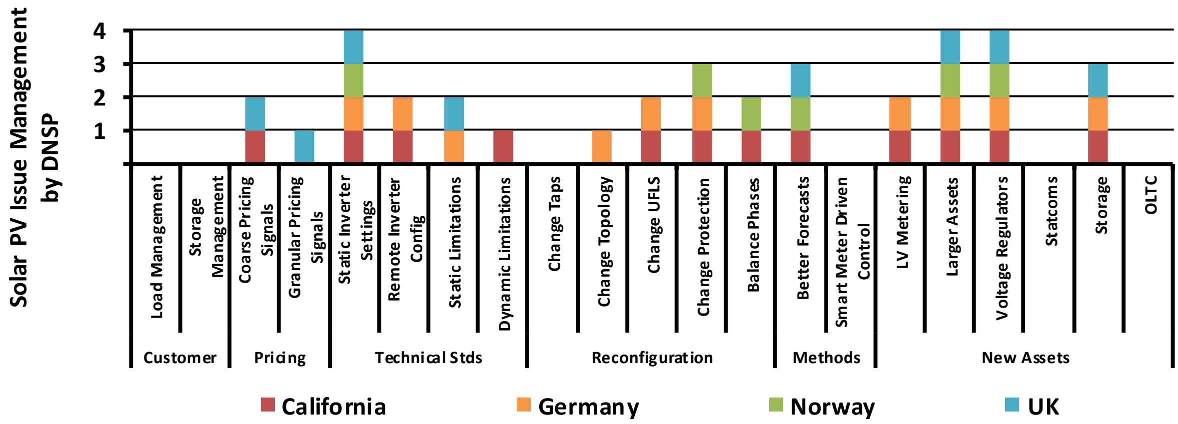
Figure 27 – Identified Solutions Incidence Reported by DNSP (Australia)



Source: Energeia

Overseas jurisdictions, such as Germany, the UK, Norway and California have similar prevalence of solutions, with an increased focus on installing new (larger) assets[95].

Figure 28 – Identified Solutions Incidence Reported by Overseas Benchmark Jurisdictions



Source: Energeia

[95] It should be noted that the NER (cl6.14) currently prohibits charges for the export of energy. Network pricing reform, by appropriately pricing the value of energy imported and exported, could potentially deliver these outcomes at lower costs, but tariff reform approaches were out of scope for this report.

3.6. Mapping Solutions to Issues

Each solution has the potential to remediate multiple network issues. Energeia has mapped the identified solutions to the relevant DER export issues, as summarised in

Table 14 and shown in detail in Table 15.

Table 14 – Summary Mapping of Remediation Options to DER Issues

Issue Stakeholder	Key Issue	Potential Solutions					
		Customers	Pricing Signals	Technical Standards	Re-configuration	New Methods	New Assets
Prosumer	Investment	✓	✓	✓*	✓*	✓*	✓*
Distribution Network Service Providers	Power Quality	✓	✓	✓*	✓*	✓*	✓*
	Reliability	✓	✓	✓*	✓*	✗	✓*
	Safety	✗	✗	✓*	✓*	✗	✓*
	System Security	✓*	✗	✓*	✓*	✓*	✓*
	Cost / Efficiency	✓	✓	✓*	✓*	✓*	✓*
Gen, Tx and Mkt Ops	Various	✓*	✓*	✓*	✓*	✓*	✓*

Source: Energeia; Note: Gen = Generation; Tx = Transmission; Mkt Ops = Market Operations; ✓ = Full Match (i.e. all of the potential solutions match all of the identified issues in these categories); ✓* = Partial Match (i.e. some potential solutions match some of the identified issues in these categories); ✗ = No Matches (i.e. none of the potential solutions match any of the identified issues).

Table 15 – Map of Remediation Options to DER Export Issues

Stakeholder	Category	Issue	Customers		Pricing Signals		Technical Standards				Reconfiguration					Methods		New Assets						
			Load	Storage	Coarse	Granular	Inverter Standards	Remote Inverter	Static Limits	Dynamic Limits	Change Taps	Change Topology	Change UFLS	Change Protection	Balance Phases	3rd Party Voltage	Improved Forecasts	LV Metering	Voltage Regulators	Voltage OLTC	Larger Assets	Harmonic Filters	STATCOMs	Network Storage
Prosumer	Investment	Connection Limits	✓	✓	✓	✓	✓	✓	✓	✓	✓					✓			✓	✓	✓		✓	✓
		Export Limits	✓	✓	✓	✓	✓	✓	✓	✓	✓					✓			✓	✓	✓		✓	✓
		Curtailment	✓	✓	✓	✓	✓	✓		✓	✓					✓			✓	✓	✓		✓	✓
		Losses / Lifetime	✓	✓	✓	✓	✓	✓		✓														
		Reduced Capacity	✓	✓	✓	✓	✓	✓		✓														
		Reduced Lifetime	✓	✓	✓	✓	✓	✓		✓														
Distribution Network	Power Quality	Over-Voltage Limit	✓	✓	✓	✓	✓	✓	✓	✓	✓					✓			✓	✓	✓		✓	✓
		Under-Voltage Limit	✓	✓	✓	✓	✓	✓	✓			✓				✓			✓	✓	✓		✓	✓
		Flicker Limit	✓	✓	✓	✓	✓	✓	✓							✓							✓	✓
		Harmonics (THD)							✓													✓		
	Reliability	Thermal Limit	✓	✓	✓	✓		✓	✓	✓											✓		✓	✓
	Safety	Protection Maloperation						✓	✓			✓		✓										
		Islanding						✓	✓			✓		✓										
	System Security	Disturbance Ride-through						✓	✓															
		Under Frequency LS	✓	✓				✓	✓				✓				✓	✓			✓			✓
	Cost / Efficiency	Phase Imbalance	✓	✓	✓	✓		✓	✓			✓	✓		✓								✓	✓
		Forecasting Error	✓	✓	✓	✓			✓								✓				✓		✓	✓
Gen, Transmission and Mkt Ops	Gen	Ramp Rate							✓							✓	✓	✓			✓		✓	✓
	Reliability	Thermal Constraints	✓	✓	✓	✓		✓	✓	✓														
	Tx	Fault Levels						✓					✓											
	Mkt Ops	Forecasting Error	✓	✓	✓	✓		✓	✓	✓											✓		✓	✓
		Generation Curtailment	✓	✓	✓	✓		✓	✓	✓											✓		✓	✓

Source: Energeia; Definitions: THD = Total Harmonic Distortion; UFLS = Under Frequency Load Shedding; OLTC = On Load Tap Changer; Gen = Generation; Tx = Transmission; Mkt Ops = Market Operations;
Notes: Grey indicates obsolete issue with current inverter technology and standards

3.7. Key Solution Costs

Energeia used desktop research, consultation with the Steering Committee and our industry network to develop indicative cost estimates for each of the key solutions, broken down into capex and opex components as shown in Table 16[96]. These costs were taken forward into the cost-benefit and optimisation analysis.

Table 16 – Key Solution Cost Estimates by Category

Category	Solution		Capex	Opex	Units
Consumer	Water Heater Management – Retrofit Control		$150	$15	kW
	EV Management – Retrofit Control		$150	$15	kW
	Storage Management – Install New Controllable		$1k	$15	kW
Pricing	Coarse (e.g. ToU pricing), excl. smart meter		Negligible	$0	Customer
Signals	Granular (e.g. real-time pricing), excl. smart meter		$12m	$250k	DNSP
Technical Standards	Inverter Standards		Negligible	$0	DNSP
	Remote Inverter Configuration		Negligible	$0	Country
	Static Limitations		Negligible	$0	DSNP
	Dynamic Limitations		$6m	$250k	DNSP
Reconfiguration	Change Taps		Negligible	$1-2k	Trip
	Change Topology		$200k-$660k	$0	Feeder
	Change UFLS		$100k-$150k	$0	Feeder
	Change Protection		$1k	$0	Feeder
	Balance Phases		Negligible	$1.5-$2k	Trip
New Methods	Third Party Data	New Install	$500	$5	Customer
		Previous Install	Negligible	$5	Customer
	Better Long – Term Forecasts		$8m	$250k	DSNP
New Assets	LV Metering		$3.5k	$30	Transformer
	Voltage Regulators		$k	2.5% of capex	Regulator
	Larger Assets		$100k-$400k	2.5% of capex	Asset
	On Load Tap Changer	Vault	$120k	$7k	Transformer
		Pole-Mounted	$60k	$7k	Transformer
	Harmonic Filters		$500k	$0	Substation
	Statcom (Single-Phase)		$5-8k	2.5% of capex	LV Phase
	Network Storage		$1.2k	2.5% of capex	kWh

Source: Energeia; Notes: 1. Changes deemed to be part of existing operations excluded, e.g. introduction of new price structures. 2. In-depth consultation with DNSPs would be required on to better understand costs on a jurisdictional basis. 3. Solutions are not mutually exclusive; the application of certain solutions may be limited by the absence of others i.e. electric water heaters must be in place to control their load.

[96] Energeia recognises that solution costs can vary widely according to numerous factors including network density and topography. These costs are intended to be estimates, and do not necessarily reflect the views of all Steering Committee members. More detail on the development of these costs is included in Appendix D – Detailed Solution Cost Breakdowns.

4. Stage 2 – Optimised DER Integration Costs

Energeia developed a high level, best practice DER-integration optimisation framework for this report based on our research of best practice approaches to DER integration solution optimisation, and our experience modelling the costs and benefits of DER across consumers, prosumers, DNSPs and the wholesale market.

Energeia's solution optimisation approach modelled the costs and benefits of various solutions, for a given category of LV network, to identify the set of solutions that is expected to deliver the highest net benefits. The modelling approach ultimately focused on optimising the costs for addressing over-voltage issues due to over-generation, mainly by rooftop solar PV systems. Over-voltage was chosen as the area of focus given the level of reported incidence of this issue by DNSPs with relatively high levels of rooftop solar PV penetration.[97]

The following sections first describe our modelling approach and then report on the key modelling results for the Expected scenario. Results for the Centralised and Decentralised scenarios are provided in Appendix F – Optimisation Results by Scenario.

4.1. Optimisation Modelling Approach

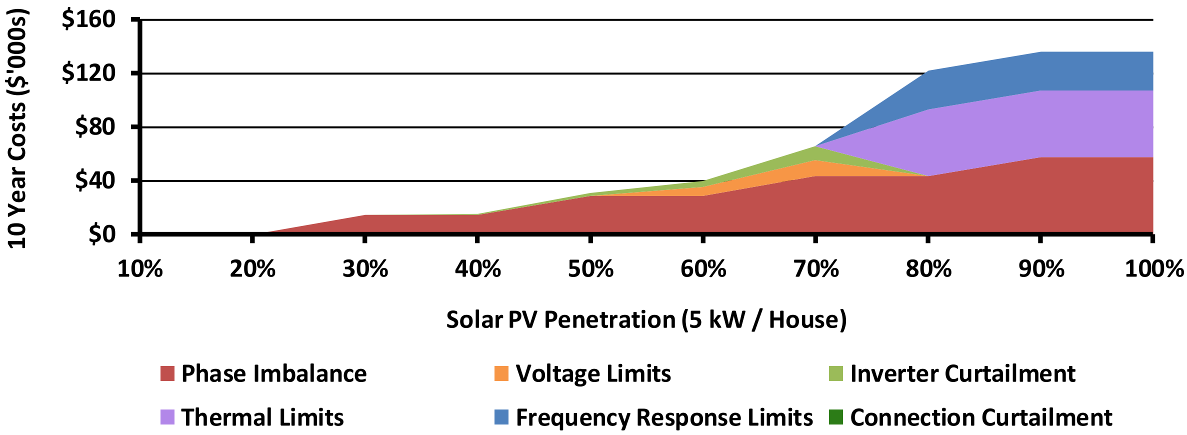
The following sections describe our approach to modelling DER integration costs and their optimisation, including the key inputs to the modelling such as network segment assumptions, network classification, hosting capacity estimates, solutions costs, and scenario assumptions and.

4.1.1. Overview of Approach

Energeia's LV network constraint solution optimisation approach models the costs and benefits of various solutions for a given category of LV network to identify the set of solutions that is expected to deliver the highest net benefits.

An illustration of the estimated cost of the current industry integration solution for a given LV network type (urban overhead, 200 kVA transformer) under a given scenario (moderate DER growth) is shown in the Figure 29. This example identifies the estimated costs across identified issue categories, by solar PV penetration level.

Figure 29 – Illustration of LV Network Integration Solution Costs by Inverter Penetration Level



Source: Energeia; Note: All costs are shown as cumulative costs over time to address each issue, e.g. 'Voltage Limits' means 'solutions to address voltage limits' and what is shown is the cumulative cost of addressing that issue.

In the example in Figure 29, at 20-40% PV penetration, only phase balancing is required, but as more PV generation is added, more issues arise and more solutions are required, such that at 70%, voltage limits and inverter curtailment are also required.

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[97] Following our review of available industry data. Energeia was unable to implement our full DER-integration cost analysis due to a lack of sufficient data on: peak demand or utilisation by LV transformer; hosting capacity functions for phase imbalance, under-voltage and under-frequency load shedding, and; solution costs for under-frequency load shedding

Following our review of available industry data, including Regulatory Information Notices (RINSs), AER proposals and feedback from stakeholders, Energeia was unable to implement our full DER-integration cost analysis due to a lack of sufficient data on:

- Peak demand or utilisation by LV transformer
- Hosting capacity functions for phase imbalance, under-voltage and under-frequency load shedding
- Solution costs for under-frequency load shedding

The modelling approach was therefore revised to focus on optimising the costs for addressing the most significant DER-associated network constraint as reported by DNSPs, i.e. over-voltage issues due to over-generation, mainly by rooftop solar PV systems.

