



Supporting
document 5.17

Future Network Strategy

2020-2025
Regulatory Proposal
23 November 2017





Future network strategy

2017 – 2030

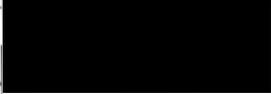
Transforming our network and services to meet customers' future energy needs

v 1.0

SA Power Networks

www.sapowernetworks.com.au

The following Stakeholders have reviewed and accepted the details within this document. Any changes to the document may only be made with the formal agreement of the signatories.

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Executive Summary

The electricity industry is in transition, and South Australia is at the forefront. Rooftop solar penetration, already the highest in the world at more than 30% of customer and business premises, continues to increase, and the battery storage market is beginning to accelerate as prices fall faster than expected. Government, AEMO and industry are grappling with emerging challenges to stability and security of supply as baseload generation is displaced by intermittent renewable energy and system inertia reduces. New energy products and services are emerging to service customers seeking empowerment in the face of rising prices. The global transition to electric vehicles is well underway, with Australia’s EV market poised to develop in the next 5 years.

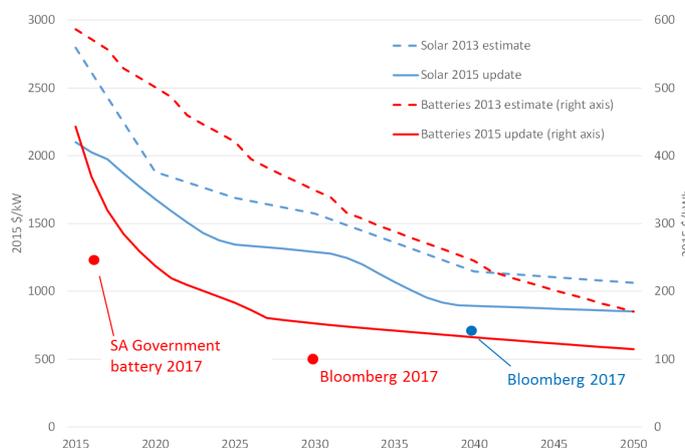
The Future Network Strategy is a response to this change. Developed in alignment with our *Future Operating Model* and the ENA/CSIRO *Electricity Network Transformation Roadmap*, it sets out six core strategies to adapt our network business to a more diverse, dynamic and distributed energy future.

Disruption in the electricity sector

The electricity industry is facing significant disruption as alternatives to grid electricity, particularly solar photovoltaics (PV) and energy storage, become more readily available and cost effective. As technology advances and global economies of scale improve, prices of distributed energy resources are falling, and falling more rapidly than recent forecasts have predicted.

At current forecast rates of price reduction, by 2030 the levelised cost of energy for rooftop solar PV will be less than 5c/kWh over the life of the system, compared to 35-45c/kWh for grid electricity. Even with the addition of battery storage, the total cost of self-produced energy will be less than 15c/kWh.

The compelling economics will drive very high levels of uptake of distributed energy resources across the NEM, leading to an unprecedented shift from centralised to decentralised energy generation. According to CSIRO’s latest forecasts, by 2050 up to 45% of all electricity consumed in the NEM will be generated by customer equipment connected at the low voltage distribution network – the opposite end of the system from its original design.



Forecast cost reductions in PV and batteries¹

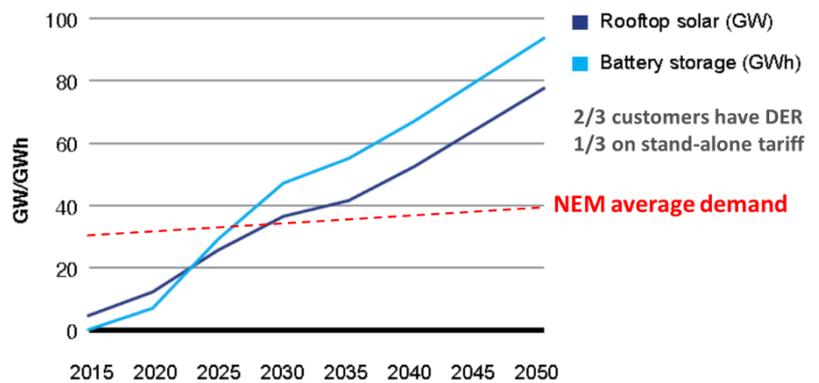
These changes are also being influenced, and to some extent accelerated, by broader societal issues and trends. Decarbonisation policy has led to a dramatic uptake of PV and large scale wind generation as a result of incentive mechanisms put in place by various levels of Government. As the imperative to reduce carbon emissions becomes more urgent, further interventions are considered likely.

¹ Source: ENA/CSIRO Electricity Network Transformation Roadmap, 2017, and Bloomberg 2017

In an environment where customers have seen significant rises in the cost of grid electricity and are seeing increasingly greater choice and higher levels of service offered in other markets, many are questioning the sustainability of traditional electricity supply business models. A number of new market entrants have already emerged that are seeking to capitalise on these changes with innovative retail products and services, and this is likely to accelerate the rate of disruption.

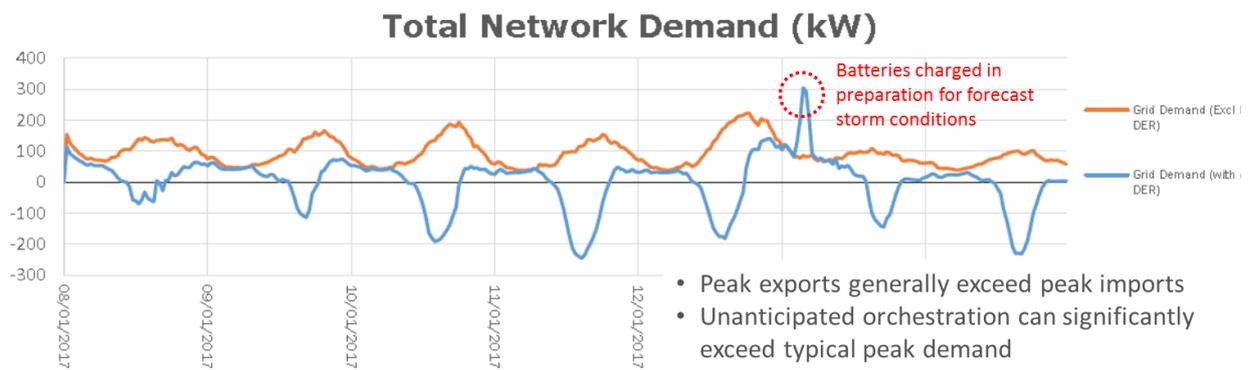
Network impacts

DER take-up at the levels forecast by CSIRO will have material impacts on networks that were not designed for complex two-way flows of energy. In South Australia, these issues are anticipated to arise in advance in of the rest of the country, with AEMO forecasting that from as early as 2027, the state demand could be met entirely by rooftop PV during low demand periods. Zone substation reverse flows will be emerging across South Australia by 2020, and by 2050, distributed solar PV load flows on high voltage feeders could potentially exceed asset ratings at times of minimum demand.



Forecast DER uptake in the NEM¹

Network impacts will arise first in the low voltage network, where the effect of increasing penetration of solar PV and other DER is to increase the dynamic range of power flows between peak demand and peak export, and the rate with which the system can swing from one end of this range to the other. This happens naturally because of the intermittent nature of solar PV, but will be exacerbated by the aggregation of customer DER into Virtual Power Plants that enable customer resources to be dispatched in a coordinated manner in response to market signals. These effects are already visible in data from our Salisbury battery trial.



- Peak exports generally exceed peak imports
- Unanticipated orchestration can significantly exceed typical peak demand

Salisbury battery trial – aggregate customer load profile

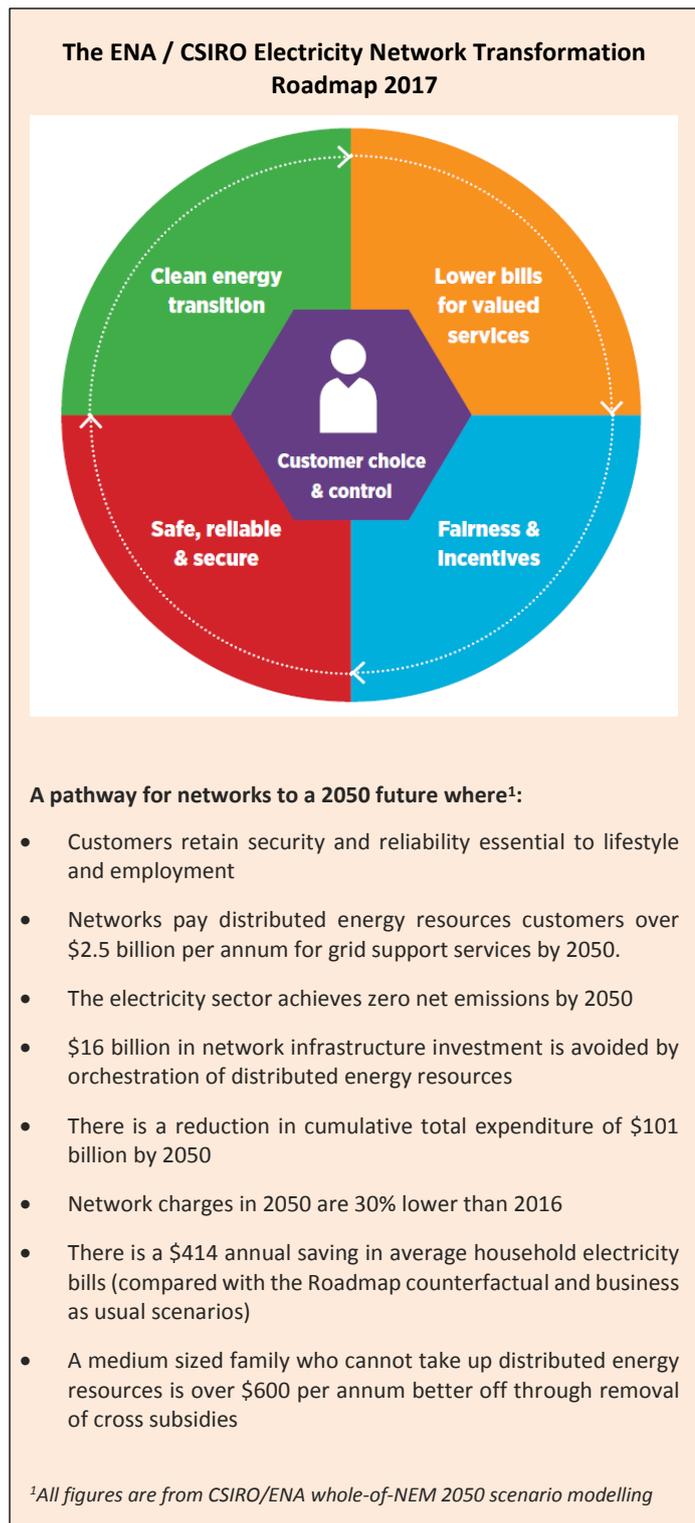
In the absence of new approaches, these changes could:

- **Overload existing assets**, particularly at times of peak export or unconstrained orchestration;
- **Exceed quality of supply (voltage) tolerances**, risking damage to customer equipment, causing customers' inverters to disconnect and increasing transient variations and flicker; and
- **Reduce the resilience of the network to faults**, whereby relatively small network perturbations could place the stability of large portions of the network at risk.

A reduction in energy transported through the network as customers become more self-sufficient may increase the unit cost of grid energy. Customers may abandon the grid in favour of standalone systems, even though this may not be efficient for the community as a whole.

Equally, this new future also presents opportunities for:

- **Improved network efficiency**, through leveraging distributed resources for network support;
- **Supporting new markets**, by providing a robust platform to enable customers to share and trade energy using their distributed energy resources and enabling electric vehicles; and
- **A new role for networks**, to add greater value as active Distribution System Operators (DSO).



In 2017, the ENA and CSIRO released the *Electricity Network Transformation Roadmap*. Built on a significant body of research and consultation, the roadmap sets out a 10-year plan for the electricity transmission and distribution sector intended to guide a structured transition over the 2017-2027 decade.

SA Power Networks was a contributor to the ENTR project through 2016. Our own Future Network Strategy development has both shaped and been shaped by this broader body of work, and the roadmap set out in this document aligns broadly with the ENTR roadmap and its key milestones

Our Future Network Strategy

Transforming our network and services to meet customers' future energy needs

Deliver services customers value



Expand choice and convenience

Being easy to deal with, offering quality advice, and providing new grades of service that are matched to what customers value



Enable new markets

Meeting emerging needs such as peer-to-peer trading, off-grid and micro-grid solutions

Enable the distributed energy transition



Increase planning scope & sophistication

More advanced planning and forecasting methods to prudently migrate to a resilient, high-DER network architecture



Manage two-way energy flows

Extending operations into the LV network and establishing new systems and incentives to support ubiquitous two-way power flows and DER orchestration

Maximise asset efficiency



Right-size our assets

Ensuring assets are appropriately sized, and where possible DER is leveraged, to minimise asset expenditure and/or decommission assets



Promote new grid applications

Encouraging electric vehicles and large-scale renewables connections

A safe, secure, reliable & fair energy platform for all customers

Strategy 1

Expand choice and convenience

In future, customers will have access to distributed energy resources such as solar PV and battery storage at low cost, and will have new opportunities to optimise their consumption of energy. Our customers will be more diverse and will require a grid connection that is optimised to complement their specific mix of local energy resources. Larger customers, customers at the fringe of the grid, and customers with non-standard connection requirements will have credible alternatives to a grid connection, and we will need to have a compelling offering to encourage them to connect.

Our strategy is to continue to improve our connection process and services to provide a more flexible, customer-centric connection experience. We will seek opportunities to remove cost and delay from our connection process, provide more convenient ways for our customers to engage with us, and broaden our service offering to give customers greater choice. We will seek to go beyond our regulatory obligations in the service levels we provide in order to position for a more competitive future.

Key elements

- 1. Reduce connection costs, delays & barriers:** by enabling simple on-line self-service tools for higher volume, indicative and/or simple requests, and by engaging regularly with customers and their representatives to identify key pain-points or improvement opportunities in our connection processes.
- 2. Offer greater choice of connection products & service levels:** providing a range of new services, developed in partnership with customers, that are well suited to varying customers' needs, for example:
 - High-reliability connections for commercial customers
 - A lower-cost 'basic' connection with low capacity
 - Back-up services for customers that are generally independent of the network but want the security of the grid when they need it
 - Thin connections for developers at the edge of the grid, and/or those seeking simply to optimise their mix of grid and local resources.
- 3. Provide energy advisory services:** that support customers in making sound choices in their selection of energy products:
 - At the time of a network connection or alteration request; or
 - Proactively, triggered by characteristics of the customer's load profile; or
 - Reactively, in response to customers' specific requests.

This advice will be available using on-line tools or otherwise automated for the majority of customers, but may also be provided through our contact centre, or face-to-face on a fee-for-service basis.

This strategy aligns closely with and both supports and is supported by SA Power Networks' 2017 *Customer Strategy*, in particular in the key opportunity areas of '*Engage, inform and communicate with customers*' and '*Simplify our processes.*'

Adapting the services offered by SA Power Networks to ensure they effectively match those that customers will value in the new energy future.

Strategy 2

Increase planning scope & sophistication

In a high-DER environment, network planners must not only consider summer maximum demand, but a range of other scenarios including minimum demands, reverse power flows, winter peaks and intermittency. Network planning must take into account the technical limits of the whole system, including the low voltage network, in order to understand the hosting capacity of the network.

In addition, consideration needs to be given as to whether the network architecture, optimised for centralised generation, is still appropriate in an environment where generation resources are substantially decentralised.

Key elements

- 1. Integrate DER into network planning processes:** incorporating DER forecasts and a broader range of scenario analysis into the planning process to identify both network constraints and opportunities to leverage DER to improve efficiency.

With this visibility, expanded modelling and forecasting capability and a toolkit of well understood network and non-network options, planners will be able to efficiently determine optimal solutions to a range of network constraints.

An analysis of the tools and data required to enable the transition to advanced DER-integrated planning will be essential.
- 2. Extend network planning into the LV network:** gain a robust, granular understanding of the DER hosting capacity of the network, its limiting factors and the most cost-effective remediation measures to permit the continued connection of customer resources.
- 3. Transition to more resilient network design and architecture:** considering changes that might be made to the architecture of the network to adapt to a high-DER future. This could include active quality of supply management technology and enabling segments of the network to operate standalone as microgrids in the event of upstream supply interruptions

Implementation of advanced planning and forecasting processes that enable the full impact and value of DER to be assessed & managed, and to prudently migrate to a high-DER network architecture

Strategy 3

Manage two-way energy flows

High levels of DER have the potential to adversely impact reliability, quality of supply and system security, particularly when DER is aggregated and coordinated. To manage these risks, we will need to extend our grid operations capabilities into the LV network, where we currently have very limited visibility, and establish new approaches to operate a network increasingly characterised by multi-directional power flows.

We will also pursue a range of measures to effectively manage DER, from passive measures such as new connection standards, tariffs and incentives through to active grid management as our role evolves from a relatively passive Distribution Network Operator (DNO) to an active Distribution System Operator (DSO).

Key elements

- 1. Model, monitor and actively manage the Low Voltage (LV) network:** we will establish and maintain an accurate model of our LV network and its connected customers. This model will include electrical parameters, connectivity between customers and assets, load and performance data, and information on installed distributed energy resources. The model will support our network planning processes and ultimately provide the operational visibility required for active DER management (DSO).

We will also increase visibility of the network through a combination of grid-side monitoring and new data sources such as advanced meters, smart streetlights and customer equipment, enabling us to proactively monitor quality of supply and to validate and calibrate the network model.
- 2. Enhance DER connection processes & standards:** to ensure that we receive notification of DER installations, and that customers' inverter settings minimise network impacts under a wider range of circumstances, utilising reactive power to manage voltage and making use of the new features available under AS 4777.2:2015.
- 3. Refine tariff design:** to ensure customers are provided with the appropriate incentives to utilise their DER to minimise network impacts or improve network performance.
- 4. Establish Distribution System Operator foundations:** we will undertake a range of measures to position for a future in which the operation of customers' DER is effectively managed in real time, ensuring that the distribution platform remains secure and reliable for all customers, including:
 - Incentives for customers to install 'smart DER' with communications capability rather than opting for passive systems;
 - Electronic enrolment of smart DER so that key information is available in real time such as location, services available, performance and sizing; and
 - Participation in trials to explore the systems, processes and capabilities required to enable DER network access to be mediated by the Distribution System Operator.

Enabling forecast amounts of DER to be connected to the network at minimum cost whilst ensuring that network safety, security, reliability and quality of supply are maintained

Strategy 4

Right size our assets

The deployment of distributed resources is generally expected to reduce the capacity requirements of network assets, however this must be balanced against the potential for new grid applications, for example electric vehicles.

DER may also potentially be applied to avoid, defer or reduce network upgrades, for example, by utilising customers' batteries or other resources to 'peak lop' during high network demand periods. Avoidance of the installation of new or upgraded assets using such approaches has the potential to yield significant cost savings.

Over time, lower capacity requirements may enable decommissioning of some network elements that are no longer adequately utilised, where this is cost-effective.

Key elements

- 1. Review ADMD standards:** After Diversity Maximum Demand (ADMD) is the nominal maximum demand assumed for each premises in a new subdivision, and is used to determine the total demand for the subdivision and hence any required local network and upstream capacity upgrades.

Current ADMD standards were developed prior to widespread uptake of DER and recent improvements in building standards and appliance efficiency, and hence should be reviewed.
- 2. Leverage DER to avoid asset expenditure:** establishing appropriate systems and processes to ensure distributed energy resources can be used to provide network support in lieu of network expenditure where it is economic to do so.
- 3. Targeted decommissioning & downsizing:** specifically targeting high cost and/or poor utilisation sections of the network for decommissioning where such an approach would be more economic than retaining the assets in service.

Over the next 20 years, there are anticipated to be small numbers of power transformers, distribution transformers and SWER lines for which this will be economical.
- 4. Review asset standards:** to ensure that assets have appropriate functionality and are "right sized" to support the future network strategy.

Examples include deferral of substation and feeder upgrades, avoided grid-side voltage control plant, etc.

Strategy 5

Promote new grid applications

Traditional drivers of energy consumption in South Australia are declining due to increasing energy efficiency and a reduction in large industrial loads. An increasing preference for electricity over other energy sources in a decarbonising economy will, however, see a growth in new grid applications such as electric vehicle charging and the connection of large scale renewable generators. These new applications offer significant future opportunities to maintain the value and relevance of the grid. Managed appropriately, they have the potential to increase energy throughput and utilisation of our network assets and therefore reduce unit cost for all customers.

Our strategy is to encourage new applications for grid-supplied energy, to maximise the role of our distribution network in supporting them, and to put in place appropriate incentives and controls to encourage efficient use of the network

Key elements

- 1. Promote electric vehicles** by ensuring that:
 - Our network is both 'EV ready' and 'EV friendly' with respect to connection processes and pricing;
 - We model the way, by maximising EV penetration within our own fleet;
 - Charging infrastructure is widely available, by supporting councils and other stakeholders to cost-effectively design, install and operate such equipment; and
 - We publicly advocate for, and promote the benefits of, EVs, including lobbying for government policy change such as vehicle emissions standards and government incentives that will stimulate the market.
- 2. Encourage large-scale renewable connections:** by streamlining connection processes and publishing maps of least-cost locations from a network connection perspective.

We will also consider a new role for a dedicated account manager to proactively seek distributed generation connections and facilitate proponents' applications and connection process.
- 3. Investigate fuel substitution:** to determine if there are material opportunities for customers to benefit from switching from other fuels to electricity

Maximising the utilisation of the network by encouraging new applications such as large scale renewable connections, electric vehicle charging and, if economic, substitution of electricity for gas

Strategy 6

Enable new markets

As the energy market evolves, customers' reliance on the NEM will decline over time. Energy that is supplied by the grid today will shift to being supplied by customer-owned DER, and customers will trade energy and energy services in new markets outside the NEM.

Rather than seek to defend traditional revenue streams in the face of change, our strategy is to leverage our core capabilities and network assets to become a leader in the transformation of the energy sector. We will seek to remove barriers to the emergence of new markets while also positioning to ensure that we remain an active participant in these markets.

Key elements

1. Explore off-grid and community energy solutions, including:

- standalone off-grid solutions where these are cost-effective or otherwise desired by customers. Energeia estimates that by 2020 most small business rural connections greater than 3km from the grid will be lower cost if connected as a standalone power system.
- private community networks, whether they be fully off-grid or retain a network connection.

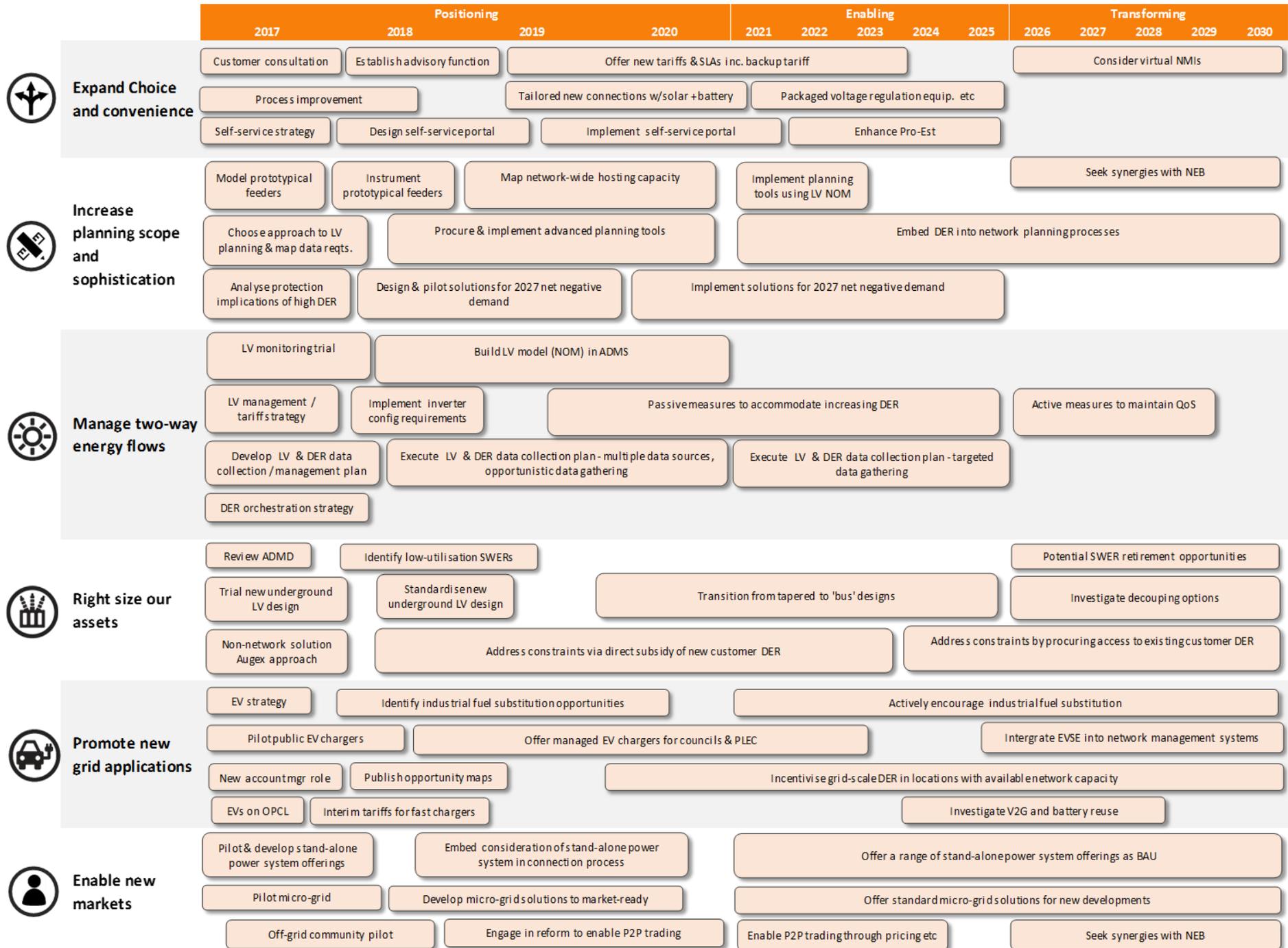
2. Support peer-to-peer trading and other non-traditional energy markets

We will seek to put in place the necessary technical standards and pricing models to enable customers to trade energy across our network in direct peer-to-peer arrangements outside the NEM (including via intermediaries). We will also investigate the potential to unlock further value by enabling such customers to receive locational and time variant distribution pricing.

3. Actively scan for new opportunities

We will establish rigorous processes in which we collaborate with our customers and partners to ensure we identify, and are well positioned for, opportunities that are not currently foreseen.

Strategy Roadmap to 2030



Priority projects

Strategic projects for 2017-18

	2017	2018	2019
1 Expand customer choice and convenience			
1.1 Customer solutions process improvements <i>Streamline processes to improve customer experience and increase productivity</i>	●	●	
1.2 Self-service strategy & business case <i>Develop strategy, business case and implementation plan for a customer self-service portal</i>	●	●	
1.3 New services consultation <i>Develop prioritised plan for introducing new products and new grades of service, including alternative connection types</i>	●		
1.4 Customer advisory function in customer solutions <i>Develop energy advisory service and train CSMs/NPOs</i>	●		
2 Increase planning scope and sophistication			
2.1 Strategy and tools for enhanced planning <i>Develop recommendations and roadmap for new planning tools, including role of ADMS, and initial tool procurement</i>	●	●	
2.2 Hosting capacity analysis and strategies <i>Engage consultant to model hosting capacity of LV network based on prototype areas, and propose costed remediation strategies for reset</i>	●	●	
2.3 High DER protection review <i>Determine protection implications of AEMO 2026 minimum demand forecast and identify any specific remedial expenditure for 2020-25</i>	●		
2.4 Network automation expansion strategy <i>Determine strategy and business case to expand feeder automation</i>	●		

3 Manage two-way energy flows		2017	2018	2019
3.1	LV transformer monitoring trial <i>Roll out transformer monitoring to 200 LV transformers in areas of high summer peak demand to assess dynamic range and capacity</i>	●		
3.2	Diverse LV monitoring trial - prototype areas <i>Targeted use of transformer monitors combined with other data sources in prototype LV areas to inform future monitoring strategy</i>	●	●	
3.3	Inverter voltage control trial <i>Trial capabilities of 'smart' AS4777 inverters for voltage management, as part of broader ENA/API research project</i>	●	●	
3.4	LV management strategy <i>Engage consultant to develop strategy and roadmap for building a detailed model of the LV network as a foundation for LV management</i>	●	●	
3.5	DSO foundations <i>Plan and implement DER registration process, and define and commence a DSO trial with a retailer to develop DSO role</i>		●	
3.6	DER forecasting in operational systems (Solcast) <i>Participate in ANU/ARENA Solcast project to explore integration of real-time solar forecast into ADMS</i>	●	●	●
3.7	Tariff strategy to minimise DER network impacts <i>Develop and execute strategy for incentives to encourage battery management algorithms that reduce network impacts</i>	●		
4 Right size our assets		2017	2018	2019
4.1	ADMD review <i>Propose and implement new ADMD standards including new negotiated options for developers</i>	●	●	
4.2	LV design standards <i>Update LV design standards based on current best practice and pilot 240mm² sectored construction method</i>	●		
4.3	Non-network solutions for network constraints <i>Develop new BAU processes to identify and evaluate non-network solutions to constraints, including for projects of < \$5 million</i>	●	●	●
4.4	Non-network solutions for resilience <i>Assess potential for generators, generator connection points to improve resilience in rural networks and determine reset proposal</i>	●		
4.5	Size opportunity for SWER decommissioning <i>Undertake detailed case studies to determine criteria for future decommissioning of high cost / low value SWER lines</i>	●	●	

5 Promote new grid applications		2017	2018	2019
5.1	Finalise and execute EV strategy <i>Determine and gain endorsement for strategies to accelerate EV adoption and position for long-term benefits of EVs</i>	●		
5.2	EV charger pilot <i>Trial of public on-street EV chargers in partnership with a council, to explore future demand management potential and other opportunities</i>	●	●	
5.3	New applications opportunity assessment <i>Detailed assessment of future opportunities for new grid applications and determine benefit of a dedicated role to develop these</i>	●	●	
6 Enable new markets		2017	2018	2019
6.1	Microgrid trial <i>Establish community microgrid trial to explore potential of community-level optimisation of DER</i>	●	●	●
6.2	Standalone power system trial <i>Deploy 3 x standalone power systems to gain insights into the market and the potential of these as alternative to rural network connection</i>	●	●	
6.3	Off-grid community trial <i>Research into remote community microgrids to gain insights into the market and regulatory issues</i>	●	●	
6.4	Position for peer-to-peer <i>Research regulatory and business issues surrounding peer-to-peer trading to form a position and approach to this</i>		●	

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1 INTRODUCTION

The coming years will be a period of tremendous change for the electricity industry, and these changes will require us to re-think the way we plan, build and operate the distribution network.

On the one hand, as distributed energy resources (DER) such as solar PV and battery storage continue to improve and become more cost-effective, elements of the distribution network may become redundant as stand-alone (off-grid) premises and/or local microgrids become more economic than a traditional network, and the grid as we know it may begin to fragment. On the other, new demands for electricity such as Electric Vehicles, and new market models such as Virtual Power Plants (VPPs) and localised peer-to-peer energy trading, may bring renewed value to the network as an enabler of a low-carbon economy and as a platform for the dynamic exchange of energy between interconnected webs of customers who are both producers and consumers.

As a network operator we face specific technical challenges in accommodating the reverse energy flows arising from the rapid and ongoing proliferation of rooftop PV and other distributed energy resources, as we transition to a future where up to 45% of all electricity may be generated by customers by 2050, at the opposite end of the system from its original design [8].

Our challenge is to adapt our business to position for the new energy future, while continuing to deliver on our primary responsibility to maintain a safe, secure and reliable supply of energy for the South Australian community.

This Future Network Strategy is SA Power Networks' strategic response to this challenge from a Network Management perspective.

1.1 Background and purpose

The Future Network Strategy project commenced in 2016 and arose from a specific goal set out in the SA Power Networks Strategic Plan 2016-20, namely to "Develop initial concepts to identify optimal network configurations and how we will transition towards them as part of the Network of the Future Project" [27].

Broadly speaking, the aim of the strategy has been to look at a range of plausible future long-term scenarios for the grid in South Australia, and consider what an optimal future distribution network business would look like under each scenario.

The goal is to identify robust 'no regrets' strategies that will guide the way the network is planned, designed, constructed, maintained and operated in coming years in order to manage the transition to the network of the future.

This high-level goal is distilled in the vision statement for the Future Network Strategy:

Transforming our network and services to meet customers' future energy needs.

The strategy has been developed in parallel with, and in close alignment with, the development of the industry-wide Network Transformation Roadmap developed by the ENA and CSIRO [8].

1.2 Business context

The Future Network Strategy is a departmental strategy for Network Management, one of a number of departmental strategies that combine to support the overall strategic goals set out in the corporate Strategic Plan 2017-2021 [28]².

² In particular, the Future Network Strategy is a specific outcome of the third Core Focus Area of the strategic plan, "Shaping out business for the future."

These strategies also feed into our Future Operating Model 2016-2031. This is a public document that sets out, at a high level, our overall long-term vision of the future of our business in South Australia. This context is illustrated in Figure 1 below.

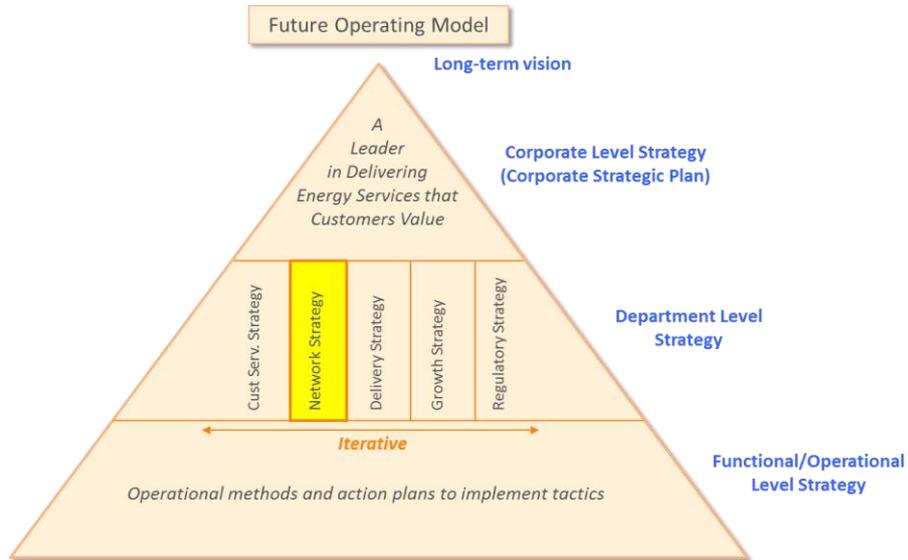


Figure 1 – SA Power Networks' strategy hierarchy

1.3 Scope

The Future Network Strategy considers both short- and long-term planning horizons. It seeks to set some overarching long-term strategic directions for the network, but also aims to identify specific, actionable initiatives that can be implemented in the next 1-3 years to begin the network transformation process.