4.1.2. Key LV Network Segments

Energeia redesigned our LV classification approach to reflect the data available in the AER's Regulatory Information Notices (RINs) segments.

Our revised approach integrates the available data from the AER RINs and they broadly reflect the different network topologies and cost structures. The chosen approach segments all LV networks into 50 kW, 250 kW and 1,000 kW, representing roughly mid-way points between the AER RIN categories. The segments are also reflective of different customer densities and reliability types (i.e. Urban, Suburban and Rural).

Table 17 – Key LV Network Segments

Name	No. of Transformers	Reliability Type	RIN Categorisation	Construction
50 kVA	350,653	Rural	< 60 kW	Overhead
250 kVA	230,988	Suburban	60 -1,000 kW	Underground
1,000 kVA	34,024	Urban	> 1,000 kW	Underground

Source: Energeia Analysis

One of the benefits of this approach is that each of these LV network categories can be weighted for a given network area or DNSP.

4.1.3. Key LV Network Characteristics

The key difference between the LV network segments is the assumed asset sizing per residential customer. The smaller LV systems, which are more likely to be in rural areas, assumed a higher after diversity maximum demand (ADMD), compared to the likely to be more densely populated 250 kW and 1,000 kW LV networks.

The number of customers on each LV network was calculated by dividing the total transformer capacity by the ADMD, given the assumed level of headroom. This resulted in relatively more customers being on the 1,000 kW LV network than the 250 kW LV network because of the larger transformer, but also the lower ADMD assumed.

Table 18 provides the key assumptions Energeia used when modelling each LV network type.

Importantly, each archetypical network segment is assumed to have off-line taps available for reconfiguration. It is also assumed to not have an online tap changer or voltage regulator installed initially. Key assumptions regarding the level of smart meters, solar PV, electric vehicles and water heating systems are based on reported Australian averages in 2019.

Table 18 – Example of Key LV Network Assumptions

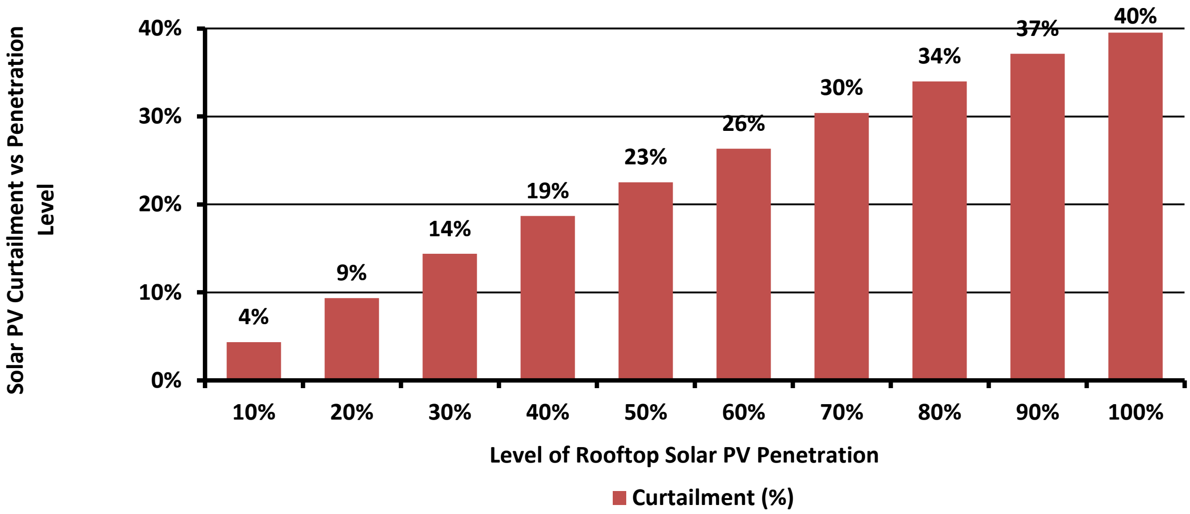
Assumption Type	50 kW Tx	250 kW Tx	1,000 kW Tx	Notes
Off-line Taps	1	1	1	-
Online Taps	0	0	0	-
Line Voltage Regulators	0	0	0	-
Load Headroom	0%	0%	0%	Assumes sized for after diversity max demand
kWh/Res Customer	7,500	7,500	7,500	Defines PV MWhs per annum
After Diversity Max Demand	7	6	5	Lower in higher density areas
Electric Water Heating	80%	80%	80%	Limited level of water heating VPP solutions
PV Capacity Factor	19%	19%	19%	-

Source: Energeia

4.1.4. LV Hosting Capacity

Energeia modelled hosting capacity for a given level of solar PV generation based on the results of our research, which found curves published by Ausgrid[98] and by the University of Melbourne[99]. We have used the University of Melbourne curve for this study (as shown in Figure 30 below), but note it results in a lower level of hosting capacity than the Ausgrid results, which are based on the *Smart Grid, Smart City* trial.

Figure 30 – Rooftop PV Curtailment as a Function of Rooftop PV Adoption



Source: Energeia

Energeia acknowledges this is a very high level modelling approach of hosting capacity as a function of solar PV adoption to adopt, but believes the methodology is sound. Furthermore, the relationship itself is based on detailed load flow modelling, as part of an ARENA funded project with AusNet.[100] In addition to the simplified modelling assumption above, Energeia applied the same function to all LV systems.

[98] Archived version of the following source: Department of Industry, Innovation and Science (2016) 'Smart Grid, Smart City', https://webarchive.nla.gov.au/awa/20160615043539/http://www.industry.gov.au/Energy/Programmes/SmartGridSmartCity/Pages/default.aspx

[99] L. Ochoa, A. Procopiou, University of Melbourne (2019), 'Increasing PV Hosting Capacity: Smart Inverters and Storage': https://resourcecenter.ieee-pes.org/education/webinars/PESVIDWEBGPS0010.html

[100] L. Ochoa, A. Procopiou, University of Melbourne (2019), 'Increasing PV Hosting Capacity: Smart Inverters and Storage': https://resourcecenter.ieee-pes.org/education/webinars/PESVIDWEBGPS0010.html

In reality, different LV systems will have different curves, as demonstrated by pioneering work completed by SA Power Networks as part of their LV Strategy[101]. Energeia is hoping to refine our modelling approach here by factoring better information as it becomes available from other DNSPs.

4.1.5. LV Solution Costs

Energeia developed unitised ($ per solar PV kW) marginal cost estimates based on a given solution cost, normalised by its impact on solar PV hosting capacity in kW terms. In the case of curtailment solutions, including No New PV, or Volt-VAR (inverter standards), Energeia estimated the incremental level of curtailment involved, and priced that at the forecast National Electricity Market (NEM) average regional reference price (RRP)[102].

Energeia's input costs for over-voltage solutions were set out in Section 3.7 and are repeated below as Table 19 for ease of reference. Please note that solutions for other DER integration issues have been removed from the original table.

Energeia's assumptions for how these prices are forecast into the future are driven by the given scenario.

Table 19 – Key Over-Voltage Solution Cost Estimates by Category

Category	Solution		Capex	Opex	Units
Consumer	Water Heater Management – Retrofit Control		$150	$15	kW
	Level 2 Charger Management – Retrofit Control		$150	$15	kW
	Storage Management – Install New Controllable		$1k	$15	kW
Pricing	Coarse (e.g. ToU pricing), excl. smart meter		Negligible	$0	Customer
Signals	Granular (e.g. real-time pricing), excl. smart meter		$12m	$250k	DNSP
Technical Standards	Inverter Standards		Negligible	$0	DNSP
	Remote Inverter Configuration		Negligible	$0	Country
	Static Limitations		Negligible	$0	DSNP
	Dynamic Limitations		$6m	$250k	DNSP
Reconfiguration	Change Taps		Negligible	$1-2k	Trip
	Change Topology		$200k-$660k	$0	Feeder
New Methods	Third Party Data	New Install	$500	$5	Customer
		Previous Install	Negligible	$5	Customer
New Assets	LV Metering		$3.5k	$30	Transformer
	Voltage Regulators		$300k	2.5% of capex	Regulator
	On Load Tap Changer	Vault	$120k	$7k	Transformer
		Pole-Mounted	$60k	$7k	Transformer
	Statcom (Single-Phase)		$5-8k	2.5% of capex	LV Phase
	Network Storage		$1.2k	2.5% of capex	kWh

Source: Energeia; Notes: 1. Changes deemed to be part of existing operations excluded, e.g. introduction of new price structures. 2. In-depth consultation with DNSPs would be required on to better understand costs on a jurisdictional basis. 3. Solutions are not mutually exclusive; the application of certain solutions may be limited by the absence of others i.e. electric water heaters must be in place to control their load.

[101] SA Power Networks (2019), 'LV Management Business Case: 2020-2025 Regulatory Proposal', https://www.aer.gov.au/system/files/Attachment%205%20Part%207%20-%20Future%20Network.zip

[102] The RRP was weighted using the solar PV generation profile; arguably it should just be the peak output period.

4.1.6. Future Scenarios

Energeia used scenarios to address the key risks, issues and uncertainties inherent in its DER-integration optimisation modelling assumptions, including:

- Future level of inverter-based generation on the system, e.g. solar PV and storage
- Future level of controllable load on the system, e.g. electric water heaters and EV chargers
- Future cost of solutions, e.g. storage, constraint engines, STATCOMS, etc.
- Future feed-in tariff levels, providing a market signal regarding the value of rooftop solar PV generation
- Future level of prosumer participation in virtual power plants

Three scenarios were developed to cover high, expected and low levels of DER on the system, which also assume different forecasts DER costs over time, i.e. lower than expected DER prices under the decentralised scenario, and higher than expected DER prices under the centralised scenario.

Table 20 provides the key assumptions applied to DER uptake and available, DER and technology driven network solutions, e.g. STACOMS, and assumed levels of customer participation in VPPs. Consensus wisdom is aligned to AEMO's Neutral scenario, which is the basis of their system planning.

Table 20 – Future Scenario Designs

Scenario Drivers		Scenario Theme Centralised	Expected	Decentralised
DER Costs	Consumer Technology Costs	50% Lower by 2040	Consensus Wisdom	50% Higher by 2040
	Network Technology Costs	50% Lower by 2040	Consensus Wisdom	50% Higher by 2040
Tariffs	Solar PV Feed-in Tariff	50% Higher by 2040	Consensus Wisdom	50% Lower by 2040
DER Adoption by Consumers	Smart Meter Installations	50% Lower by 2040	Consensus Wisdom	50% Higher by 2040
	Rooftop Solar PV Installations	50% Lower by 2040	Consensus Wisdom	50% Higher by 2040
	EV Sales	50% Lower by 2040	Consensus Wisdom	50% Higher by 2040
	BTM Storage Installations	50% Lower by 2040	Consensus Wisdom	50% Higher by 2040
Level of DER Controllability	EV Charge Controller Installations	40%	80%	90%
	Water Heating Controller Installations	40%	80%	90%
	BTM Storage VPP Adoption	40%	80%	90%
	EV Charge Controller VPP Adoption	40%	80%	90%
	Water Heating Controller VPP Adoption	40%	80%	90%

Source: Energeia; Note: "Controller" here means that the technology is controlled by a home energy management system, and VPP means including that capability is aggregated into a VPP,

4.2. Optimisation Results

The following sections report on the results of our modelling of DER-integration costs by LV network segment, solution, scenario and year, including our identification of the least cost solution and the total expenditure required by scenario, solution and LV network segment.

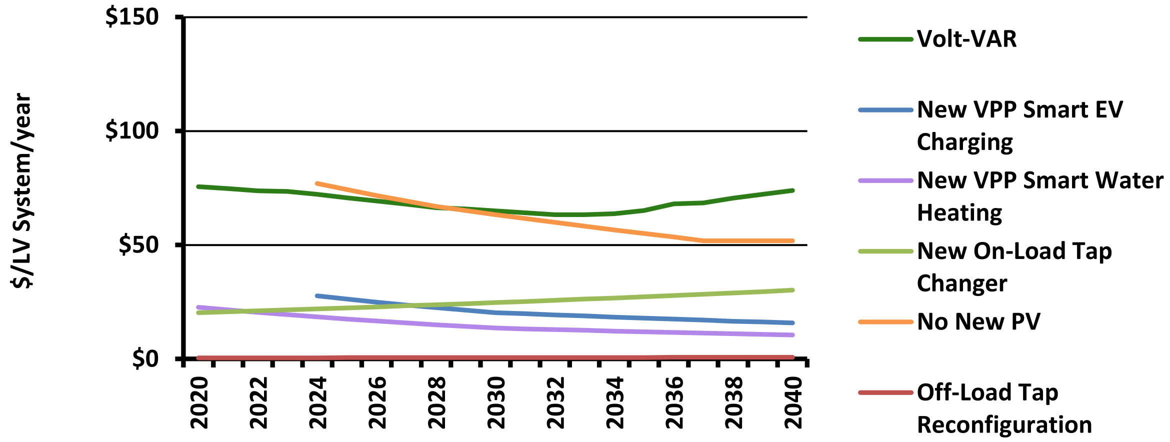
The final section summarises our key findings, conclusions and recommendations.

4.2.1. Solution Availability and Marginal Cost Over Time by Network Type

Energeia's modelling of the optimal DER-integration solution over time focused on addressing the voltage rise issue, given the prominence of this problem, and the limitations of data availability. The redesigned approach was based on our research in Stage 1 of this project on the marginal cost and availability of selected network and prosumer solutions.[103]

Energeia's modelling of the optimal DER-integration solution over time was based on the marginal costs and availability of selected network and prosumer solutions. The results of our modelling of the marginal costs and availability of selected network and prosumer solutions are shown below in Figure 31, Figure 32 and Figure 33 for the Neutral Scenario.[104]

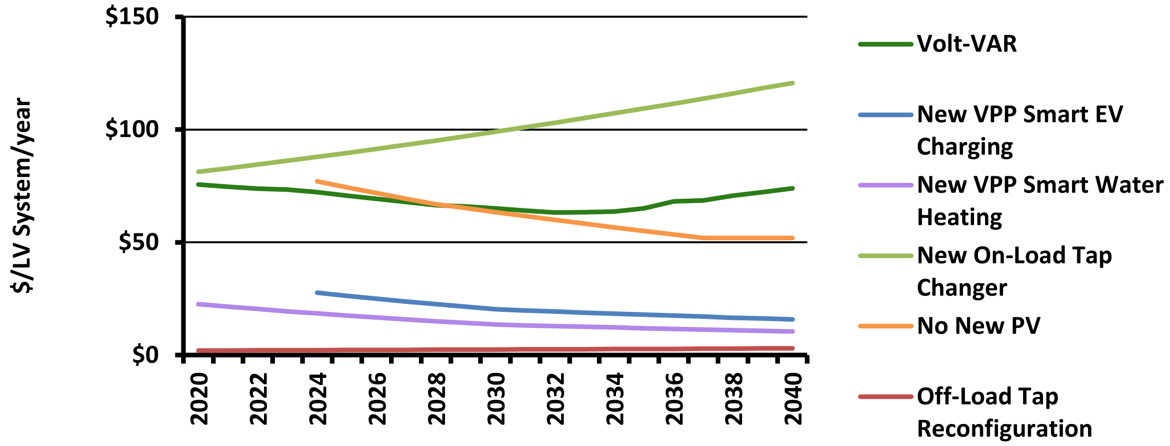
Figure 31 – Urban LV System: Least Cost Annual Expenditure by Solution – Neutral Scenario



Source: Energeia

Our modelling of the Urban LV network segment, outlined in Figure 31, shows offline tap changers as providing the lowest cost additional hosting capacity sufficient to meet forecast requirements over the period.[105] The cheapest consumer solution in this scenario is a new, VPP connected electric water heater, but it is significantly more expensive.

Figure 32 – Suburban LV System: Least Cost Annual Expenditure by Solution – Neutral Scenario



Source: Energeia

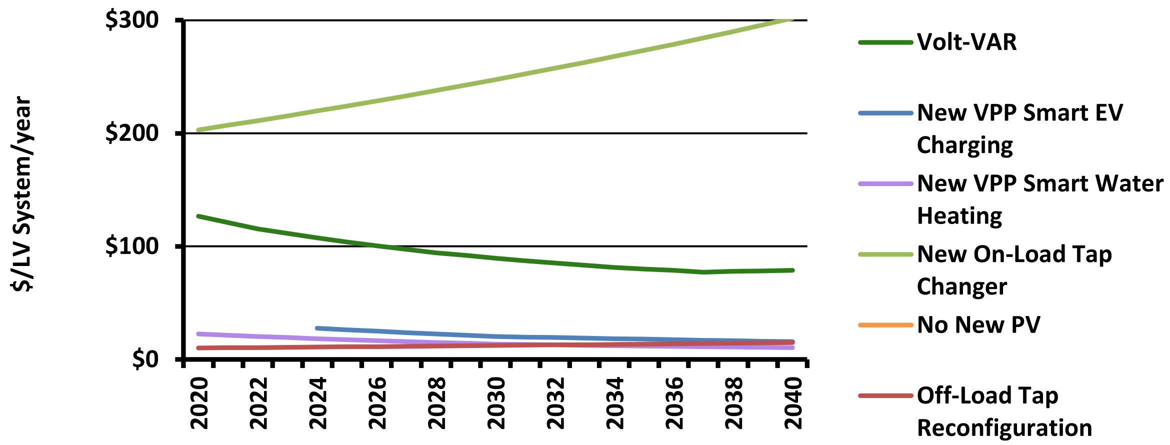
[103] The modelling excludes analysis of existing VPP resources due to the complexity of opportunity cost analysis, a subject for Phase II.

[104] See Appendix F – Optimisation Results by Scenario for all scenario results.

[105] Under the high DER scenario, reconfiguration of fixed tap settings is insufficient and online tap changers are required.

For the Suburban LV network segment shown in Figure 32, offline tap changes are also the lowest cost solution over the modelling period. It is worth mentioning that the identified network solutions are much cheaper than the curtailment options including static network limitations (i.e. No New PV) and Volt-VAR inverter settings, mainly due to the forecast value of solar PV generation[106].

Figure 33 – Rural LV System: Least Cost Annual Expenditure by Solution – Neutral Scenario



Source: Energeia

Looking at Figure 33 for the Rural LV network segment, the relatively low customer density leads to relatively high cost per customer for network solutions. This results in a new VPP enabled electric water heating solution being the lowest cost consumer solution, until the resource is exhausted in 2036. By that time, a new, VPP-enabled smart EV charging solution is available, and forecast to offer the lowest cost per unit of increased hosting capacity in this network.

4.2.2. Solution Costs Over Time by Network Type

The results of Energeia's modelling of the lowest cost solutions needed to address forecast DER-integration issues over the next 20 years are shown for the Neutral scenario (i.e. expected rate of technology adoption) scenario per LV network by LV network type in Figure 34, Figure 35 and Figure 36.[107]

- **Manual Tap Changes are Lowest Cost** – Our high-level analysis suggests that most expenditure should go to off-load tap reconfigurations as the lowest cost solution for the level of DER forecast to 2040 for most low voltage systems. Expenditure on prosumer (behind-the-meter) solutions is suggested from 2033 onwards in rural (50 kVA) low voltage systems, where there are lower network economies of scale.
- **Lowest Cost Solutions Vary by Feeder Type** – Overall, our analysis shows that, under the Neutral scenario, the optimal annualised cost of mitigating overvoltage due to solar PV adoption is expected to amount to around $260, $205 and $175 per LV network type per annum (p.a.). by 2040 for Urban, Suburban and Rural LV systems, respectively.
- **Costs Per Customer are Lowest on Urban Networks** – Due to economies of scale, this translates into $1.30, $4.90 and $25.00 p.a. per customer by 2040 for Urban, Suburban and Rural LV networks, respectively. In other words, although more is spent per Urban LV network, it translates to a lower cost per connected customer, and the opposite is true for Rural LV networks.

It is important to emphasise that different scenarios, representing the range of potential futures between centralised and decentralised extremes, result in different optimal solutions and forecast expenditure.

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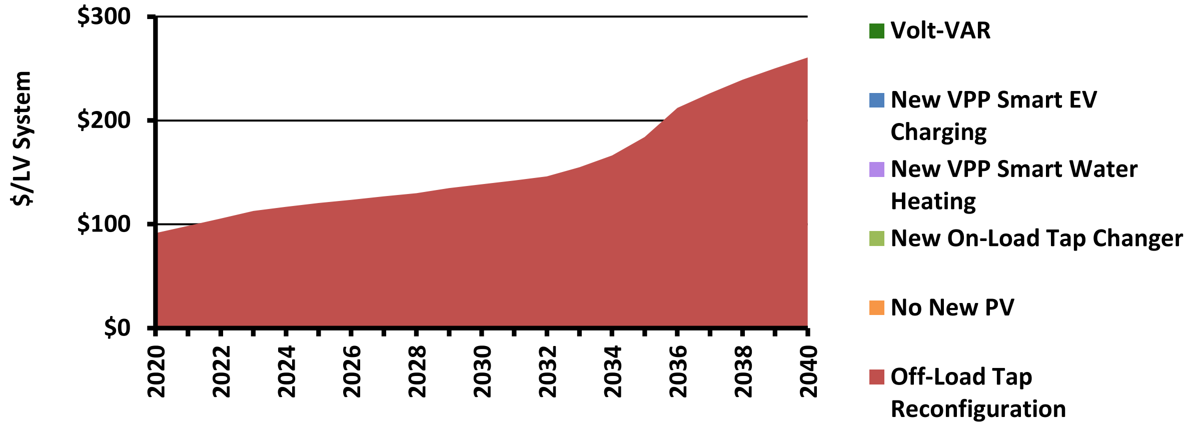
[106] Energeia has calculated the value of solar PV on the basis of electricity from the wholesale market that it replaces, rather than the value of the feed-in-tariff.

[107] Solutions were limited to data availability and the most prospective options based on stakeholder feedback.

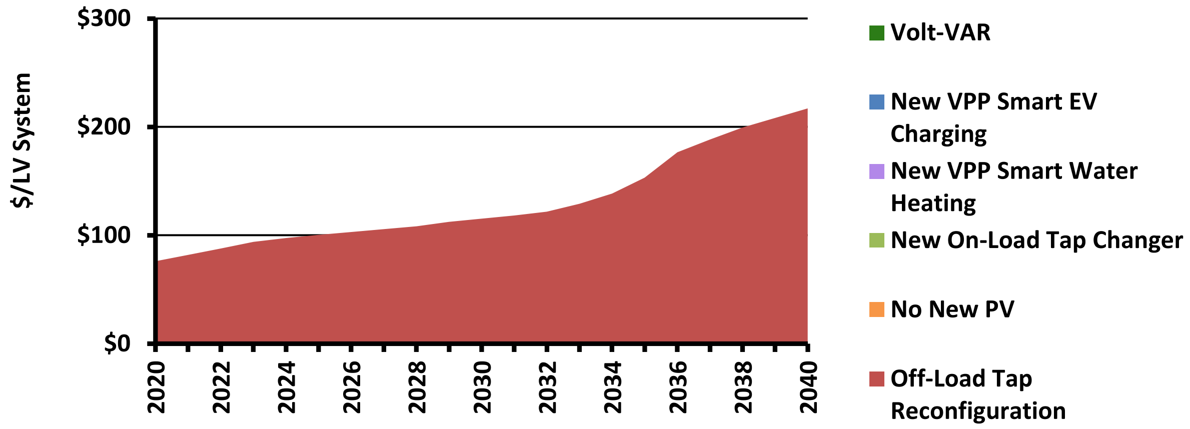
Full modelling results by scenario are shown in Appendix F – Optimisation Results by Scenario.

Figure 34 – Urban LV System: Least Cost Cumulative Expenditure by Solution – Neutral Scenario



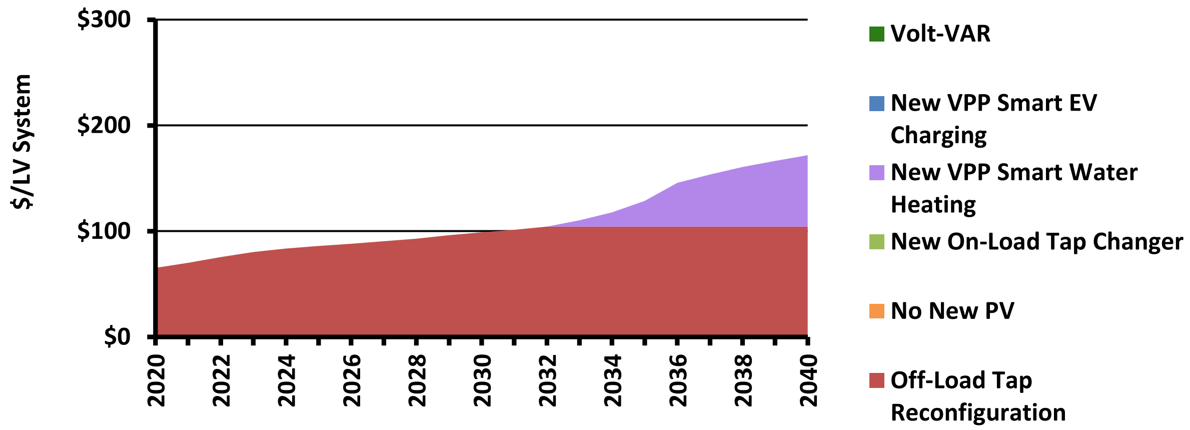
Source: Energeia

Figure 35 – Suburban LV System: Least Cost Cumulative Expenditure by Solution – Neutral Scenario



Source: Energeia

Figure 36 – Rural LV System: Least Cost Cumulative Expenditure by Solution – Neutral Scenario



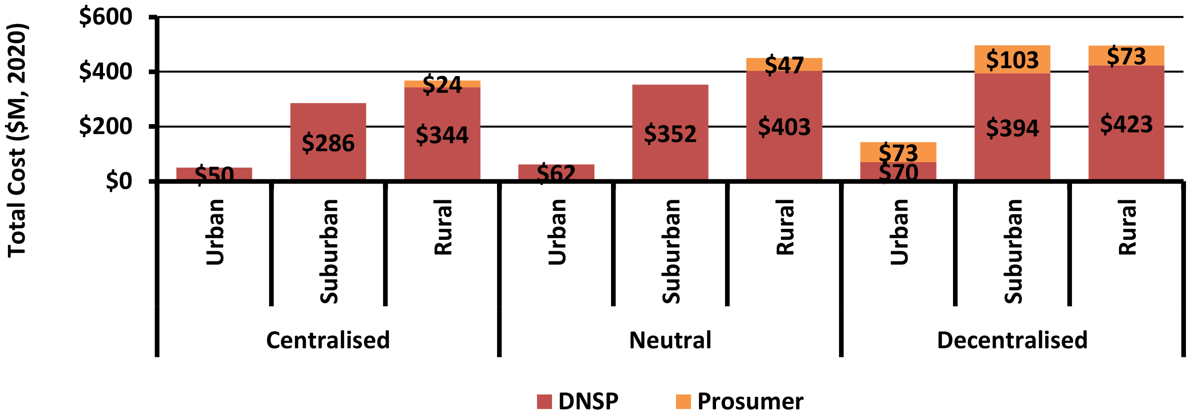
Source: Energeia

4.2.3. Total Solution Expenditures by Network Type, Solution Provider and Scenario

In order to provide a benchmark estimate against which future DER-integration optimisation studies can be compared, Energeia calculated total forecast expenditures by type of LV network, solution and scenario over the 20 year modelling period. The results of this analysis are shown below.