The following assumptions inform the overall scope of the strategy:

- The Future Network Strategy is a strategy for Network Management and is concerned primarily with the planning, design, build, operation and maintenance of the network, and the evolution of these activities into future new roles and business models.
- In developing the strategy we have taken a long-term view, taking into consideration forecasts and future scenario models that extend as far as 2050, the time horizon used in CSIRO's future scenario modelling for the ENA Network Transformation Roadmap. Our strategic roadmap, however, extends only to 2030, with the primary focus being on strategies for the remainder of this regulatory period (2017-20) and the next (2020-25).
- The strategy considers possible future new business activities that may develop from and build upon our core capabilities within Network Management, but is not intended to consider unregulated lines of business. The strategy does, however, seek to take into account the future impact on the distribution network of new and emerging technologies and business models.

1.4 Methodology

1.4.1 The strategy development process

The strategy development project commenced in June 2016 and ran to the end of December 2016, as shown in the figure below. Further work has been undertaken in the first half of 2017 to review and refine the short-term roadmap of projects arising from the strategy.



Figure 2 – Methodology

Consultant 2nd Road were engaged to assist with and facilitate a series of cross-functional stakeholder workshops in Q3 2017 as part of the strategy development process. Further details of the process are included in Appendix A.

1.4.2 Sources of data

Wherever possible, AEMO’s latest forecasts have been used as the best available reference source for future trends in energy consumption, uptake of solar PV, battery storage and electric vehicles and so on. Our longer-term scenario modelling (to a 2050 time horizon) relies substantially on the future scenario modelling undertaken by CSIRO for the 2016 ENA/CSIRO Network Transformation Roadmap project [8]³.

³ This in turn builds on CSIRO’s 2013 modelling for the Future Grid Forum (FGF), subsequently updated and refined in the ENA-funded FGF refresh project in 2015.

2 THE CHANGING ENERGY LANDSCAPE

“The next decade to 2027 is likely to see a step change in the rapid adoption of new energy technologies, driven by falling costs and global carbon abatement measures. This decade provides a limited window of opportunity to reposition Australia’s electricity system to deliver efficient outcomes to customers.”

ENA/CSIRO Electricity Network Transformation Roadmap Key Concepts Report, December 2016.

2.1 The continuing growth of distributed energy resources

The electricity industry is facing significant disruption as alternatives to grid electricity, particularly solar photovoltaics (PV) and energy storage, become more readily available and cost effective. As technology advances and global economies of scale improve, prices of distributed energy resources are falling, and falling more rapidly than recent forecasts have predicted.

This is illustrated in Figure 3 below, which compares CSIRO’s 2013 long-term market price forecasts for solar PV and battery storage with their updated forecast issued in 2015. CSIRO’s 2015 study found that the 2013 forecast had significantly under-estimated the rate with which prices were falling. As at mid-2017, the latest data shows that the market is already moving ahead of CSIRO’s revised 2015 price paths.

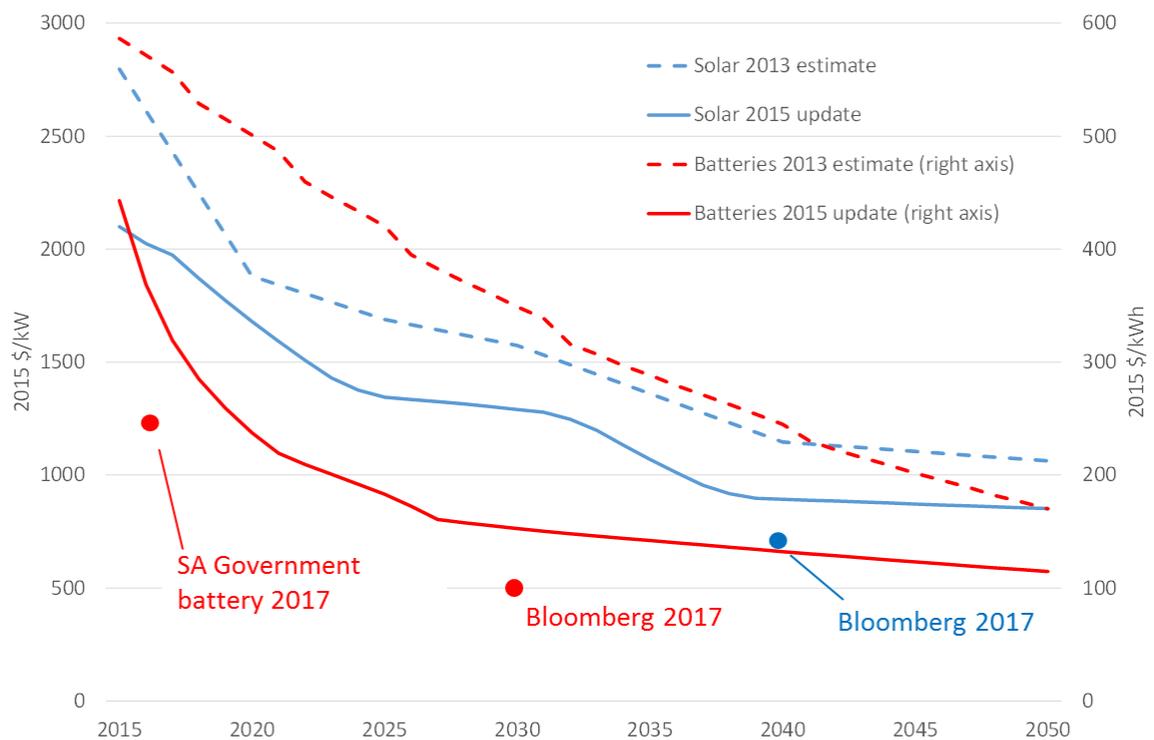


Figure 3 – Forecast cost reductions in solar PV and batteries (Source: CSIRO [6], Bloomberg [29])

At current forecast rates of price reduction, by 2030 the levelised cost of energy for rooftop solar PV will be less than 5c/kWh over the life of the system, compared to 35-45c/kWh for grid electricity. Even with the addition of battery storage, the total cost of self-produced energy will be less than 15c/kWh. These compelling economics will drive very high levels of uptake of distributed energy resources across the NEM, leading to an unprecedented shift from

centralised to decentralised energy generation. According to CSIRO’s latest forecasts (Figure 4 below), by 2050 up to 45% of all electricity consumed in the NEM will be generated by customer equipment connected at the low voltage distribution network – the opposite end of the system from its original design.

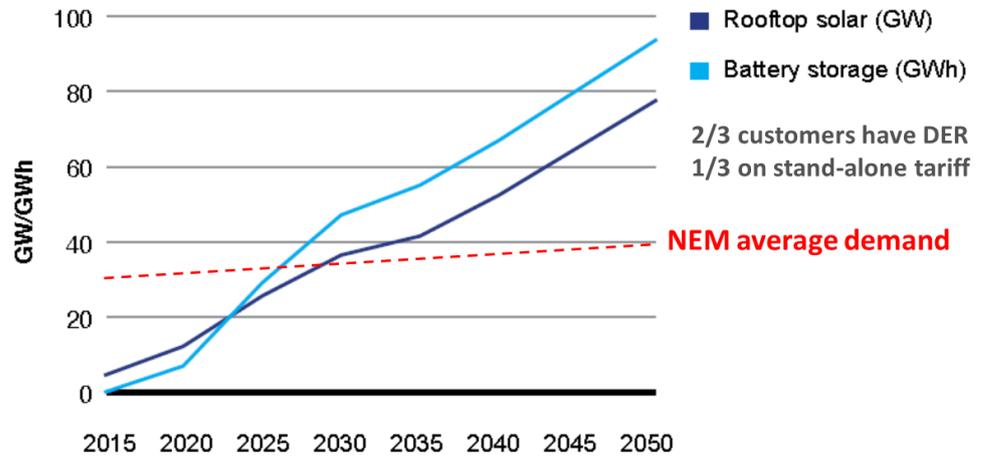


Figure 4 – National Electricity Market PV and battery uptake forecast (Source: CSIRO/ENA [8])

South Australia has led the nation – and arguably the world – in this transition. Figure 5 below is from AEMO’s 2016 Future Power System Security program [30] and shows the growth in installed rooftop solar PV capacity in SA as a proportion of state-wide demand, compared to the other NEM states.

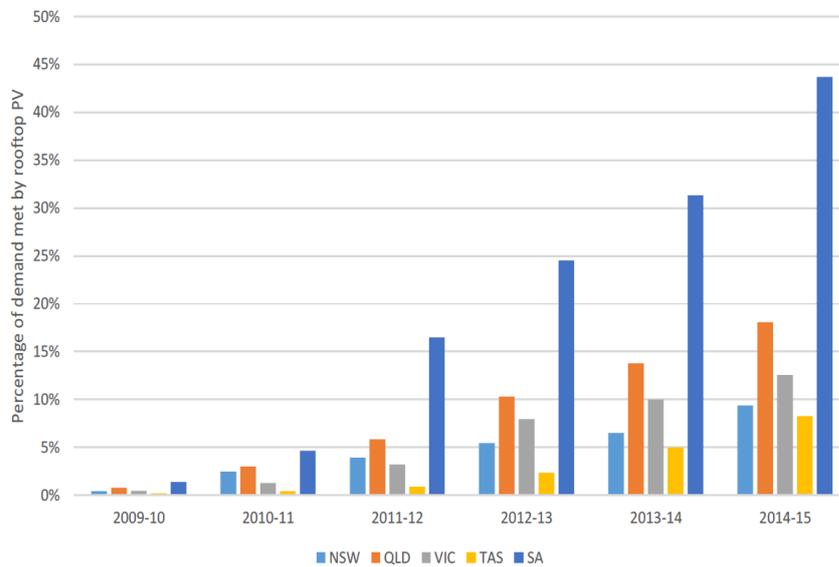


Figure 5 – Percentage of demand met by rooftop PV (Source: AEMO [30])

As solar PV uptake continues to rise, ENA/CSIRO modelling (Figure 6 below) suggests that as early as 2020, zone substation reverse flows due to excess solar will be widespread in South Australia during times of minimum demand, and will be beginning to emerge across the whole of the NEM.

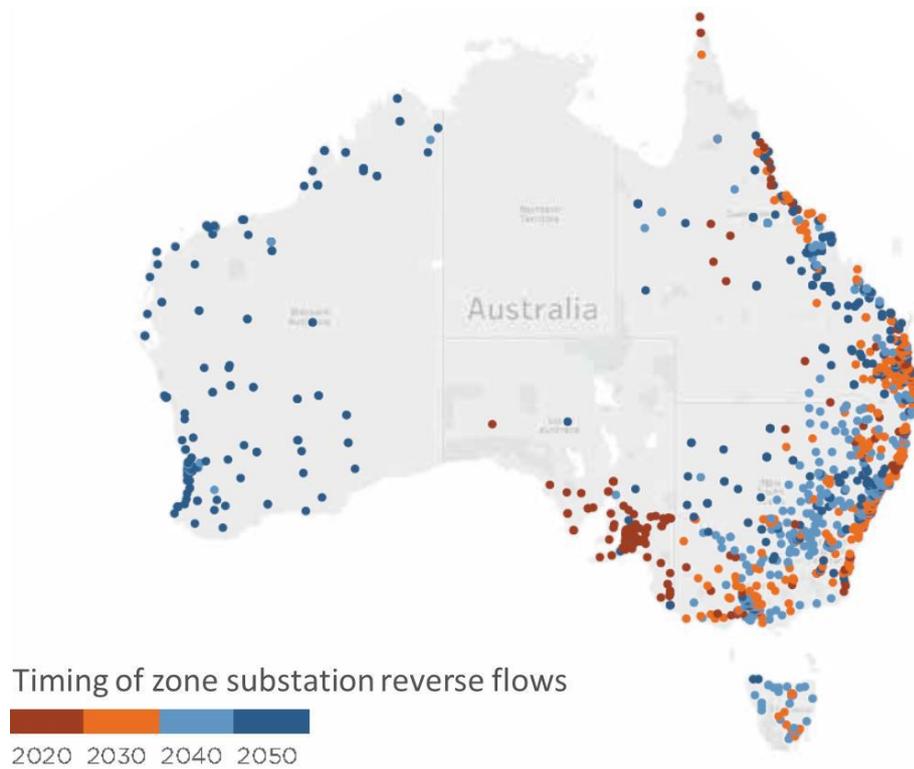


Figure 6 – Forecast zone substation reverse flows (Source: ENA/CSIRO [8])

AEMO is forecasting that in 2027 we will reach the point where installed PV capacity exceeds the state-wide minimum demand of around 1.1 MW – i.e. there will be times when the state’s entire demand for energy will be met by rooftop solar alone. AEMO’s 2016 minimum demand forecast is shown in Figure 7 below.

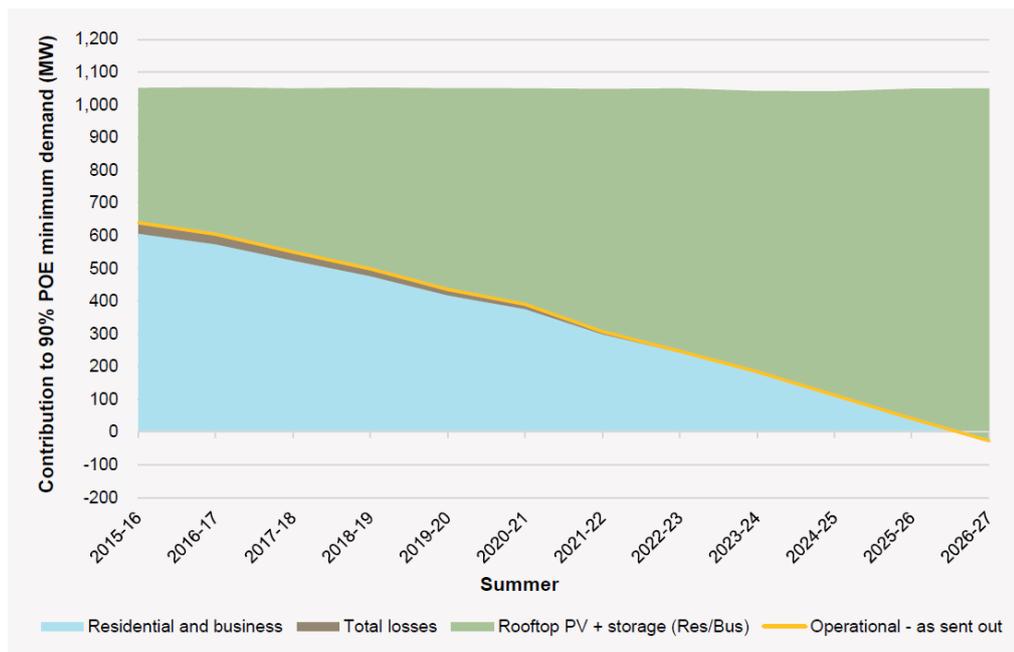


Figure 7 – SA minimum demand forecast (Source: AEMO [31])

As uptake increases from 2027 onwards, we will increasingly experience times when there is a net surplus of energy from rooftop solar, which we will be reliant on the interstate interconnectors to export. At such times the distribution network is effectively running in reverse.

South Australia is also leading the rest of Australia in the uptake of battery storage, and is currently the focus of retailers and others seeking to develop the battery market. SA Power Networks rolled out the first large-scale Virtual Power Plant (VPP) based on residential (behind the meter) battery storage in 2016 with the 100-customer Salisbury battery trial. AGL subsequently announced a 1,000 customer VPP project in SA, which is (as of mid 2017) currently rolling out. At the time of writing we are in discussion with another retailer who is seeking to roll out another VPP of similar size to AGL's, again in South Australia.

The focus on South Australia is driven by the fact that SA now has the highest wholesale and retail prices in the NEM, and the desire to unlock greater benefits from the very high penetration of rooftop solar by storing energy for use during times of high demand. There is also strong interest in the potential of batteries to provide both backup power for individual customers and system-wide grid stability services such as very fast frequency response, to mitigate emerging grid stability and availability risks in South Australia arising from the very high levels of intermittent generation and associated low system inertia, discussed further below.

2.2 Decarbonising energy supply and the changing energy mix

These changes are also being influenced, and to some extent accelerated, by broader societal issues and trends.

On a global scale, investment in new generation is shifting away from traditional thermal plant to renewables, primarily wind and solar, driven by the international carbon reduction agenda. Global coal consumption peaked in 2014 and is declining [32], and 2016 saw a succession of announcements from major countries of targets to phase out coal generation, including Canada (2030), the UK (2025), France (2023), Germany (2050), Finland (2030), the Netherlands (2030), Austria (2025) and Portugal (2020), with several other nations such as Belgium already having closed their last coal-fired power stations.

These global market forces, combined with domestic emissions reduction policies, are accelerating the phasing-out of coal-fired generation in Australia and the shift away from baseload thermal generators to large-scale renewables. Australia's most emissions-intensive coal-fired power station, Hazelwood in Victoria, closed in March 2017. At that time an Australian Government Senate Inquiry recommended that an orderly plan be established to retire Australia's remaining coal-fired power stations, although no specific target date has yet been set [33].

As a signatory to the Paris Climate Agreement, Australia has committed to reduce carbon emissions to 26%-27% below 2005 levels by 2030.

The ENA/CSIRO Electricity Network Transformation Roadmap (ENTR) project has modelled long-term future pathways for the electricity sector in Australia and concludes that if Australia is to meet its commitments under the Paris Agreement then the electricity sector must reduce sector-wide emissions to 40% below 2005 levels by 2030, and fully decarbonise by 2050. The ENTR final report finds that with the right policy settings and industry actions this can be achieved while preserving security of supply and reducing cost to customers [8]. Figure 8 below shows the forecast change in generation mix in Australia to 2050 under the ENTR pathway to decarbonisation.

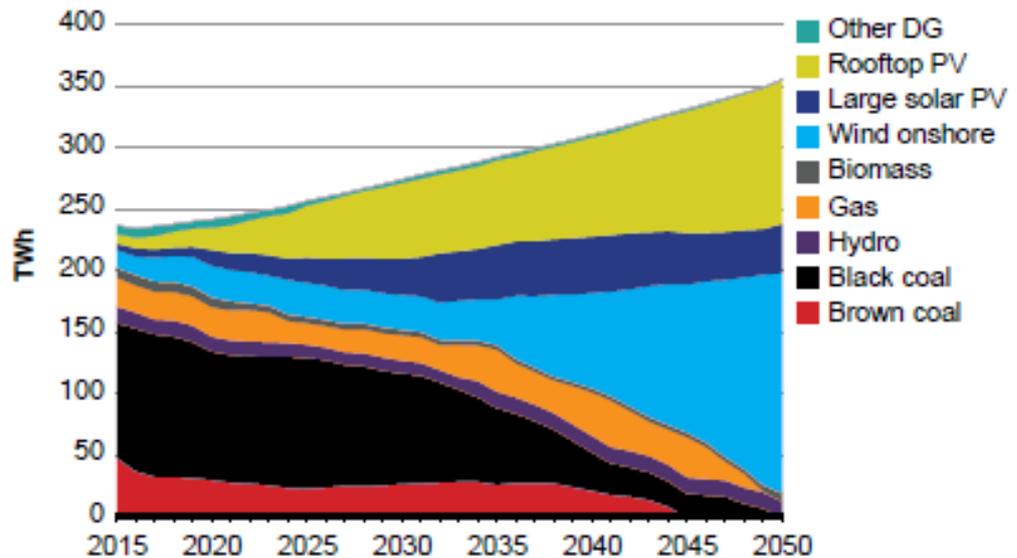


Figure 8 – Australian electricity generation mix forecast, ENTR pathway for decarbonisation by 2050 (Source: ENA/CSIRO [8])

As with behind-the-meter technology, South Australia is at the forefront of this transition in large-scale generation. In 2015 the South Australian Government set aggressive targets of 50% of energy to be produced from renewables by 2025, and state emissions to be net zero by 2050 [34]. SA's last coal-fired power station was retired in 2016, and in April 2017 the Government announced that its 2025 target had already been met, with 53% of energy generated from renewables in the prior 12 months.

As the use of local dispatchable thermal baseload generation has declined, replaced by increasing reliance on intermittent, inverter-connected wind and solar plant, there has been an increase in market price volatility in South Australia, which has contributed to significant retail price rises in 2016 and 2017, to the point that SA's prices were reported to have become 'the highest in the world' in mid-2017 [35].

There has also been a significant reduction in system inertia in South Australia, and an increasing reliance on energy flows across the interstate interconnectors for grid stability and security of supply. This issue and the associated risks were highlighted in the state-wide blackout event in September 2016 [36], and have been the subject of numerous reports and extensive public debate since, not only as an issue for South Australia but also as an indication of the risks and challenges facing the whole of the NEM as the energy sector decarbonises and system-wide inertia reduces, at a time when extreme weather events are expected to become more prevalent due to the effects of climate change.

In response to these issues the South Australian Government announced an Energy Plan in March 2017 comprising \$550 million of Government investment in a range of measures intended to reduce risks to supply and relieve pressure on prices, including a grid-connected 100MW/100MWh battery, 200MW of temporary diesel generation to mitigate potential supply shortfalls in the 2017/18 and 2018/19 summers, a new gas-powered peaking plant, and increased power for the Energy Minister to direct the market during times of risk [37].

2.3 Electric vehicles

The other global trend that has the potential to have a significant impact on the electricity system in Australia is the electrification of transport.

2.3.1 Global outlook

According to the most recent data from the International Energy Agency [19] the worldwide stock of electric cars reached 1.3 million in 2015, a near-doubling on 2014 levels, with the US, China and Europe being the largest markets. IEA's forecast is that the number of EVs globally will rise to more than 30 million by 2025 and will be between 150 million and 715 million by 2040, depending on carbon reduction policy⁴.

In 2016 and 2017 several European countries have announced targets to phase out new sales of internal combustion engine vehicles, including Norway (2025), the Netherlands (2025), Germany (proposed an EU-wide ban by 2030), France (2040) and the UK (2040).

50% of automotive executives surveyed in KPMG's Global Automotive Executive Survey in 2017 cited electric vehicles as the #1 key trend in the industry. This is borne out by recent public statements from major manufacturers including VW, Renault, Ford and BMW all committing to significant investment in electric vehicles, most recently Volvo's announcement in July 2017 that all new models from 2019 onward would be electric or hybrid.

Public charging infrastructure also continues to grow, with IEC figures showing that the number of AC chargers grew from 94,000 in 2014 to 148,000 in 2015, and the number of DC fast chargers reached an estimated 57,000 by the end of 2015 [20].

There is also a trend towards faster (higher-powered) chargers, with the most popular EV in Europe in 2016, the Renault Zoe, capable of charging at up to 22kW (AC). In November 2016 BMW Group, Daimler AG, Ford Motor Company and Volkswagen Group (including Audi and Porsche) signed a MoU for a joint project to roll out a network of 400 ultra-fast DC charging stations of up to 350kW (three times the size of a Tesla 'Supercharger' station) across Europe, commencing in 2017 [21].

2.3.2 South Australia

While the global market for electric vehicles is accelerating, driven by generous Government incentives in countries with strong carbon reduction targets (50% of all new cars sold in Norway in the first half of 2017 were electric or hybrid), a lack of similar incentives in Australia means that the domestic market is yet to take off. AEMO's latest EV uptake forecast, published in August 2016 based on modelling work undertaken by Energeia [14], predicts that, under a 'Neutral' growth scenario, EV uptake will grow slowly in South Australia prior to 2025, after which expected price parity with conventional vehicles drives more rapid uptake. By 2036 in this scenario there are some 240,000 EVs on the road in South Australia, representing 22% of all vehicles. Under a strong growth assumption in which EV prices fall more rapidly than expected and there are additional government incentives to stimulate the market, EVs represent 34% of the SA vehicle fleet by 2036. These forecasts are shown in the figure below.

⁴ IEA's base case is aligned with current international commitments for carbon abatement. Their high case, which sees the number of EVs reach 715 million in 2040, is based on the more aggressive rate of carbon abatement expected to be required to limit global warming to 2 degrees.

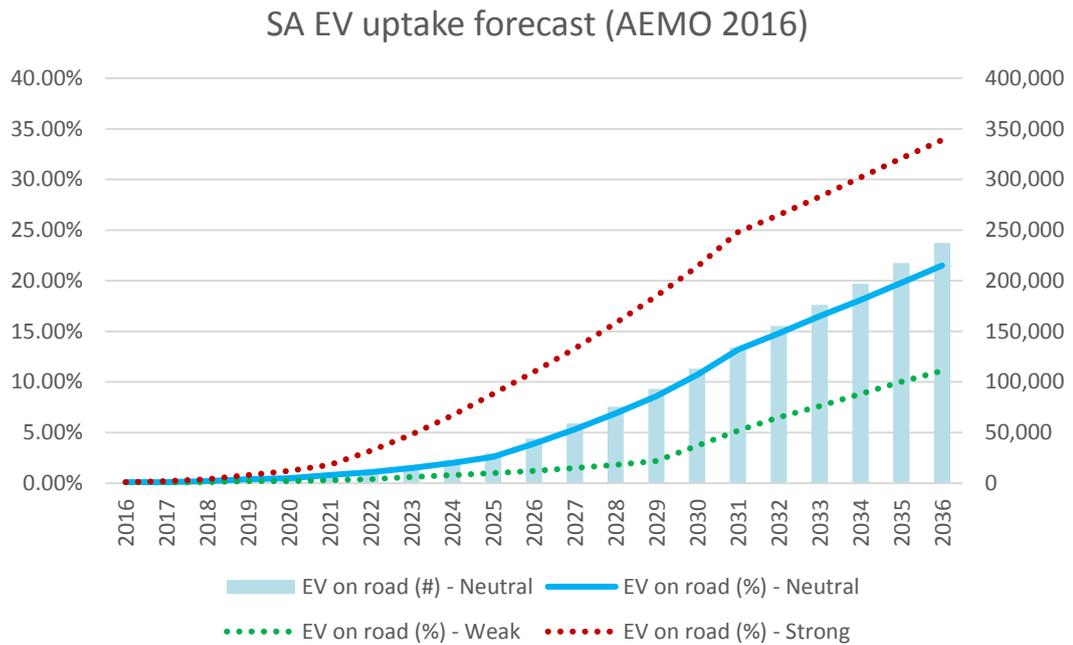


Figure 9 - AEMO forecast of EV uptake in South Australia

CSIRO’s 2016 study for the ENA Network Transformation Roadmap project used the same Energeia modelling and extrapolated further, predicting that EVs could represent 40% of the vehicles on the road in South Australia by 2050 under the ‘neutral’ case [3].

AEMO’s ‘Neutral’ EV uptake scenario would result in an additional 500 GWh of energy consumption annually in SA by 2036, as shown in Figure 10 below. According to CSIRO’s long-range extrapolation of these forecasts, this could potentially rise to 1,500 GWh by 2050, a 15% increase in energy compared to today.

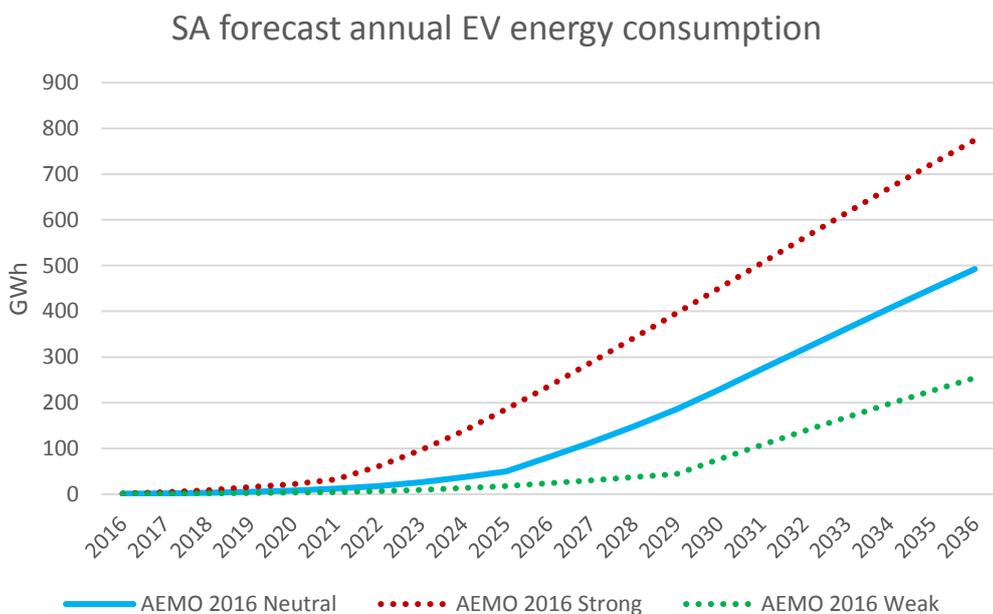


Figure 10 - AEMO forecast EV energy consumption

If the transition is managed appropriately, the electrification of transport has the potential to materially increase energy throughput and utilisation of our network assets and therefore reduce unit cost for all customers. On the other hand, EV fast charging infrastructure, if used in an unconstrained way, has the potential to worsen network load factor and drive new pockets of local peak demand growth.

2.4 Impact on the distribution network

The continued uptake of DER will have material impacts on networks that were not designed for complex two-way flows of energy. These impacts will arise first in the low voltage network, where the effect of increasing penetration of solar PV and other DER is to increase the dynamic range of power flows between peak demand and peak export, and the rate with which the system can swing from one end of this range to the other. This happens naturally because of the intermittent nature of solar PV and the transient effects of cloud cover⁵, but will be exacerbated by the aggregation of customer DER into Virtual Power Plants that enable customer resources to be dispatched in a coordinated manner in response to market signals.

These effects can be seen in the data from our Salisbury battery trial shown in Figure 11 below.

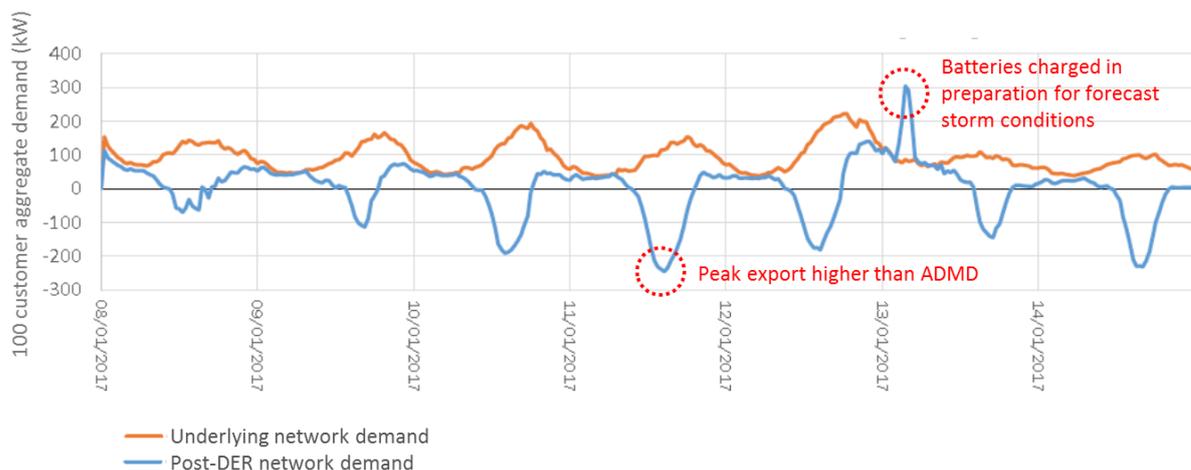


Figure 11 – Salisbury battery trial – aggregate customer load profile

The figure shows the aggregated load profile for 100 customers, each with 3-5kW of solar and at least 6.4 kWh of battery storage, for a week in January 2017. The data illustrates three emerging phenomena:

- The peak solar export for these customers, during the middle of the day, was greater than their afternoon peak demand. This is because afternoon peak demand is reduced, in aggregate, by diversity, whereas solar output is largely undiversified. In this case the addition of battery storage has had almost no effect on the size of the solar trough, because customers' batteries are normally fully charged by early afternoon, leaving their solar to export to the grid at full power.
- Without DER, demand for these customers would have varied each day between a minimum of around 50kW overnight and a maximum of 250kW in late afternoon, a range of 200kW. With the addition of DER the dynamic range has more than doubled, with demand varying from -250kW +200kW in a single day.

⁵ In its 2016 Future Power System Security roadshow, AEMO cited an example of a 100MW solar plant in SA that recorded an 80MW drop in output in one 5 minute interval, due to cloud cover passing overhead [38].

- On the morning of the 13th of January, SA Power Networks sent a signal to all customers' batteries to charge from the grid, to maximise available backup power in anticipation of possible outages due to a severe storm forecast for the afternoon. The resulting spike in demand from this co-ordinated event can be seen in the figure. As more and more batteries are installed they will be aggregated into VPPs by retailers and others precisely for the purpose of dispatching them in a coordinated manner in response to market price signals. In the absence of any mediation, the resulting spikes in import or export energy will exceed the ratings of network assets that were designed based on an assumed level of diversity.

These variations in energy flows have an immediate impact on system voltage in the LV network, which shifts from low voltage at peak demand times to high voltage at times of high export. Once a threshold level of solar PV is installed in a local area, existing approaches to voltage regulation will be insufficient to maintain voltage within the regulated range. Modelling undertaken by consultant PSC for SA Power Networks in 2014 [9] indicates that this issue will be observed first in older, thinner LV networks⁶ and rural locations where PV is not consumed locally. For older overhead networks PSC found that compliance limits are likely to be breached when DER penetration reaches 25% of households, a figure that is already being exceeded in many areas of the network. As well as flicker and the potential to damage customer equipment, voltage excursions will cause AS4777 inverters to disconnect, potentially leading to cycles of connection and disconnection in areas of high DER penetration.

As DER penetration continues to grow, the unconstrained co-ordinated dispatch of DER has the potential to overload assets or breach technical constraints higher in the distribution network and even ultimately at transmission level, placing overall system security of supply at risk.

At a state level, system inertia in South Australia will continue to decline as the energy mix continues to shift towards inverter-connected generation. This, combined with the intermittency of solar and wind generation and the general trend towards more frequent episodes of extreme heat and storm events as global temperatures rise, presents significant future challenges to AEMO in balancing supply and demand and maintaining system stability, in particular when the system is perturbed by damage, fault or a market irregularity. SA Power Networks will have greater opportunities in future to use distribution network-connected assets to provide system support, and hence will have a greater role to play in helping AEMO to manage the overall stability and performance of the electricity system in South Australia.

Finally, in an environment where customers have seen significant rises in the cost of grid electricity and are seeing increasingly greater choice and higher levels of service offered in other markets, this is causing many to question the sustainability of traditional electricity supply business models. A number of new market entrants have already emerged that are seeking to capitalise on these changes and this is likely to accelerate the rate of disruption.

2.5 The ENA / CSIRO Electricity Network Transformation Roadmap

In late 2015, Energy Networks Australia (ENA), in partnership with CSIRO, launched a major project to develop an industry-wide response to the profound changes occurring in the electricity sector. This work followed on from the *Future Grid Forum* process convened by CSIRO in 2012 [39] and involved a substantial body of new research into the future of Australia's energy system, as well as extensive consultation across industry, government and consumer groups.

The ENA project culminated in the publication in April 2017 of the *Electricity Network Transformation Roadmap*, a 10-year plan for the electricity transmission and distribution sector

⁶ Newer network is expected to have fewer and/or more easily resolved issues due to thicker conductors and higher density of consumption.

intended to guide a structured transition over the 2017-2027 decade. The Roadmap seeks to achieve five consumer outcomes expressed in the ENTR Balanced Scorecard, shown below.