Energeia notes that most expenditure is in the 250 kVA (Suburban) and 50 kVA (Rural) LV networks, due to the marginal cost of their specific solutions but also the number of these systems across Australia in the case of the 50 kVA (or Rural) systems. Energeia also notes that network solution expenditure dominates spending in Urban and Suburban networks, while prosumer solution expenditure is mainly focused the Rural feeder type in the Centralised and Neutral scenarios.

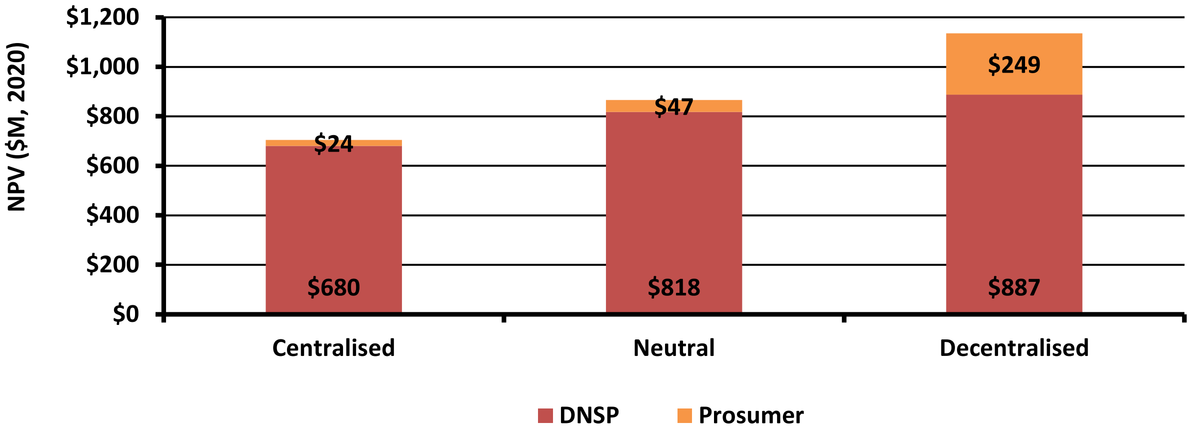
Figure 37 – NPV of DER Integration Costs by Scenario and Voltage System (2021-40, 2020$s)



Source: Energeia

Based on this analysis, Energeia's modelling carried out for this project has found that Australia's overall cost of mitigating over-voltage due to solar PV installations over the next 20 years is forecast to range by from $0.7 to $1.1 Bn, depending on the level of DER-adoption. It also shows that $0.7 to $0.9 Bn revenues flowing to networks and $0.0 to $0.2 Bn flowing to prosumers or their agents for providing DER-integration services.

Figure 38 – NPV of DER Integration Costs (2021-40, 2020$s)



Source: Energeia

Conclusions and Recommendations

Based on the above analysis, Energeia's key findings, conclusions and recommendations include:

- $0.7-$1.1 billion expenditure on optimal network and prosumer solutions will deliver greater net benefits to Australia than other sub-optimal solutions
- Solar PV curtailment is higher cost than network and prosumer side solutions
- Deploying prosumer water heating and EV load control solutions could provide lower cost options in suburban and rural networks in the future

It is important to note that the above analysis has been limited to over-voltage due to over-generation, and that the findings could change when the full range of potential issues are included in the modelling, including thermal overloads, phase balancing, under-frequency control, updating protection settings or applying more cost reflective pricing for prosumers. Furthermore, the optimal solution could also change if existing VPP enabled DER is included in the analysis.[108]

[108] Energeia and Renew are planning to address these questions in a Phase II project.

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Appendix B – Updated Australian Standards

Standards on managing the LV network are outlined in Table 21 with key standards ensuring the following:

- **Power Quality** – Ensures steady state voltage limits at the customer connection point and limits the occurrence of voltage fluctuations or flickers.
- **Safety** – States the process and action required to maintain customer safety in over-current protection, faults and potential islanding of inverters.
- **System Security** – Outlines the frequency state that is required to maintain system security.
- **Reliability –** Provides a framework on the level of reliability to customers.

Table 21 – Low Voltage Management Standards

Category	Name	Standard	Requirements	Notes
Power Quality	Steady State Voltage	AS61000.3.100 Voltage Standard	Supply voltage range 230V +10%/-6% for 98% of the time	Published 2011, DNSPs should aim to deliver a lower average voltage, to allow for the connection of embedded generators
	Flicker	TR IEC 61000.3.7	Planning levels of Pst = 0.9 and Plt = 0.7	Recommended standard by ENA in 2014
	Transients	Not Found	-	Transient events fall within the steady-state voltage standards. However, Italy has a transient standard of <1 sec per MAIFI-transient event
Safety	Over-current Protection	AS/NZS 3000.2.5.2	Circuit breakers required in the event of overcurrent	-
	Fault Level	AS/NZS 3000.2.5.5	Protection shall be initiated at a current less than 30% of the three-phase prospective fault level	-
	Islanding	AS/NZ 4777.2-2015	The automatic disconnection device must be able to inhibit the power from entering into the point of supply or grid to avoid the formation of islanding with the grid.	Values are subject to variation at the discretion of the local network operator
System Security	Under Frequency Load Shedding	Frequency Operating Standards	Load shedding schemes triggered when frequency is outside operational frequency tolerance band (49-51 Hz for NEM excl. TAS)	In 2019, it was decided following a review not to align the generation band to the operational frequency tolerance band
Reliability	SAIDI	Service Target Performance Incentive Scheme	Target SAIDI and SAIFI results lower than limit	Non-binding limits designed to encourage spending on reliability, vary by DNSP and feeder type
	SAIFI			

Source: Energeia; Note: ENA = Energy Networks Australia, DNSP = Distribution Network System Provider, NEM = National Electricity Market, SAID = System Average Interruption Duration Index, SAIFI = System Average Interruption Frequency Index.

Inverters provide the pathway for solar PV system to connect and export to the grid. There are several technical standards for inverters which provide a framework for network power quality, security and safety. Table 22 outlines the key components of the AS/NZS 4777 standards.

Table 22 – AS/NZS 4777 Technical Inverter Standards

Category	Name	Standard	Requirements	Notes
Power Quality	Voltage Rise	AS/NZS 4777.1:2016	AS/NZS 4777.1:2016 now specifies that the overall voltage rise from the point of supply to the inverter AC terminal to be 2% or less of the nominal voltage at the point of supply	Current standard was updated 2016, the previous standard was updated in 2005
	Power Factor	AS/NZS 4777.1:2016	0.95 leading to 0.95 lagging for inverters with rated nominal output currents up to 20 A per phase or; 0.90 leading to 0.90 lagging for inverters with rated nominal currents greater than 20 A per phase	-
	Inverter Power Quality Response Mode	AS/NZS 4777.1:2016	An inverter can maintain power quality at the point of connection through: Volt-Watt Response, Volt-VAR response, Fixed power factor or reactive power mode, or a power rate limit	-
System Security	Ride-Through	AS/NZS 4777.2:2015	DRM 3 Do not consume at more than 75% of rated power and source reactive power if capable	-
Safety	Anti-Islanding	AS/NZS 4777.2:2015	The automatic disconnection device must be able to inhibit the power from entering the point of supply or grid to avoid the formation of islanding with the grid	The most recent version of the standard (Previous version was updated in 2005) includes an anti-islanding in the event of DRM 0 - disconnect within 2 seconds of receiving signal from network
	Limits for Sustained Operation	AS/NZS 4777.1:2016	The inverter must disconnect from the grid within 3 seconds if the average voltage for a 10-minute period exceeds the nominal maximum voltage setting (default of 255V and maximum of 258V in Australia)	-

Source: Energeia

In addition to the AS/NZS 4777 standards, there are emerging international standards which focus on transitioning towards smart inverter capability to support the grid:

- **UL 1741 SA** – A product safety standard for inverters that outlines the manufacturing, software and product testing[109] requirements for smart, reactive control capability. A key focus is to transition from completely disconnecting, or anti-islanding measures, to adapting their output algorithm to assist in stabilising the grid.
- **IEEE 1541-2018** – An upgrade to the existing IEEE 1541 standard, the IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces sets out requirements for grid supportive capabilities[110] from grid-connected DER technology, including inverters. The requirement also includes two way communication between the smart inverter and the grid which will allow for remote monitoring and control of the device

[109] Product tests include anti-islanding (with advanced features active during the test), low and high voltage ride through, low and high voltage frequency ride through, must trip test, ramp rate, specified power factor and vol/var mode. Optional tests include frequency watt and voltage watt. More information can be found here: https://legacy-uploads.ul.com/wp-content/uploads/sites/2/2016/08/UL-1741-SA-Advanced-Inverters.pdf

[110] Grid supportive capabilities from the IEEE 1541-2018 standard include voltage and frequency ride-through, voltage and frequency regulation and communication and control functionality.

ENERGEIA

Appendix C – Summary of DER Integration Initiatives

Energeia has characterised these responses in two broad categories, updates to standards and guidelines and industry initiatives. These are summarised in the following sections.

Updates to Standards and Guidelines

Both the Australian Standards process (for both network practices and technology), and the ENA National Connections Guidelines process have introduced updates to the Australian standards and guidelines:

- **AS Updates (Network and Inverter)** – Standards Australia continually update the Australian Standards for both operation and management of the LV network and the capabilities of inverters, and recent updates have responded to some of the known issues with both DNSP practice and inverter technologies.
- **ENA National Grid Connection Guidelines** – National Grid Connection Guidelines (released in September 2019) aims to provide standardised guidelines for the connection of DER across the NEM.[111] These guidelines provide a consistent technical framework for network service providers in Australia to adopt for small-scale DER and micro embedded generator connections at the LV, MV and HV level, consisting of connection process and technical requirements for connection. Although a voluntary industry framework, all Australian DNSPs have signalled their intention to adopt the guideline (which limits single-phase DER connections to 5kW and three-phase DER connections to 30kW).

Industry Initiatives

Various industry and government bodies (ENA, AEMO, ARENA, AEMC and others) are working collaboratively together to deliver a range of initiatives across grid connection, DER orchestration and DER integration.

These initiatives are currently in train or recently concluded and they include the following key programs of work by the following market and industry bodies:

- **ARENA** – Distributed Energy Integration Program (DEIP; currently in progress)[112], which aims to bring together the key stakeholders across the industry to influence the development of the regulatory environment for DER
- **ENA and AEMO** – Open Energy Networks Program (currently in progress)[113], which is focused on developing the market models for future distributed services operator (DSO) approaches to managing the LV network
- **AEMO** – Distributed Energy Resources Program (currently in progress)[114], co-ordinates AEMO's response to both the Open Energy Networks Program and ARENA's DEIP.
- **AER** – Distributed Energy Resources Integration Expenditure review (currently in progress)[115], aims to develop a guideline for DNSPs DER integration expenditure proposals.

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[111] ENA (2019), *'Distributed Energy Resources Grid Connection Guidelines,* Technical Guidelines for Basic Micro EG Connections*'*: https://www.energynetworks.com.au/assets/uploads/cmpj0127_technical_guideline_v6.0_basic_micro_eg_0.pdf

[112] ARENA (2019), '*Distributed Energy Integration Program*': https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/ (Accessed on 8/11/2019)

[113] ENA (2019), '*Open Energy Networks*': https://www.energynetworks.com.au/projects/open-energy-networks/ (Accessed on 8/11/2019)

AEMO (2019), '*Markets and Framework*': (https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program/Markets-Framework (Accessed on 8/11/2019)

[114] AEMO (2019), '*Distributed Energy Resources Program*': https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program (Accessed on 8/11/2019)

[115] AER (2019), *'Assessing DER integration Expenditure'*: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/assessing-distributed-energy-resources-integration-expenditure (Accessed on 17/05/2020)

- **AEMC** – Distribution Market Model project (completed in 2017)[116], lays out a vision for a competitive 'distribution market' which enables consumers to get the most value out of their DER market design changes; improved DNSP management of LV networks and guaranteed access for DER connections.