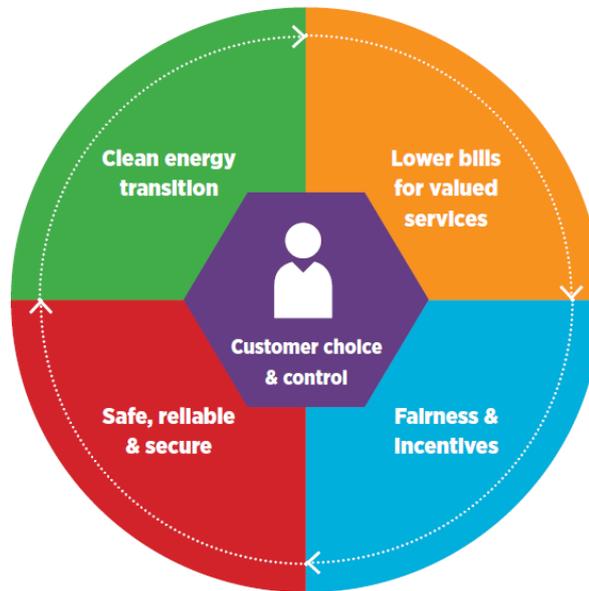


Figure 12 – ENTR Balanced Scorecard (Source: ENA/CSIRO [8])

The modelling undertaken for the Electricity Network Transformation Roadmap offers a positive message: in spite of the significant challenges currently facing the electricity sector in Australia, a future with affordable, secure, reliable and low emission electricity is entirely feasible with technology that is already at hand, given the right policy settings and actions by industry.

The ENTR modelling envisions a 2050 future where⁷:

- Customers retain security and reliability essential to lifestyle and employment
- Networks pay distributed energy resources customers over \$2.5 billion per annum for grid support services by 2050.
- The electricity sector achieves zero net emissions by 2050
- \$16 billion in network infrastructure investment is avoided by orchestration of distributed energy resources
- There is a reduction in cumulative total expenditure of \$101 billion by 2050
- Network charges in 2050 are 30% lower than 2016
- There is a \$414 annual saving in average household electricity bills (compared with the Roadmap counterfactual and business as usual scenarios)
- A medium sized family who cannot take up distributed energy resources is over \$600 per annum better off through removal of cross subsidies

SA Power Networks was a contributor to the ENTR project through 2016. Our own Future Network Strategy development has both shaped and been shaped by this broader body of work,

⁷ Note that all figures are from CSIRO/ENA 2050 scenario modelling and are indicative NEM-wide average outcomes

and the roadmap set out in this document aligns broadly with the ENTR roadmap and its key milestones.

2.6 Summary

The electricity sector is in the early stages of a profound and unprecedented transition, driven primarily by accelerating customer adoption of new distributed energy resources. If we do not move quickly enough to adapt our own network and business, these changes could:

- **Overload existing assets:** particularly at times of peak export;
- **Exceed static quality of supply (voltage) tolerances:** risking damage to customer equipment and/or limiting customers' ability to export energy from their DER;
- **Increase short-term voltage variations:** due to, for example, variable cloud cover, or 3rd party dispatch of large numbers of resources, resulting in flicker and potential appliance malfunction; and
- **Reduce the resilience of the network to faults:** whereby relatively small network perturbations could place the stability of large portions of the network at risk.

Aside from technical challenges, these changes could also significantly reduce the amount of energy transported through the network, as customers become more and more self-sufficient, thereby increasing the unit costs of energy supplied via the grid. Increasing energy costs in turn risk customers leaving the grid altogether and relying on standalone systems, potentially even if this is not efficient for the community as a whole.

Equally, this new future also presents opportunities for:

- **Improved network efficiency:** through leveraging distributed resources for network support, leading to a long-term reduction in cost to consumers; and
- **Supporting new markets:** by providing a robust platform to enable customers to share energy and/or trade utilising their distributed energy resources, and supporting the electrification of transport.

Given these significant risks and opportunities, it is important that we develop robust strategies to transition the way the network is planned, designed, constructed, maintained and operated in coming years to ensure that our distribution network and service offerings are fit for purpose in the new energy future. If we can integrate DER effectively in our network and business processes we will have tremendous opportunities to enhance efficiency, improve resilience, reduce costs, and develop new value streams.

Further, given our annual investment in the order of \$300 million, and asset lives typically measured in tens of years, it is important that we commence this transition urgently.

3 THE FUTURE NETWORK STRATEGY

Transforming our network and services to meet customers' future energy needs

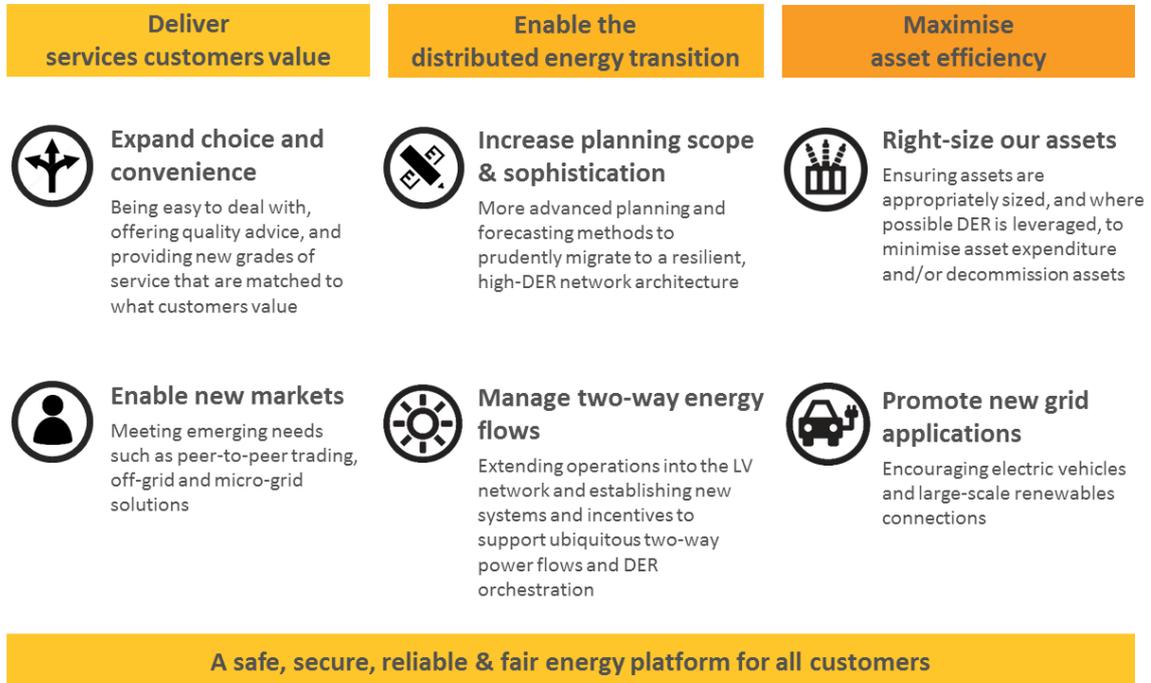


Figure 13 – Future Network Strategy

The Future Network Strategy is summarised in Figure 13 above. At its core it is a strategy for managing the transition from a centralised energy system to one increasingly defined by the actions of very many small-scale distributed energy resources (DER). It is fundamentally concerned with the synergy between the value the network provides to DER owners as a platform for the exchange of energy, and the value that DER can provide to the network in the dynamic management of energy flows.

3.1 Our goals

Our strategy is framed by the following four strategic goals:

- **Deliver services customers value**, by adapting our services to meet customers' changing needs and expectations
- **Enable the distributed energy transition**, to keep pace with the forecast rate of connection of new distributed energy resources
- **Maximise asset efficiency**, by promoting new grid applications and leveraging DER to minimise new asset expenditure
- **Maintain a safe, secure, reliable and fair energy platform for all customers**, that meets the expectations of the South Australian community for an essential service

3.2 Our six core strategies

We will deliver on our goals through six core strategies:

Strategy 1 – Expand choice and convenience

We will become a more customer-focused network. We will make sure that we are easy for our customers to deal with, and we will broaden our service portfolio to offer customers a wider range of choices, with new grades of service that are matched to what customers value. We will support our customers in choosing the best energy solutions through high-quality, independent advice.

Strategy 2 – Increase planning scope and sophistication

We will raise our network planning capability to the level required for a high-DER network, by implementing advanced planning and forecasting processes that take into account the dynamic behaviour of distributed energy resources such as solar PV, battery storage and controllable loads. Building the capability to model network impacts of DER right down to the low voltage network, to forecast constraints arising from reverse energy flows and to identify opportunities for non-network solutions to network constraints, will underpin our ability to migrate to a high-DER network architecture.

Strategy 3 – Manage two-way flows

We will extend our grid operations capabilities into the LV network and establish new standards to operate and control a network increasingly characterised by multi-directional power flows. We will integrate the orchestration of DER as an operational tool to help to maintain reliability, stability and quality of supply.

Strategy 4 – Right-size our assets

We will adapt our asset investment processes and standards to ensure assets are appropriately sized to meet future customer needs, including ensuring sufficient capacity in the local network to accommodate times of peak solar export. Where possible, we will seek to leverage DER to minimise asset expenditure, and we will explore future possibilities to decommission instead of replace failed assets if there are effective non-network alternatives.

Strategy 5 – Promote new grid applications

We will seek opportunities to increase asset utilisation and enhance the relevance and value of the distribution network by encouraging and supporting new and emerging applications for grid energy such as electric vehicles. We will also actively promote the distribution network as the logical connection point for new utility-scale energy resources such as renewable generators or grid-connected storage.

Strategy 6 – Enable new markets

We will ensure that our network provides a platform that can support new energy market models such as peer-to-peer trading and micro-grid solutions, and we will seek to bring value to the new market through enabling services such as stand-alone power systems.

4 STRATEGY 1: EXPAND CUSTOMER CONVENIENCE

Adapting the services offered by SA Power Networks to ensure they effectively match those that customers will value in the new energy future.

4.1 Strategy

In future, customers will have access to distributed energy resources such as solar PV and battery storage at low cost, and will have new opportunities to optimise their consumption of energy. Our customers will be more diverse and will require a grid connection that is optimised to complement their specific mix of local energy resources. Larger customers, customers at the fringe of the grid, and customers with non-standard connection requirements will have credible alternatives to a grid connection, and we will need to have a compelling offering to encourage them to connect.

Our strategy is to continue to improve our connection process and services to provide a more flexible, customer-centric connection experience. We will seek opportunities to remove cost and delay from our connection process, provide more convenient ways for our customers to engage with us, and broaden our service offering to give customers greater choice. We will seek to go beyond our regulatory obligations in the service levels we provide in order to position for a more competitive future.

There are three key elements to this strategy:

- 1. Reduce connection costs, delays & barriers:** by enabling simple on-line self-service tools for higher volume, indicative and/or simple requests, and by engaging regularly with customers and their representatives to identify key pain-points or improvement opportunities in our connection processes.
- 2. Offer greater choice of connection products & service levels:** providing a range of new services, developed in partnership with customers, that are well suited to varying customers' needs, for example:
 - High-reliability connections for commercial customers
 - A lower-cost 'basic' connection with low capacity
 - Back-up services for customers that are generally independent of the network but want the security of the grid when they need it
 - Thin connections for developers at the edge of the grid, and/or those seeking simply to optimise their mix of grid and local resources.
- 3. Provide energy advisory services:** that support customers in making sound choices in their selection of energy products:
 - At the time of a network connection or alteration request; or
 - Proactively, triggered by characteristics of the customer's load profile; or
 - Reactively, in response to customers' specific requests.

Such advice will be available using on-line tools or otherwise automated for the majority of customers, but may also be provided through our contact centre, or face-to-face on a fee-for-service basis.

This strategy aligns closely with and both supports and is supported by SA Power Networks' 2017 *Customer Strategy* [11], in particular in the key opportunity areas of '*Engage, inform and*

communicate with customers and *'Simplify our processes.'* Further information on alignment of these strategies is included in Appendix D.

4.2 Rationale

SA Power Networks has historically offered a 'one size fits all' approach to small customer connections, aligned with our regulatory obligations and established technical standards. For larger customers and non-standard connections, we apply a rigorous assessment process, which has served us well from a technical and regulatory perspective but has led to the perception among some customer groups that we are difficult, time consuming and expensive to deal with.

If we are to succeed in the long term, when customers have credible alternatives to a grid connection, we must ensure that all customers seeking to connect to the network are highly satisfied with the service they receive from SA Power Networks.

4.2.1 Reducing connection costs, delays and barriers

In order to improve the customer experience and promote grid connections it is important to remove any barriers that make this more difficult for the customer, and offer a connection process that is as simple, cost-effective and painless as possible.

The following statistics are based on information retrieved over 1 year and provide an insight into the potential opportunities to streamline our customer connection process and the savings that could be achieved.

Total customer Enquiries/Connections/Alterations		Embedded Generation Enquiries/Connections (subset of total)	
Indicative Estimates	805	Large (>200kW)	24
Firm Estimates	2,647	Small (30kW-200kW)	63
Basic Connections/Alterations	28,679	PV (Import/Export)	10,293

Number of Offers Generated from 1/7/2015 to 30/6/2016

Table 1 – Volume of customer enquiries, connections and alterations

Total customer Enquiries/Connections/Alterations		Embedded Generation Enquiries/Connections (subset of total)	
Indicative Estimates (8 to 25 hours)	\$1,200	Large (>200kW) (75 hours)	\$9,000
Firm Estimates (13 to 42 hours)	\$1,900	Small (30kW-200kW) (16 hours)	\$2,000
Basic Connections/Alterations (0.5 to 1.5 hours)	\$70	PV (Import/Export) (1/6 hour)	\$20

Estimated Cost per Task of Processing based on \$120/hour

Table 2 – Estimated cost per unit of processing for customer enquiries, connections and alterations

Total customer Enquiries/Connections/Alterations		Embedded Generation Enquiries/Connections (subset of total)	
Indicative Estimates	\$1.0M	Large (>200kW)	\$0.2M
Firm Estimates	\$5.0M	Small (30kW-200kW)	\$0.1M
Basic Connections/Alterations	\$2.0M	PV (Import/Export)	\$0.2M

Estimated Cost Based on Volume x Estimated Cost per Task of Processing

Table 3 - Estimated cost per annum of processing for customer enquiries, connections and alterations

A review of current processes identified opportunities for a total of 24 short, medium and long-term initiatives targeted at improving the customer connection process. The most important of these are summarised below, and the complete list is included in Appendix B.

Towards customer self-service

The statistics included above indicate that the greatest opportunity for reducing cost is in the provision of indicative estimates (~\$1 million in 2015/16) and firm estimates (~\$5 million in 2015/16). We currently take a rigorous approach in providing indicative estimates that, despite the high use of IT systems (PROEST), still requires considerable manual processing by technical staff.

Over the 2017-20 period we propose to develop a customer self-service portal to automate a portion of the work that is done manually today, in particular for straightforward or standard connection requests. The self-service portal will offer a range of functions including:

- Easy access to relevant and up-to-date technical and price information for customers seeking to connect, so that they can quickly assess their available options. This could include information on stand-alone power system options⁸ as well as traditional grid connections
- Self-service customer quotations
- Online generator connection feasibility assessment
- Tracking of customer connection projects

We intend to progress to a detailed study of the costs and benefits of the self-service portal in 2017 to validate the business case for this initiative, with a view to implementing the portal in stages from 2018.

Process improvement

We have identified a number of other opportunities for improvement in the customer connection process that will be investigated further from 2017. These include:

- Simplify the enquiry, response, evaluation and connection processes associated with the connection of embedded generators
- Simplify our standard customer offers to make them shorter and more easily understood by our customers (in progress)

⁸ To the extent ring-fencing guidelines preclude SA Power Networks providing these as a regulated service, this could be general information on cost and capabilities of such systems.

- Develop a tool that facilitates the provision of electronic invoices for our customers and improve our credit card payment facilities for customers (in progress)
- Critically analyse the effectiveness and efficiency of our indicative offer process and investigate whether a simplified, less formal process could be adopted with consideration of the appropriate level of risk management
- Revise the current standard charges associated with basic connections and investigate whether they could be minimised, removed and/or condensed so that the application of charges for our services can be made clearer for our customers and contractors (in progress)
- Improve visibility of Field Services work, and introduce a service level agreement with Field Services for connection timeframes and provision of dates for customer connections
- Ongoing development of PROEST that simplifies our estimating, adds more standard templates and provides for electronic NPA approval.

Improving customer experience

We propose to consult with customers in 2017 to seek feedback on areas for improvement in the customer connection process, from the original development application through to the final network connection. Based on the outcomes of this survey, and taking into account alignment with the broader Customer Strategy, we will develop a Customer Experience Improvement Plan for customer connections, to address:

- Internal service standards
- Training for customer-facing staff
- Customer communication plans tailored to specific customer segments, e.g. major customers
- Provision of information, on-line resources and dedicated customer support facilities specifically tailored to customers seeking connections for infill land developments.

We also propose in 2017 to review the current Service and Installation Rules (SIR) with a view to making them less prescriptive and allowing greater flexibility for the customer, while still maintaining a safe electric connection. In particular, we will seek to make the SIR more suited to infill or community title developments.

Finally, we will investigate opportunities to simplify the pricing for customer connections, for example

- A 'no cost' standard connection option
- Replace some of our smaller fees for customer work with a small number of fees that are simple to understand by all concerned and are easy to apply. For example, some network operators in Victoria have a standard fee for a range of 'single truck roll' jobs, based on average cost per job.

Reducing cost

We will seek opportunities to reduce connection costs for customers over time, to encourage customers to continue to connect to the grid. One opportunity to influence the cost of connections across the board is in the application of overheads. In 2017 we propose to investigate whether there is scope to rebalance the allocation of overheads in order to reduce the overhead rate applied to some or all categories of customer connection project

Another strategy in regard to reducing connection cost and/or increasing customer-perceived value is to develop a broader range of connection options, so that customers can choose the service and price point that most suits their requirements. This is considered in more detail in the following section.

4.2.2 Offer greater choice of connection products and service levels

SA Power Networks has historically offered a single standard service to customers, particularly in the small customer segment. This is reflective of a number of factors including technical and regulatory constraints that have limited our ability to be able to differentiate service levels between customers.

As the energy market evolves to be more diverse and dynamic there is the potential to offer customers services, products and price points more specifically tailored to their needs and willingness to pay. A greater range of offers may increase customer satisfaction, be more economically efficient, and provide new revenue opportunities.

Different service levels, connection fees and charges

Our strategic goal is to progressively broaden our service offerings over time by introducing a range of new connection products at different price points. Further work is required to develop specific service lines and prices, which will require a detailed analysis of regulatory and revenue implications. At this stage we have identified a number of services at a conceptual level that are candidates for development into new service lines, for investigation in 2017:

- A low-cost 'back up' tariff for customers who are largely self-sufficient, to encourage customers who would otherwise consider going off-grid to remain connected by providing the option to pay a modest annual fee to retain their connection for occasional use, e.g. in the event of a failure of their own DER, or for a 'trickle charge' service to top up their batteries outside of peak hours during extended periods of low solar generation. The development of this kind of tariff was a recommendation arising from the ENA / CSIRO Network Transformation Roadmap project in 2016 [6].
- Options for a high-reliability supply at a premium price, or conversely a low-reliability supply for customers who are prepared to accept an increase in outage risk in return for a lower connection fee and/or network tariff. Further investigation is required into the potential regulatory barriers to offering customers these kinds of choices.
- Capacity tariffs or standing charges that have an agreed maximum power in both import and export directions, e.g. a '12 kVA import / 4 kVA export' service. From the consumer's perspective this would be analogous to familiar broadband connection products (e.g. a standard broadband service has a much lower uplink speed than downlink, but a business user can pay a premium to have a higher uplink capacity). From SA Power Networks' perspective this would be an enabler for future price signals that would more accurately reflect the cost to the network of managing excessive reverse flows at times of peak solar export, as well as high import demand in the traditional later afternoon summer peak.
- Schemes that enable customers or groups of customers to aggregate multiple NMIs into a single tariff, to provide better price signals for commercial customers who are willing to manage their maximum demand across multiple sites, and as an enabler for new community peer-to-peer trading schemes.

These and other opportunities are summarised in Table 4 below, grouped into the following indicative timeframes for delivery: items marked as 'QW' are quick wins, which are either already actively being pursued, or can potentially be implemented in less than 12 months. 'S',

‘M’ and ‘L’ are short (< 3 years), medium (3-5 years) and longer-term (> 5 years) opportunities respectively.

No.	Item	Timeframe	Description
1	Aggregate NMIs	QW	Aggregate site NMIs for specific customers to optimise tariffs
2	Options for customers to have access to cheaper tariffs at off-peak times	S	Provide access to better tariffs for customers for specific items, eg. Controlled Load tariff for electric vehicles.
3	Tariff for optimum load profiles	M	Develop a tariff that enables customers to get discounted power costs if used at the optimum grid periods
4	Higher reliability connection	M	Install the infrastructure necessary with cost reflective charging to ensure a higher reliability connection.
5	Lower reliability connection	M	Minimise the connection assets at a lower cost to an agreed level of reliability
6	Lower capacity connection	S	Minimise customer charges by installing lower capacity and load limiting infrastructure (e.g. for customer / development with high DER) but with agreement on associated risks and contingency including load shedding capabilities.
7	Virtual(Portable) NMIs	L	Allow groups of customers to sum a number of NMI's to one main one to enable advanced network charging (e.g. for P2P trading) or allow their NMI to be portable.
8	Back-up tariff	L	Introduce a back-up tariff that provides back-up facilities in the event of power outages

Table 4 – Options for different service levels

Network-integrated products and services

Another future opportunity is the provision of ‘network aware’ smart distributed generation (e.g. solar), battery storage and other customer-side energy products such as EV chargers or power factor correction equipment along with the network connection. These would be products that are pre-approved to integrate with SA Power Networks’ systems, or pre-configured to operate with specific network tariffs, incentives or connection types. Ready availability of such products could provide the customer with a number of benefits:

- A network connection that is tailored to match the characteristics of their own embedded energy resources and, conversely, energy resources that are optimised to suit the characteristics of their specific network connection and network tariff; for example, an EV charger that is pre-configured with a daily power profile that limits charging rates during peak times, to minimise cost to the customer
- Access to network support incentives, by installing equipment that is pre-integrated into a demand response / distributed energy resource management platform that we can access

- Access to lower cost connections, e.g. by avoiding network augmentation charges in return for providing us the ability to monitor the connection and curtail import or export power from time-to-time when the network is under stress.

The most effective way to provide customers with integrated solutions that combine smart DER with specific network services will need to be explored in the context of the AER’s new ring-fencing guidelines [10], but it is likely that such ‘network aware’ behind-the-meter products will be provided to the customer through third parties and affiliates. The potential benefits for SA Power Networks include:

- Greater visibility of customer-side energy assets, for network planning
- Opportunities to optimise supply arrangements for local network conditions
- Increased DER hosting capacity at lower overall cost to the community
- Opportunity to grow an ecosystem of demand-response enabled resources.

The table below lists four specific opportunities in this area that have the potential to add value to specific customer segments (commercial and industrial) as part of our regulated distribution service. These are grouped into indicative timeframes using the same convention as in Table 4 above.

No.	Item	Timeframe	Description
9	Tendering on behalf of customers	S	Provide customers with the option of SAPN tendering for work on their behalf as part of their connection offer
10	Offer 3 Phase converters	M	Offer the supply of 3 phase conversion equipment to customers
11	Offer LV regulators – (customer side regulation)	M	Offer LV regulation as part of customer connections where appropriate
12	Offer motor start equipment to previous customers to reduce demand peaks	L	Review customer pumps that have been installed in less technologically advanced times and offer to replace with the benefit of a cost benefit analysis which includes capital cost, ongoing operating and maintenance costs and include options of a lease if appropriate.

Table 5 – Bundled products and services

An expanded list of opportunities for new products and services, including those shown above and others that could potentially be delivered in partnership with third-parties, is included in Appendix C.

Summary

The figure below summarises the proposed new connection products from the perspective of the expected difficulty of implementation and likely business impact of each one.

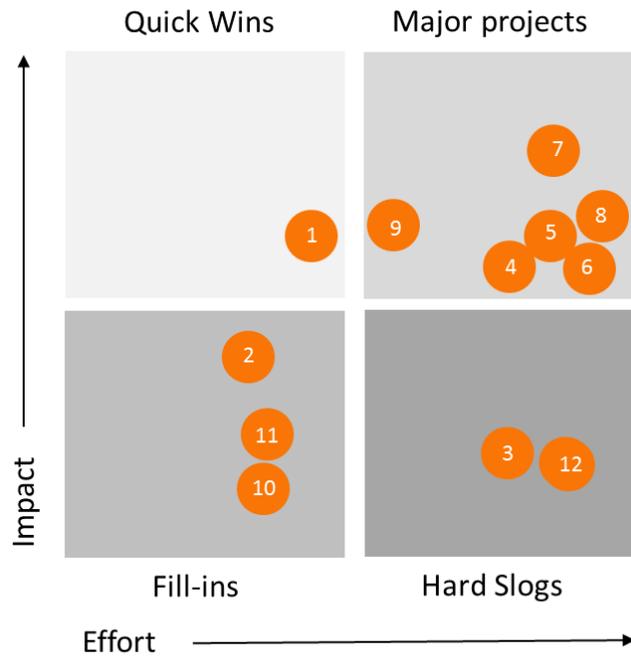


Figure 14 – Prioritisation

As the first step towards an implementation plan for this part of the strategy, we intend to undertake a customer consultation process in 2017 to seek feedback on these potential new service options from our customers.

4.2.3 Provide energy advisory services

With much greater complexity in the energy market, our future customers will value independent, unbiased advice on their total energy solution, not just their grid connection. Customer expectations expressed during consultation for the 2015-2020 Price Reset indicate that customers expect that SA Power Networks should be able to provide such advice. In light of this, SA Power Networks has identified the provision of an energy advisory service as a key plank of our future customer service offering.

A series of interviews were conducted across the organisation in 2016 to establish what advice we currently offer customers. This process found that, while we do offer a range of advice to our customers, this is unstructured and at times ad-hoc. Customers do value the advice and the personalised service that they receive from SAPN, in particular the Major Customer Management group.

SA Power Networks is currently working to define and scope a more formal energy advisory service offering as part of the *‘Engage, inform and communicate with our customers’* stream of the Customer Strategy (refer Appendix D). The scope of this service is expected to include the following:

- Commercial solar and battery
 - Advice for business customers who are seeking protection from electricity price increases and wish to optimise their energy consumption.
- Community grids, off-grid networks and ‘thin grids’
 - Advice in relation to land release developments that incorporate DER, and establishment of micro-grids.

- Embedded networks (inset networks)
Advice on management of an embedded network (e.g. Large shopping centres, airports, apartment and office buildings, aged care facilities) from metering provision through to billing customers.
- Public lighting
Advice on lighting solutions aimed at Local Councils (LGA), SA State Government and Renewal SA.
- Single customer off-grid
To consider customers on the outer reaches of the existing network and the options available to introduce DER and other solutions in lieu of costly network augmentation.
- Tariff advice
To help customers to compare different tariff options and make informed choices
- Business energy audits
Fee-for-service audits of premises to determine optimal energy usage and provide solutions
- Operating costs of domestic and small business appliances
Information that provides customers with the typical running costs of domestic and small business style appliances.
- Residential solar / battery advice
Advice on connecting Solar and/or Batteries for homes
- Electric vehicles
Advice on electric vehicles insofar as how they connect to the network, recharge locations, available tariffs for charging, how to arrange a connection at home, tips and hints for recharging⁹

The intent initially is to provide this advice as a free service to customers delivered through our call centre, web site, major customer management group and other customer channels. From a network perspective, an effective, independent energy advisory service will provide a platform to educate and empower our customers to make sound choices in energy products that will not only deliver the best outcome for them as individuals, but also result in the most efficient long-term use of the distribution network assets for the long-term benefit of all South Australian energy consumers.

Our strategy is to ensure that key points of contact are established between the energy advisory function and relevant areas within network planning and operations, so that our advisory service is informed by the best available information and aligns with our long-term strategies to maximise network utilisation. The advisory function will also form a channel for the customer engagement required to deliver the other strategic initiatives set out in this document.

4.3 Strategic roadmap

The roadmap for Strategy 1 is shown in Table 6 below.

⁹ This also supports Strategy 5, Promote new grid applications, which recommends that SA Power Networks provides new information resources for current and prospective EV owners. Strategy 5 is described in section 8 of this document.

PERIOD	STRATEGIC INITIATIVES
2017 - 2020	<ul style="list-style-type: none"> • Review and simplify Service & Installation Rules and offer letter • Review overhead rates for CC work • Customer consultation and develop customer experience improvement plan • Implement 'quick win' process improvements in connection processes • Improve customer internet experience, develop self-service strategy and design and pilot self-service portal and associated process changes • Pilots to explore network implications of stand-alone power systems and thin microgrids • Investigate options for tailored DER options with connection • Develop energy advisory service
2020 - 2025	<ul style="list-style-type: none"> • Implement self-service portal • Implement customer experience improvement plan • Pro-Est improvements • Expand service offerings to include customer-side equipment: voltage control, 3-phase converters, etc • Offer new tariffs & service levels including backup tariff • Enhance energy advisory service
2025 - 2030	<ul style="list-style-type: none"> • Introduce contractor connection services • Introduce virtual NMIs

Table 6 – Strategy 1 roadmap

5 STRATEGY 2: INCREASE PLANNING SCOPE AND SOPHISTICATION

Implementation of advanced planning and forecasting processes that enable the full impact and value of DER to be assessed & managed, and to prudently migrate to a high-DER network architecture

5.1 Strategy

In a very high DER penetration environment, network planners must not only consider summer maximum demand, but a range of other scenarios including minimum demands, reverse power flows, winter peaks and intermittency. Impacts on the low voltage network must also be considered owing to new and more complex bidirectional power flows.

In addition, consideration needs to be given as to whether the network architecture, optimised for centralised generation, is still appropriate in an environment where generation resources are substantially decentralised.

There are three key components to this strategy:

- 1. Integrate DER into network planning processes:** incorporating DER forecasts and a broader range of scenario analysis into the planning process to identify both network constraints and opportunities to leverage DER to improve efficiency. With this visibility, expanded modelling and forecasting capability and a toolkit of well understood network and non-network options, planners will be able to efficiently determine optimal solutions to a range of network constraints. An analysis of the tools and data required to enable the transition to advanced DER integrated planning will be essential.
- 2. Extend network planning into the LV network:** gain a robust, granular understanding of the DER hosting capacity of the network, it's limiting factors and the most cost-effective remediation measures to permit the continued connection of customer resources.
- 3. Transition to more resilient network design and architecture:** considering changes that might be made to the architecture of the network to adapt to a high-DER future. This could include active quality of supply management technology and enabling segments of the network to operate standalone as microgrids in the event of upstream supply interruptions.

5.2 Rationale

As DER penetration continues to increase, network planning will need to increase in scope to consider expanded load forecasts, scenario analysis modelling and a more holistic and strategic approach to area planning. The depth of planning will also need to extend into the LV network to help gain an understanding of DER hosting capacity across the wider network. This expansion in scope and depth is shown in Figure 15 and explored in detail in the subsequent sections.

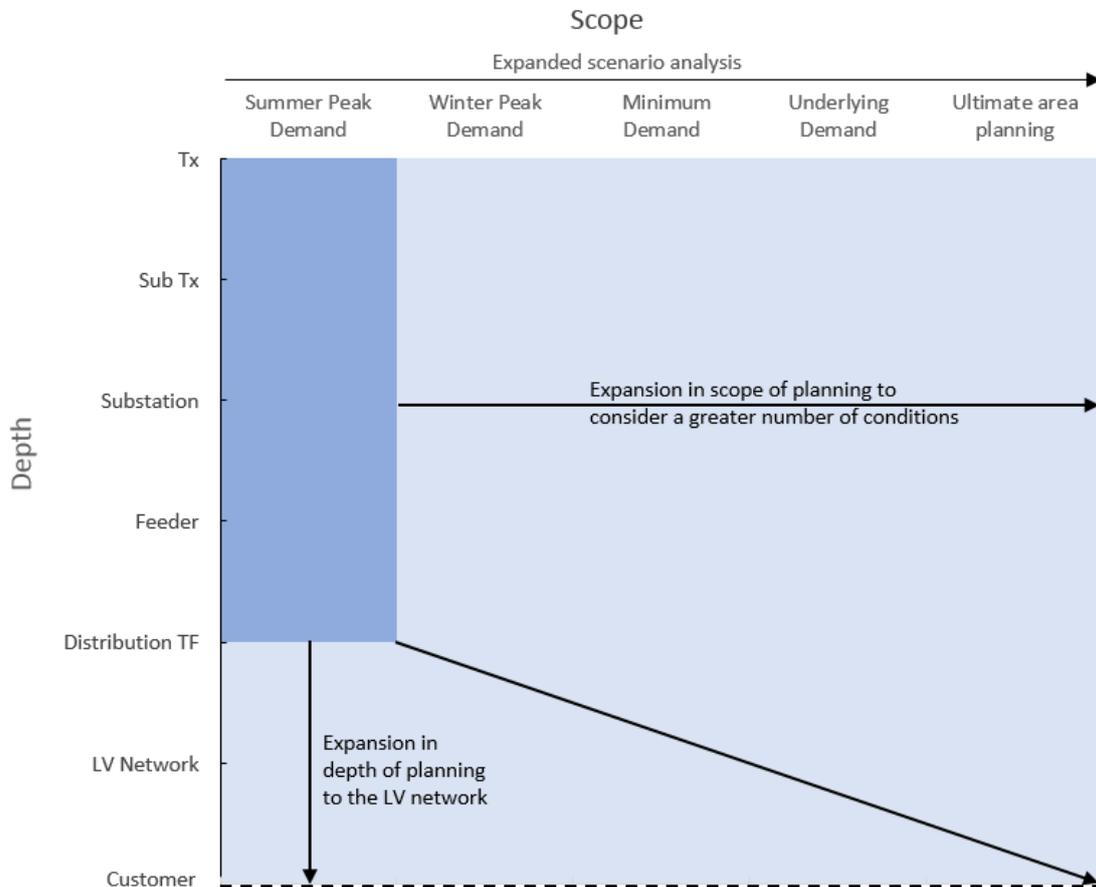


Figure 15 – Increasing depth and scope of network planning activities

5.2.1 Integrating DER into network planning processes

5.2.1.1 Forecasting

With increasing DER penetration it will no longer be sufficient to only produce a summer peak demand forecast. Network planning tools, data sources and capabilities will need to be expanded to allow for winter, minimum and underlying demand forecasts to be produced. These are discussed further below.

Winter Peak Forecast

AEMO’s forecast reduction in summer peak demand due to PV will cause parts of the network to become winter peaking during the 2020-2025 period [31]. SA Power Networks is then obliged under the NER to produce and publish winter forecasts. These alternative peak loads and the corresponding different winter plant ratings will need to be considered when analysing the network for constraints or connection of new load.

Minimum Demand Forecast

During times of mild weather when demand is low and PV output is high, the network will experience minimum demands that are much lower than observed in the past. In some cases, peak reverse power flows may exceed the peak demand in the forwards direction and become the primary factor driving the need for local network augmentation or other remediation measures. Minimum demand forecasts will need to be produced that consider forecast DER to enable modelling of voltage and reverse power flow capacity constraints.

Underlying Demand Forecast

It will also become more critical to understand the underlying native demand of the network to plan for the impact of transient events on the network. For instance, fluctuating cloud cover and reclosing events at times of high PV export could see a rapid change in feeder demand and cause quality of supply issues for customers. In order to produce a forecast of underlying demand, data relating to the location, size and electrical characteristics of DER will need to be captured. This is discussed further in section 6.

The expansion of the forecasting capability is summarised in the figure below.

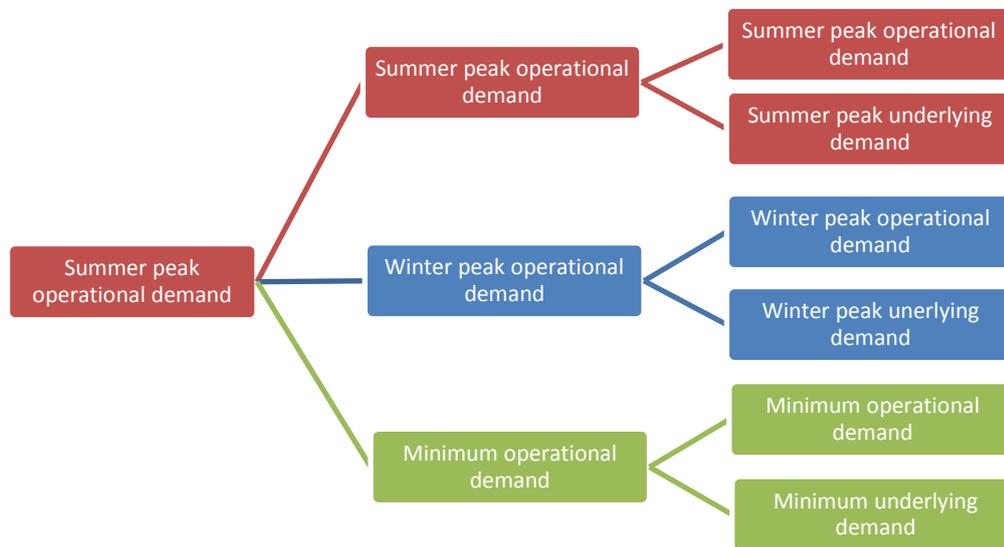


Figure 16 – Expanding scope of modelling for network planning

In addition to informing capacity planning, the new forecast will assist in operational tasks such as preparing feeder/substation offload advice and contingency planning.

Currently an assumed stable load growth rate is used for summer peak forecasting. Forecasting DER is significantly more challenging as it relies on many externalities that are not certain including customer behaviour, technology enhancement and maturity, reductions in price, incentives and business models, etc.

5.2.1.2 Network Modelling

The intermittency and lack of diversity in DER output means that a greater level of scenario analysis modelling will be required to fully understand the impact of DER on the network. The

modelling will need to consider a much larger range of scenarios and factors than our traditional approaches, including:

- A wider range of quality of supply measures
- Different usage patterns of DER
- Transient conditions
- Contingency and maintenance conditions.

This analysis will ultimately need to utilise the more comprehensive forecast data along with information on the local network and the resources on that network.

Modelling tools

In the short term there is an important piece of work in determining if our existing modelling tools will be fit for purpose and to plan the evolution of this tool set, including scenario analysis, data sources and tool automation.

5.2.1.3 Holistic Planning

In addition to the increased scope and depth to existing planning processes, there is an opportunity for an expanded role for network planners that considers a strategic, holistic, long-term approach to planning of whole network areas. Under this expanded role, planners will develop 'ultimate area plans' or strategies utilising the expanded forecasting and modelling capability at their disposal, considering all opportunities to leverage new technologies to implement broad hosting capacity improvements, network automation, system strength improvements and decommissioning of underutilised assets.

5.2.1.4 Other considerations

DER has the potential to increase asset utilisation and defer network augmentations by smoothing load profiles or reducing the ADMD of properties, e.g. in new subdivisions. This potential smoothing of the load profile will require monitoring and may require the review of cyclic rating factors that are presently applied to transformers and cables.

Managing voltage during low demand times in feeder offload scenarios could become an increasing planning challenge. This may result in greater limitations on when feeder offloads can be performed, which will impact operational planning.

5.2.2 Extending network planning to the LV network

Network planning will need to increase in scope to include modelling and simulation at the LV level in order to determine DER hosting capacity across the network, taking into account constraints and solutions at all levels of the system.

It is proposed that this modelling is approached in two phases, described further in the sections that follow:

- 1. Modelling of a small number of prototypical feeders:** across a range of categories and then extrapolating across the network to draw conclusions about hosting capacity, timing of required remediation measures and projected costs.
- 2. A complete electrical model of the system:** the LV electrical model will be augmented onto our HV Network Operating Model (NOM) to allow accurate analysis of individual circuits both for real-time constraints and for forecast and simulated conditions. Ultimately the

modelling tools will be enhanced such that this analysis will be conducted automatically across the network, informing Network Planners exactly where to focus their attention.

5.2.2.1 Phase 1: model prototypical feeders to estimate hosting capacity across the network

In 2014, SA Power Networks engaged consultant PSC in a limited study to model the impact of increasing penetration of solar PV on quality of supply at the customer premises [9]. This study modelled fifteen typical LV circuits representing a cross-section of distinct kinds of supply area and applied the findings to draw some general conclusions as to the likely DER hosting capacity in different regions of the network.

Phase 1 will extend this work to consider:

- The categorisation of our entire network into prototypical models.
- Modelling of these networks to determine underlying DER hosting capacity, including consideration of the upstream HV network performance.
- An analysis of wide range of potential remediation measures to determine the most economical approaches.
- Extrapolating the results of the prototypical modelling with current DER penetrations and DER uptake forecasts to draw conclusions about the DER hosting capacity of the wider HV and LV network, the timing of required remediation measures and the expected spend profile.
- The development of a “ready reckoner” tool that enables simple analysis of any distribution circuit based off some input parameters.

These results can be used to strategically develop and deploy directed HV and LV solutions to increase the DER hosting capacity in areas of the network. It is recommended that a trial of these solutions is undertaken to prove their effectiveness and the accuracy of the modelling.

5.2.2.2 Phase 2: model the whole LV network

The long-term goal is to be able to undertake simulations for network planning purposes based on a complete and accurate electrical model of the whole LV network. The development of such a model at the LV level is an enabler for future network operations as well as network planning, and is a core part of Strategy 3, ‘Manage Multi-directional energy flows’ described in section 6.

Once the LV Network Operating Model (NOM) is complete in ADMS, the abstract model of DER hosting capacity developed in phase 1 may be phased out and replaced by either new scenario analysis tools developed in ADMS or a separate set of modelling tools that leverage the ADMS as a data source.

5.2.3 Planning the transition to a high-DER network architecture

As generation becomes progressively more decentralised and reverse energy flows become increasingly prevalent, our challenge is to ensure that the network architecture of the future is fit for purpose in this new two-way mode of operation.

THE FUTURE DISTRIBUTION NETWORK

NETWORK RESILIENCE

Automatic islanding of micro-grids during upstream interruptions
 Network automation and self-healing

NEW NETWORK DESIGN

Fewer distribution transformers
 Greater meshing of HV and LV networks
 “Decoupling” of network segments for better voltage management and resiliency
 No “tapering” of HV & /LV feeder backbones

SUBSTATIONS

Less redundant plant, N-1 delivered via alternate means
 Greater voltage control
 Energy storage for FCAS, FFR and distribution support
 Greater modularity

UTILITY SCALE RESOURCES

Renewable generation
 Energy storage
 Grid stabilisation plant

CONTROL AND AUTOMATION

Expanded SCADA connectivity, more mid-line equipment
 Greater voltage control technology e.g. automatic tapping distribution TF, STATCOM etc.
 Smart customer inverters and HEMS for grid support
 Aggregated DER dispatch and orchestration

NETWORK PROTECTION

Dynamically adapting to network conditions
 Advanced and fine grained load/generator shedding capability

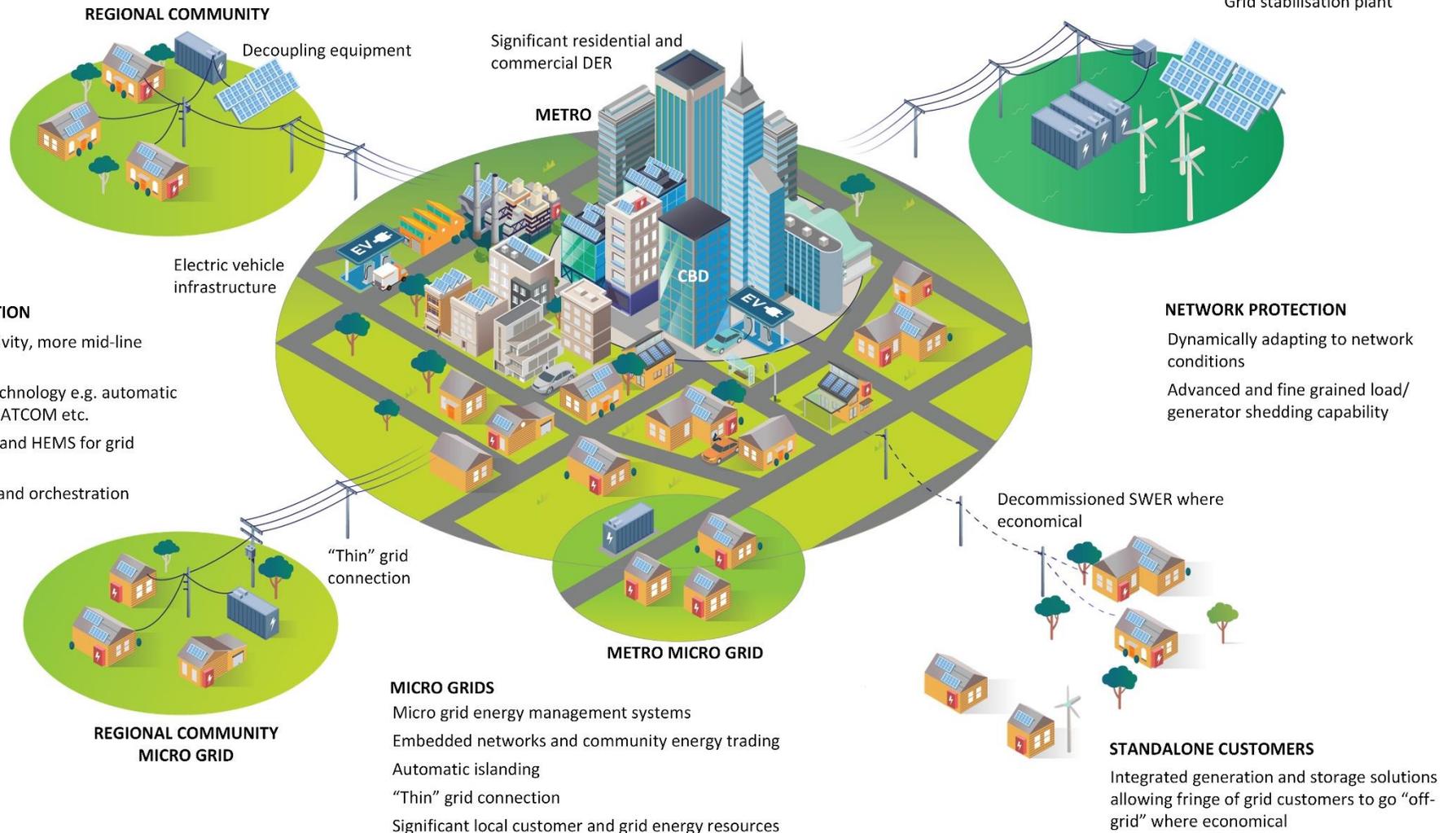


Figure 17 - Future network architecture vision

5.2.3.1 *The future distribution network*

Figure 17 above illustrates some of the elements of the future distribution network:

- In sparsely-populated rural areas, where a SWER line requires significant maintenance or replacement it may become more cost-effective to decommission the line and establish a stand-alone energy system for the local community, or for individual premises.
- More often, regional communities will have sufficient local energy resources to be mostly self-sufficient, but it will be most economical to retain a 'thin' (low capacity) network connection in order to top up local battery storage during winter if there is a shortfall in local solar generation, and to export surplus solar energy in summer.
- New metropolitan and suburban housing developments are expected to be similar, with the energy needs of new infill housing being met largely through local resources, with a 'thin grid' connection to allow occasional import from and export to the grid when required. These communities will also have the capability to operate fully stand-alone for short periods of time, islanded from the rest of the grid, increasing overall resilience of the network.
- New utility-scale resources such as solar farms and grid-scale batteries will connect directly to the distribution network.

5.2.3.2 *Zone substations and sub-transmission*

An optimal future network is likely to have fewer, larger zone substations with greater interconnectivity between them, to provide greater capacity for dynamically managing and balancing power flows. Other design principles that apply to zone substations include:

- Less redundant plant with 'N-1' delivered through other means described in 5.2.3.5
- Substation transformers with greater tap ranges which support both remote and local control
- Installation of grid-scale batteries, potentially owned by third parties, that may be used to trade energy on the wholesale market, provide FCAS or FFR services as well as provide distribution network support
- Greater modularity in design to support greater flexibility in deployment

We expect to see more connection of utility-scale energy resources (e.g. renewable generators) at the high voltage / sub transmission network, and will seek actively to encourage this through Strategy 5, 'Promote New Grid Applications,' described in section 8.

SA Power Networks is required to maintain an agreed power factor at transmission connection points. This has historically only been enforced at peak load times, but in future the challenge will be to supply sufficient reactive power to maintain power factor at times of minimum demand (high solar output). These compliance issues may manifest themselves before significant voltage issues are encountered on the distribution network.

5.2.3.3 *Protection*

Our future network protection devices must operate reliably in an environment characterised by variable two-way energy flows and the low fault currents associated with predominantly inverter-connected generation. As a minimum this may require the capability to vary protection settings dynamically and/or remotely to adapt to changing conditions, but further analysis is required in the short term to determine whether more fundamental changes to our protection schemes will be required.

5.2.3.4 Frequency support and load shedding

SA Power Networks is likely to have a greater role to play in future in helping AEMO to manage the overall stability and performance of the electricity system in South Australia, using network assets to provide system support when there is an imbalance in supply and demand. Some opportunities that exist in this space include:

- deployment of finer-grained and more intelligent load shedding measures to enable us to avoid disconnecting customers who are generating (in under-frequency events) and conversely provide the capability to shed these customers for over-frequency events. Smart meters and greater prevalence of controllable load may, in future, enable load limiting rather than complete disconnection of customers when load shedding is required.
- network dispatched storage to allow SA Power Networks to provide FCAS and/or FFR support
- systematically upgrading Under Frequency Load Shedding (UFLS) relays to support more dynamic settings that can respond appropriately to different rates of change in frequency.

5.2.3.5 Network Resilience

As assets continue to age, system strength decreases and feeders become more difficult to offload due to higher asset utilisation and residential in-fill, we may see a degradation in network reliability and resiliency. New principles will need to be used to meet the reliability and resiliency needs of the future network, for example:

- Greater meshing of the HV and LV networks
- Automatic islanding of network areas during upstream interruptions utilising grid-side equipment in conjunction with customer DER
- Network automation and self-healing

5.2.3.6 HV Feeders

The future HV network will standardise larger conductors and the historical design practice of ‘tapering’ the network so that conductor size reduces towards the end of the line will be abolished.

Extensions and alterations to the HV network will be designed to increase the amount of meshing at the HV network level, to allow for greater flexibility in switching to accommodate feeder configurability, DER hosting and to maximise the opportunity for feeder automation and other self-healing technologies.

SCADA-enabled automation and protection devices will provide valuable monitoring and control points in the HV network to support network operations as well as improved data input for forecasting and model validation.

The introduction of 22kV feeders instead of 11kV for future greenfields developments has been considered, as this offers potential benefits in reduced losses, increased substation capacities, longer overhead feeders and synergies with VPN in purchasing. Initial investigations have concluded, however, that these benefits would be outweighed by disadvantages such as the cost and complexity of introducing a new asset class, the complexity in integrating with the existing 11kV network, and the increased reliability risks that come with larger feeders.

5.2.3.7 LV networks and distribution transformers

As with the HV network, the future LV network will no longer be designed to ‘taper’ but rather to have a constant conductor size to accommodate two-way power flows and to allow for fewer,

larger distribution transformers and greater interconnection in the LV network. Underground construction will continue to be the norm for new developments.

Future distribution transformers will feature automatic voltage regulation. The extent to which these will be deployed will depend on the extent and effectiveness of other voltage regulation means.

Distribution transformers will also, ultimately, have the ability to de-couple the LV network from the HV through AC/DC/AC conversion. This will allow for frequency and voltage control that is independent of the upstream network and enables automatic islanding of the LV network when coupled with grid side or customer battery storage.

The future LV network will also have increased DER hosting capacity simply through effective balancing of load and generation across phases, enabled by greater visibility of the LV network.

5.2.3.8 Transition

Developing the optimal architecture for the future network, and setting out a roadmap to progressively transform the network to this future state in a manner that is prudent and timely, is a major undertaking that will require significant investigation and analysis. This process will commence in 2017 through the initiatives set out in the roadmap below, and will be informed by, and build upon, some key insights captured through the workshops and research tasks undertaken during the development of this strategy

5.3 Strategic roadmap

The strategic roadmap for this strategy to 2030 is summarised below.

PERIOD	STRATEGIC INITIATIVES
2017 - 2020	<ul style="list-style-type: none"> Determine a strategy to expand the scope of current planning processes to integrate DER and extend into the LV network Develop LV hosting capacity model & strategies (inc. modelling / prototypical LV circuits) A trial of various remediation measures for DER management including smart inverter control Select and implement advanced planning & forecasting tools (inc. ADMS data export enhancements and new tool selection) High-DER protection review Feeder automation commissioning & expansion strategy
2020 - 2025	<ul style="list-style-type: none"> Integrate and embed LV NOM and customer DER data into network planning process Implement protection solutions for 2027 net negative demand Expand feeder automation
2025 - 2030	<ul style="list-style-type: none"> Continue to embed DER into network planning process

Table 7 – Strategy 2 roadmap

6 STRATEGY 3: MANAGE TWO-WAY ENERGY FLOWS

Enabling forecast amounts of DER to be connected to the network at minimum cost whilst ensuring that network safety, security, reliability and quality of supply are maintained.

6.1 Strategy

Significant DER penetration has the potential to adversely impact reliability, quality of supply and system security, and will require significant changes to our planning and operational capabilities to manage these risks. In the absence of investment in the capability to more actively manage DER, we will need to continue to rely on highly inefficient 'broad brush' restrictions placed on DER (e.g. static export limits), that may only actually be required a small amount of the time at discrete locations across the distribution network.

To manage increasing DER penetration we will need to extend our grid operations capabilities into the LV network, where we currently have very limited visibility. We will pursue a range of measures to effectively manage DER, from passive measures such as new connection standards, tariffs and incentives through to active grid management as our role evolves from a relatively passive Distribution Network Operator (DNO) to an active Distribution System Operator (DSO).

There are four key components to this strategy:

- 1. Model, monitor and actively manage the Low Voltage (LV) network:** we will establish and maintain an accurate model of our LV network and its connected customers. This model will include electrical parameters, connectivity between customers and assets, load and performance data, and information on installed distributed energy resources. The model will support our network planning processes and ultimately provide the operational visibility required for active DER management (DSO).

We will also increase visibility of the network through a combination of grid-side monitoring and new data sources such as advanced meters, smart streetlights and customer equipment, enabling us to proactively monitor quality of supply and to validate and calibrate the network model.

- 2. Enhance DER connection processes & standards:** to ensure that we receive notification of DER installations, and that customer's inverter settings minimise network impacts under a wider range of circumstances, utilising reactive power to manage voltage and making use of the new features available under AS 4777.2:2015.
- 3. Refine tariff design:** to ensure customers are provided with the appropriate incentives to utilise their DER to minimise network impacts or improve network performance.
- 4. Establish Distribution System Operator foundations:** we will undertake a range of measures to position for a future in which the operation of customers' DER is effectively managed in real time, ensuring that the distribution platform remains secure and reliable for all customers, including:
 - Incentives for customers to install 'smart DER' with communications capability rather than opting for passive systems;
 - Electronic enrolment of smart DER so that key information is available in real-time such as location, services available, performance and sizing; and
 - Participation in trials to explore the systems, processes and capabilities required to enable DER network access to be mediated by the Distribution System Operator.

6.2 Rationale

6.2.1 Modelling, monitoring and actively managing the Low Voltage (LV) network

Traditionally the power system was designed and operated on simple one-way energy flows. The behaviour of customers was predictable and the daily load profile was largely consistent and slow-changing. As such, the expected behaviour of the power system was easy to understand and did not require detailed knowledge of each individual customer, LV network connectivity or the actual performance of that network. It was sufficient to monitor and manage the network at the high voltage (HV) level and, consequently, the lower levels of the network (LV) required only basic record keeping, no real-time monitoring and limited pro-active planning.

In a future where over 45% of energy generation will be connected to the distribution network¹⁰, variable two-way energy flows in the LV network and the lack of data and visibility at this level will make the network performance very difficult to predict and manage using traditional measures.

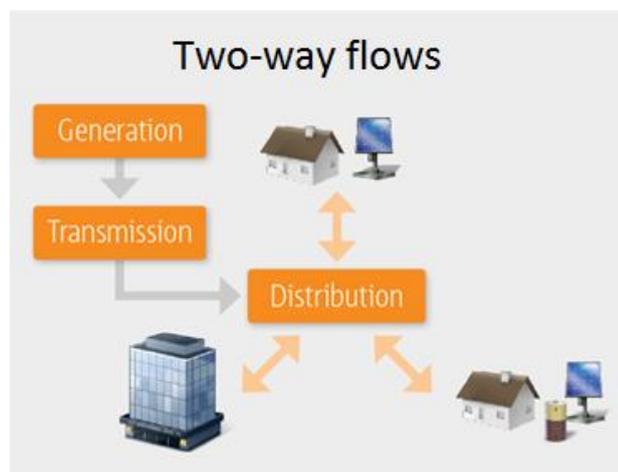


Figure 18 – Two-way energy flows

To support the continued integration of DER onto the network, it is essential that we begin to more actively model, monitor and manage the LV network. The implementation of the model will be used as input for our planning processes, enable us to strategically re-enforce the network to increase hosting capacity, understand how to best leverage DER and provide the operational visibility required for active DER management (DSO).

This model will need to include electrical parameters, phasing, topology, customer connections, load and performance data and information on installed distributed energy resources. It is envisaged that the core model will simply be an extension of the ADMS high voltage model, although other supporting systems are likely to be required for data collation and analysis.

Current state of the LV model

Today LV data is stored in GIS and contains missing, incomplete and incorrect information. Day-to-day switching in the LV network is managed in a de-centralised way by each local depot, meaning that central records do not necessarily reflect the actual state of the network.

¹⁰ ENA / CSIRO modelling – refer ENTR Final Report [8]

The following matrix displays a qualitative measure of the current state of LV network data. The types of data captured for each network level are:

- **Location:** The geographical location of the asset in GIS
- **Topology:** Current topological state (state of switches at each network layer)
- **Characteristics:** Electrical characteristics of the asset
- **Monitoring:** Active data acquisition of state or measured electrical quantities

		Current state of available data			
		Location	Topology	Characteristics	Monitoring
LV Network Layers	Distribution Transformers	Generally well known	Overhead network simple, known Some underground circuits unknown and challenging to identify	Tap position and capability largely unknown	Spot investigations only
	Conductors	Generally well known, poorer for customer connection assets	N/A	Conductor data expected to be poor and with significant modelling errors as per ADMS HV experience	N/A
	Switchable Devices	Some unknowns	Feeder backbones generally known but open points knowledge only fair	N/A	N/A
	Customer	Customer connection location not well known e.g. which side of switching devices	Customer phase information is poor	Generic load profiles Good PV data due to CEC registration, storage an emerging issue	large customers only

Figure 19 – LV network data – current state

Transitioning to a full LV model

The transition to a more complete LV model that will enable active management of the low voltage network will be a significant undertaking that will require both large scale data capture and process improvements across the business to be fully realised. A detailed LV management strategy will need to be developed in 2017 to determine the approach and timeframe for this transition, and to what extent the model can be developed incrementally over time, e.g. to prioritise high-DER areas initially.

Preliminary investigation undertaken during the strategy development process suggests a three-step approach to capturing the required data:

- 1. Review and improve Processes:** A review of Field and Network records feedback processes will be conducted to inform where the non-conformances are and develop a plan to make this process more effective.
- 2. Opportunistic data capture:** using the opportunity to capture data when crews are on site undertaking BAU field work or during unplanned outages. This approach would require simple means for the crews to record and feedback the information to model managers.
- 3. Active data capture:** scoping the entire LV feeder to capture the relevant information. This is likely the costliest option as it requires dedicated labour and often lengthy travel time to reach site.

If implemented effectively, it is anticipated the bulk of the data could be captured using methods 1 and 2 over a period of years. The remaining sites that are visited infrequently under BAU activities could be actively visited. There may also be data analytic solutions to capture some of this data in future; for example, Victorian networks have been able to infer customer phase information through analysis of data captured from smart meters.

Systems will have to be implemented to ensure the model is maintained including LV switching management, network revisions and customer DER records. To inform this strategy, it is proposed that a selection of the feeders from the hosting capacity modelling project described earlier in section 5.2.2.1 are modelled in the ADMS including complete site data gathering.

Active monitoring of the LV network

Active monitoring within the LV network will enable us to proactively monitor quality of supply and validate and calibrate the network model.

There are an increasing number of smart communications-enabled devices connected to the LV network that can measure energy or voltage. These new devices will include 3rd party aggregation systems, EV chargers, advanced meters, smart streetlights, smart inverters and Home Energy Management Systems. Tapping into the data from these devices has the potential to greatly extend our visibility of the LV network, complementing traditional grid-side solutions such as transformer monitors. Many of these devices will be owned by other parties and a method of acquiring and integrating the data needs to be determined.

Instrumentation of prototypical feeders

In the short term, it is proposed to heavily instrument a number of prototypical feeders from the hosting capacity modelling project¹¹ using a variety of traditional and non-traditional data sources. This data will be used to validate and tune the models produced for these feeders and inform the trials of any subsequent remediation works. Extending this monitoring to numerous feeders of each type will test if the prototypical models can form valid representations for the majority of our LV network. The project will also help inform the optimum balance of modelling vs. monitoring and determine the value of monitoring at each level in the system.

This initiative will incorporate a trial of the integration of this data to a common data platform, inform the requirements for operational system requirements and pave the way for ADMS integration.

¹¹ Refer section 5.2.2.1.

LV network management summary

The following table outlines the components that make up the active management of the low voltage network and the capability they will deliver for the business.

Component	Capability
<p style="text-align: center;">LV connectivity</p>	<p style="text-align: center;">Customer to asset mapping Improved notification management GSL and SPS management Outage management Customer management (individual customer experience) Remediation (phase balance)</p>
<p style="text-align: center;">LV model (electrical)</p>	<p style="text-align: center;">Hosting capacity analysis Broader QoS management Foundation for DSO Advanced network planning Foundation for DSO</p>
<p style="text-align: center;">Static customer information*</p> <ul style="list-style-type: none"> - Installed distributed energy resources and major appliances - Embedded generator information - Aggregation platform or scheme 	<p style="text-align: center;">Improve quality of LV model Support energy advisory service and other customer initiatives Foundation for DSO</p>
<p style="text-align: center;">LV monitoring (near real-time)</p> <ul style="list-style-type: none"> - Transformer monitoring - Non-traditional (inverters, smart street lights, smart meters etc.) 	<p style="text-align: center;">Calibration of model Identification of issues Performance analysis Foundation for DSO</p>

Table 8 – LV network management components

*Note this data may be received actively from smart connected resources.

6.2.2 Enhance DER connection processes & standards

Connection notification

Although we currently collect information about customer inverters as part of connection applications, there is an increasing risk of installations with no or outdated data, particularly as incentives to register associated with feed-in-tariffs decrease and the first generation of inverters is upgraded and replaced.

Furthermore, additional distributed energy resources such as energy storage and electric vehicles don't have formal registration processes and an inability to capture, maintain and audit this data will be a limiting factor in the modelling of the network for both planning and

operations. Poor DER data will result in difficulties producing reliable models of the system and may result in having to obtain a much greater quantity of measurement data at significant cost.

A plan will be developed to determine approaches to ensure we receive notification of DER installations/modifications and that sufficient data is captured such that we can assess the capabilities/performance of the DER for network modelling. This will form part of the LV management project static data inputs.

Connection Standards

It is envisaged that simple, low cost measures such as the optimisation of customer inverter settings through standards and/or incentives will go a long way in DER management before more active measures are required.

Currently, the vast majority of small scale inverters connected to our system are set at a constant unity power factor and their only dynamic response capability is to trip on over-voltage. AS4777.2-2015 introduced recommended mechanisms to decrease the impact of inverter connected systems on quality of supply. These include volt-watt and volt-var control modes which vary the real or reactive power output of the inverter in response to the voltage at the inverter terminals. Preliminary modelling indicates that sinking/sourcing small amounts of reactive power can have a significant impact on the voltage and potentially keep customers within acceptable limits even with high penetrations of solar generation on the local network. While the initial focus is on PV generating system, the functionality could be extended for energy storage and electric vehicle application.

There is an opportunity for SA Power Networks to mandate or incentivise the enablement of these modes as either a blanket approach or directed to areas of the network with hosting capacity constraints. These solutions will be trialled as part of an Inverter voltage control trial over 2017/2018 to inform the Hosting Capacity Analysis remediation studies. This project will produce recommendations relating to the standards, requirements and settings of smart inverters across the broader network.

6.2.3 Refine tariff design

Our tariff strategy needs to ensure that, as DER adoption grows, customers transition to network tariffs that provide incentives to use their DER in ways that increase, rather than decrease, network efficiency.

Our experience with the Salisbury Residential Energy Storage Trial has shown that existing energy-only tariffs may result in minimal network benefit from DER. The series of figures below demonstrates the impact of solar PV and storage on a traditional load profile and how different tariffs could encourage more efficient use of DER.

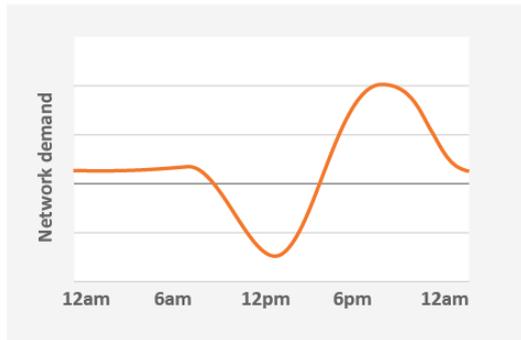


Figure 20 – Customer net demand with solar PV

Adding solar PV does not significantly reduce afternoon peak demand, but imposes a significant ‘negative’ peak in the middle of the day.

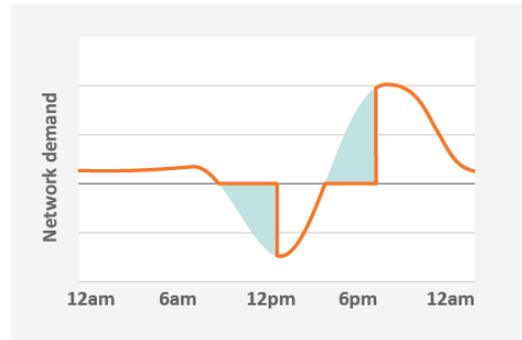


Figure 21 – Optimal PV and battery operation with flat network tariffs

A battery enables solar energy to be stored for evening use. With flat tariffs, the battery is usually fully charged before midday and would be fully discharged during the early evening resulting in no reduction in peak demand or generation.

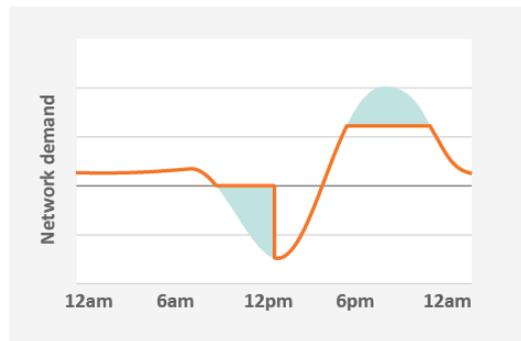


Figure 22 – Optimal PV and battery operation with network demand tariffs

An efficient network demand tariff provides an incentive to discharge the battery more slowly in the evening to reduce the network peak demand. There is, however, still no incentive to reduce peak generation.

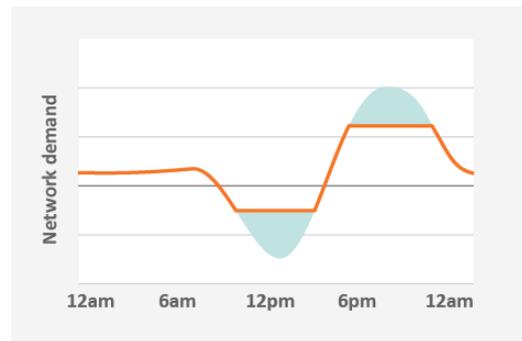


Figure 23 – Optimal battery operation required to minimise network costs

To achieve the optimal charge and discharge operation, some form of incentive is required to ensure the peak generation period is reduced as well as peak demand

Our strategy should consider:

- **Bi-directional or dynamic range demand tariffs:** In a future where over half of all energy generation occurs in the distribution network, the role of the network is shifting from meeting demand to enabling customers to share their energy resources with others. This infers that the ability for customers to export energy is no longer supplementary, but a core service. It is not difficult to foresee a future where large numbers of residential ‘customers’ export far more energy than they import. In turn, this suggests that distributors should be offering firm access to the network to export energy, and consequently, charge customers for this access – otherwise customers who primarily export are effectively subsidised by those that primarily import.

The current National Electricity Rules (NER) do not allow for the concept of a bi-directional demand tariff or a demand dynamic range tariff as networks cannot charge

for generation exports¹². We need to determine the best way to accommodate a price signal for exported energy within the NER framework.

- **Electric vehicles:** Tariffs need to incentivise home EV charging at low power and at off-peak times. We may also need specific tariffs designed for public fast charging infrastructure, which will be associated with very high peak demand potential but low load factors. These issues are considered more in section 8.
- **Opt in vs. opt out:** The AEMC rule change mandating advanced metering for new and replacement meters from December 2017 [12] will enable customers to transition to more cost-reflective tariffs. ENA/CSIRO research shows that if customers are left to 'opt in' to new network tariffs, 70% of customers will remain on legacy tariffs by 2026. By contrast, when customers are assigned automatically to demand tariffs with the option to 'opt out' only 10% would choose to return to legacy tariffs [6].
- **Price signal transparency:** Even with appropriate tariffs in place, the packaging of the customer bill by retailers may obscure the network tariff, disconnecting the pricing signal from the customer. It is unlikely that many customers will directly respond to the pricing signal in any case, instead relying on advice and solutions from energy services companies, 3rd party aggregators, retailers etc. to optimise their energy costs with the help of energy management systems and DER. Our tariff strategy will need to consider how to ensure the network tariff is incorporated into these mechanisms.
- **Loss of diversity:** Care must be taken in tariff implementation that they are scalable, stable response mechanisms and that the algorithms that control their behaviour do not lead, in aggregate, to undesirable, non-proportional, un-diversified responses. Traditionally networks have relied on natural diversity to spread loads, however when we start to introduce tariffs that have specific peak and off-peak periods we introduce the risk of a demand spike occurring at the end of the peak price period. This effect has already been seen with hot water load control, and will become increasingly likely as customers have smarter appliances that bring more load under automated control, including large new loads such as home EV chargers.

6.2.4 Establish Distribution System Operator foundations

Significant DER penetration, if not controlled appropriately, will result in widespread overload and/or breach of technical constraints on the distribution network. The forecast scale of these resources is such that unanticipated orchestration could even breach constraints at transmission level and put overall system security of supply at risk. However, with appropriate controls in place DER could be utilised for the advantage of the network, improving network performance, efficiency, stability, security and ultimately reducing cost to consumers.