ARENA's Distributed Energy Integration Program

To maximise DER benefits to networks and consumers, ARENA has brought together a range of industry stakeholders (AEMO, Australian Energy Council, Clean Energy Council, Clean Energy Finance Corporation, Energy Consumers Australia, ENA, the Clean Energy Regulator, the Australian Energy Regulator, CSIRO and the AEMC) to prioritise and accelerate the reforms required to integrate DER into the existing market design.

The DEIP program involves the following both regulatory reform[117] and hosting capacity[118] workstreams. Table 23 and Table 24 summarise the current DEIP project programme.

Table 23 – Current DEIP Projects – Network Hosting Capacity

Recipient	Contact	Project	Status
ANU	Marnie Shaw	Community Models for Deploying and Operating DER	Current
CitiPower & Powercor	Andrew Dinning	Distributed Energy Resources Hosting Capacity Study	Near Completion
CSIRO	Gavin Cross	National Low-Voltage Feeder Taxonomy Study	Current
Dynamic Limits	Alex Lloyd	DER Feasibility Study	Near Completion
Jemena	Peter Wong	Demonstration of Three Dynamic Grid-Side Technologies	Current
OGW	Lance Hoch	Pricing and Integration of DER	Near Completion
SAPN	Bryn Williams	Advanced VPP Grid Integration	Current
Solar Analytics	Jon Dore	Enhanced Reliability through Short Time Resolution Data	Current
University of Melbourne	Nando Ochoa	Advanced Planning of PV-Rich Distribution Networks Study	Current
University of Tasmania	Evan Franklin	Optimal DER Scheduling for Frequency Stability	Current
Zepben	Bill Tarlinton	evolve DER Project	Current

Source: ARENA

Table 24 – Current DEIP Projects – Other

Recipient	Contact	Project	Status
ANU	Sylvie Thiebaux	CONSORT Bruny Island	Complete
Ausgrid	Greg Strain	Power2U Project	Current
Horizon Power	David Edwards	Business Model Pilot Project – Phase 1	Current
NOJA Power	Mehdi Mosadeghy	Intelligent Switchgear	Current
Solar Analytics	Jon Dore	Monitoring for Better Energy Outcomes	Current
United Energy	Rodney Bray	Distribution Demand Response	Current
United Energy	Rodney Bray	Voltage Controlled Frequency Regulation System	Current
University of QLD	Luis Ochoa	Solar Enablement Initiative	Near Completion

Source: ARENA

[116] AEMC (2019), '*Distribution Market Model*': https://www.aemc.gov.au/markets-reviews-advice/distribution-market-model (Accessed on 8/11/2019)

[117] i.e. to address how the regulatory framework can be developed to deliver an optimal amount of distribution network investment and non-network enabling expenditure

[118] i.e. to determine how distribution network capacity should be allocated and paid for when there are competing users

AEMO and ENA's Open Energy Networks Program

ENA and AEMO launched the Open Energy Networks program investigating the most optimal pathways in DER integration into the grid. Their 2019 report[119] outlines the key DNSP capabilities required to support DER integration with minimal impact to customers and the grid, as shown in Table 25 below.

Table 25 – Open Energy Networks' Required Capabilities and Associated Milestones

Milestone 1	Milestone 2	Milestone 3
DNSPs defining network visibility requirements and network export constraints: • Define DNSP requirements for increased network visibility to maintain network operations within required parameters • Define how to achieve increased network visibility to maintain network operations within required parameters (operating envelopes) • Establish an iterative and targeted approach for the timing of investments required to provide network visibility to maintain network operations within required parameters	Defining communication requirements for operating envelopes: • Define protocols for operating envelope communication • Establish an Australian standards and/or guidelines to support the establishment of operating envelopes • Define data access permissions	Establishing an industry guideline for operating envelopes for export limits • Develop an Industry guideline that outlines the requirements and use of operating envelopes

Source: ENA and AEMO[120]

AEMO's DER Program

As the market operator, AEMO have identified the significant benefits that DER has on the electricity grid. As such, AEMO have released a 2019 report[121] discussing a pathway to better utilise DER for the grid through developing and improving appropriate DER standards. These would:

- Improve DER disturbance withstand capabilities, consistent with international practice.
- Expand use of beneficial grid support control modes (such as Volt-VAR, Volt-Watt, and Frequency-Watt), improving the hosting capacity of feeders and allow more consumers to install DER, without the additional network costs that would flow through to the continuum of consumers.
- Provide optimal support for system security.
- Enable consumers to utilise these capabilities to access new markets and services at a time of their choice.

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[119] Open Energy Networks (2019), *'Required Capabilities and Recommended Actions Report'*: https://www.energynetworks.com.au/sites/default/files/open_energy_networks_-_required_capabilities_and_recommended_actions_report_22_july_2019.pdf

[120] Open Energy Networks (2019), *'Required Capabilities and Recommended Actions Report'*: https://www.energynetworks.com.au/assets/uploads/open_energy_networks_-_required_capabilities_and_recommended_actions_report_22_july_2019.pdf

[121] AEMO (2019) '*Technical Integration of Distributed Energy Resources, Improving DER capabilities to benefit consumers and the power system'*: https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Technical-Integration/Technical-Integration-of-DER-Report.pdf

AER's DER Integration Expenditure Review

The AER is developing a guideline for DNSP proposals for expenditure to facilitate the integration of increasing levels of DER connection to networks. The process has commenced, and a consultation paper was published in November 2019, which considers:

- the current and predicted effects DER is having on networks,
- the AER's current approach to assessing DER integration expenditure, and
- whether or not the AER's current set of expenditure assessment tools are fit for purpose both now and into the future.

AEMC's Distribution Market Model

As the market rule setting body, the AEMC completed a review of potential distribution markets in 2017. The AEMC laid out a vision for a competitive 'distribution market' which enables consumers to get the most value out of their rooftop solar panels, batteries and other distributed energy resources as we move to a lower emissions future. The report identified a range of enablers required to bring about this vision, namely:

- Increasing the opportunities for DER through market design changes;
- Improved management of network risks and opportunities, and;
- Developing a set of clear and consistent arrangements for DER connections.

Appendix D – Detailed Solution Cost Breakdowns

Table 26 shows the initial Energeia cost breakdown of each solution, including descriptions and assumptions used. Table 17 shows the process of how DNSP feedback from the initial release helped to develop the final cost estimates.

Table 26 – Initial Energeia Key Distribution Network Solution Cost Assumptions

Category	Solution	Capex	Opex	Units	Description / Assumptions
Consumer	Water Heater retrofit	$150	$15	kW	Purchase and install 3kW DRED device ($495/customer including installation)
	Level 2 Charger retrofit	$150	$15	kW	Purchase and install 3kW DRED device ($495/customer including installation)
	New storage	$1,000	$15	kW	Installation of new, VPP enabled storage system
Pricing Signals	Coarse	$0	$0	Customer	No incremental smart meter costs assumed
	Granular	$1M	$250k	DNSP	Implementation of next generation locational marginal pricing engine
Technical Standards	Inverter Standards	$0	$0	DNSP	No additional costs when included at design stage. Enforcement costs excluded
	Remote Inverter Config.	$0	$0	Country	Cost of communications port and security infrastructure, already included in most inverters
	Static Limitations	$0	$0	DSNP	Enforcement costs and lost opportunity costs excluded
	Dynamic Limitations	$1M	$250k	DNSP	Implementation of next generation operating envelope engine
Re-configuration	Change Taps	0	$1-2k	Trip	Manual tap change
	Change Topology	$200k-$660k	$0	Feeder	Per feeder
	Change UFLS	$2M	$0	Feeder	Estimated cost over determination period
	Change Protection	$1k	$0	Feeder	Anti-islanding grid protection relay
	Balance Phases	$1.5-$2k	$0	Trip	Per one location
New Methods	Third Party Data	$1.5-$2k	$0	Customer	Per customer
	LT Forecasts	$500k	$250k	DSNP	Implementation of next generation forecasting software and processes, one per network
New Assets	LV Metering	$3.5k	$30	Transformer	Evoenergy 200 monitors per year at $700K p.a., assumes uses existing LAN (opex of $6,000 a year)
	Voltage Regulators	$176k	2.5% of capex	Regulator	$15.7 million ($2015) to install 89 bi-directional regulators into the network.
	Larger Assets	$100k-$400k	2.5% of capex	Asset	Per site
	OLTC	$120k	$7k	Transformer	Eaton $120k capex and a life cost of $295k (opex $35k every 5 years). UTS $200k-$300k
	Harmonic Filters	$519k	$0	Substation	Per site; From a project which installed harmonic filters at five zone substations
	STATCOM	$5-8k	2.5% of capex	LV Phase	LV VAR compensators (STATCOMs) for single phase. Can stack 3 to build for three-phase
	Network Storage	$1.8-$2m	2.5% of capex	Asset	Grid battery project

Source: Energeia

Table 27 – Key Distribution Network Solution Cost Assumptions Estimation Process

Category	Solution		Initial Assumptions		Revised Assumptions				Final Assumptions		
					DNSP 1		DNSP 2				
			Capex	Opex	Capex	Opex	Capex	Opex	Capex	Opex	Units
Consumer	Water Heater retrofit			$50				$15	$150	$15	$166
	Level 2 Charger retrofit			$50				$15	$150	$15	$166
	New storage			$50				$15	$1,000	$15	$1,000
Pricing Signals	Coarse (e.g. ToU pricing), excl. smart meter			$0	Negligible				Negligible	$0	Customer
	Granular (e.g. real-time pricing), excl. smart meter			$250k			$11.99m*		$11.99m	$250k	DNSP
Technical Standards	Inverter Standards			$0	Negligible				Negligible	$0	DNSP
	Remote Inverter Configuration			$0	Negligible				Negligible	$0	Country
	Static Limitations			$0	Negligible				Negligible	$0	DSNP
	Dynamic Limitations			$250k			$5.46m*		$5.46m	$250k	DNSP
Re-configuration	Change Taps			$1-2k	Negligible	750			Negligible	$1-2k	Trip
	Change Topology			$0					$200k-$660k	$0	Feeder
	Change UFLS			$0			$100k-$150k		$100k-$150k	$0	Feeder
	Change Protection			$0					$1,098	$0	Feeder
	Balance Phases			$1.5-$2k	Negligible				Negligible	$1.5-$2k	Trip
New Methods	Third Party Data	New Install	$1.5-$2k	$0				$5	$1.5-$2k	$5	Customer
		Previous Install	$0	$0	Negligible			$5	Negligible	$5	Customer
	Better Long – Term Forecasts			$250k			$7.76m*		$7.76m	$250k	DSNP
New Assets	LV Metering			$30					$3,500	$30	Transformer
	Voltage Regulators			2.5% of capex	$300,000				$300,000	2.5% of capex	Regulator
	Larger Assets			2.5% of capex					$100k-$400k	2.5% of capex	Asset
	On Load Tap Changer	Vault	$120k	$7k					$120k	$7k	Transformer
		Pole-Mounted					$60k		$60k	$7k	
	Harmonic Filters			$0					$518,693	$0	Substation
	Statcom (Single-Phase)			2.5% of capex					$5-8k	2.5% of capex	LV Phase
	Network Storage			2.5% of capex					$1200	2.5% of capex	kWh

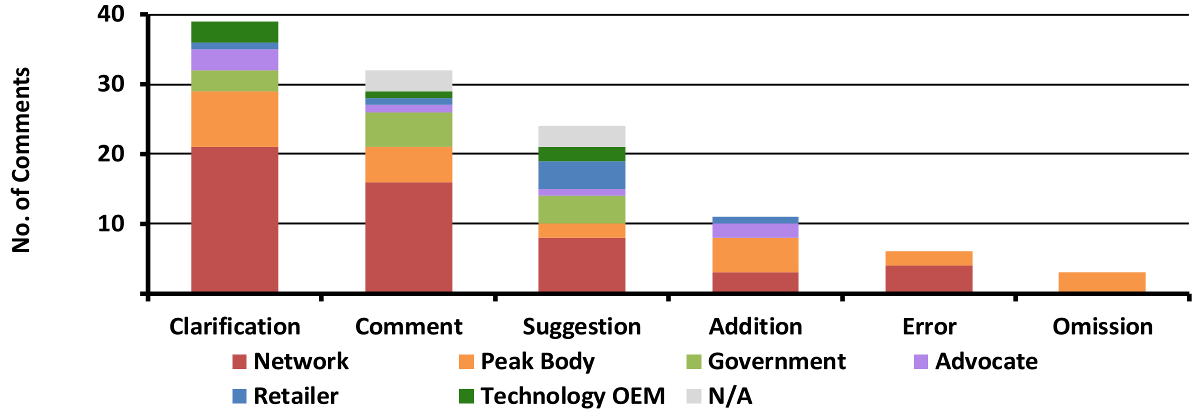
Source: Energeia

Appendix E – Feedback Summary

Renew's Initial Classifications of Response

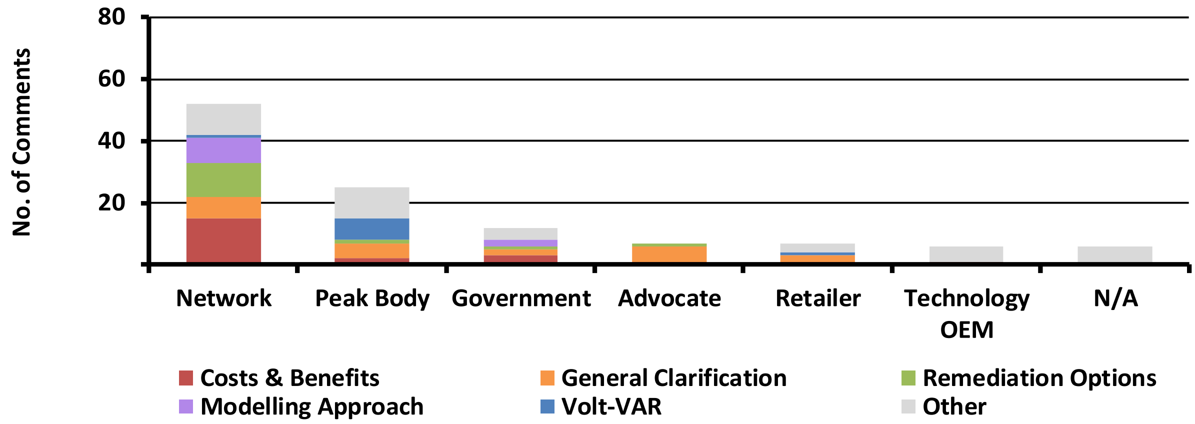
Renew classified the responses received by feedback type, stakeholder segment and subject matter. The results of this classification approach are reported in the following graphics.