The active management of DER will be achieved by implementing a range of progressive measures in the evolution to Distribution System Operator role. This section describes the current thinking regarding this evolution, however the architecture, extent and rate of implementation will be informed by the output of the hosting capacity, LV management and DSO trial initiatives of this strategy and the broader industry development of the Distribution System Operator role and distribution energy markets.

Aggregated and undiversified DER

While it is envisaged that passive measures such as tariffs, grid side solutions and inverter settings standards will go a long way in extending the ability of the network to host DER, significant penetrations and lack of diversity across DER fleets e.g. 3rd party orchestrated control, virtual power plants, will require more active forms of management.

¹² Refer NER 6.1.4

ENA/CSIRO modelling suggests that if incentives are implemented correctly, within 10 years up to a third of customers will participate in some kind of additional incentive scheme either through distributors or third parties, resulting in significant DER under some form of orchestrated control.

It is predicted that a new market for DER network services and energy will emerge and SA Power Networks will be ideally suited to play the role of the Distribution System Operator in mediating access to the network, publishing complex and real time varying constraints to which aggregated dispatches into the Distribution Energy Market must adhere. The DSO will be responsible for maintaining the safe, secure and reliable operation of the distribution network.

This is akin to the role already played by AEMO in ensuring the NEM doesn't exceed the physical constraints of the interconnected system considering real time conditions, forecasts and contingency events and setting the constraints in which the market must operate. The DSO may also have to ensure adherence to constraints published by AEMO and/or the Transmission Network Operator for transmission connection points.

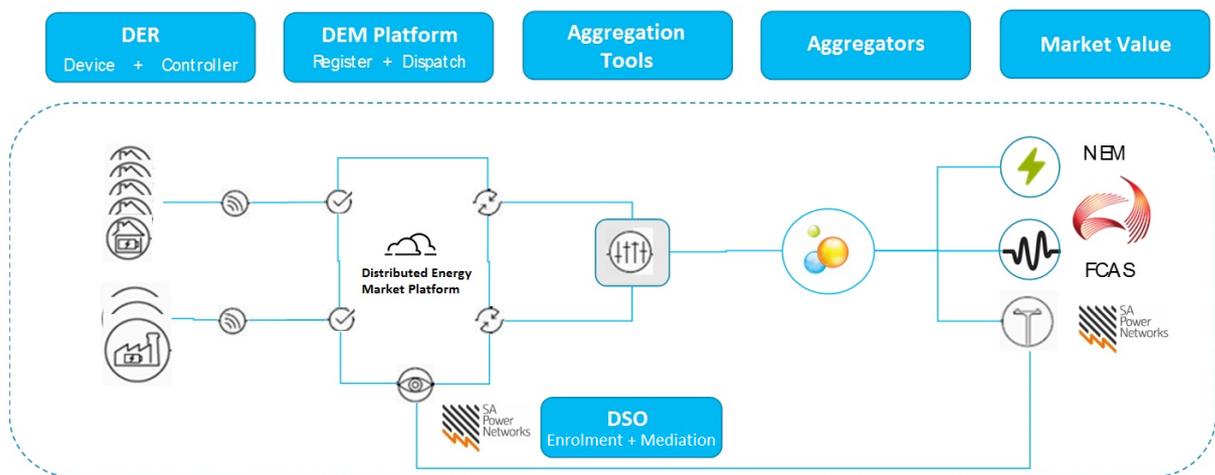


Figure 24 – The role of the DSO in the emerging distributed energy market (Source: Simply Energy)

The solution would likely involve implementing and managing a platform to mediate requests from aggregators to dispatch storage and other generation. This will either need to encompass or integrate closely with the market platform that actually manages these transactions. This platform will rely on the accurate modelling and monitoring of the power system to determine these constraints. Managing the “enrolment” of DER, having accurate real time information about the location and capabilities of DER installed on the network, will be key requirements for DSO/DMO/AEMO during this transition.

Separate from the “policing” function of the DSO, SAPN may also use the forecast or real-time conditions to procure DER resources from the market to support the network in times of constraint. Likewise, customer resources will be bid into the NEM and FCAS markets by aggregators opening up new revenue streams for distributed energy resources.

DSO Strategic Response – foundational capabilities and no regrets actions

Although there is still great uncertainty in the path towards Distribution System Operator, there are some ‘no regrets’ actions that form the essential foundations for the transition to enhanced DER management.

1. **Smart ready DER:** Consideration should be given to incentivise customers to install ‘smart’ rather than passive DER, with **standard interfaces and communications**, on the basis that such smart capabilities could:
 - a) be installed at low incremental cost at the time of DER installation (and are standard already in some vendor’s offerings)
 - b) obviate the need for passive registers of DER, enabling instead active, real-time DER key information to be obtained such as location, services available, performance and sizing;
 - c) provide low cost monitoring of local network conditions to distribution businesses
 - d) provide significant ‘option value’ such that AEMO, DNSPs, aggregators and other parties are provided the ability to readily offer value-added services to these customers once distribution markets become more mature

Smart inverters may also be essential for AEMO to ensure sufficient reserves in the SA market once PV generation exceeds minimum demands in 2026 or earlier.

SA Power Networks will work with Energy Networks Australia and participate in consultation with the AEMC and AEMO to pursue the smart ready DER strategy.

2. **Electronic enrolment:** Establish a register for the automatic electronic enrolment of smart DER. The responsible party of such a register will need to be determined however in any case, systems from the DSO, TSO, DMO, AEMO and aggregators are all likely to require access.
3. **DSO trial:** Establish a DSO trial to explore the systems, processes and capabilities required to enable DER network access to be mediated by the Distribution System Operator.

6.3 Strategic roadmap

The strategic roadmap for this strategy to 2030 is shown below.

Period	Strategic initiatives
2017-2020	<ul style="list-style-type: none"> • Determine LV management strategy • DSO foundations trial • Develop plan for smart ready DER and DER enrolment • Work with other stakeholders (internal, CEC, COAG) to ensure correct DER data is captured and accessible • Inverter voltage control trial • Influence smart inverter standards to ensure we get desired functions • Tariff strategy reform • Data capture and diverse LV monitoring trial of prototypical LV feeders • Common data platform trial • OMS replacement project • Commence opportunistic LV data capture through BAU FS operations • Produce strategy for optimal monitoring deployment
2020-2025	<ul style="list-style-type: none"> • Opportunistic and targeted LV data capture • Mandate/ incentivise smart inverter standards • Implement cost-reflective tariffs and passive measures to manage DER • Non-traditional data sources integration
2025-2030	<ul style="list-style-type: none"> • Directed data capture of remaining LV sites • Active DER mediation (DSO) • Acquire tools and systems to implement locational DER pricing

Table 9 – Strategy 3 roadmap

7 STRATEGY 4: RIGHT SIZE OUR ASSETS

Adapting our asset investment processes and standards to ensure assets are appropriately sized to meet future customer needs in a high-DER environment and to leverage non-network solutions.

7.1 Strategy

The deployment of distributed resources is generally expected to reduce the capacity requirements of network assets, however this must be balanced against the potential for new grid applications, for example electric vehicles.

DER may also potentially be applied to avoid, defer or reduce network upgrades, for example, by utilising customer's batteries or other resources to 'peak lop' during high network demand periods. Avoidance of the installation of new or upgraded assets using such approaches has the potential to yield significant cost savings.

Over time, lower capacity requirements may enable decommissioning of some network elements that are no longer adequately utilised, where cost effective to do so.

There are four key components to this strategy:

- 1. Review ADMD standards:** After Diversity Maximum Demand (ADMD) is the nominal maximum demand assumed for each premises in a new subdivision, and is used to determine the total demand for the subdivision and hence any required local network and upstream capacity upgrades. Current ADMD standards were developed prior to widespread uptake of DER and recent improvements in building standards and appliance efficiency, and hence should be reviewed.
- 2. Leverage DER to avoid asset expenditure:** establishing appropriate systems and processes to ensure distributed energy resources can be used to provide network support in lieu of network expenditure where it is economic to do so. Examples include deferral of substation and feeder upgrades, avoided grid-side voltage control plant, etc.
- 3. Targeted decommissioning & downsizing:** specifically targeting high cost and/or poor utilisation sections of the network for decommissioning where such an approach would be more economic than retaining the assets in service. Over the next 20 years, there are anticipated to be small numbers of power transformers, distribution transformers and SWER lines for which this will be economical.
- 4. Review asset standards:** to ensure that assets have appropriate functionality and are "right sized" to support the future network strategy.

7.2 Rationale

7.2.1 Review of ADMD standards

7.2.1.1 Opportunity

Existing After Diversity Maximum Demand (ADMD) standards of 4-10kVA per dwelling were developed to ensure that the distribution network was adequately sized, taking into account typical household maximum demands and allowing for future load growth.

Since the development of these standards there has been a significant shift in the typical load profile of new dwellings. Summer peak demand has been reduced by a combination of modern energy-efficient housing construction, uptake of solar PV and improved energy performance standards of appliances, in particular air-conditioners; the least efficient air conditioner (less than 4kW) today is more efficient than the most efficient air conditioner on the market in 2001 [13].

These changes mean that real-world ADMDs for modern housing developments can be significantly lower than the existing standards suggest. For example, Lightsview is a standard new 6-star energy rated development with low PV penetration and exhibits an ADMD of less than 5kVA. The 7.5-star energy rated Lochiel Park development with high PV penetration reveals an ADMD in the order of 1-3kVA, using less than 25% of the installed transformer capacity.

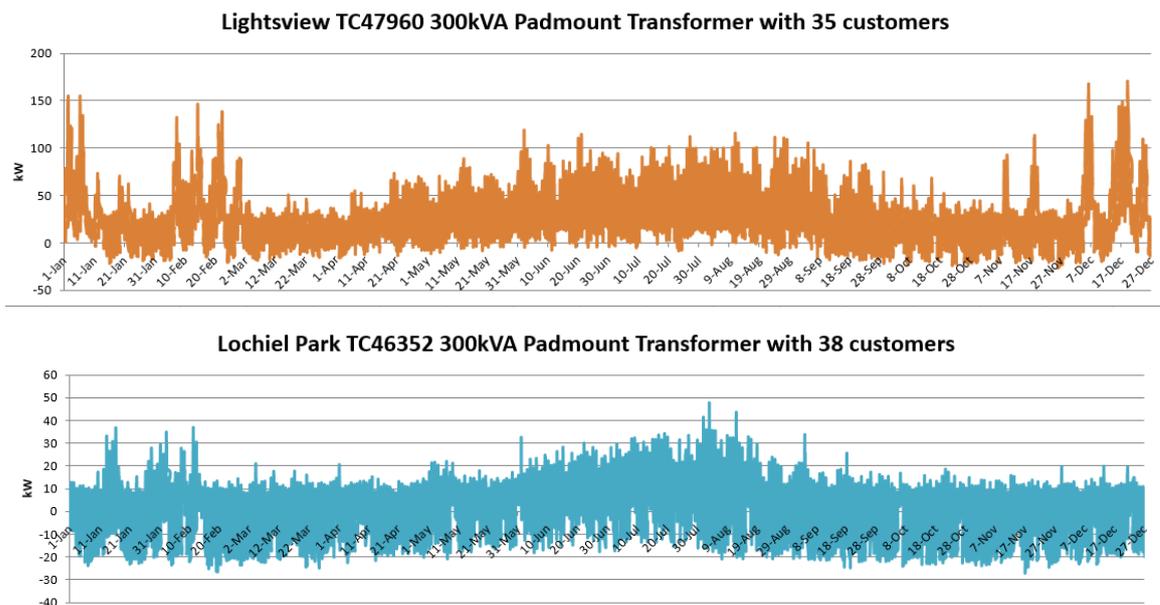
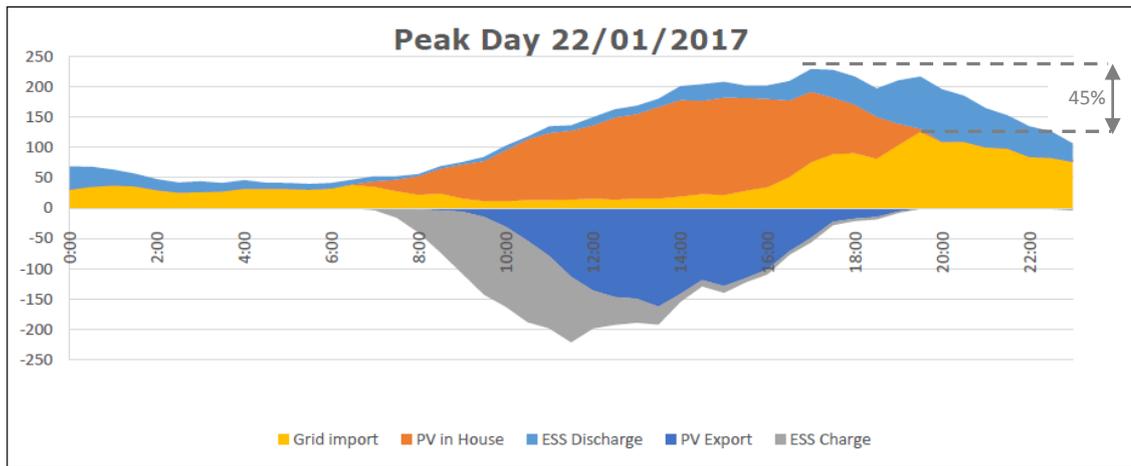


Figure 25 – Annual demand profiles measured at the LV transformer for Lightsview and Lochiel Park

Similar ADMD reductions are being observed for customers participating in the Salisbury battery trial. In the example shown below, which was a hot day in January 2017, these customers saw a 45% reduction in peak demand in aggregate due to the combination of solar PV and energy storage.



Peak Day Statistics (98 customers)

Max Demand (no DER)	227.8kW	Max Demand (inc DER)	125.4kW
Day Imports	1058kWh	Day PV Generation	2630.2kWh
Day self-sufficiency	63.40%	Day Exports	853kWh

Figure 26 – Peak demand reduction for Salisbury battery trial customers

Building to a reduced ADMD can yield substantial capital expenditure reductions. In 2016 SA Power Networks undertook a study with a developer to model the cost to build a 240 dwelling subdivision to a significantly reduced ADMD, enabled by an embedded network and distributed solar PV and battery storage on every premises. As shown in the table below, the study found that a 44% reduction in upfront capital for the developer was achievable through reduced network infrastructure – essentially fewer but larger transformers. The design also achieved a 21% decrease in spending on electrical infrastructure when connection costs (including augmentation) and rebates were applied.

Item	Standard build	Low ADMD build	Reduction
Annual network energy (kWh)	1520	424	
Network demand (kVA)	1276	350	
Network design capacity (kVA)	1500	500	
Average ADMD	6	2	
Local network assets	\$312,600	\$176,385	44%
Local network build	\$109,505	\$77,837	
Balance of build (design, public lighting, etc.)	\$178,491	\$178,491	
Connection	\$333,000	\$193,000	
Rebate	-\$414,000	-\$211,000	
Total network cost (after rebate)	\$519,596	\$414,713	21%

Table 10 Standard vs. low-ADMD build and connection costs for 240 dwelling development

7.2.1.2 Potential risks

The benefits of adopting lower ADMD standards and ‘leaner’ network infrastructure must be balanced against the potential risk that the network assets will turn out to be under-sized and

have to be upgraded during their service life. This risk could arise from a number of factors including:

- The adoption of electric vehicles, which could drive increased ADMD if charging occurs at peak times.
- De-carbonisation policy which encourages substitution of electricity for other fuels.
- Export ADMD exceeding import ADMD. A finding from our solar/battery trial in Salisbury is that that peak exports for the 100 customers regularly exceed maximum imports, in part because all PV export tends to occur at the same time (i.e. there is no diversity).
- New markets, tariffs, or incentives that encourage energy trading. Designing to a lower ADMD may reduce the capacity for customers to transfer energy into and out of their premises in response to external price signals, reducing their ability to participate in new markets and limiting the value they can obtain from their DER.
- Loss of diversity. Natural diversity in usage patterns means that the ADMD for a group of customers can be 2-5 times smaller than any individual customer's peak demand. In future, as more domestic loads come under the control of home energy management systems or demand aggregators, diversity may reduce, as any external price signal may trigger a coordinated response across multiple customers.
- Customer DER could fail, revealing the higher underlying (native) demand. For example, low or high network voltages or frequency instabilities can cause customer inverters to trip *en masse*.

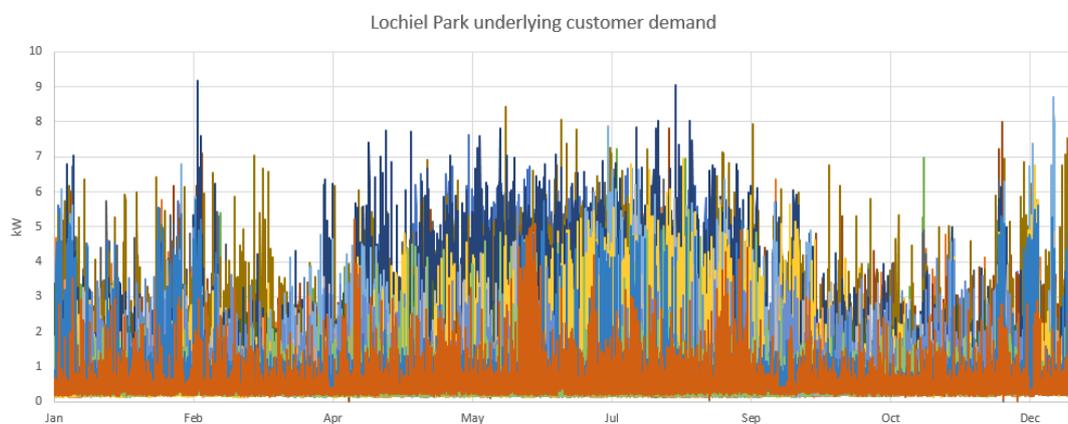


Figure 27 – Underlying demand for a Lochiel Park customer, with solar PV removed

Any or all of these factors could lead to future augmentation costs that would outweigh the original benefit in reducing standards and building to a lower network capacity.

7.2.1.3 Proposed approach

Lower, flexible ADMD standards can be enabled by sufficient mechanisms to manage risks. This may be achieved by:

- Imposing limits on customer or low voltage area connections for import and export to ensure capacities are not exceeded. These limits could be enforced through static settings on customer inverters, smart meters or through dynamic control of customer devices.
- Purchasing control and co-ordination of distributed energy resources, directly from customers or through third party aggregators.

- Designing for lower ADMD at the distribution transformer by increasing the size of low voltage mains to ensure energy can be exchanged at low voltage between customers with distributed energy resources. This would include ensuring adequately sized low voltage reticulation becomes a standard for all new developments and existing areas when performing maintenance or upgrades.
- Ensuring that customers have appropriate tariffs and incentives to mitigate risk and promote desirable behaviour, as discussed in section 6.2.3.

7.2.1.4 Regulatory Implications

Any change to ADMD standards will need to consider potential regulatory implications in three key areas:

- 1.** Benchmarking via Multilateral Total Factor Productivity (MTFP): lower ADMD standards increase benchmarking effectiveness by increasing utilisation of assets.
- 2.** Regulatory Asset Base (RAB): gifted assets are zero-valued in the RAB so a reduction in asset expenditure should have no effect on the RAB where third party developers build and gift the network assets.
- 3.** Efficiency Benefit Sharing Scheme & Capital Expenditure Sharing Scheme (EBSS & CESS): 70% of any benefits realised are shared with customers under these schemes.

7.2.1.5 Summary – reviewing ADMD standards

Evidence from modern housing developments with high penetrations of solar PV suggests that existing ADMD standards should be reviewed for future high-DER developments. It is recommended that a project is initiated to:

- Develop new, more flexible ADMD standards aligned to future customer requirements
- Develop methods to minimise or negate the risks associated with reduced design standards. These could involve new subdivisions with encumbrances requiring certain levels of PV and batteries to be maintained, particularly where SA Power Networks can influence the configuration of this equipment and/or exercise some level of control.

As a starting point 2, 3 and 4kVA import (depending on house sizing) and 5kVA export ADMD should be investigated.

7.2.2 Leveraging DER to avoid asset expenditure

With the reducing cost of distributed energy resources (DER), network constraints that have been traditionally solved through augmenting the network may be more economically solved through the use of DER in the future.

7.2.2.1 Approaches

DER solutions can be implemented in three different ways, requiring differing levels of investment, engagement, and incentives.

1. Network-side solution

A network-side DER solution is fully funded and operated by the network. The level of control and risk is optimised with this method however the capital outlay is largest.

2. Upfront financial incentive

Customers are incentivised to install DER with an upfront capital subsidy but are required to allow control during network constraints, potentially in return for an additional agreed reward each time their DER is dispatched. Customers are assumed to contribute at a level that ensures that they financially benefit from the DER, with a reasonable payback period. Evidence from the Salisbury battery trial indicates that, in today's market, a typical customer may be willing to invest approximately a third of the upfront capital cost of a combined battery/solar system.

3. Subscription incentives

Customers who already own DER are incentivised to allow control of their asset when required for an agreed rate. It may also be necessary to pay customers a subscription fee to be available for dispatch, for example \$20/month.

As well as providing network support, methods 2 and 3 also provide customers with a range of benefits, including financial savings, additional supply reliability and carbon abatement. It should be noted, however, that in any customer-side solution the effective capacity available for dispatch for network support at any given time will be lower, and possibly considerably lower, than the installed capacity of the DER. This is because the customer's regular usage pattern, e.g. for solar shifting, is likely already to be somewhat optimised to reducing peak demand, in particular once customers transition to cost-reflective tariffs; they may not have 'much extra to give' when they are dispatched for network support. A level of over-subscription will therefore be necessary to ensure that a sufficient response can be achieved when required¹³.

7.2.2.2 Opportunities

An investigation was conducted into potential opportunities to use DER to avoid network augmentation, taking into account the expected cost of traditional solutions and future

¹³ The Salisbury trial demonstrates approximately 1/3 of customer storage capacity could be rescheduled to network-optimize instead of customer-optimize with no negative effect on customer benefit while they are on energy only tariffs. This suggests an over-subscription of 3 times would be required today to achieve the required level of demand reduction. In the future, the introduction of cost-reflective tariffs will tend to increase the level of over-subscription required, possibly balanced against increasing levels of spare capacity due to future increased size of customer DER.

reductions in the cost of DER. The findings are summarised in the table below and the sections that follow. Further details are provided in Appendix E.

Network constraint	Maximum forecasted net benefit after DER	Opportunity location(s)
Feeder capacity	\$141,000 p.a. per constraint ¹⁴	Gawler East and Aldinga region constraints
Substation capacity	Some constraints financially productive after 2025.	No forecast constraints in the next 5 years.
Sub-transmission capacity	\$100,000 p.a.	Robe 33kV overload
Distribution transformer capacity	Some constraints financially productive after 2025, conceivably up to \$100,000 p.a.	DER saturated LV networks
SWER capacity and reliability	\$20,000 p.a.	No forecast SWER capacity constraints however typically, 3 per regulatory period

Table 11 – Potential opportunities to use DER to avoid network expenditure

Feeder capacity upgrades

Modelling indicates that it can be economical to use a network-side DER solution to address feeder capacity constraints today in very specific circumstances, when the constraint is small with minimal (0.1%) load growth, but the required network expenditure is large (\$3 million or more). In such cases the net benefit of a DER solution could be up to \$141,000 in per annum savings. For more typical feeder augmentation projects involving smaller network expenditure and larger constraints, the only economical approach is likely to be a customer-side DER solution involving upfront financial incentives or subscription incentives, leveraging customers' contribution to the DER cost. Such solutions may become economically feasible options for feeder upgrades from 2025.

Substation capacity upgrades

Although it is technically feasible to defer low load growth substation capacity upgrades today if large network expenditure is required, it is extremely unlikely a substation would have a small overload that required substantial capital investment. The more likely scenario would be a large constraint requiring large capital expenditure. This type of constraint will be feasibly solved by upfront financial incentive or capacity purchasing after 2025. This means in general, substation constraints will need to be assessed on a case-by-case basis given the current low demand growth climate.

Sub-transmission capacity upgrades

For sub-transmission capacity constraints the DER solution will depend greatly on the length of the line and works required and will need to be assessed on a case-by-case basis. Given the current low demand growth climate, some constraints are likely to be able to be economically deferred using DER today. For example, deferral of the Robe 33kV capacity constraint is likely financially viable today using a DER solution, even when considering ancillary project costs.

¹⁴ Best case, based on largest augmentation and smallest growth.

Infill distribution transformers

The typical network standard infill transformer is equivalent to \$2,000-\$2,500 in deferral benefit per year. It is conceivable that network-side DER will never reach a price low enough to be cost competitive with a traditional network solution. At this stage customer-side solutions do not look likely to become cost-effective either, other than in exceptional cases where the expenditure required is significantly more than the typical cost to install an in-fill transformer.

SWER Capacity Upgrade

SWER capacity constraints can conceivably be solved using DER today under favourable conditions, and under most conditions from 2025 given slow load growth. These opportunities are explored more in Appendix E.

Customer voltage support

LV regulation which was once considered non-traditional is now becoming normal. It is likely that DER will offer a cost-effective alternative to network-side voltage regulation from 2025. In the meantime, solutions involving programming existing inverters and setting standards for new inverters may be able to mitigate voltage constraints without the need to actively control DER. An example is explored in Appendix E.

Improving reliability – islanding small/medium towns

The opportunity exists to deploy grid-scale DER to enable communities at the end of poor-reliability radial lines to island. Modelling indicates, however, that this is unlikely to be financially viable on SPS benefits alone for the foreseeable future. Large fixed costs associated with telecommunications and protection are a significant factor. An example is explored in Appendix E.

7.2.2.3 Summary – leveraging DER to avoid asset expenditure

Feeder, SWER and voltage constraints are the most likely candidates for non-network solutions, and some of these are now becoming viable, in particular if the constraints are small. Further details of these opportunities and specific case studies are included in Appendix E.

Our processes should be modified to enable DER solutions to be considered much sooner than when regulatory investment tests are required. Prior to 2025, however, DER costs are such that the number of opportunities, and the available value, will be limited. Third party DER providers who can access multiple value streams will be best placed to bridge the gap and unlock value for networks and customers.

7.2.3 Targeted decommissioning and downsizing

SA Power Networks' asset management strategy is shifting to favour value-based asset management. For example, there is a draft *redundant infrastructure removal process* which enables the decommissioning of disused network assets to avoid unnecessary safety risks, operational expenditure and reliability penalties. In the section below we consider where value might be in decommissioning or downsizing assets *before* they become entirely disused or redundant. This pre-emptive retirement may be provoked by decreasing consumption and demand in light of increasing adoption of distributed energy resources.

A survey across a range of asset types identified three asset classes as potential candidates for decommissioning or downsizing pre-emptively before failure, where further investigation is warranted: SWERs/rural lines, LV transformers and substation transformers.

7.2.3.1 SWERs and rural lines

One possibility is to decommission an under-utilised SWER or rural line by providing each connected customer with an alternative stand-alone power system. This requires a substantial investment of capital, engineering and in some instances regulatory change. The following graph demonstrates the scale of investment required to implement a stand-alone power system

comprising a cost-optimised mix of solar PV and battery storage, at current and forecast future DER prices. The chart also shows how cost is influenced by load factor, which depends on the type of customer.

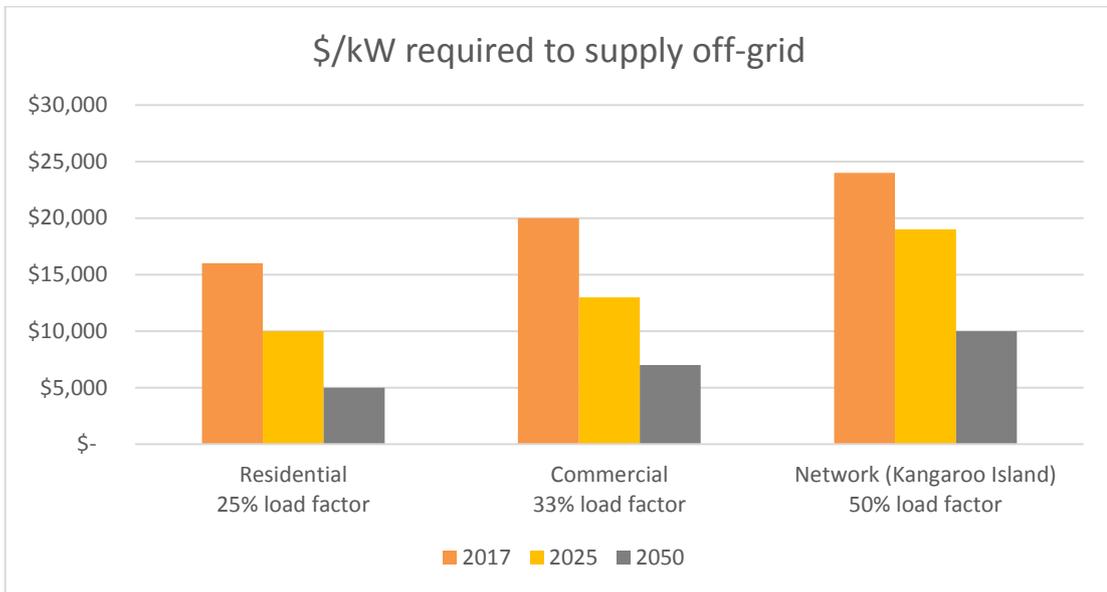


Figure 28 – Current and future costs of stand-alone power systems

These costs can be compared against the business as usual (BAU) network costs required to maintain a rural line or SWER. The annual cost to provide routine inspection, vegetation management and corrective maintenance for a SWER or rural line has been estimated to be \$362/km. The chart below considers the economics of decommissioning SWERs with different customer densities (in line km per connected customer). The chart shows the annualised cost for a single customer¹⁵ to decommission their portion of the SWER and provide them with a stand-alone power system. This is compared against the annual BAU maintenance cost for their part of the SWER.

¹⁵ Assuming a single residential sized load of 5kW with 25% load factor.

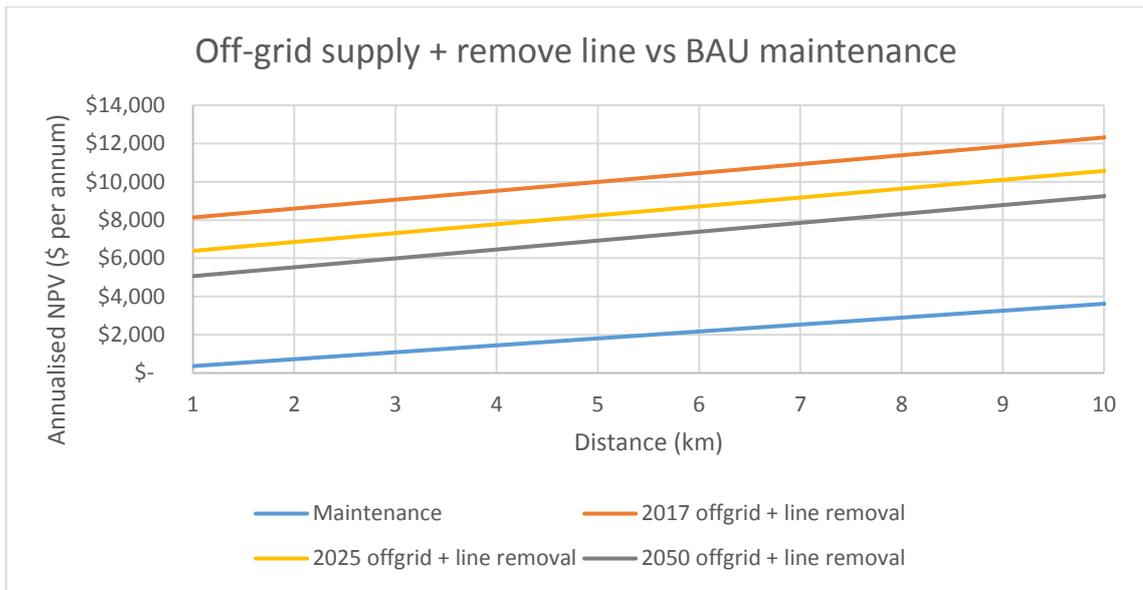


Figure 29 – Comparison of maintenance vs. retirement cost for SWER

This graph highlights that it is never cost-effective to supply a customer off-grid if you are required to remove the SWER or rural line. Simply, the estimated average capital cost of \$8,100/km to remove a SWER or rural line outweighs the cost of maintenance for the same SWER or rural line over a 40-year asset life¹⁶.

If the line does not need to be removed, it begins to be cost-effective to disconnect a customer served by 40km of line today¹⁷, assuming an ongoing operational expenditure of \$180/km per annum is necessary to ensure the abandoned line does not pose a safety risk. This can be seen in the point where the blue (BAU) line and the orange (2017) line intersect in the chart below. By 2025 falling DER prices make it economic to disconnect a customer beyond 32km of line and by 2050, 25km.

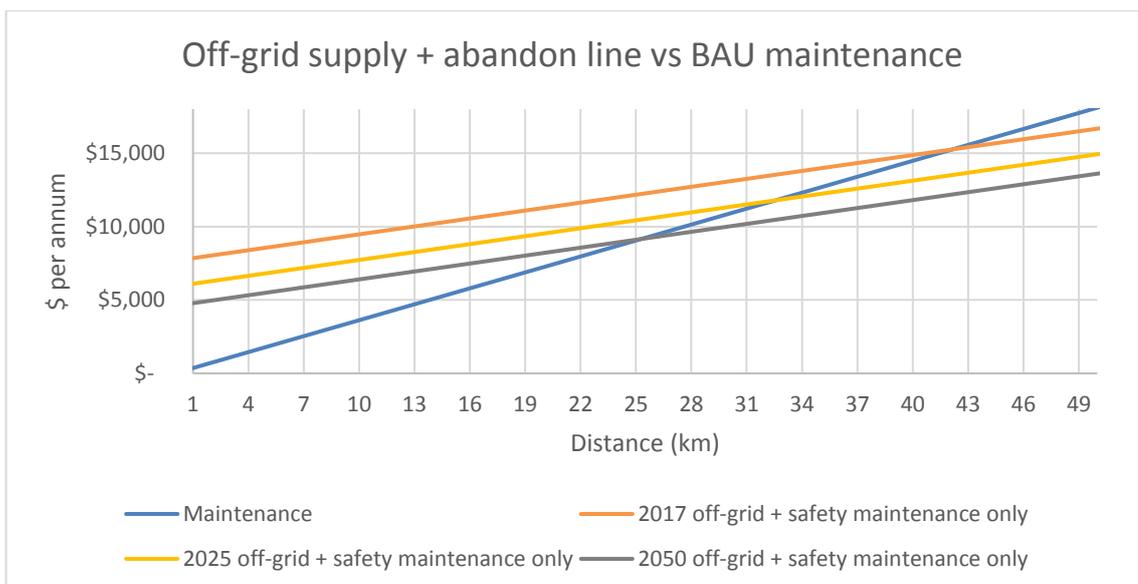


Figure 30 – Example where line is abandoned but not decommissioned

¹⁶ Note that in the chart the cost of decommissioning is shown as an annualized cost

¹⁷ Or, put another way, to decommission a SWER with an average customer density of one per 40km.