Figure 39 – Comments by Feedback Type and Stakeholder Segment



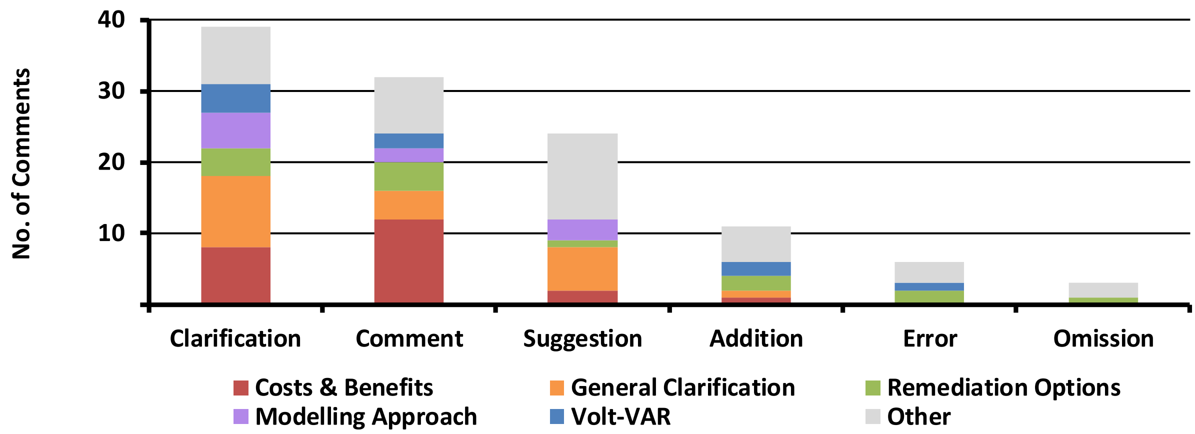
Source: Renew

Figure 40 – Comments by Stakeholder Segment and Subject Matter



Source: Renew

Figure 41 – Subject Matter by Feedback Type



Source: Renew

Energeia's Actions in Response to Consultation Feedback

Energeia reviewed each item of feedback and either actioned or addressed over 80% of the comments received via direct updates of the report or via clarifications in the Energeia and Renew feedback register, as shown in Table 28.

The remaining comments either spoke to a potential Phase 2 piece of work, and fed into Renew and Energeia's scoping of more detailed optimisation modelling, or were comments that required no action.

Table 28 – Energeia's Response to Feedback by Subject Matter Area

	Actioned	Addressed	Out-of-Scope	No Action	Total
Costs & Benefits	3	17	1	2	**23**
General Clarification	6	15	0	0	**21**
Remediation Options	3	10	0	1	**14**
Modelling Approach	1	4	4	1	**10**
Volt-VAR	6	2	0	1	**9**
Issues Table	3	4	0	0	**7**
Suggestions	1	5	0	0	**6**
Data/Metering	1	2	2	1	**6**
Standards	1	3	0	0	**4**
Prosumer focus	0	2	0	1	**3**
N/A	0	0	0	2	**2**
Storage	0	1	1	0	**2**
Terminology	2	0	0	0	**2**
Cross-Subsidies	0	1	0	0	**1**
Export Limits	1	0	0	0	**1**
Peer to Peer	0	0	0	1	**1**
Principles	0	0	1	0	**1**
Regulatory	0	0	1	0	**1**
Relevant Initiatives	0	1	0	0	**1**
Additional Sources	0	0	0	0	**0**
Total	**28**	**67**	**10**	**10**	**115**

From Energeia's review of the areas of interest, excluding general clarifications around the research or queries on the proposed modelling approach it could be seen that the three main areas to be addressed were:

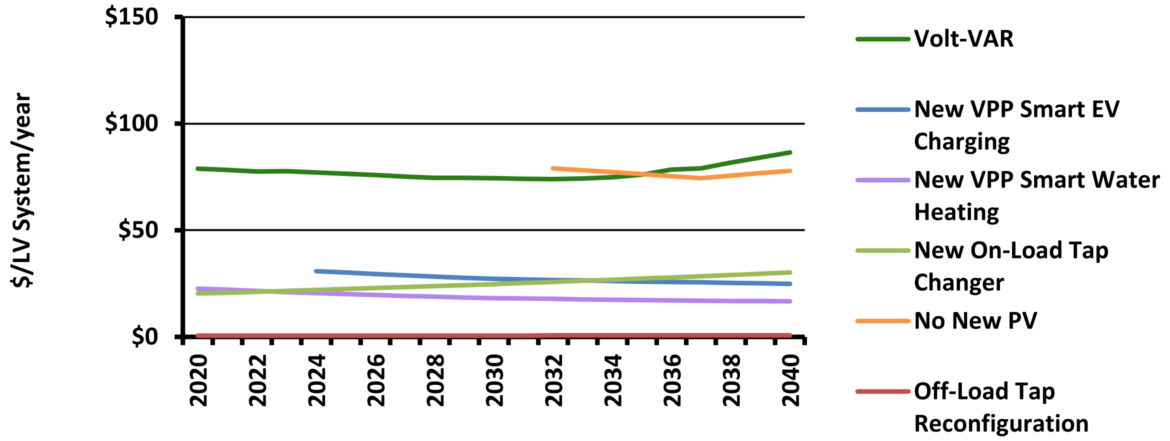
- **Estimating Costs and Benefits** – All stakeholders, but particularly networks, were interested in being more specific regarding the costs and benefits associated with increasing solar PV impacts on LV networks, particularly around different types of LV networks
- **Remediation Options** – Networks were also the main stakeholder providing feedback that focused on clarifying or providing more information on the available remediation options that could reduce the impact of increasing solar PV impacts on their LV networks
- **Volt-VAR Standards** – The various peak bodies who have contributed strongly to the development of smart inverter standards provided extensive feedback on the inverter operation and the relevant provisions in the latest standards

Appendix F – Optimisation Results by Scenario

Centralised Scenario – Unit Pricing by Solution

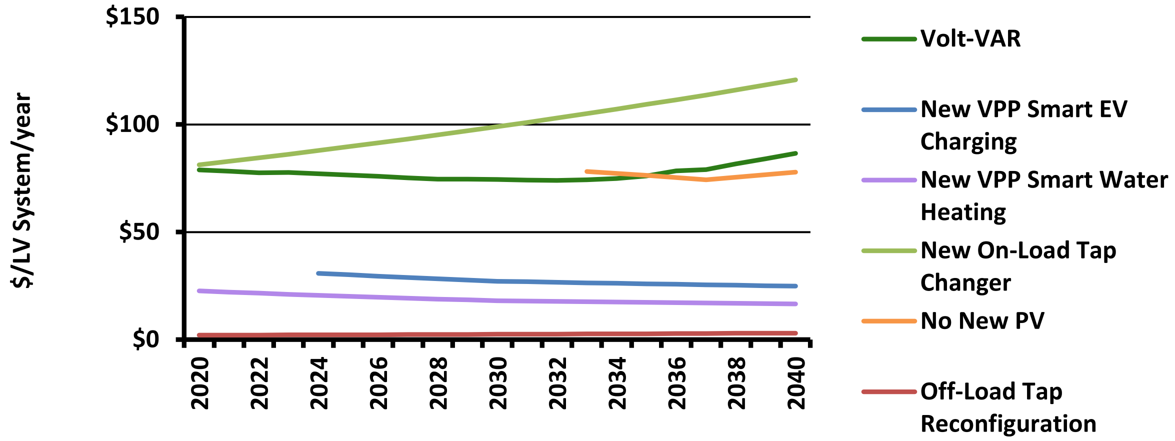
The following figures report on the forecast marginal pricing of selected over-voltage solutions, including curtailment options.

Figure 42 – Urban LV System: Least Cost Annual Expenditure by Solution



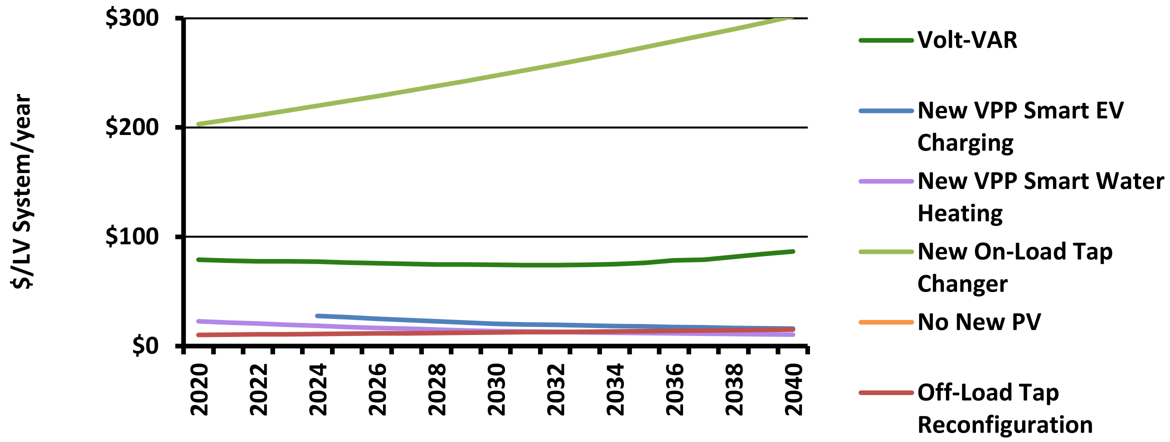
Source: Energeia

Figure 43 – Suburban LV System: Least Cost Annual Expenditure by Solution



Source: Energeia

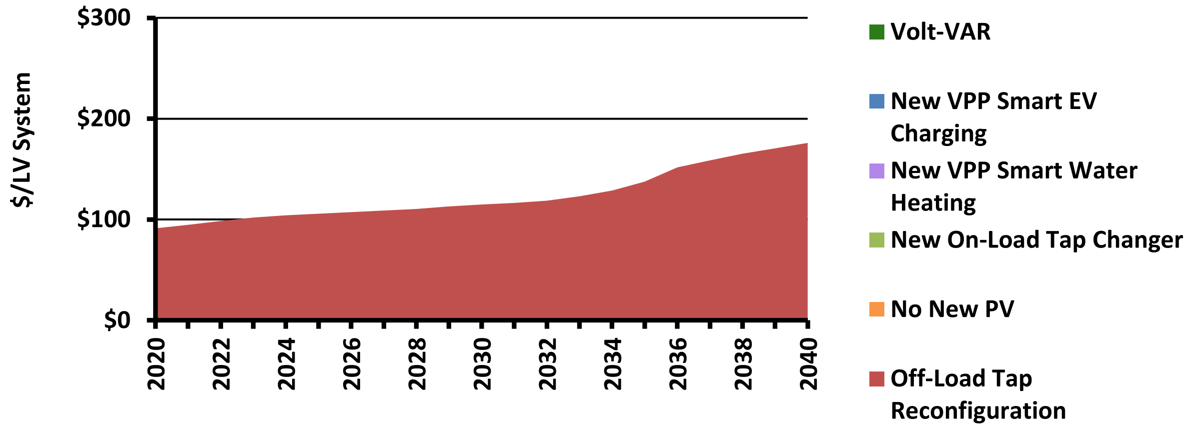
Figure 44 – Rural LV System: Least Cost Annual Expenditure by Solution



Centralised Scenario – Cumulative Solution Costs

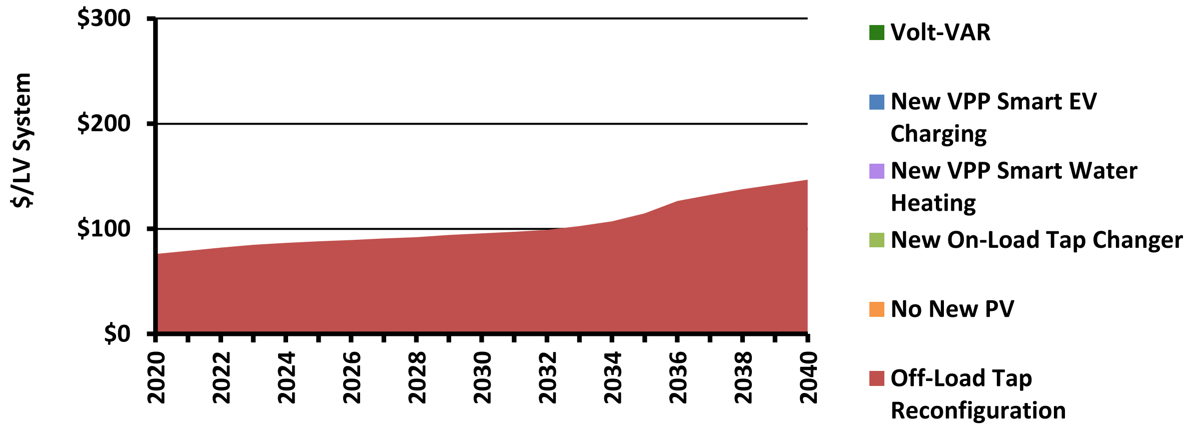
The following figures report on the forecasted cumulative costs of addressing over-voltage over time by solution.

Figure 45 – Urban LV System: Least Cost Cumulative Expenditure by Solution



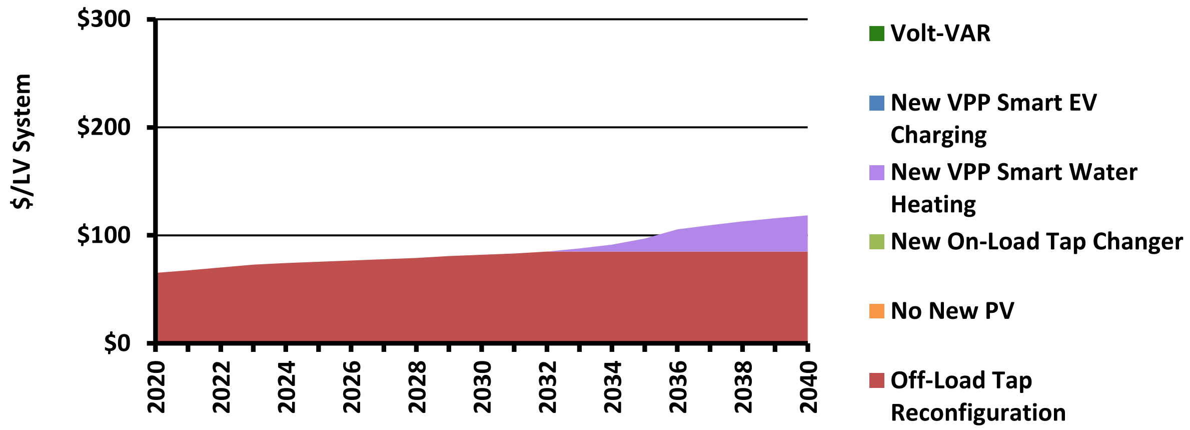
Source: Energeia

Figure 46 – Suburban LV System: Least Cost Cumulative Expenditure by Solution – Centralised, 250 LV



Source: Energeia

Figure 47 – Rural LV System: Least Cost Cumulative Expenditure by Solution – Centralised, 50 LV

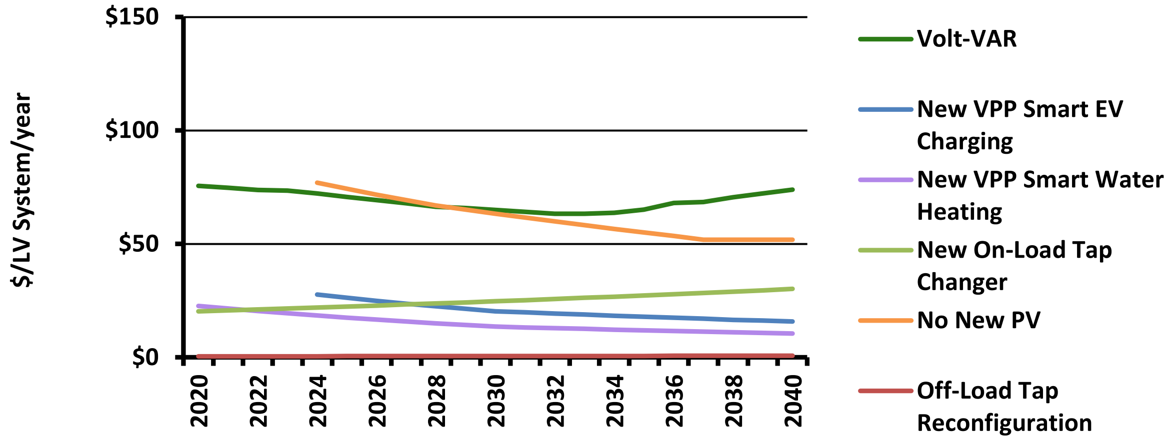


Source: Energeia

Neutral Scenario – Unit Pricing by Solution

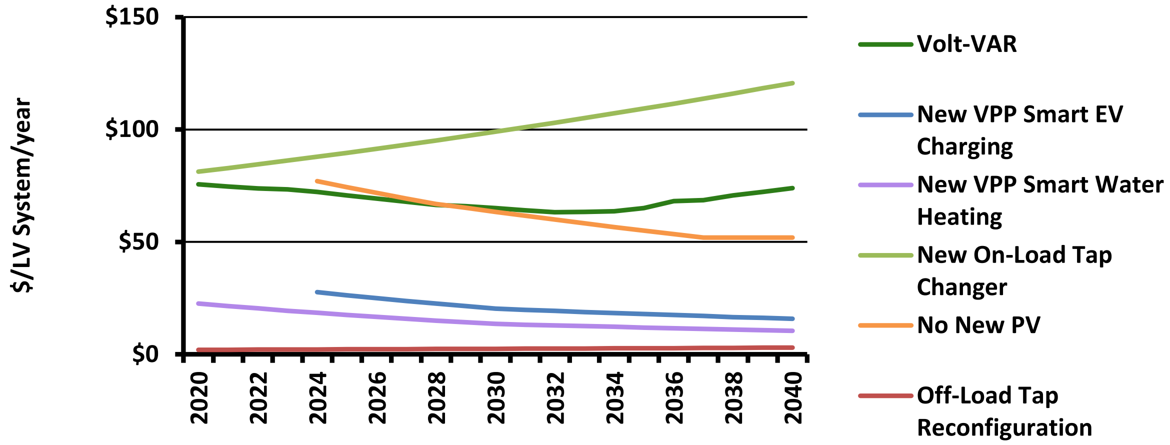
The following figures report on the forecast marginal pricing of selected over-voltage solutions, including curtailment options.

Figure 48 – Urban LV System: Least Cost Annual Expenditure by Solution



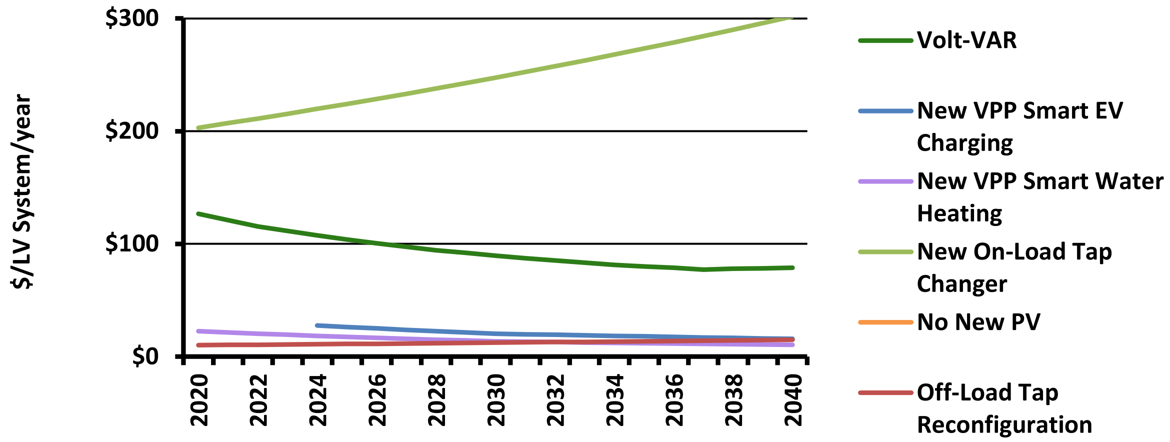
Source: Energeia

Figure 49 – Suburban LV System: Least Cost Annual Expenditure by Solution



Source: Energeia

Figure 50 – Rural LV System: Least Cost Annual Expenditure by Solution

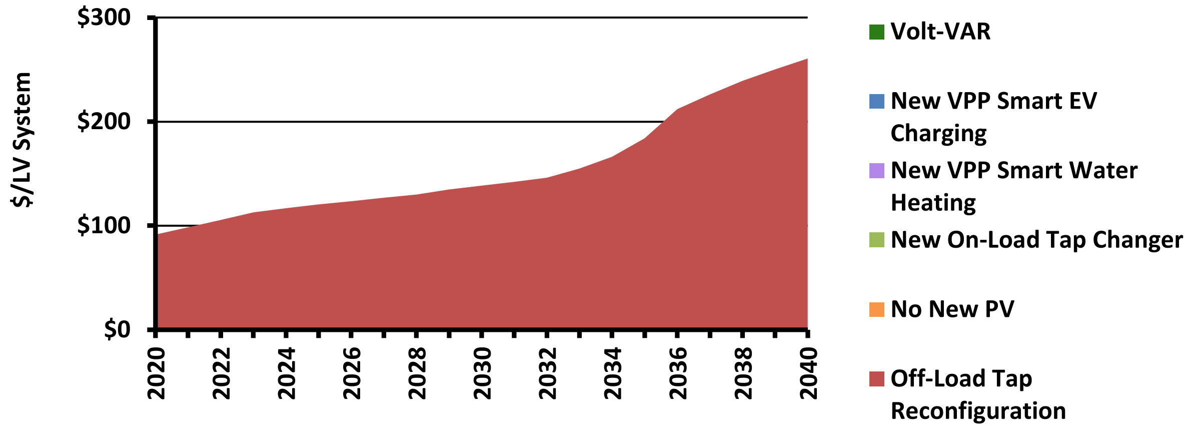


Source: Energeia

Neutral Scenario – Cumulative Solution Costs

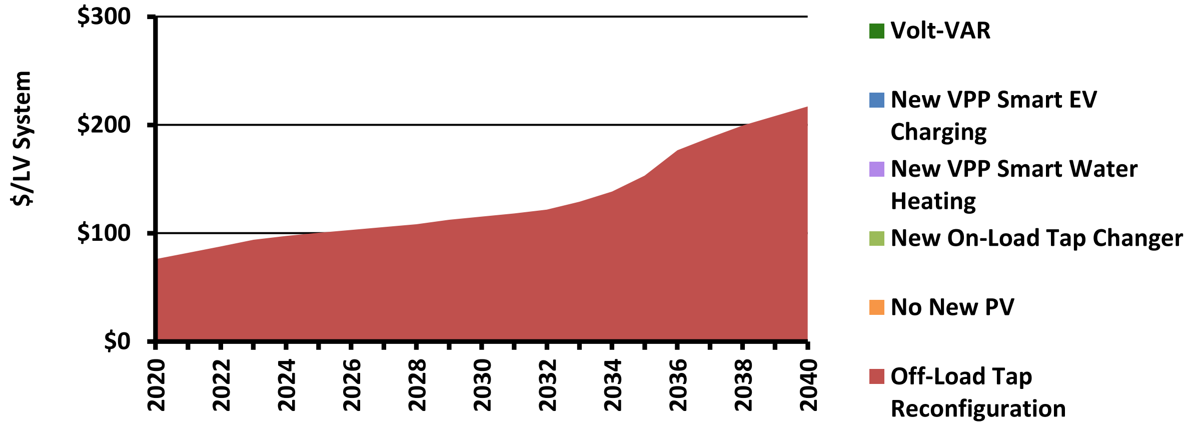
The following figures report on the forecast marginal pricing of selected over-voltage solutions, including curtailment options.