In cases where a significant capital expenditure like a restring is required on a SWER or rural line, the economics of abandoning the line and moving customers to stand-alone power systems improve considerably. For example, at an estimated cost of \$18,000/km to restring a SWER or rural line, the following graph illustrates the breakeven thresholds¹⁸. At today's DER prices the breakeven point is around 6km of line per customer. This falls to 5km per customer in 2025, or 4km per customer in 2050.

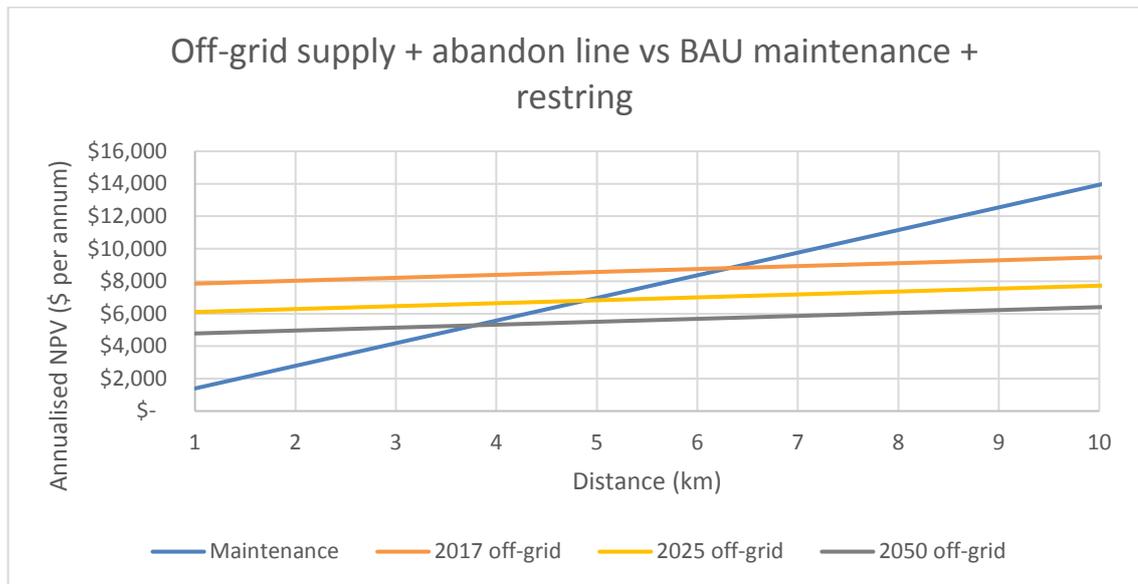


Figure 31 – Example where the cost of a restring is avoided

7.2.3.2 LV transformers

In areas of the LV network where peak demand is reducing due to uptake of DER (and assuming peak export can be controlled), it may be possible in future to reduce the number of LV transformers, either by 'harvesting' under-utilised transformers to redeploy elsewhere or by simply not replacing some transformers when they fail.

Padmount transformers

Harvesting a padmount transformer for re-use poses a number of technical difficulties.

1. Identifying transformers that are lightly loaded is expensive and time consuming as there is almost no permanent low voltage monitoring today.
2. Neighbouring transformers must have sufficient capacity to cover the removed capacity.
3. Low voltage reticulation would need to be meshed to neighbouring circuits. Existing low voltage reticulation design would prevent this from being possible in all but a few locations. For example, it may be feasible where a single customer transformer had a substantial load

¹⁸ This example assumes the same ongoing cost to maintain an 'abandoned' de-energised line in a safe condition as in the example above.

decrease that was able to be reverse fed from the street feed. In locations where it is possible, voltage drop and quality of supply would need to be taken into account.

4. Few padmount transformers fail per year, limiting the maximum potential benefit.

Better data will be available in future to identify under-utilised transformers, from network-side transformer monitoring or customers with smart meters or inverters. Future low voltage reticulation could be designed to take into account potential harvesting of padmount assets.

Financially, it costs in the order of \$6,000 to remove a padmount transformer and \$30,000 to reconfigure the local low voltage reticulation. This means that the saving that can be achieved by recovering and re-using an existing padmount transformer compared to purchasing and installing a new one is between \$3,000 to \$20,000, depending on the amount of installation and civil work required.

In the last calendar year 12 padmount transformers were replaced due to failure. In a best case scenario if all of these were replaced with under-utilised transformers harvested from the field this would equate to a saving of approximately \$240,000.

Overhead transformers

Reconditioned overhead transformers are net \$1,000-\$5,000 cheaper compared to their new counterpart depending on type and age. On average it is estimated to cost approximately \$4,000 to recover an overhead transformer from the field. This means in the best case scenario a re-furbished overhead transformer would save approximately \$1,000 of the typical \$35,000 install cost.

To ensure harvesting overhead transformers were possible the low voltage mains would also need to be in a re-configurable state that did not lead to quality of supply issues. Anecdotally, few if any failed overhead transformers would fulfil these criteria, the possible exception being transformers that were installed for infill for which the anticipated increase in demand did not eventuate. Identifying which transformers to harvest or decide not to replace would pose the same issues as discussed above for padmount transformers.

Additional investigation is required to determine the potential benefits, if any, of not replacing some overhead transformers when they fail.

7.2.3.3 Substation power transformers

An ad-hoc process already exists for re-purposing substation power transformers before their end of life. It is estimated that approximately two large substation power transformers fail or need pre-emptive replacement in each 5-year regulatory period. If an existing transformer can be re-used, potential savings are in the order of \$500,000, as demonstrated by the relocation of 25MVA transformer supplying GM Holden at Edinburgh to Woodville in 2016.

7.2.3.4 Summary – decommissioning and downsizing

Although there are limited opportunities for downsizing or re-using assets at this point in time, the three areas identified above have the potential to yield future savings and should be monitored as DER prices decline and load profiles change with increasing DER adoption. The table below provides a summary.

Strategy	Potential benefit
SWER /rural line decommissioning, in particular for lines where restring is required	Annual avoided OPEX of \$362/km (maintenance) - \$1394/km (annualised cost of restring + maintenance)
Harvesting padmount transformers for reuse	\$20,000 per padmount transformer \$240,000 p.a.¹⁹
Harvesting pole top transformers for reuse	Not financially viable
Not replacing overhead transformers	More investigation required to determine
Relocating substation transformers upon failure	\$500,000 per transformer \$200,000 p.a.²⁰

Table 12 – Summary of potential decommissioning opportunities

A specific recommendation is that a project is initiated to identify when customers on long, low density or high cost rural lines could feasibly be supplied with DER.

7.2.4 Review asset standards

Asset standards should be reviewed on an ongoing basis to ensure that the new assets we procure are suited for the network of the future. A high-level review across a range of asset classes identified a number of criteria that should be considered in developing future asset standards. These are summarised briefly below.

Are the assets appropriate for the long-term future architecture of the network?

The first example of this is the choice of LV cable for new underground LV networks. The opportunity has been identified to transition from 150mm² to 240mm² LV cable as standard. This will increase DER hosting capacity, while also reducing costs and supporting our standards rationalisation strategy. As seen in the table below, this change is expected to yield an annual saving in equipment-only of around \$250,000.

Existing standard purchases 150mm ²		Proposed standard purchases 240mm ²		Saving
25km single circuit	\$313,000	25km single circuit	\$425,000	
45km double circuit	\$1,130,000	45km single circuit	\$765,000	
115km total	\$1,443,000	70km total	\$1,190,000	45km \$253,000

Table 13 – Per annum cost comparison – 150mm² vs 240mm² LV cable

Should we forgo longevity for reduced cost?

If we identify areas of the network where demand is declining and some future decommissioning is expected, it may become prudent to purchase lower cost but shorter-lived assets. While this approach may have merit in future, no immediate opportunities have been identified. Those options that have been examined, for example using a mild steel finish instead

¹⁹ Based on 12 failures during the 2015 calendar year

²⁰ Based on an estimate of 2 failures per regulatory period

of galvanising on pole mounted transformers, have been found to offer minimal savings but with significant reductions in asset life.

The opportunity to trade asset life for cost is also limited more generally by uncertainty in future network requirements, and by the fact that minimum product specifications tend to be dictated by broader industry standards.

Should we prefer increased functionality?

Additional functionality is a consideration during the tender process for any network asset. The short-term focus should be on technologies such as transformers with in-built tap changers and/or voltage regulation which are available in suitable configurations that can be used on our network today.

How can we maximise useful life?

Extending the life of our equipment has been our focus for many years with the focus on whole of life cost evaluations. Many assets now incorporate stainless steel housings and components due to issues of premature failure from atmospheric corrosion. This has proven to not impact greatly on the upfront price of assets while providing benefits to the longevity of assets. With the introduction of more electronics into equipment, it is evident that the expected life of this equipment in many cases will be less than a 'traditional' asset. Equipment specifications need to ensure that these electronic devices are as robust as possible while also being simple to replace in the field ('plug and play') to reduce the impact on maintenance.

Should we prefer relocatable or modular assets?

In a changing network, it may be prudent to prefer flexible assets that can be reconfigured or relocated. Many existing equipment classes are 'relocatable' from a backwards compatible point of view. The effort required to physically relocate these assets is, however, relatively large and as such it is not feasible to relocate on a regular basis (e.g. in response to an increase/decrease in loads). There may be opportunities to 'design for relocatability' in future to make it more cost-effective to reconfigure, add or re-deploy assets.

7.3 Summary

As we transition to a high-DER future, we need to adjust our asset management and standards planning processes to take into account the impact of DER on future asset utilisation, and the opportunities to use non-network solutions in lieu of asset replacement. These opportunities are now beginning to emerge in a few areas, and will increase over time as DER prices fall and DER penetration grows.

In the short term, non-network solutions will require some capital investment in DER and will be best delivered either by direct subsidies to customers purchasing DER, or by outsourcing to third parties seeking to invest who can capture multiple benefit streams. In the longer term, as DER penetration grows, there will be opportunities to incentivise aggregators or customers who already have DER to provide network support.

The following table summarises the size of the opportunity as it stands today, in terms of potential annual savings, in each of the specific areas discussed above. The figures represent a theoretical upper bound of possible benefits, and are intended primarily to illustrate the relative scale of the potential benefits in each area in order to set priorities for more detailed investigation.

Strategy	Theoretical maximum available benefit
Design to lower ADMD standards	20% of new subdivision capital expenditure Equivalent to \$1.8m pa.²¹
Capacity constraints (avoided AUGEX)	
Feeder capacity	\$141,000 p.a. per constraint²² Gawler East and Aldinga region constraints
Substation capacity	Some constraints financially viable after 2025. No forecast constraints in the next 5 years.
Sub-transmission capacity	\$100,000 p.a. Robe 33kV overload
Distribution transformer capacity	Financially impractical given today's forecasts
SWER capacity and reliability	\$20,000 p.a. No forecast SWER capacity constraints, however historically 3 per regulatory period
SWER/rural line decommissioning	Annual avoided OPEX of \$362/km (maintenance) - \$1394/km (annualised cost of restring + maintenance) No forecast restring requirements identified in next 5 years
Harvesting padmount transformers for reuse	\$20,000 per padmount transformer \$240,000 p.a.²³
Harvesting pole top transformers for reuse	Not financially viable
Not replacing overhead transformers	More investigation required to determine
Relocating substation transformers upon failure	\$500,000 per transformer \$200,000 p.a.²⁴
Transition from 150mm ² to 240mm ² LV cable	\$250,000 pa.

Table 14 – Potential opportunities to use DER to avoid network expenditure

²¹ 2014-2015 RIN reported \$8.6m new subdivision expenditure.

²² Best case, based on largest augmentation and smallest growth.

²³ Based on 12 failures during the 2015 calendar year

²⁴ Based on an estimate of 2 failures per regulatory period

7.4 Strategic roadmap

The strategic roadmap for this strategy is shown below.

Period	Strategic initiatives
2017-2020	<ul style="list-style-type: none"> • Develop flexible ADMD standards • Trial and implement new underground LV design • Subsidise customers to install DER to solve network constraints
2020-2025	<ul style="list-style-type: none"> • Integrate non-network solutions into asset management processes • Identify low-utilisation SWERs
2025-2030	<ul style="list-style-type: none"> • Purchase control of DER from customers / aggregators to solve network constraints • Potential SWER retirement opportunities

Table 15 – Strategy 4 roadmap

8 STRATEGY 5: PROMOTE NEW GRID APPLICATIONS

Maximising the utilisation of the distribution network by encouraging new applications such as large scale renewable connections, electric vehicle charging and, if economic, substitution of electricity for gas.

8.1 Strategy

Traditional drivers of energy consumption in South Australia are declining due to increasing energy efficiency in housing and appliances and a reduction in large industrial loads. An increasing preference for electricity over other energy sources in a decarbonising economy will, however, see a growth in new grid applications such as electric vehicle charging and the connection of large scale renewable generators. These new applications offer significant future opportunities to maintain the value and relevance of the grid. Managed appropriately, they have the potential to increase energy throughput and utilisation of our network assets and therefore reduce unit cost for all customers.

Our strategy is to encourage new applications for grid-supplied energy, to maximise the role of our distribution network in supporting them, and to put in place appropriate incentives and controls to encourage efficient use of the network. There are three key components to this strategy:

1. Promote electric vehicles by ensuring that:

- Our network is both 'EV ready' and 'EV friendly' with respect to connection processes and pricing;
- We model the way, by maximising EV penetration within our own fleet;
- Charging infrastructure is widely available, by supporting councils and other stakeholders to cost-effectively design, install and operate such equipment; and
- We publicly advocate for, and promote the benefits of, EVs, including lobbying for government policy change such as vehicle emissions standards and government incentives that will stimulate the market.

2. Encourage large-scale renewable connections: by streamlining connection processes and publishing maps of least-cost locations from a network connection perspective. We will also consider a new role for a dedicated account manager to proactively seek distributed generation connections and facilitate proponents' applications and connection process.

3. Investigate fuel substitution: to determine if there are material opportunities for customers to benefit from switching from other fuels to electricity.

In 2016 work commenced on some of the above strategic initiatives in relation to EVs. In June 2016 we introduced 12 Mitsubishi Outlander Plug-in Hybrid EVs (PHEVs) to our fleet as pool vehicles for Keswick, with a dedicated charging area in the basement carpark completed in 2017. We also updated our Off-Peak Controlled Load tariff in July 2016 to allow EV chargers to be connected to the tariff, which provides an immediate opportunity for savings of more than 50% on energy costs for South Australian EV and PHEV owners and brings SA Power Networks in line with DBs in other states. At the time of writing we are engaging with Adelaide City Council to explore opportunities to partner with them to install ten 'smart' public EV chargers for on-street parking in Adelaide.

8.2 Rationale

8.2.1 The impact of EV uptake

Electric Vehicles have the potential to have material impact on our business in the long term. AEMO's 2016 'neutral' forecast uptake of EVs would see 240,000 EVs on the road in South Australia by 2036 [14], requiring an additional 500GWh of electricity consumption annually. According to CSIRO's long-range extrapolation of these forecasts [3], this could potentially rise to 1,500 GWh by 2050, a 12% increase in energy compared to today.

CSIRO's modelling indicates that if EV charging occurs predominantly outside of peak times, the impact of this increased energy throughput will be that customer bills will, on average, be 20% lower in 2050 than they would otherwise have been. This outcome relies on a timely transition to cost-reflective network tariffs to drive efficient charging behaviour. On the other hand, in a 'slow tariff reform' scenario in which flat tariffs continue to be the norm for the majority of customers through 2035 and beyond, CSIRO found that most of this benefit is lost due to the cost of growing peak demand, and customer bills are reduced by less than 4% [3]. Further information on this modelling is included in Appendix F.

8.2.2 Promoting electric vehicles

It is in our interest, to the extent that we can influence the market, to encourage the early adoption of EVs and accelerate the rate of EV uptake. We also need, however, to ensure that appropriate incentives and controls are in place as the market develops to encourage efficient charging behaviour.

Although the take-up in SA is forecast to be slow, we consider that it is better to be proactive and intervene early, before significant numbers of EV charging stations are installed in the state, than to take a reactive approach, in particular given the speed with which adoption rates can change in response to factors outside our control such as government policy intervention. Our experience with the rapid growth in air-conditioning load in SA and, more recently, the rollout of rooftop PV suggests that a reactive approach can lead to technical challenges and, ultimately, upward pressure on prices that could potentially be mitigated by early introduction of appropriate price signals and technical standards.

8.2.2.1 An EV friendly network

We will facilitate EV uptake and encourage efficient charging behaviour by ensuring that our network is 'EV-friendly,' commencing with a number of low-cost initiatives that can be implemented immediately.

EV-friendly tariffs and controlled load

The first step has already been taken. In 2016 we made a change to our controlled load tariff to allow residential EV chargers to be connected to a controlled load circuit. This enables EV owners to access our controlled load tariff and charge overnight for less than half of their normal energy cost. The change brings SA into line with NSW, Victoria and Queensland which already allowed EV chargers on controlled load.

In the short term this has the potential to significantly improve the economics of EV ownership for our customers without any loss of convenience (the EV can be plugged in earlier in the evening when the driver returns home, in the knowledge that it will not begin charging until the off-peak period), while keeping charging load out of the peak period. In the longer term, as smart meters roll out more broadly across the state from 2018, a transition to demand-based tariffs will ultimately provide customers with more flexibility to manage their EV charging load along with other loads in their house.

In 2017 we are reviewing our connection rules to allow for chargers of up to 32A, in response to feedback from the local EV community that the original 25A limit precludes connection of many

of the in-home chargers on the market in Australia, as the market has already moved from 16A to 30A as the standard size for a home wall charger.

An EV web site

In 2017 we will improve our web site to add an EV page to raise the profile of SAPN as ‘EV friendly’ and promote available incentives such as the controlled load tariff. The site will also offer a range of other resources to help educate customers on the benefits of EVs, compare products available on the market and understand the costs, leveraging our reputation as a trusted independent provider of information on energy. It will include information on locations of available EV charging stations in SA, links to other relevant web resources and ongoing updates with news relevant to SA customers who own or are interested in EVs and plug-in hybrids. Figure 32 below shows the site recently developed by Ergon Energy [4] which provides an example of what can be done.

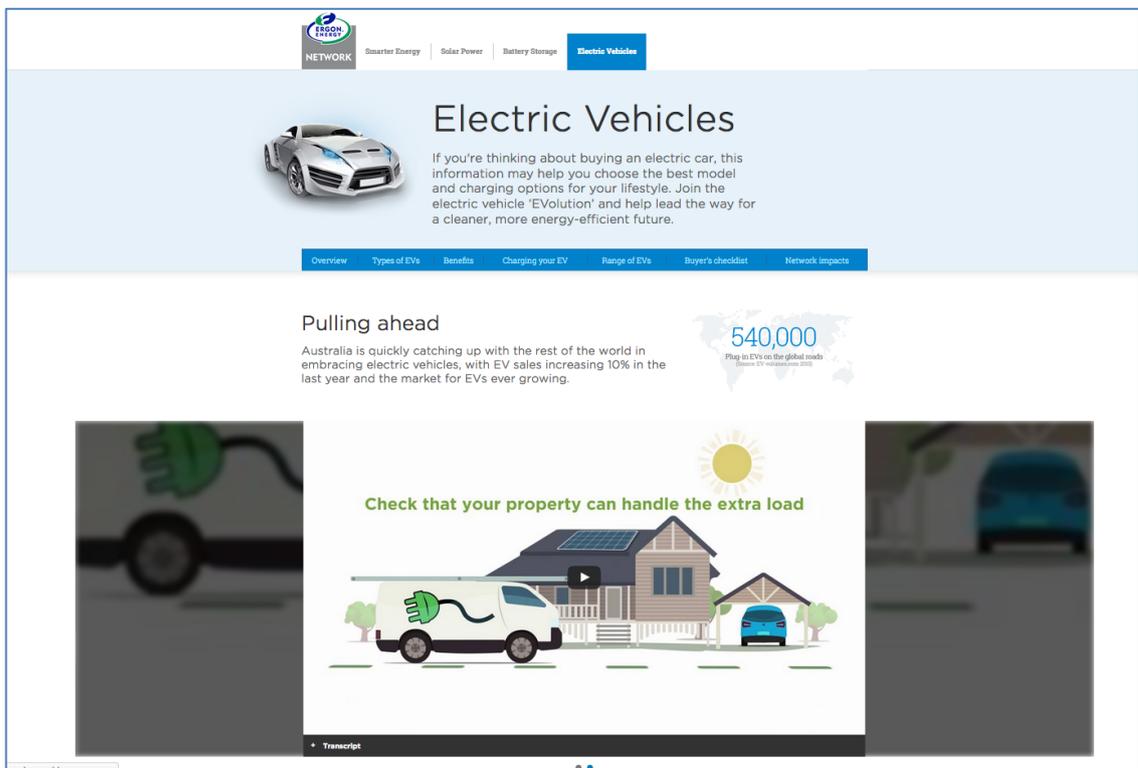


Figure 32 – ERGON’s EV web site (source: Ergon Energy)

Engagement with South Australian early adopters and the EV community

We will engage with the SA branch of the Australian Electric Vehicle Association (AEVA) and similar interest groups in South Australia such as the UniSA Research Node for Low Carbon Living to promote SA Power Networks within the early-adopter community as ‘EV friendly’ and publicise our tariffs and any other incentives or initiatives.

8.2.2.2 Supporting the rollout of smart EV charging infrastructure

Ready availability of public charging infrastructure is a key pre-requisite for more widespread adoption of EVs, and several progressive local councils have already begun installing small numbers of AC chargers in their council areas in South Australia.

At the present time the market is still very immature and there are limited choices available to councils, businesses, car park owners and others who want to install EV chargers to encourage EV adoption and/or attract EV owners to their premises. Companies such as ChargePoint and

JETcharge offer managed 'smart' chargers that can be monitored and controlled remotely and have the facility to take payment for charging, but these have significant annual fees associated with them, of the order of \$200 per annum per charger or more, and require activation cards issued by the managing company. As a consequence, those councils that have installed public chargers in the last 12 months have tended to favour basic stand-alone units that have no capacity for monitoring or control, but are cheaper, have no ongoing cost other than the cost of energy, and are 'open access.'

Although the number of EVs on the road is not expected to be material, in terms of network impact, for at least the next 5 years, by 2030 public EV chargers could present significant pockets of daytime load, particularly in car parks where many EVs may be parked in close proximity for extended periods. Understanding the nature of this load will ultimately be important in forecasting network demand. Moreover, if the chargers are networked and can be controlled remotely to vary the available charging current, there may be considerable opportunity in future to manage this load in aggregate to modulate demand, perhaps in combination with dynamic pricing, to avoid creating new peaks, to optimise the use of surplus daytime solar energy, and to shed load in response to a shortfall in supply or network constraint.

Our strategy, therefore, is to support and encourage councils and others seeking to install public EV chargers and, in particular, to encourage the installation of 'smart' chargers with communications that can be monitored and, potentially, controlled in future, and avoid any proliferation of un-controlled stand-alone chargers.

Our aim is to ensure that EV charging patterns can be adapted over time as conditions change. For example, in the early years of the market overnight charging at home may be the norm, but this may shift progressively to daytime charging at workplaces and shopping centres as solar PV penetration continues to grow and there is increasing value in soaking up surplus solar generation in the middle of the day.

In November 2016 Adelaide City Council announced a project to install 40 EV chargers in the Adelaide CBD in 2017. In 2017 we have engaged with ACC with a view to supplying and operating some smart on-street chargers as a partner in this project, as a pilot. If successful, this will establish a model that we can offer to other councils. The council would benefit from a monitored charging solution at a lower annual cost, and with a more open-access platform, than a commercial charging network, and we would benefit from access to data from the units and the potential to use them for demand response in future.

This model could also be extended to a home EV charger offering along similar lines, wherein the customer would benefit from access to any network incentives we might offer in future to apply direct control to their charger, and we would benefit from detailed visibility of charging loads.

A further opportunity that we will explore in 2017 is to bundle public (kerb-side) EV chargers as part of any new PLEC projects. The incremental cost to install a small number of EV charging stations will not be material for the customer in the context of a PLEC project, and it is the ideal opportunity to ensure that adequate cable capacity is installed for future EV charging needs in the area.

Finally, we will review our tariffs for commercial and industrial customers to determine whether we can introduce tailored tariffs to better serve the needs of customers wishing to install DC fast chargers, which are 50kW or more, such as service stations or local councils. Adequate availability of fast chargers along major highways is required to stimulate the broader adoption of EVs and overcome 'range anxiety' associated with longer journeys, but so long as EV penetration remains low (i.e. for at least the next five years), these units are likely to be idle for most of the time, and hence they will tend to be associated with very low annual energy use but occasional spikes of very high demand (50kW or more for 30 minutes to 1 hour at a time).

Businesses on our current demand tariffs are likely to find the tariff impact prohibitive for the benefit they receive in attracting EV owners to their premises²⁵.

Through our trial with Adelaide City Council we will investigate whether we can develop alternative tariffs that are less of a barrier to adoption of large chargers, at least as an interim to support the early growth period of the market.

8.2.2.3 *Leading the way: transitioning the SA Power Networks fleet to EVs*

We will actively seek opportunities to phase in electric vehicles (EV or PHEV) to our own fleet, whenever there is a positive or neutral business case to do so. Phasing in EVs as fleet vehicles has a number of benefits

- It will ultimately reduce OPEX through reduced running costs
- It puts more EVs on the road in South Australia, which will help to promote public awareness and acceptance of EVs, stimulating the market
- Fleet vehicles will flow down to the used car market when they are replaced after their normal service life, broadening the market to include those who cannot afford to buy new, particularly in the period before EVs reach price parity with petrol engine vehicles (expected in the mid 2020s).

In June 2016 we took the first step to mainstream use of plug-in electric vehicles in our fleet with the procurement of 12 Mitsubishi Outlander Plug-in Hybrid EVs (PHEVs) as pool vehicles for Keswick, for staff working predominantly in and around the CBD. The livery for these vehicles was deliberately chosen to stand out enough to make it clear to anyone seeing them on the road that they are electric vehicles, but without being too overtly 'green' or different, the intention being to raise awareness of EVs while also conveying that these are now mainstream working vehicles, no longer 'special' or experimental.



Figure 33 – SA Power Networks' 2016 Outlander PHEV

²⁵ The same situation will exist for customers who want to install several lower-powered (e.g. 7.6kW or 22kW) AC chargers at the same location.

A dedicated EV charging area has been established for these vehicles in the Keswick basement. This includes a network of smart charging stations that can be monitored and controlled using a central control system, and forms the prototype for the kind of solutions we are seeking to enable for councils.

From 2017, we will continue to seek opportunities to expand the use of PHEVs in our fleet as more models come on to the market, and will expand our own EV charging network, initially to include charge stations in the visitor parking area at Keswick and the Network Innovation Centre, and subsequently at other sites and depots.

A final strategic initiative in the short term is to revisit, in 2017, the concept of the 'Hybrid EWP' an EWP that can operate its boom using battery power to avoid the need to idle the engine at the worksite, which reduces fuel costs and has a number of environmental and noise benefits. SA Power Networks undertook a trial of several hybrid EWPs custom-built by GMJ in 2010 but limitations with the battery technology and charging system, as well as high price, meant that this initiative did not proceed beyond the trial stage. Given the significant advances in technology and reduction in battery price since, it is now appropriate to re-examine the business case for this kind of vehicle.

8.2.2.4 Promotion and advocacy

Historically, SA Power Networks has taken a passive approach to EVs, in line with its generally neutral public stance on emissions reduction and green energy. Our strategy from 2017 onward is that we should take a more active role in the promotion of EVs, engage more in the public debate on issues such as emissions standards and government incentives, and support the State government and parties such as ACC in lobbying for policy measures that will accelerate EV adoption. Further details on the policy landscape are included in Appendix F.

We will also investigate short-term opportunities to make some small, targeted investments in the provision of public charging infrastructure, not as a commercial proposition, but to help stimulate interest and adoption of EVs and raise the public profile of SA Power Networks as a progressive company willing to lead the way in the transition to electric vehicles. Examples could be a capital contribution to one or more high-visibility projects such as Adelaide City Council's EV charger rollout, or the provision of an SA Power Networks-branded public DC fast charger similar to the one Mitsubishi has installed at its Tonsley site, which currently attracts a small core of local Tesla owners who have no other option for fast charging in SA.

8.2.2.5 Other opportunities

We have considered two other long-term network opportunities associated with EVs:

- Vehicle-to-grid (V2G), in which EVs that are plugged into charging stations can be dispatched to discharge their battery into the grid for network support
- Battery second use (B2U) in which EV batteries that have reached end-of-life, insofar as their capacity and performance has dropped below the level required for the automotive application, can be re-used for grid-connected storage, e.g. for peak shaving or smoothing intermittent renewable generation, where they may have a further four to ten years of usable life before finally being recycled.

Both V2G and B2U have been around as concepts for more than ten years and have been demonstrated in various small-scale pilot projects, but it remains to be seen whether either will ever become part of the mainstream EV market.

V2G is not supported by current-generation charging infrastructure, and vehicle manufacturers may not be supportive of this use because it potentially changes the duty cycle of the vehicle battery and hence affects battery life.

A comprehensive study in 2015 by the National Renewable Energy Laboratory in the US found that the economic case for B2U is likely to be marginal, and the future supply of used EV batteries is likely to be far greater than the demand for these in static energy storage applications.

Our approach to these technologies is to keep a watching brief, noting that, at forecast EV uptake rates in SA, neither would be expected to yield any material opportunities for the network, or as a commercial proposition, until after 2025.

8.2.3 Encourage grid-scale renewable connections

As the energy sector continues to decarbonise, investment in new generation capacity in South Australia will continue to be focused on renewable generation, primarily wind and solar. We will actively seek opportunities to promote the distribution network as a preferred connection point for new small- and medium-scale grid-connected generators and grid-scale energy storage devices, through the initiatives set out below.

Opportunity mapping

We will develop and publish maps of least-cost locations for the connection of grid-scale generation (and other large DERs including EV ‘superchargers’) from a network connection perspective, i.e. areas of the network where we have surplus capacity to accommodate these without network augmentation. This will build on the ARENA-funded Network Opportunity Map project, which launched its first interactive on-line maps in August 2016 through the Australian Renewable Energy Mapping Infrastructure (AREMI) web portal [17].

Reducing the effort and cost to connect

We will seek to streamline the connection process for generators and DER owners and reduce costs, including consideration of incentives to connect to under-utilised assets.

Address regulatory barriers

As part of a 2015 project led by AGL and Electranet entitled *Energy Storage for Commercial Renewable Integration South Australia* (ESCRI-SA), ARENA investigated the regulatory issues surrounding the connection of large scale energy storage devices (ESDs) to the grid [18]. They found that AEMO would categorise an ESD as a generator rather than a load, which means that TUOS charges would not apply if the ESD is connected to the transmission network. For an ESD connected at the distribution network, on the other hand, the rules allow for DUOS to be charged on energy imported. In ARENA’s view this has negative implications for the economics of connecting at the distribution network level:

As ESDs only currently have a very marginal positive net present value, even seemingly localised or small charges can impact on decisions to go ahead with investments and installations. As ESDs are likely to be classed as generators for the general applicability of NEM regulations, DUOS charges for generators would be unfavourable.

As our strategy is to remove barriers to proponents seeking to connect grid-scale energy resources at the distribution network level, we will investigate this issue further in 2017 in order to gain a deeper understanding of the implications, with a view to formal advocacy (e.g. through a rule change request) for any regulatory changes necessary to remove disincentives to connect at the distribution network level.

Consider a dedicated account manager role

We will consider a new role for a dedicated account manager to proactively seek distributed generation connection opportunities and facilitate proponents’ applications and connection process.

8.2.4 Investigate fuel substitution

As part of the ENA/CSIRO Network Transformation Roadmap project, CSIRO has investigated the likelihood of a future shift from other fuel sources to electricity in the building services sector and for industry.

8.2.4.1 Fuel substitution in the building services sector

CSIRO examined two studies undertaken in 2016 by Jacobs and ClimateWorks [3] on the potential shift from gas to electricity for space heating, water heating and cooking in the residential and commercial building services sector, and compared their forecasts with those in AEMO's 2015 *National Gas Forecasting Report*. CSIRO found that there was little consensus between these forecasts, as shown in Figure 34 below.

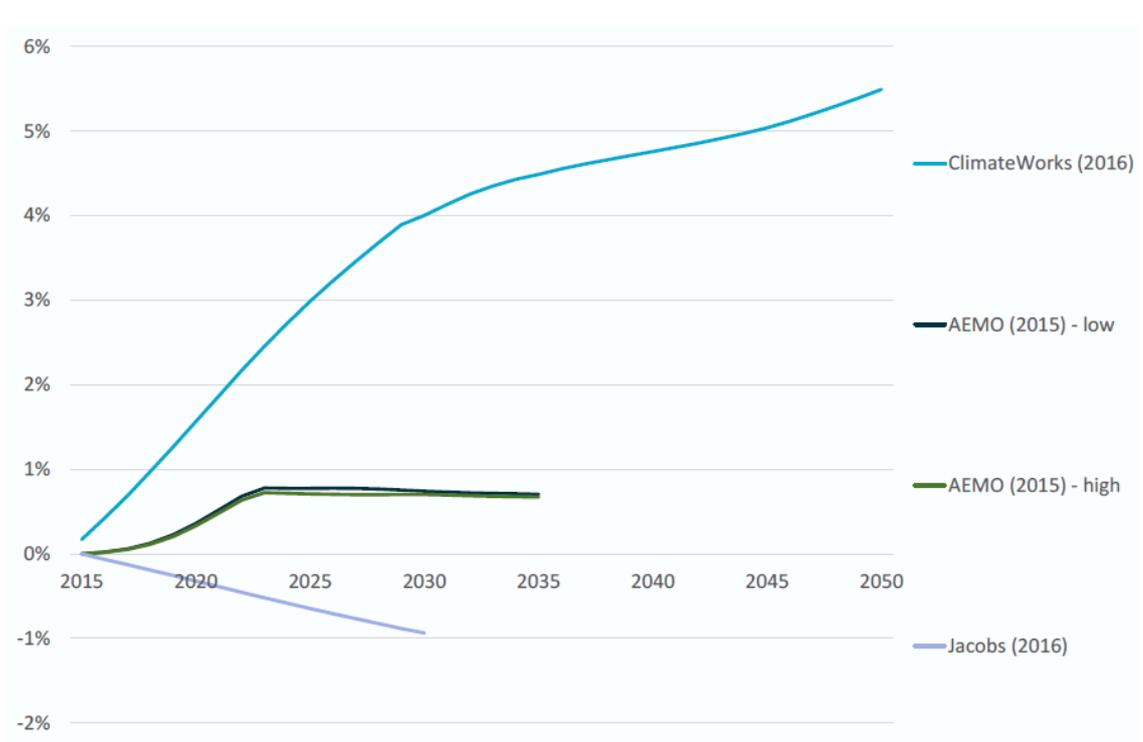


Figure 34 – Comparison of recent forecasts of gas-to-electricity fuel substitution (Source: CSIRO)

Both AEMO and ClimateWorks forecast a modest trend towards substitution of electricity for gas over time, driven by the following factors:

- The trend towards multi-unit developments and apartments for new housing, which are more likely to be all-electric homes than older housing stock
- The fact that householders can generate their own electricity using solar PV, but cannot generate their own gas, which makes electrical appliances more attractive to customers investing in PV
- Uptake of, and conversion to electric heat-pumps and solar hot water systems in favour of gas hot water heating

The Jacobs study was more limited than the others insofar as it focused on hot water heating and did not consider space heating or air conditioning. In contrast to the other studies, Jacobs forecast a modest substitution in the other direction, with an increase in the number of gas hot water systems sold relative to electric systems, driven primarily by rising electricity prices.

On balance, CSIRO believes that a modest substitution of electricity for gas over time is the most likely outcome, taking into account the above studies and other factors such as possible future carbon costs and the feedback loop of reducing gas consumption driving higher gas prices. They do not, however, expect this to have a major impact on electricity consumption or peak demand.

ClimateWorks’ forecast, which is the most bullish, is that by 2050 some 169 PJ of gas consumption could have shifted to electricity Australia-wide, 78% of which would be in the residential sector, as shown in Figure 35 below. This would equate to an increase in energy consumption of 5% – 6% across the NEM.

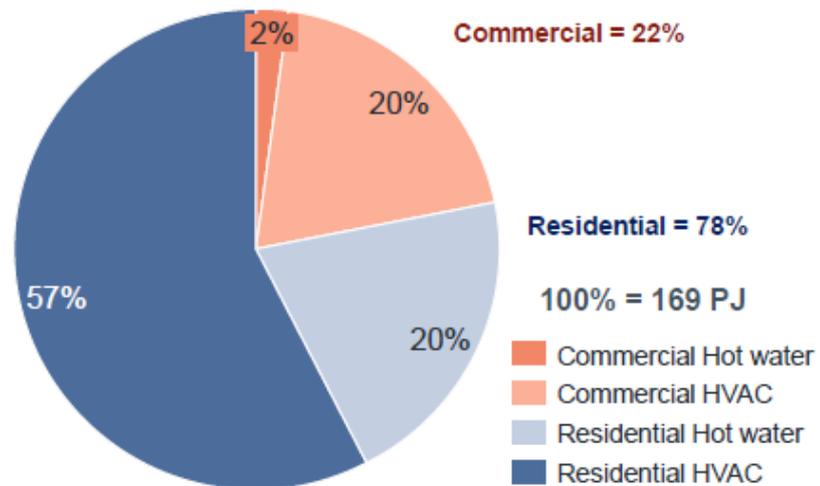


Figure 35 – Gas to electricity substitution by 2050 (Source: CSIRO, from ClimateWorks)

The forecast extent of gas-to-electricity substitution varies considerably by state, however, with Victoria, NSW/ACT and WA accounting for the majority of the shift, and SA less than 10% [3].

ClimateWorks also considered the likely impact of gas-to-electricity substitution on electricity network peak demand. Their analysis indicated that much of the substituted energy is heating load, and so it will tend to increase winter peak demand but not summer peak. This being the case, there would be little impact on overall network peak in South Australia.

8.2.4.2 Fuel substitution in the industrial sector

CSIRO also considered the potential for future fuel substitution in the industrial sector driven by Australia’s carbon reduction targets. They found that even with deep cuts in emissions in the electricity and transport sectors, Australia cannot meet its greenhouse gas emissions reduction target of 26% below 2005 levels by 2030 without significant reduction in emissions from the industrial direct combustion sector [3]. Moreover, carbon reduction efforts will need to accelerate from 2030 to 2050 if Australia is to contribute its share towards the longer-term international target to limit global mean temperature rise to less than 2 degrees Celsius.

Given that electricity generation is expected to lead other sectors in decarbonising, a natural pathway to decarbonising in the industrial sector is to electrify processes that are currently undertaken with direct combustion of fossil fuels.

In its 2014 Deep Decarbonisation Pathways Project, ClimateWorks estimated that electricity contributed between 8 to 33 percent of energy requirements for the industrial sector nationally. CSIRO commissioned ClimateWorks to review this data and assess the potential for further electrification. This analysis indicated that by 2050 the industrial sector could increase its use of electricity to 34 to 60 percent of total energy needs, based on economically and technically

plausible process changes, with the remainder delivered by a mix other fuel sources such as coal, gas, petroleum and biomass.

This degree of electrification in the industrial sector, should it eventuate, would result in an increase in electricity consumption of around 90% for the sector by 2050, which would clearly have a very material impact on SA Power Networks. CSIRO notes, however, that the analysis is preliminary and rests on a number of assumptions around climate policy [3].

8.2.4.3 Fuel substitution in summary

CSIRO has, through the 2016 Network Transformation Roadmap project, undertaken considerable research and analysis on the potential opportunity for a shift from fossil fuels to electricity in the building services and industrial sectors.

On the basis of this work, we expect to see a slight trend towards switching from gas to electricity for building services such as space heating and hot water. In South Australia this is expected to result in a slight positive outcome for the network, with increased asset utilisation arising from increased energy throughput with no increase in summer peak demand. However, the overall impact on the network is not expected to be material.

The future electrification of industrial processes that currently rely on direct combustion of fossil fuels has the potential to materially impact on energy throughput and local peak demand. This appears to represent a significant long-term opportunity to increase network utilisation, in particular if Australia is to meet international targets for emissions reduction.

The analysis undertaken by CSIRO and ClimateWorks is, however, very preliminary and based on modelling at a national level. We propose, therefore, to engage a suitably qualified consultant in 2017-18 to undertake further work in this area to gain a deeper understanding of the specific opportunities in South Australia, taking into account the present and future industry mix in the state. If possible, we will seek to collaborate with other interested parties, e.g. the SA Government and/or Electranet, to share the cost of this study.

8.3 Strategic roadmap

The strategic roadmap for this strategy to 2030 is shown below.

PERIOD	STRATEGIC INITIATIVES
2017 - 2020	<ul style="list-style-type: none"> Promote home EV charging on OPCL Increase use of PHEV in our fleet. Deploy pilot network of smart chargers at Keswick Establish pilot with a council for SAPN-supplied EV chargers, develop backoffice control solution and business model for other councils. Consider small investment in high-profile public SAPN charger(s) Develop opportunity maps to encourage connection of embedded generation and EV fast chargers Establish dedicated account manager for embedded generators Engage consultant to investigate fuel substitution opportunities in industry
2020 - 2025	<ul style="list-style-type: none"> Continue fleet transition to PHEV Offer managed EV chargers to councils and as part of PLEC projects Actively expand amount of grid-connected DER in underutilised network areas through incentives Actively encourage fuel substitution for industrial processes
2025 - 2030	<ul style="list-style-type: none"> Continue to support and encourage fuel substitution for industrial processes Integrate EV charger demand management into network management systems Investigate opportunities for V2G and EV battery reuse (B2U)

Table 16 – Strategy 5 roadmap

9 STRATEGY 6: ENABLE NEW MARKETS

Expanding our range of services to meet customers' emerging energy needs

9.1 Strategy

As the energy market evolves, customers' reliance on the NEM will decline over time. Energy that is supplied by the grid today will shift to being supplied by customer-owned DER, and customers will trade energy and energy services in new markets outside the NEM.

Rather than seek to defend traditional revenue streams in the face of change, our strategy is to leverage our core capabilities and network assets to become a leader in the transformation of the energy sector. We will seek to remove barriers to the emergence of new markets while also positioning to ensure that we remain an active participant and contributor to new energy markets.

There are three key components of this strategy:

1. Explore off-grid and community energy solutions, including:

- standalone off-grid solutions where these are cost-effective or otherwise desired by customers. Energeia estimates that by 2020 most small business rural connections greater than 3km from the grid will be lower cost if connected as a standalone power system [22].
- private community networks, whether they be fully off-grid or retain a network connection.

2. Support peer-to-peer trading and other non-traditional energy markets

We will seek to put in place the necessary technical standards and pricing models to enable customers to trade energy across our network in direct peer-to-peer arrangements outside the NEM (including via intermediaries). We will also investigate the potential to unlock further value by enabling such customers to receive locational and time variant distribution pricing.

3. Actively scan for new opportunities

We will establish rigorous processes in which we collaborate with our customers and partners to ensure we identify, and are well positioned for, opportunities that are not currently foreseen.

9.2 Rationale

Our strategy is outlined in more detail in the sections that follow.

9.2.1 Stand-alone power systems

Customers located at the fringe of the network in rural areas can face significant costs, of the order of tens or even hundreds of thousands of dollars, to connect to the network. The further away from the nearest suitable network connection point the customer's premises, the more expensive it is to extend the network, so that beyond a certain distance it is more economical for the customer to remain off grid and install a stand-alone power system with enough local generation and storage capacity to be self-sufficient year-round.

Continuing improvements in the price and availability of DER are progressively improving the economics of installing a stand-alone power system. This is illustrated in Figure 36 below, which shows the average NPV for a stand-alone power system, relative to the cost of a grid connection, for customers with varying energy requirements and at varying distances from the grid. The figure shows how falling DER prices mean that the distance at which it becomes un-economical to connect to the grid will reduce significantly by 2020 from today [22].

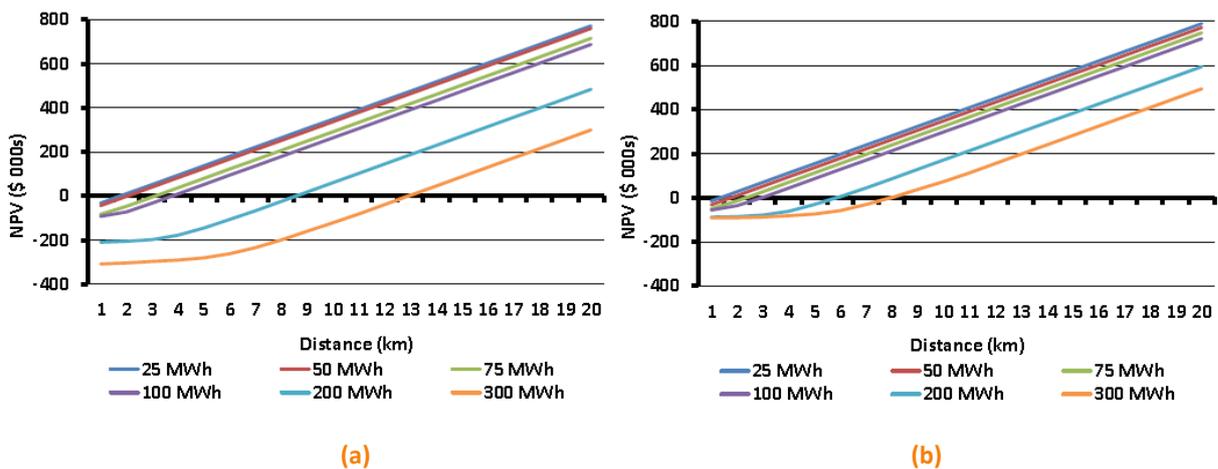


Figure 36 – Average NPVs of standalone power systems (a) in 2016 and (b) in 2020 (Source: Energeia)

In response to this change, we propose in 2017 to investigate the economics of a range of stand-alone power system offerings tailored to different customer energy requirements. Each package would comprise a combination of solar PV, battery storage, conventional (e.g. diesel) generation, and a suitable control system (including, potentially, a local demand management capability). In parallel, we will also develop the associated internal processes to assess all new fringe-of-grid connection requests for their suitability for a stand-alone alternative, develop public information resources and undertake training for staff involved in the new customer connection process.

Our goal is that, by 2019, any time a fringe-of-grid customer requests a new grid connection we will have a process in place to determine whether a stand-alone solution would be more cost-effective. If so, we will be able to immediately offer the customer advice in relation to a solution sized and configured appropriately for their energy requirements.

9.2.2 Local microgrids and community energy schemes

Since 2015 we have developed a detailed model to estimate the optimal mix (in terms of annualised cost of energy) of local energy resources and grid-supplied energy, both for individual customers and for groups of customers with shared resources such as community microgrids or future housing developments. The model builds on work originally undertaken for

SA Power Networks by Energeia [23], and enables us to explore how the optimal mix of energy resources will change over time as the price of DER reduces.

Two key conclusions emerge from this modelling:

1. Grid-connected microgrids with shared local distributed energy resources could potentially offer the least-cost means of providing energy to customers within 5 – 10 years. We are already seeing considerable interest from developers in creating new housing developments that incorporate a significant amount of solar PV and battery storage. Today this is driven primarily by a desire to differentiate by achieving a low (or net-zero) carbon footprint for the community, but our model predicts that in the near future this will become the norm for new developments simply because it makes economic sense.
2. Community schemes are likely to continue to offer better economic outcomes for customers than individual systems for the foreseeable future, even as DER prices continue to fall, because communities with shared energy resources require less DER per household in aggregate due to the benefit of natural diversity in demand profiles across the homes within the community.

These findings are illustrated in Figure 37 below. Figure 37 (a) shows the average annualised cost of electricity, including DER costs, at 2016 prices, for the following customer types (from left to right): a single grid-connected customer; a single customer with solar PV; a single customer with solar PV and battery storage, and a customer who is a member of a community scheme of 200 dwellings that has shared solar PV and battery storage assets²⁶.

At today’s prices, adding battery storage to a solar PV system gives a net increase in annualised cost compared to having solar alone. A customer with battery storage and PV who is in a community scheme is, however, better off than a similar customer operating as a single household. Figure 37 (b) shows the same costs at forecast 2026 prices for solar PV and battery storage²⁷. By this time a community solution incorporating battery storage and PV is expected to offer the lowest annualised cost of energy overall.

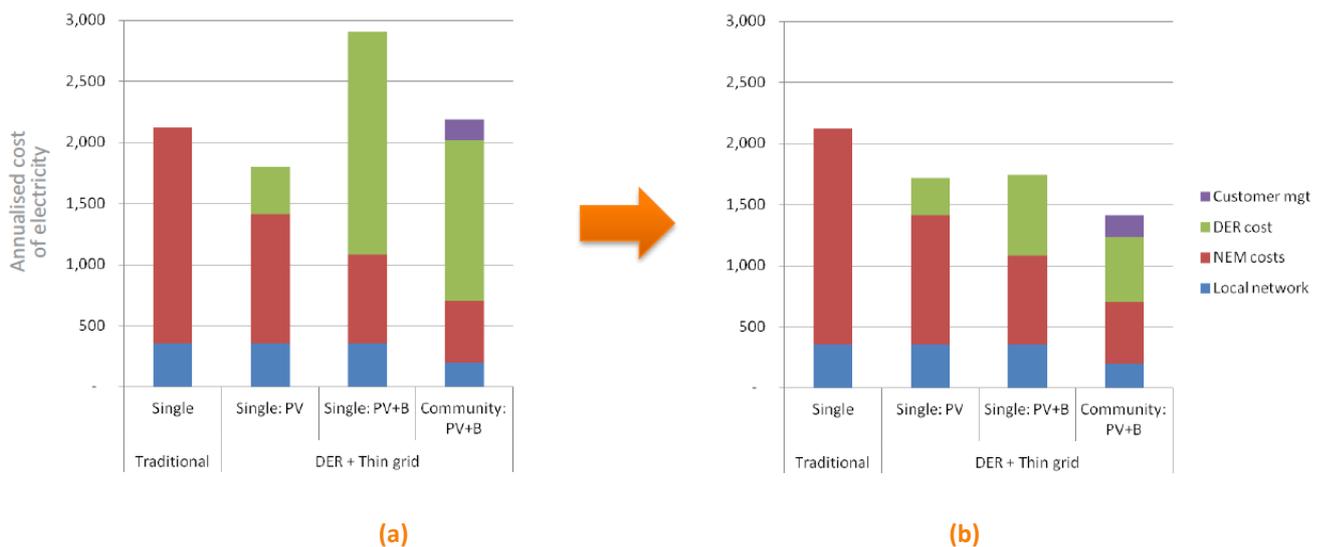


Figure 37 – Cost breakdown for individual vs. community DER (a) in 2016 and (b) in 2026

²⁶ The modelling assumes that every customer in the community scheme pays an equal share of the cost of the DER, as well as a share of the cost of control systems and administrative costs to manage the scheme ('Customer mgt' on the chart) and local network reticulation.

²⁷ Assuming solar PV price is 80% of 2016 price, and battery storage is 25% of 2016 price.

Based on this modelling we expect these types of high-DER private community microgrids to become commonplace for new developments by the early 2020s; we are already seeing considerable interest from infrastructure investment companies.

In 2017 and 2018 we will further explore the potential of ‘thin-grid-connected’ microgrids for new property developments, and the associated regulatory and network implications. In particular, consideration will need to be given to the long-term impact on network pricing if developers prefer embedded networks, as an embedded network operator can avoid the requirement for postage-stamp pricing for the local network. This has the potential to provide lower network costs for customers within the precinct than regulated rates, but will in turn tend to increase postage-stamp pricing for other regulated network customers.

At the time of writing in Q1 2017 we have secured ARENA funding, in partnership with a developer, for a project to pilot such a microgrid in a new development of some 240 houses in the Adelaide metropolitan area commencing in late 2017, to explore these issues.

9.2.3 Support peer-to-peer trading

In the last five years, the spectacular success of disruptive new business models such as Uber and Airbnb has popularised the notion that individuals that own resources of value can bypass traditional markets and trade directly with their peers, quickly and easily through new lightweight market platforms accessed through smartphone apps. This trend, combined with a sense of disempowerment due to the widening gap between electricity prices and feed-in-tariffs, is fuelling interest in peer-to-peer energy trading: rather than sell surplus solar energy to their retailer at a low price, some customers would prefer to trade surplus energy directly with their neighbours or as part of wider non-NEM community energy markets.

There is also interest among environmentally-conscious customers who don’t have ready access to install their own renewable energy resources (e.g. renters and apartment owners) in ‘solar gardens’ and similar schemes, in which customers can group together to fund a communal generator at a central location that can (notionally) supply their energy.

At the present time there are specific regulatory impediments preventing the widespread adoption of peer-to-peer energy trading schemes in Australia. In the US the ‘solar gardens’ model is enabled by legislation that enables virtual net metering (VNM), so that energy is ‘transferred’ from generator to customer via a credit on the customer’s retail bill. This enables specific benefits over a community-owned solar model in which community members join together as shareholders in a solar generator which sells energy into the regular wholesale market: firstly, it enables the participants to avoid network charges for the transferred energy, since it is netted off their total consumption before the retail tariff is applied. Secondly, it means that participants pay no tax on the benefit they receive, whereas if they are shareholders in a generator then they are liable to pay tax on earnings from energy sold.

There is currently no provision in the NER for VNM. To enact a power purchase agreement between a generator and consumer that have different NMIs, the generated energy must be sold on to the wholesale market at market price, and purchased back by the consumer through a retailer. This means that normal network charges apply to the transferred energy at the point of consumption. Postage-stamp network pricing means that there is no incentive to establish neighbourhood peer-to-peer energy trading schemes that encourage local generation to match local consumption, even though such schemes would tend to reduce system losses and the demand on upstream network assets.

At the time of writing, various trials of peer-to-peer trading and virtual net metering are underway in Australia. In 2015 Byron Shire in NSW announced a trial with the support of Essential Energy and the NSW Government to establish a peer-to-peer trading scheme with virtual net metering [24]. In 2016, startup PowerLedger commenced a small trial of its blockchain-based peer-to-peer trading platform in Western Australia with 10 households in a

lifestyle village, with support from Western Power [25]. ACT startup Reposit Power is also seeking to enable peer-to-peer trading through its own energy market platform.

While there is considerable interest in the concept of peer-to-peer trading in Australia, current activities such as those described above are all at the pilot stage, and very small scale, as they rely on special arrangements with the local DNSP in the absence of the general regulatory reform to support a peer-to-peer market.

The most significant attempt to change regulation in this space to date has been a rule change request to the AEMC submitted in July 2015 by the City of Sydney, the Total Environment Centre and the Property Council of Australia proposing a mechanism for DNSPs to provide a 'Local Generation Network Credit' (LGNC) to embedded generators commensurate with the expected value in reduced network costs and reduced system losses of local generation. Unfortunately, the mechanism proposed was not ideal, being essentially a generic cross-subsidy for embedded generators that did not take into account locational or other issues that would determine the actual value (or cost) to the network attributable to the generator. As a consequence, AEMC rejected this proposal, a position supported by ENA members including SA Power Networks.

ARENA has also funded a 1-year research project by the Institute of Sustainable Futures at University of Technology Sydney to examine different network charging models to support peer-to-peer trading. This study has recently concluded, but given that the project was strongly supportive of the failed LGNC rule change, it is not yet clear whether an alternative, more viable rule change proposal will result from this work.

In summary, this is a complex issue and one that warrants further investigation within SA Power Networks. It is our view that customers will increasingly demand, and ultimately achieve, a means of peer-to-peer trading. Our general strategy, therefore, is to support regulatory change that will enable virtual net metering and/or alternative network pricing models (e.g. some form of locational pricing) required to facilitate and encourage local peer-to-peer energy trading, to the extent that this can be achieved in an equitable manner that will not introduce new cross-subsidies or otherwise disadvantage any customer group. We propose to develop deeper knowledge of this issue within the business in order to become a more active participant in this debate as it continues, and seek to influence positive regulatory change.

9.2.4 Actively scan for new opportunities

The final element of our strategy in respect of positioning our network as an enabler of new energy markets, and an active participant in these new markets, is to establish a process and dedicate permanent resources to actively scan for new opportunities as they emerge, and to progress these through a repeatable process from concept, through pilot to new products and services.

These functions are detailed in the New Business Strategy [26] and not discussed further here.

9.3 Strategic roadmap

PERIOD	STRATEGIC INITIATIVES
2017 - 2020	<ul style="list-style-type: none"> • Develop and pilot initial stand-alone power system offerings • Develop and implement process changes to embed consideration of stand-alone systems in new customer connection process • Pilot a high-DER community microgrid • Develop commercial community microgrid solutions to market-ready • Deepen understanding of impediments to peer-to-peer trading and work with industry to remove these including new network tariff pricing and regulatory change
2020 - 2025	<ul style="list-style-type: none"> • Expand portfolio of stand-alone power system offerings • Stand-alone solution offered as standard for eligible new connections • Packaged community microgrid solutions offered as standard for new developments • Actively enable peer-to-peer trading across our network
2025 - 2030	<ul style="list-style-type: none"> • Continued engagement with New Business ventures to maximise synergies between the distribution network and the new energy market

Table 17 – Strategy 6 roadmap

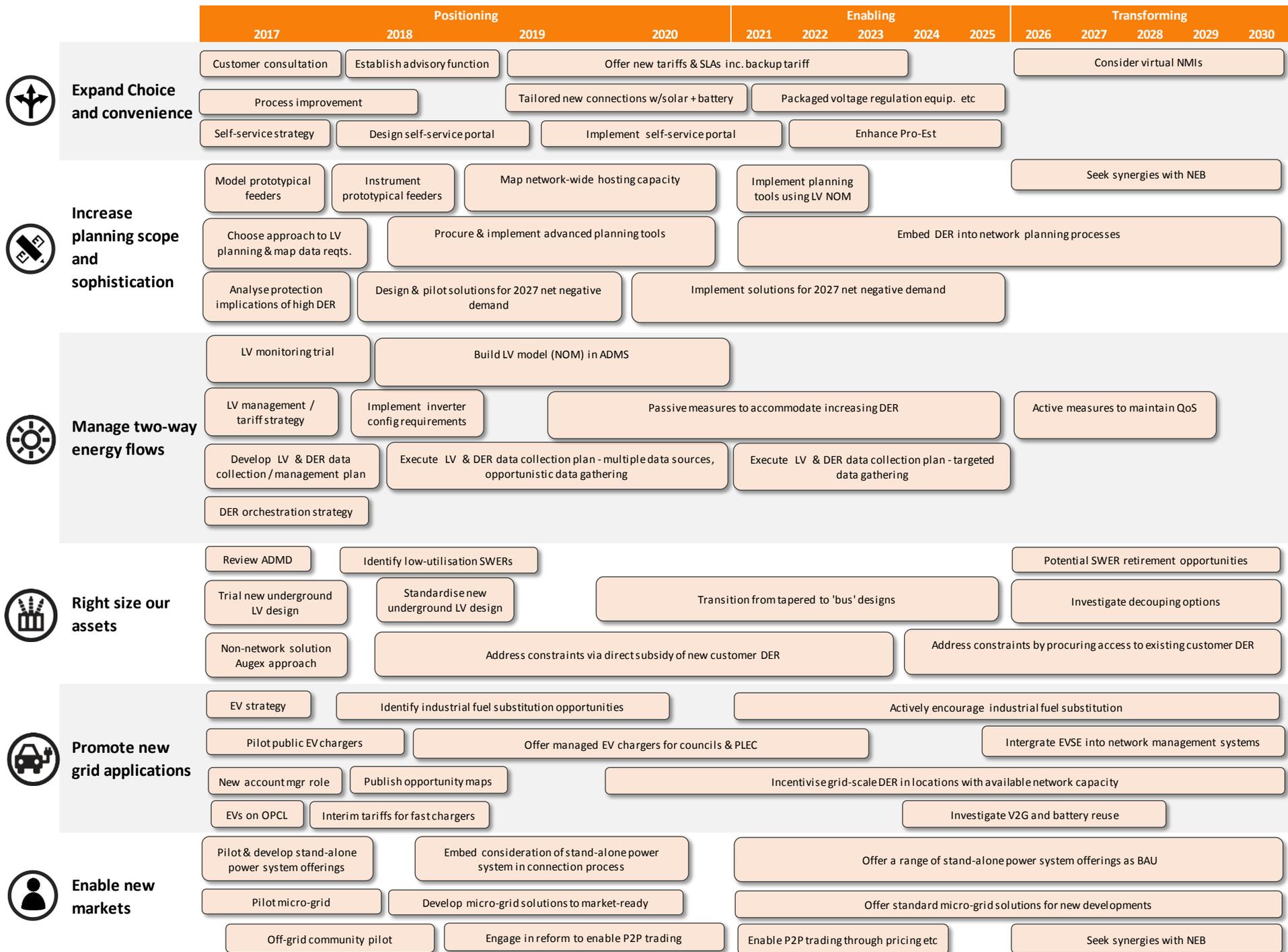


Figure 38 – Strategic roadmap to 2030

10 STRATEGY ROADMAP

10.1 Consolidated roadmap to 2030

Figure 38 above shows the consolidated strategic roadmap to 2030 for the six core strategies.

10.2 Strategic projects for 2017 and 2018

A total of twenty-six strategic projects have been identified across the six strategies to commence in 2017 or 2018, some of which are already underway. These projects represent the first phase of work in executing the strategic roadmap. Some are focused on refining our understanding of opportunities, costs and benefits in several areas to inform our 2020-25 reset submission, some are to address immediate issues, while others are intended to lay the foundations for our long term strategic direction. These projects are summarised below, and described in more detail in Appendix H.

	2017	2018	2019
1 Expand customer choice and convenience			
1.1 Customer solutions process improvements <i>Streamline processes to improve customer experience and increase productivity</i>	●	●	
1.2 Self-service strategy & business case <i>Develop strategy, business case and implementation plan for a customer self-service portal</i>	●	●	
1.3 New services consultation <i>Develop prioritised plan for introducing new products and new grades of service, including alternative connection types</i>	●		
1.4 Customer advisory function in customer solutions <i>Develop energy advisory service and train CSMs/NPOs</i>	●		
2 Increase planning scope and sophistication			
2.1 Strategy and tools for enhanced planning <i>Develop recommendations and roadmap for new planning tools, including role of ADMS, and initial tool procurement</i>	●	●	
2.2 Hosting capacity analysis and strategies <i>Engage consultant to model hosting capacity of LV network based on prototype areas, and propose costed remediation strategies for reset</i>	●	●	
2.3 High DER protection review <i>Determine protection implications of AEMO 2026 minimum demand forecast and identify any specific remedial expenditure for 2020-25</i>	●		
2.4 Network automation expansion strategy <i>Determine strategy and business case to expand feeder automation</i>	●		

3 Manage two-way energy flows		2017	2018	2019
3.1	LV transformer monitoring trial <i>Roll out transformer monitoring to 200 LV transformers in areas of high summer peak demand to assess dynamic range and capacity</i>	●		
3.2	Diverse LV monitoring trial - prototype areas <i>Targeted use of transformer monitors combined with other data sources in prototype LV areas to inform future monitoring strategy</i>	●	●	
3.3	Inverter voltage control trial <i>Trial capabilities of 'smart' AS4777 inverters for voltage management, as part of broader ENA/API research project</i>	●	●	
3.4	LV management strategy <i>Engage consultant to develop strategy and roadmap for building a detailed model of the LV network as a foundation for LV management</i>	●	●	
3.5	DSO foundations <i>Plan and implement DER registration process, and define and commence a DSO trial with a retailer to develop DSO role</i>		●	
3.6	DER forecasting in operational systems (Solcast) <i>Participate in ANU/ARENA Solcast project to explore integration of real-time solar forecast into ADMS</i>	●	●	●
3.7	Tariff strategy to minimise DER network impacts <i>Develop and execute strategy to encourage incentives to encourage battery management algorithms that reduce network impacts</i>			
4 Right size our assets		2017	2018	2019
4.1	ADMD review <i>Propose and implement new ADMD standards including new negotiated options for developers</i>	●	●	
4.2	LV design standards <i>Update LV design standards based on current best practice and pilot 240mm² sectored construction method</i>	●		
4.3	Non-network solutions for network constraints <i>Develop new BAU processes to identify and evaluate non-network solutions to constraints, including for projects of < \$5 million</i>	●	●	●
4.4	Non-network solutions for resilience <i>Assess potential for generators, generator connection points to improve resilience in rural networks and determine reset proposal</i>	●		
4.5	Size opportunity for SWER decommissioning <i>Undertake detailed case studies to determine criteria for future decommissioning of high cost / low value SWER lines</i>	●	●	

5 Promote new grid applications		2017	2018	2019
5.1	Finalise and execute EV strategy <i>Determine and gain endorsement for strategies to accelerate EV adoption and position for long-term benefits of EVs</i>	●		
5.2	EV charger pilot <i>Trial of public on-street EV chargers in partnership with a council, to explore future demand management potential and other opportunities</i>	●	●	
5.3	New applications opportunity assessment <i>Detailed assessment of future opportunities for new grid applications and determine benefit of a dedicated role to develop these</i>	●	●	
6 Enable new markets		2017	2018	2019
6.1	Microgrid trial <i>Establish community microgrid trial to explore potential of community-level optimisation of DER</i>	●	●	●
6.2	Standalone power system trial <i>Deploy 3 x standalone power systems to gain insights into the market and the potential of these as alternative to rural network connection</i>	●	●	
6.3	Off-grid community trial <i>Research into remote community microgrids to gain insights into the market and regulatory issues</i>	●	●	
6.4	Position for peer-to-peer <i>Research regulatory and business issues surrounding peer-to-peer trading to form a position and approach to this</i>		●	

11 GOVERNANCE AND STRATEGY EXECUTION

11.1 Governance

Appropriate governance of the strategy will be essential to ensure effective implementation, but most importantly, continued integration, as the changes required to support the future network will require unprecedented collaboration across our business. Furthermore, the strategy is unlikely to be ‘set and forget’, as technology advances and new customer trends will inevitably require aspects to be continually reconsidered.

Figure 39 below shows the proposed governance structure for the strategy.

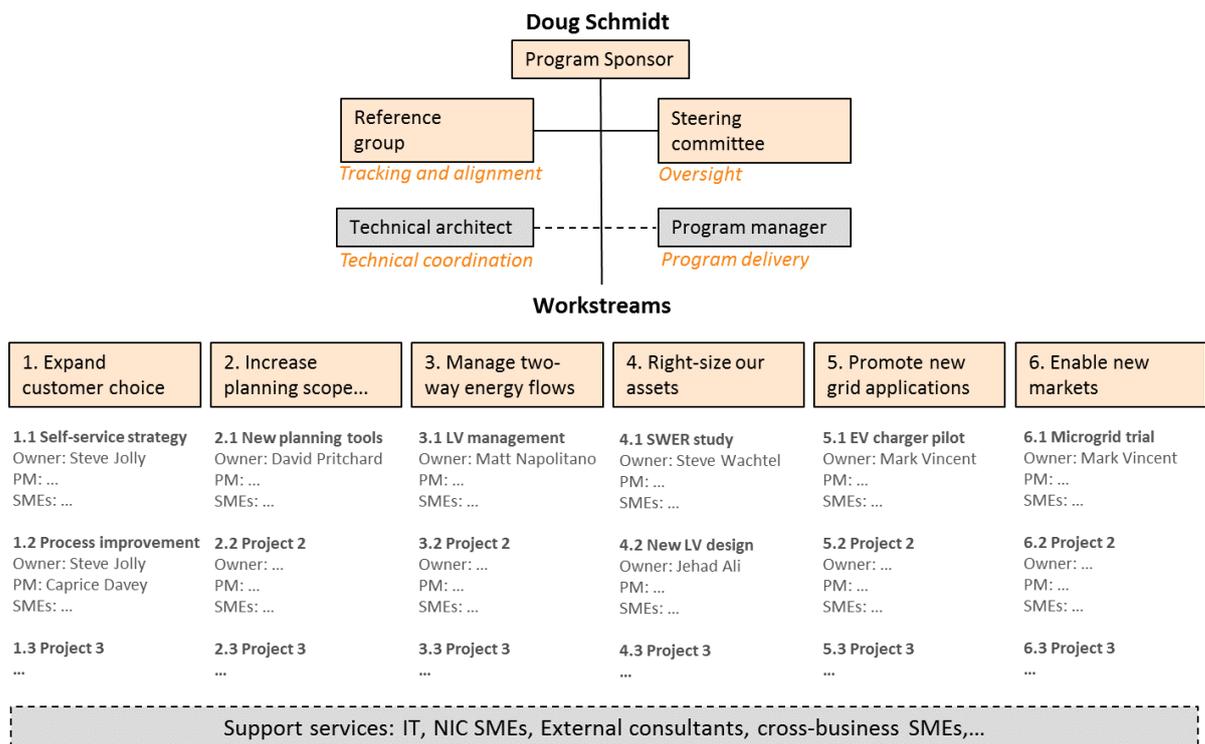


Figure 39 – Strategy governance

This structure includes the following roles:

- Future Network Steering Committee:** responsible for ensuring effective and timely execution of the strategy, as well as annual reviews and updates and ensuring alignment with the corporate strategic plan. The Steering Committee will meet 2-3 times annually.
- Future Network Reference Group:** responsible for tracking progress of strategic initiatives against key milestones, maintaining strategic alignment between workstreams, and making recommendations to the steering committee. The Reference Group will meet 2-3 times annually, around two weeks prior to each Steering Committee meeting.
- Future Network Architect:** responsible for integrating each aspect of the portfolio at a detailed level.
- Future Network Program Manager:** responsible for overall program delivery and convening Steering Committee meetings and other meetings.

Individual strategic projects will be managed by the project manager appointed by the business owner, using BAU project management processes. The schedule for regular project meetings will be at the PM's discretion, according to the nature of the project.

Oversight and co-ordination of projects within each of the six workstreams will be achieved through strategy workstream meetings to be held every two months, attended by the workstream business owner(s), PMs and key SMEs.

11.2 Cross-business enablers

Successful execution of the strategy will rely on support from many areas across the broader SA Power Networks business. Key cross-business functions that are enablers for the strategy include:

- **Regulation and engagement with regulatory reform**

Ensuring that SA Power Networks is ambivalent to either network or non-network solutions, and that there is a clear mandate for actions to support hosting of DER at the levels forecast by CSIRO and others as distinct from an approach that would see caps placed on the levels of allowable DER on each network segment.

- **Network pricing and incentives**

Continuing the transition to cost reflective pricing to encourage customers to make efficient investments, configure their equipment and, to the extent they are willing, alter behaviours commensurate with the long term marginal costs and benefits of those actions. Also establishment of an incentive framework, on a locational basis, for customers willing to adopt measures that avoid network expenditure in those areas.

- **Technical standards**

Engagement in evolving industry standards, and ensuring that the transition to new network architectures, designs, equipment and approaches, including the leverage of customer equipment, occurs effectively and efficiently.