Figure 51 – Urban LV System: Least Cost Cumulative Expenditure by Solution – Neutral, 1000 LV



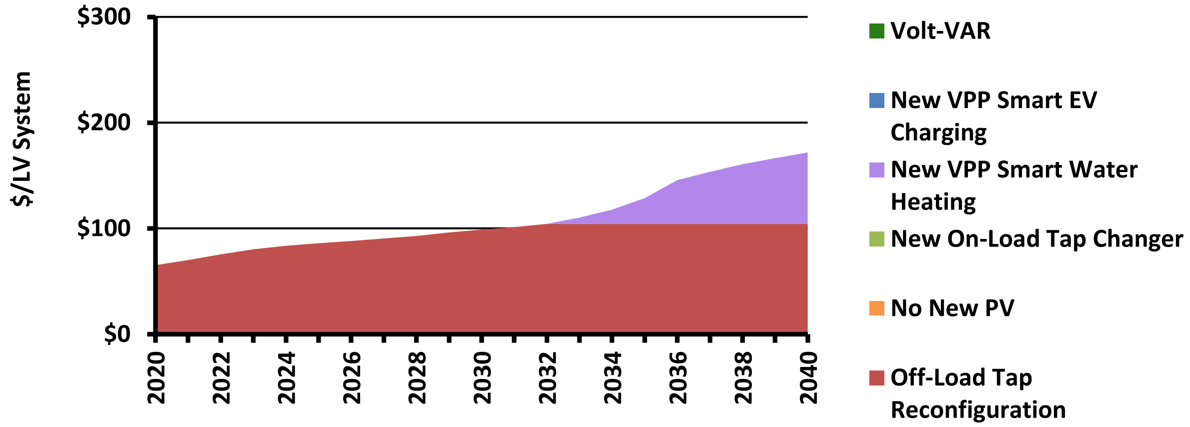
Source: Energeia

Figure 52 – Suburban LV System: Least Cost Cumulative Expenditure by Solution



Source: Energeia

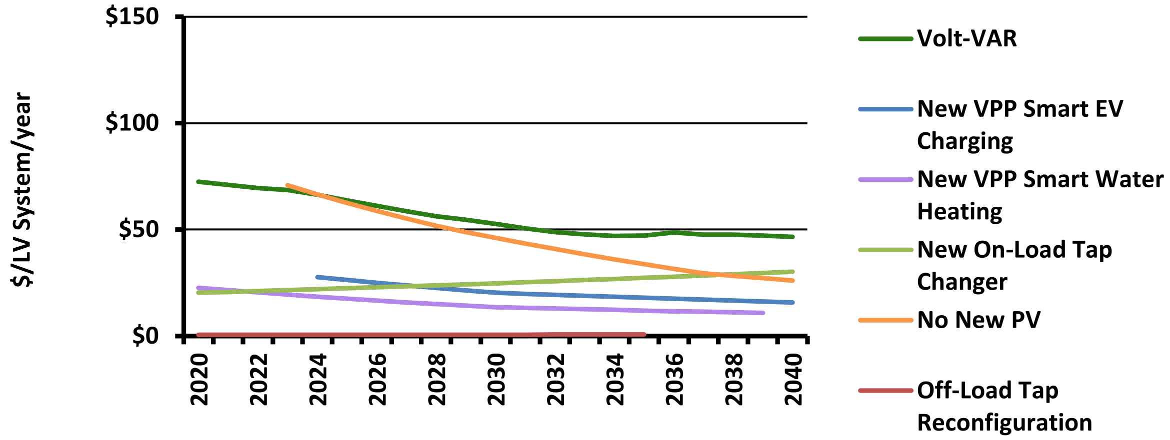
Figure 53 – Rural LV System: Least Cost Cumulative Expenditure by Solution



Source: Energeia

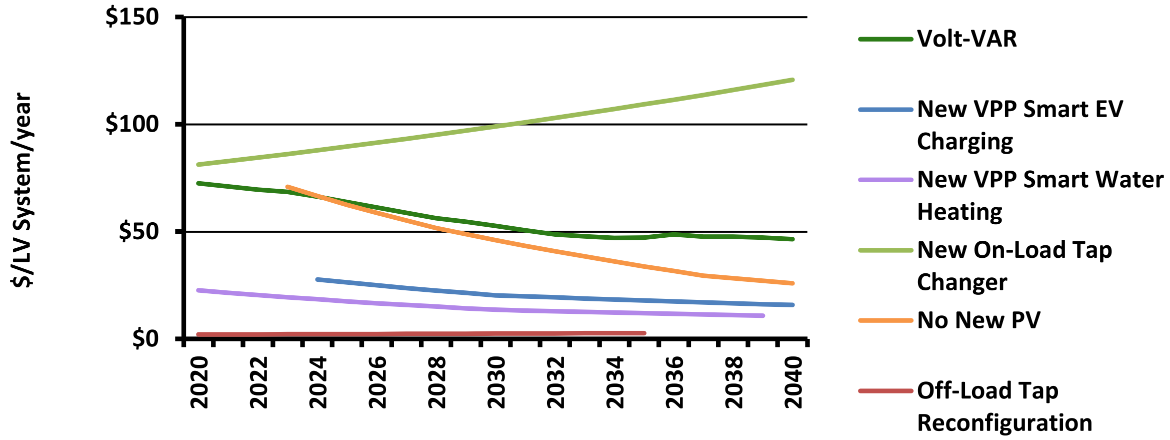
Decentralised Scenario – Unit Pricing by Solution

Figure 54 – Urban LV System: Least Cost Annual Expenditure by Solution



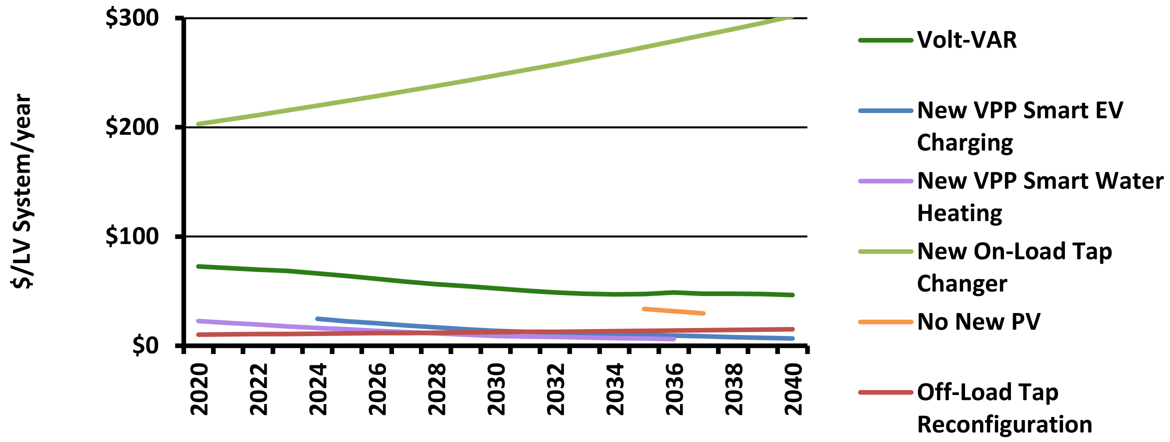
Source: Energeia

Figure 55– Suburban LV System: Least Cost Annual Expenditure by Solution



Source: Energeia

Figure 56 – Rural LV System: Least Cost Annual Expenditure by Solution

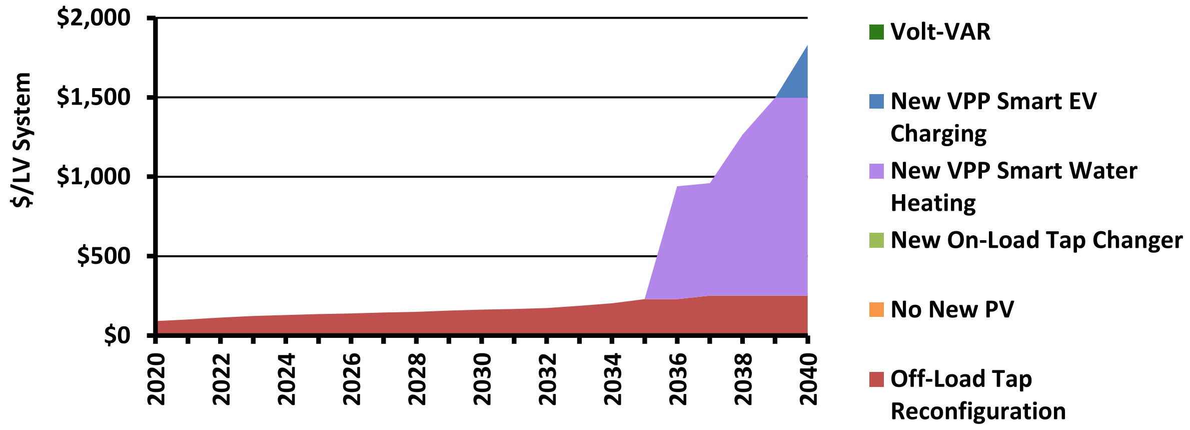


Source: Energeia

Decentralised Scenario – Cumulative Solution Costs

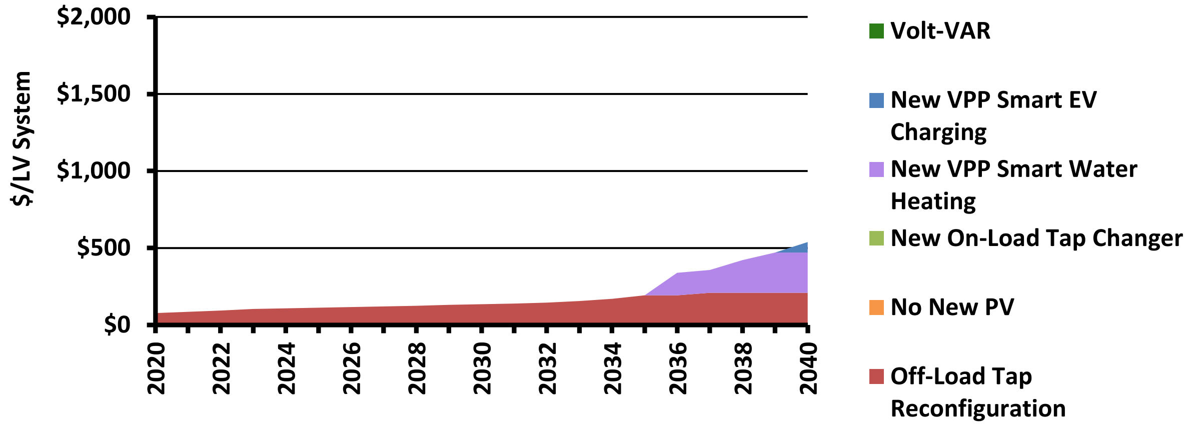
The following figures report on the forecasted cumulative costs of addressing over-voltage over time by solution.

Figure 57 – Urban LV System: Least Cost Cumulative Expenditure by Solution



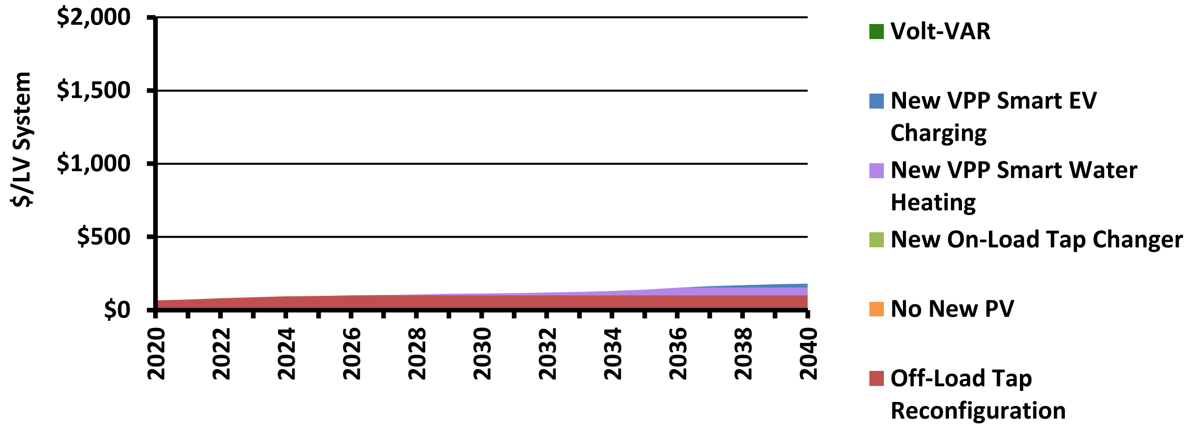
Source: Energeia

Figure 58 – Suburban LV System: Least Cost Cumulative Expenditure by Solution – Decentralised, 250 LV



Source: Energeia

Figure 59 – Rural LV System: Least Cost Cumulative Expenditure by Solution – Decentralised, 50 LV



Source: Energeia

Appendix G – Glossary

Table 29 – Glossary of Abbreviations and Acronyms

Abbreviation / Acronym	Meaning
ADMD	Average Daily Maximum Demand
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
AS	Ancillary Service
BTM	Behind-the-Meter
C&I	Commercial and Industrial
DAPR	Distribution Annual Planning Report
DER	Distributed Energy Resource
DFE	Demand Forecast Error
DMIA	Demand Management Innovation Allowance
DNSP	Distribution Network Service Provider
DRED	Demand Response Enabled Device
DSO	Distribution System Operator
ENA	Energy Networks Australia
EV	Electric Vehicle
FiT	Feed-in Tariff
HV	High Voltage
LMP	Locational Marginal Pricing
LRMC	Long-Run-Marginal Cost
LV	Low Voltage
MV	Medium Voltage
NEM	National Electricity Market
NER	National Energy Rules
OLTC	On Load Tap Changer
PV	Photovoltaic
Statcom	Static Synchronous Compensator
THD	Total Harmonic Distortion
UFLS	Under-frequency Load Shedding
V2G	Vehicle to Grid
VAR	Volt-ampere Reactive
VPP	Virtual Power Plant
VWA	Volume Weighted Average
ZS	Zone Substation

Source: Energeia

Energeia's mission is to empower our clients by providing the evidence-based advice using the best analytical tools and information available

Heritage

Energeia was founded in 2009 to pursue a gap foreseen in the professional services market for specialist information, skills and expertise that would be required for the industry's transformation over the coming years.

Since then the market has responded strongly to our unique philosophy and value proposition, geared towards those at the forefront and cutting edge of the energy sector.

Energeia has been working on landmark projects focused on emerging opportunities and solving complex issues transforming the industry to manage the overall impact.

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