- **IT&T, information and analytics**

The strategy will require step changes in a number of systems in order to support new capabilities including:

- Low voltage network monitoring, modelling, planning and configuration management
- Integration of DER into planning processes and tools
- Management of incentive mechanisms
- Network support (demand or voltage) utilising distributed and/or 3rd party resources
- Active management of DER as part of Distribution System Operator role
- Real time operational data collection, storage and power system modelling
- Analysis of customer data to provide energy advice
- Microgrid and stand-alone power system design, operation & maintenance

- **People, processes and capabilities:** will also need development in order to support the new capabilities described above.

- **Business operating model:** will need to be clarified, once the ring-fencing rule change is finalised, to confirm which areas of the business will be responsible for each area of strategy execution.

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A STRATEGY DEVELOPMENT METHODOLOGY

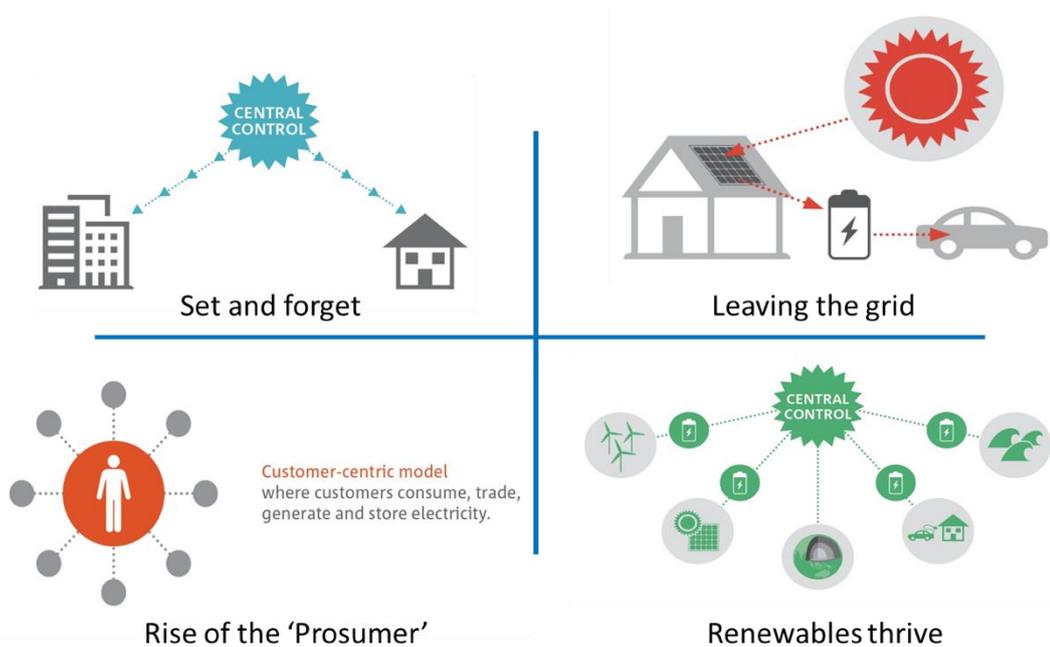
The strategy was developed from June 2016 to early 2017 in five steps, as shown in the figure below and described in more detail in the sections following.



Methodology

Step 1 – Develop scenarios

The first step was to define a set of plausible long-term future scenarios for the grid in SA to set the parameters within which to develop the strategy. These were based on the four future network scenarios developed by CSIRO and ENA through the Future Grid Forum, shown below.



CSIRO Future Grid Forum 2050 scenarios

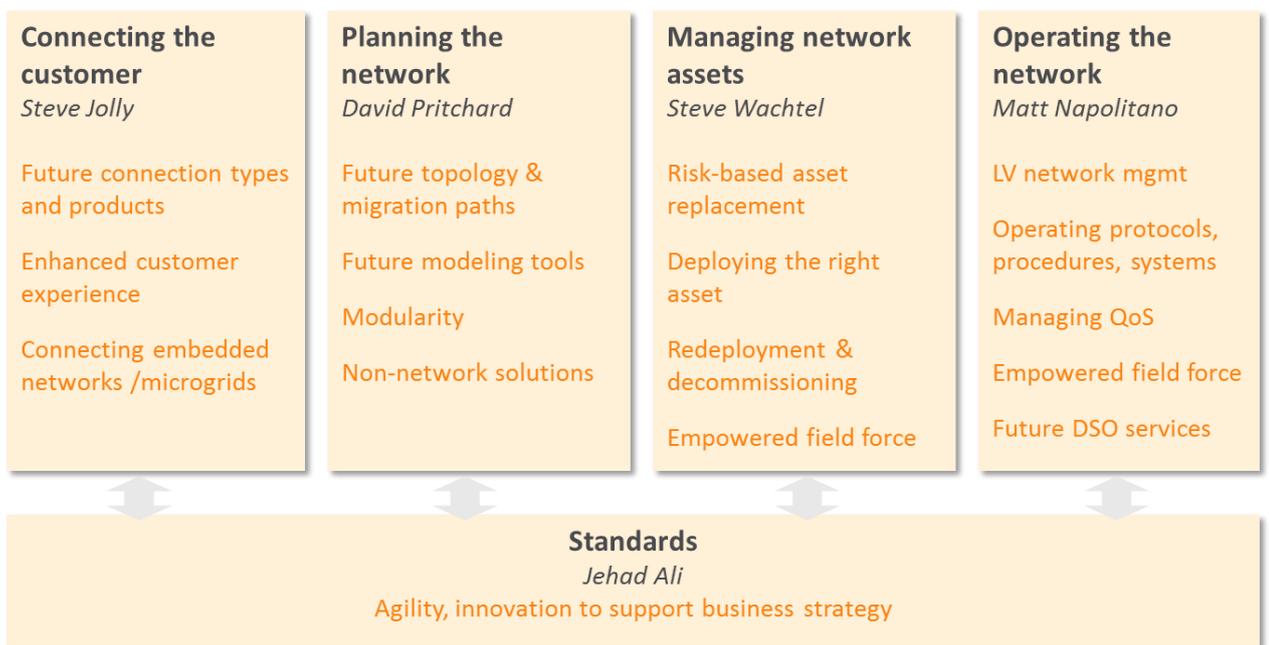
Referred to as 'Set and Forget,' Rise of the Prosumer,' 'Leaving the Grid,' and 'Renewables Thrive' these four scenarios represent four different but plausible visions of the Australian energy sector in 2050, based on four sets of assumptions around consumer behaviour, technology price paths and Government policy. These scenarios were first developed by CSIRO in 2013, and were updated and refined in 2016 through the ENA Network Transformation Roadmap project.

The four CSIRO future scenarios were used to develop some SA-specific future scenarios to set context for stakeholder workshops, taking into account new information and information specific to South Australia including:

- AEMO long-range forecasts
- SA Power Networks' internal forecasts
- SA-specific data in relation to energy mix, renewable targets, policy directions and issues (e.g. interconnector capacity)
- Energeia's recent market reports
- Internal modelling on impact on load profiles / energy flows of DER and EVs at forecast 2050 saturation.

Step 2 – Ideation workshops

A series of all-day 'ideation' workshops was conducted with key business stakeholders in order to explore the future scenarios and elicit strategic ideas. Five workshops were held, as shown in the figure below.



Ideation workshops

The first four workshops each focused on a specific business function within the overall function of Network Management, being:

- Connecting the customer
- Planning the network
- Managing network assets
- Operating the network

These workshops were organised along current business lines in order to assign a business owner to each area (shown in the figure), to ensure that existing strategic initiatives in each area were captured through the process, and to allow for some deep technical group discussion among SMEs on specific topics of interest identified during the scoping phase, some of which are listed in the figure above. It was recognised, however, that many of the new ideas and strategies emerging through the workshop process would be cross-functional, in part because the future business structure may differ from today. In light of this, each workshop also included stakeholder representatives from the other business areas, as well as a range of stakeholders able to represent important perspectives from the broader business, e.g. Regulation, Field Services, IT, NEB, etc. In this way the workshops aimed to surface a broad range of ideas, from

specific short-term technical initiatives in each focus area, through to ‘blue sky’ long-term strategies that may cut across multiple areas of the network business.

The fifth workshop, ‘Standards,’ was conducted after the first four. It considered the outputs of the earlier workshops (noting that Standards was represented as a role in each of the preceding workshops) and explored the implications of the emerging strategic themes and initiatives on future network standards.

External consultant Second Road was engaged to assist with workshop design and facilitation during this stage of the project. Second Road have previously worked with SA Power Networks on the Strategic Choices project, and were also engaged to assist in the development of the updated Future Operating Model and Corporate Strategic Plan during 2016, both of which ran in parallel to, and were interdependent with, the Future Network Strategy development process.

Step 3 – Select and prioritise

The aim of the ideation workshops was to ‘cast the net wide’ and generate the ‘raw material’ for the Future Network Strategy – a large number of ideas that varied widely in detail, scope and feasibility, across both short- and long-term time horizons. Some were specific to adapting the business to particular future scenarios, e.g. ‘Leaving the Grid,’ while others were equally applicable across all of the plausible future scenarios.

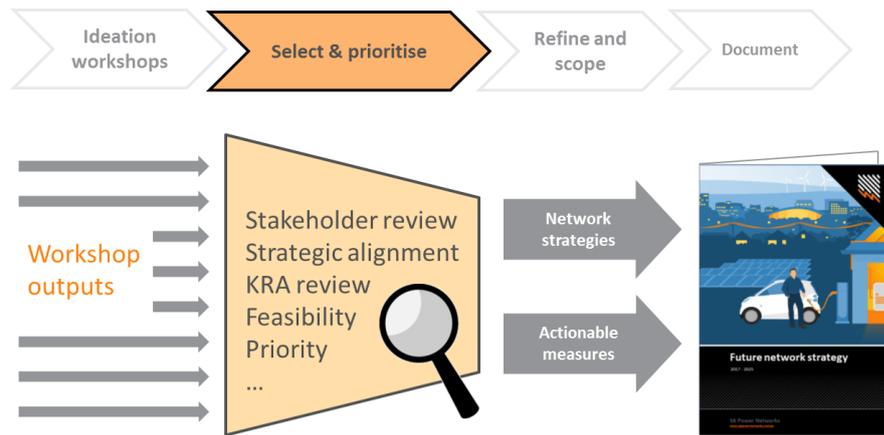
The next phase was to process the outputs of the ideation phase and distil the ideas into some common strategic themes. Ideas were assessed from a number of perspectives, including review against five specific Key Result Areas (KRAs) identified during the scoping phase of the project, shown below:

KEY RESULT AREAS (KRAs)

Enable new customer value	<ul style="list-style-type: none"> Support new customer technologies, e.g. solar PV, electric vehicles and battery storage Make it easy for customers to connect and use the network Manage 2-way energy flows Enable new network services
Manage risk	<ul style="list-style-type: none"> Maintain safety for the public and our personnel Operate the business within the board’s risk profile
Optimise asset investment	<ul style="list-style-type: none"> Minimise long-term capital and operating costs Maximise asset utilisation
Manage reliability	<ul style="list-style-type: none"> Continue to meet community expectations for network reliability Pursue reliability improvements for worst-served customers and where economic
Future-proof the business	<ul style="list-style-type: none"> Position for a range of plausible long-term futures

Key Result Areas

The output of this step was a set of emerging high-level strategic themes and a prioritised list of ideas that were candidates for inclusion in the strategy, some of which required further investigation.



Idea selection and prioritisation

Step 4 – Refine and scope

In this step further investigation was undertaken to explore, develop, refine and validate the specific concepts and ideas identified in the previous stage, and to explore key questions that had emerged.

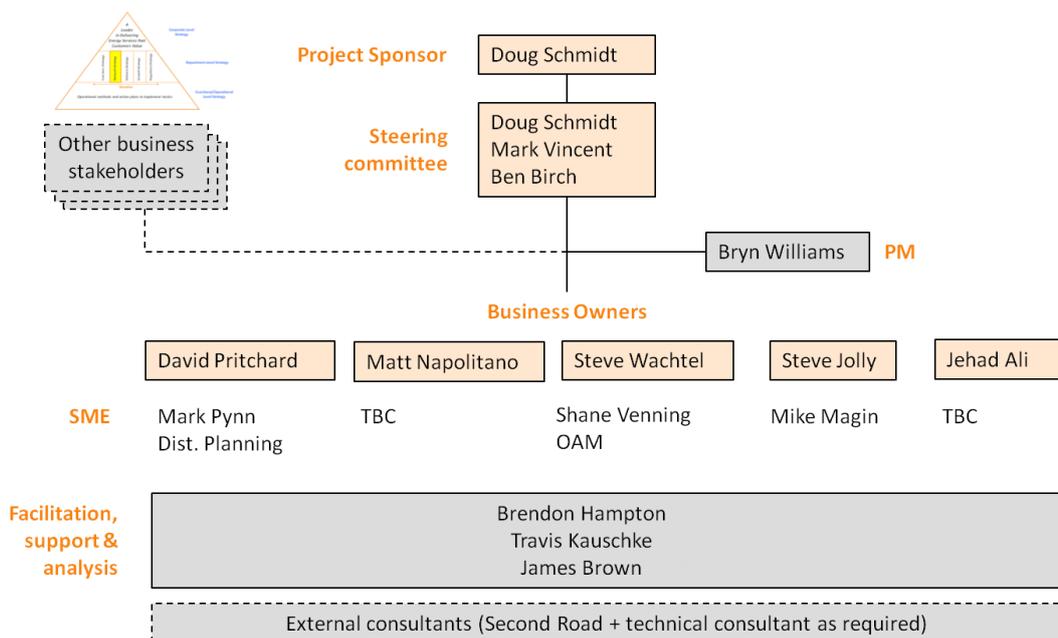
The core team from the Network Innovation Centre co-ordinated this activity, which comprised a series of ten self-contained work packages with specific research objectives. The core team engaged with the relevant teams within Network Management to identify resources to undertake these work packages.

Step 5 – Document and deliver

The final stage of the project was to prepare the Future Network Strategy document. The majority of drafting and document preparation was undertaken by the core team, with key SMEs within the business units responsible primarily for technical input and review.

Governance and resources

The figure below shows the project governance structure and core team. Additional Subject Matter Experts (SMEs) were nominated from each business unit as required.



Project governance and resources

B CUSTOMER CONNECTION PROCESS IMPROVEMENT OPPORTUNITIES

Output of Future Network Strategy Research task 6 internal workshop – November 2016

In order to improve the customer experience and promote grid connections it is important to remove any barriers that make this more difficult for the customer. This could be assisted by providing a faster turnaround for an estimate of the cost, making more options available for standard charging or simply increasing the number of no-cost options available. Our customer response effectiveness, connection process and costing methodology can all be improved to determine if it is feasible to provide for cheaper, faster and easier responses to customer's requests for connection to the network.

No.	Item	Timeframe	Description
Information Technology			
1	Improved internet experience with a simplified interface for customers	S	Improve the company web page to provide a simplified interfaced and improved experience for our customer
2	Self-service options for customers	M - L	Improve our internet based self-service offerings to our customers that includes: <ul style="list-style-type: none"> • customer quotations • tracking of customer connection projects • generator connection feasibility
Processes			
3	Simplify Generation Process	S	Improve the embedded generator process that simplifies the associated enquiry, response, evaluation and connection processes
4	Work with stakeholders to improve timeframes of the Residential Development process	S	Consult with stakeholders to analyse and highlight areas for improvement of the residential development connection process. This includes from the original development application through to the final connection to the network.
Customer Experience			
5	Survey of customers to understand what they value	S	Survey customers that have required a response to an inquiry through to final connection for basic and negotiated customer connection/alterations/convenience applications
6	Minimum service standards for responding to customers for phone and email messages	S	Develop a set of service standards that raises our performance to an agreed standard for communication with our customers
7	Provide customer service training for employees	S	Ensure our frontline staff have the right training and personal tools necessary to deal appropriately with our customers
8	Formalise how we engage with our Major Customers	M	Develop a process and communication plan for our major customers

No.	Item	Timeframe	Description
9	Engage with local councils on infill-developer connection process by providing an information sheet for their use	S	Develop a fact sheet and other associated documentation that assists with the understanding of how to enable a seamless connection to the network for infill land developments
10	Investigate restructure of Customer Solutions	M	Investigate whether the existing Customer Solutions structure is suited to the Customer Service strategy for streamlining enquiries, indicative estimates and centralised administration and whether changes should be made to better effect this.
11	Review Service and Installation Rules to simplify for customers.	S	Substantially alter the Service and Installation Rules that are less prescriptive and allow greater flexibility for the customer whilst still maintaining a safe electricity connection. Some examples are shown below: <ul style="list-style-type: none"> • Infill housing or community title developments where the rules are not conducive to multiple connection points. • The number of connection points available from pits and pillars
12	Better knowledge and management of customers' supplies	L	Register all customer supply information on the GIS(Geocortex) – include as much info as is available such as service size, max/min loads, tariff, etc. This would allow for a fast turnaround of customer queries whether for use by SAPN or the customer when needed.
Improving Timeframes			
13	Shorten and simplify the offer letter	QW	Simplify our customer offers that make it shorter and more easily understood by our customers
14	Provide electronic invoices to customers	QW	Develop a tool that facilitates the provision of electronic invoices for our customers
15	Fast-track the indicative estimate process	S	Critically analyse the effectiveness and efficiency of our indicative offers and whether a simplified, less formal process could be adopted with consideration of the appropriate level of risk management
16	Review standard charges	QW	Revise the current standard charges associated with basic connections and if they could be minimised, removed and/or condensed so that the application of charges for our services can be made clearer for our customers and contractors
17	Benchmark connection timeframes	S	Benchmark the SAPN connection timeframes of other utilities, including similar interstate providers
18	Service Level Agreements	S	Introduce a service level agreement with Field Services for connection timeframes and provision of dates for customer connections.

No.	Item	Timeframe	Description
19	PROEST improvements	M-L	Ongoing development of PROEST that simplifies our estimating, adds more standard templates and provides for electronic NPA approval
Reducing Costs			
20	Benchmark project costs	S	Benchmark costs with interstate service providers (including generation and standard connections).
21	Review charging methodology	M	Review Charging Methodology for customers for the 2020 Reset Proposal that send appropriate pricing signals, including the cumulative 5 year URD charge, providing incentives to customers to connect to under-utilised assets. Review the Connection Policy that allows for different charging methods for new or upgraded supplies as an alternative to the current methods. Eg. Use a financial evaluate tool in lieu of the current 'C-R' method
22	Modify connection scopes	S	Reduce connection scopes for customers (including choice of no backup, reduced telecommunication scope requirements). Alter the construction standards of some items of equipment that allow for improved Distributed Energy Resources, require less installation cost and provide more flexibility for connections. Examples include: <ul style="list-style-type: none"> • multiple or modular service connections boxes • increased LV cable sizes • Improved service pillars with more connect ability
23	Challenge requested maximum demands	S	Challenge the maximum demands requested by our customers to ensure they get the most efficient use of SAPN infrastructure that meets their electricity supply needs for the least cost
24	Review overhead rate charges	QW	Examine whether overhead rates can be reviewed to apply differently for different categories of projects
25	Leasing costs option in lieu of capital charge	M	Offer customer charges via a lease agreement rather than a capital lump sum

Table 18 - Opportunity list: streamlining customer connection process

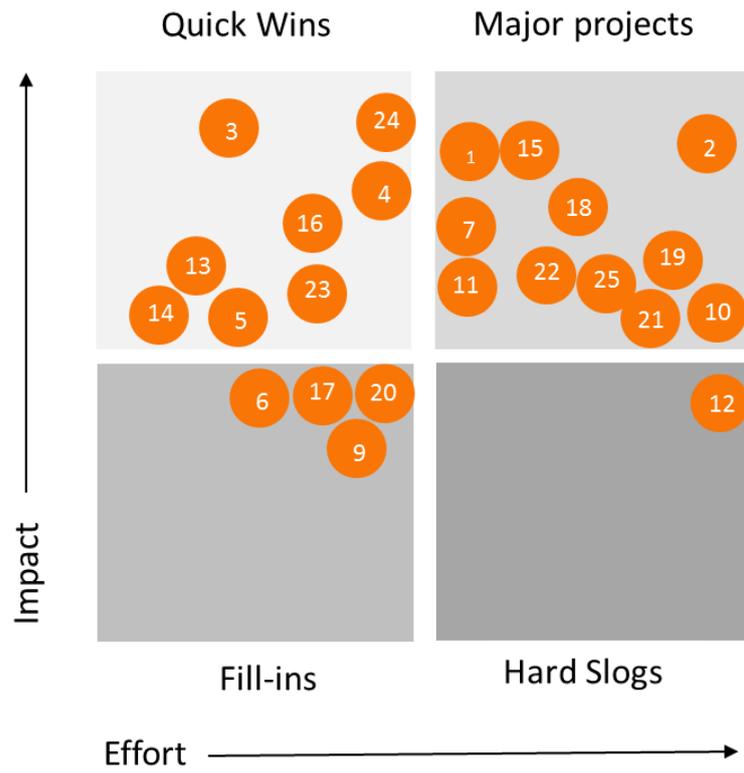


Figure 40 - Action priority matrix

C OPPORTUNITIES FOR NEW SERVICES

Output of Future Network Strategy Research task 7 internal workshop – November 2016

Traditionally, SA Power Networks has offered largely ‘one size fits all’ network connections – particularly to the small customer market. For some customers, this may poorly match their willingness to pay. Potentially customers could be offered a variety of levels of reliability and/or capacity. A greater range of offers may increase customer satisfaction, be more economically efficient, and provide new revenue opportunities.

No.	Item	Timeframe	Description
Tariff Changes and Customer Charges			
1	Aggregate NMIs	QW	Aggregate site NMIs for specific customers to optimise tariffs
2	Options for customers to have access to cheaper tariffs at off-peak times	S	Provide access to better tariffs for customers for specific items, eg. Controlled Load tariff for electric vehicles.
3	Tariff for optimum load profiles	M	Develop a tariff that enables customers to get discounted power costs if used at the optimum grid periods
4	Higher reliability connection	M	Install the infrastructure necessary with cost reflective charging to ensure a higher reliability connection.
5	Lower reliability connection	M	Minimise the connection assets at a lower cost to an agreed level of reliability
6	Lower capacity connection	S	Minimise customer charges by installing lower capacity and load limiting infrastructure (e.g. for customer / development with high DER) but with agreement on associated risks and contingency including load shedding capabilities.
7	Virtual(Portable) NMIs	L	Allow groups of customers to sum a number of NMI's to one main one to enable advanced network charging (e.g. for P2P trading) or allow their NMI to be portable.
8	Back-up tariff	L	Introduce a back-up tariff that provides back-up facilities in the event of power outages
Products and Services			
9	Tendering on behalf of customers	S	Provide customers with the option of SAPN tendering for work on their behalf as part of their connection offer
10	Offer 3 Phase converters	M	Offer the supply of 3 phase conversion equipment to customers
11	Offer LV regulators – (customer side regulation)	M	Offer LV regulation as part of customer connections where appropriate

No.	Item	Timeframe	Description
12	Offer motor start equipment to previous customers to reduce demand peaks	L	Review customer pumps that have been installed in less technologically advanced times and offer to replace with the benefit of a cost benefit analysis which includes capital cost, ongoing operating and maintenance costs and include options of a lease if appropriate.
13	Stand-alone Power Systems	QW	Explore Stand-alone Power System options as a standard inclusion in advice in relation to customer offers in addition to, or in lieu of standard grid connections
14	Alternatives for customers eg. using other energy sources for URD connections in addition to a grid connection	QW	Explore implications of customers seeking other energy sources such as solar or battery storage that assist to offset the grid supply demand and reduce the costs of a grid connection. This is particularly suited to areas where minimal grid supply is readily available such as areas reticulated with SWER mains or similar.
15	Micro-grid options	S	Explore implications of micro-grid in lieu of a standard grid connection. This could include a variety of energy sources for electricity supply and would allow for the islanding or otherwise of the development to operate in the optimum manner
16	Offer Thin Grid options – limit supply at least cost	S	Variation on micro-grid service above. As part of land developments allow a ‘thin grid’ option where the customer can minimise the electricity infrastructure and augmentation costs by including alternative energy sources in the development to reduce the grid demand.
17	Solar and/or battery options in addition to grid connections for single customers	S	Explore facilitating uptake of alternative energy products at time of connection whether this be a single residence, multi tenancy or commercial connections.
18	Offer back-up generation options	M	Explore options for UPS and/or back-up generation to allow for a more reliable electricity supply
19	Offer Power Factor correction equipment	M	Offer Power Factor Correction equipment to customers to avoid power upgrades or to reduce or eliminate charges
Process			
20	Allow electrical contractors to do more of the connection services	L	Allow electrical contractors to do more work associated with servicing, such as install the connection box, neutral screen, meter connections, pit connections, etc. of a minor nature.

Table 19 - Opportunity list: new service opportunities

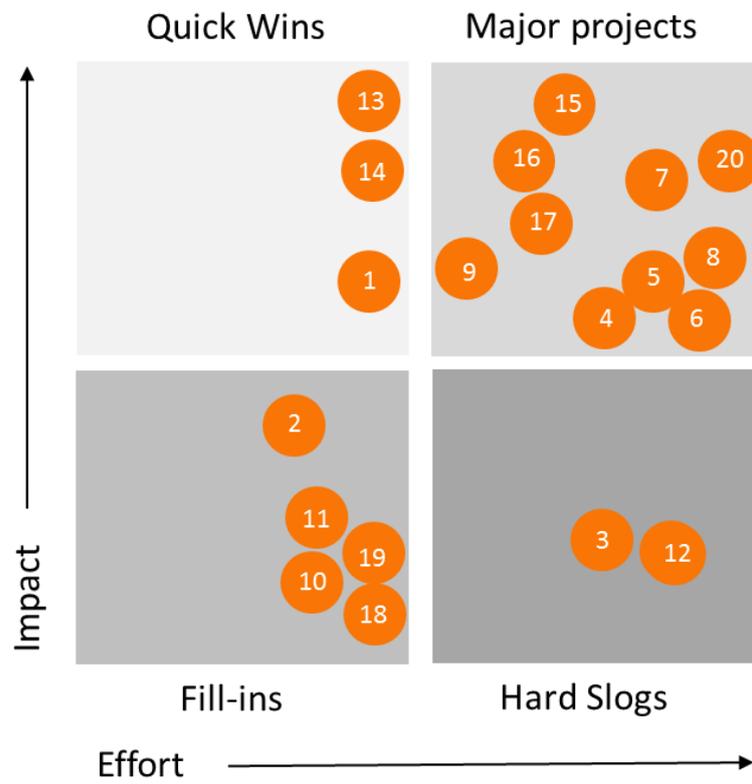


Figure 41 - Action priority matrix

D ALIGNMENT WITH CUSTOMER STRATEGY

The figure below summarises how the Future Network Strategy relates to the key opportunity areas identified in SA Power Networks' Customer Strategy [11].

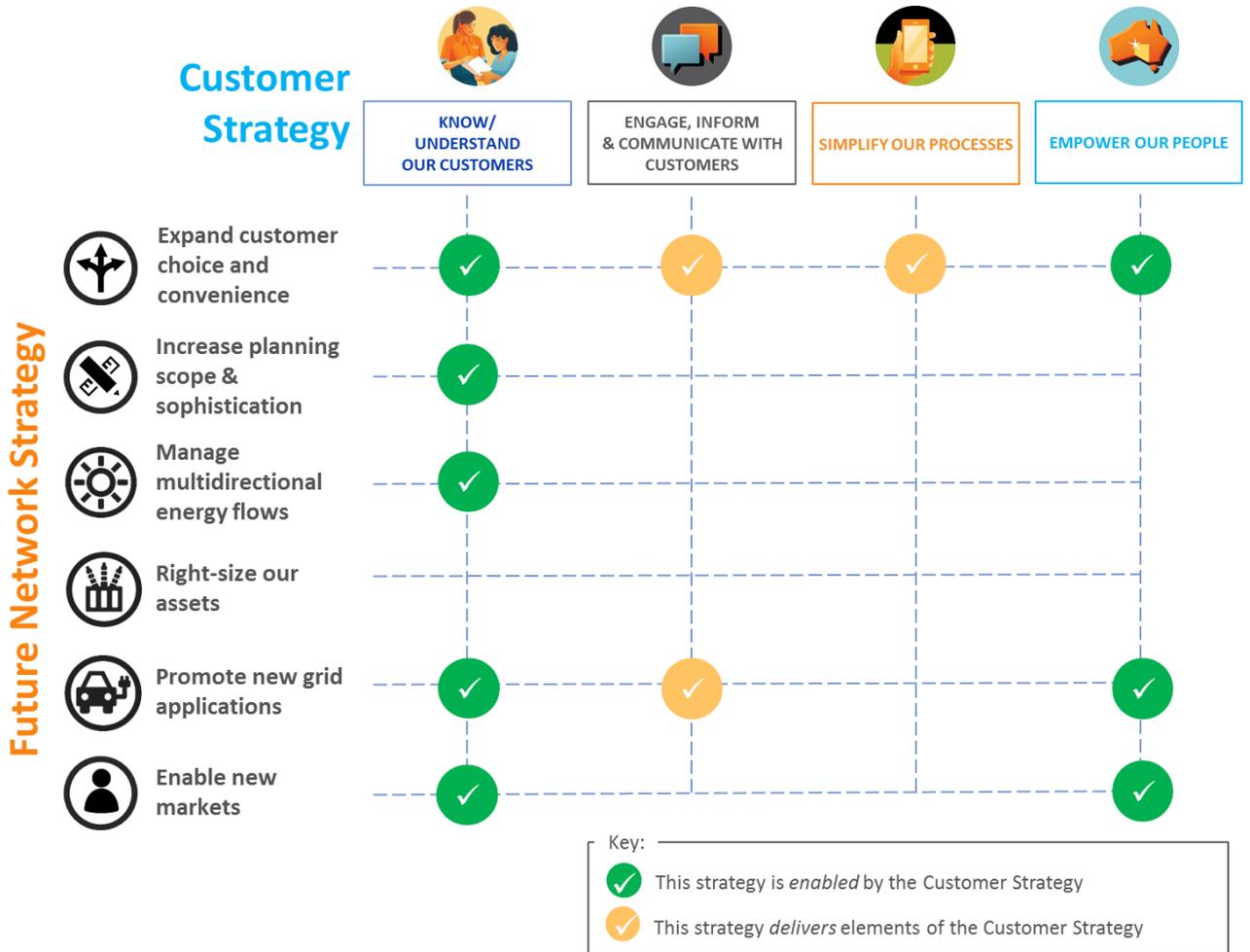


Figure 42 – Alignment with Customer Strategy key opportunities

E OPPORTUNITIES TO LEVERAGE DER TO AVOID NETWORK EXPENDITURE

Feeder capacity upgrades

Feeders are typically upgraded when one of the following are forecast to occur:

- a) The normal cyclic rating of the feeder exit or backbone is forecast to be overloaded during peak summer conditions.
- b) For a feeder exit failure, the customer load is unable to be transferred to adjoining feeders utilising their emergency cyclic ratings.

In case a) DER will need to be deployed at peak load times to avoid overloading the feeder backbone. In case b) DER will need to be deployed only for loss of supply due to a feeder exit fault.

The amount of DER required for a typical feeder constraint depends on the normal cyclic rating, which is typically 525A (10MVA) for a metropolitan feeder. The growth rate on a feeder requiring augmentation is likely between 0.1 and 2%. The DER required to avoid the overload would therefore be between 10kVA and 200kVA per year (assuming the feeder is 100% loaded in year one then exceeded by 0.1 to 2% per year). The typical peak lasts four hours which determines the minimum energy required to be offset, estimated at 40kWh to 800kWh each year.

The typical solution for an overloaded feeder is to construct a new 11kV feeder tie to an adjacent feeder to enable the transfer of load, or construct a whole new 11kV feeder to split the existing feeder. These solutions can range in cost from \$300,000 to \$3,000,000. Capital expenditure in this order translates to approximately \$16,000 to \$160,000 in annual deferral benefit per year.

The equivalent DER solution could foreseeably require 10kW/40kWh to 200kW/800kWh of DER to be installed per year. The DER solution could be implemented using any of the 3 methods listed above with varying cost and feasibility.

DER implementation method	DER Implementation cost range (\$/annum)	
	Small constraint	Large constraint
0 – Network standard	\$16,000 to \$160,000	
1 – Network sided	2017	\$30,000
	2025	\$20,000
	2050	\$10,000
2 – Upfront financial incentive	2017	\$19,000
	2025	\$9,000
	2050	\$1,000
3 – Subscription incentive	\$1,000	\$31,000

Compared to the annual deferral capital available (\$16,000 to \$160,000) these results demonstrate feasibility to defer low load growth feeder capacity upgrades today if large network expenditure is required. For example, the best case scenario could generate \$141,000 per annum savings given 0.1% load growth requiring \$3,000,000 capital expenditure. For smaller network expenditure and higher low growth constraints, upfront financial incentives or capacity purchasing would be required.

The traditional network solution of creating a new 11kV feeder tie or splitting the 11kV feeder reduces the number of customers supplied by the feeder. This has SPS benefits (fewer

customers interrupted for an 11kV fault) and provides additional operational flexibility for planned maintenance. These benefits are not realised through reduction of peak demand using DER. Contrastingly there are additional benefits in market participation, and active quality of supply management using DER when it is not utilised for peak reduction. These benefits however are highly dependent on market and network conditions.

Substation capacity upgrades

Substations are typically upgraded when one of the following are forecast to occur:

- a) The normal cyclic rating of the substation transformers are forecast to be overloaded during 10% POE summer conditions (a one in 10-year summer)
- b) For a transformer failure during 50% POE summer conditions (a one in 2-year summer) the customer load is unable to be supplied by any remaining substation transformer and transferred to adjoining substations utilising their emergency cyclic ratings – with a risk margin (this risk margin is typically 3MVA).

In case a) DER will need to be deployed at peak load times to avoid overloading the substation transformers. In case b) DER will need to be deployed only for the loss of a substation transformer.

The amount of DER required for a substation depends on the size of the substation and load at risk. Substations range in size from small pole-top 33/11kV transformers (as small as 150kVA) through to major metropolitan substations (as large as 90MVA). The DER required to avoid a substation overload could range from 30kVA to 1MVA depending on the size of the substation and the growth rate. The typical peak lasts four hours which determines the minimum energy required to be offset, estimated at 120kWh to 4,000kWh each year.

The typical solution for an overloaded substation is to construct a new 11kV feeder tie to an adjacent substation to enable the transfer of load, or upgrade an existing substation, or construct a new substation. These solutions can range in cost from \$300,000 to \$20,000,000. Capital expenditure in this order translates to approximately \$16,000 to \$1,000,000 in annual deferral benefit per year (based on a 4.88% benefit).

The equivalent DER solution could foreseeably require 30kW/120kWh to 1MW/4MWh of DER to be installed per year. The DER solution could be implemented using any of the 3 methods listed above with varying cost and feasibility.

DER implementation method	DER Implementation cost range (\$/annum)		
	Small constraint	Large constraint	
0 – Network standard	\$16,000 to \$1,000,000		
1 – Network sided	2017	\$90,000	\$3,000,000
	2025	\$60,000	\$2,000,000
	2050	\$30,000	\$1,000,000
2 – Upfront financial incentive	2017	\$60,000	\$2,000,000
	2025	\$27,000	\$900,000
	2050	\$3,000	\$155,000
3 – Capacity purchase	\$3,000	\$155,000	

Although it may seem technically feasible to defer low load growth substation capacity upgrades today if large network expenditure is required, it is extremely unlikely a substation would be overloaded in a small way requiring substantial capital investment. The more likely scenario

would be a large constraint requiring large capital expenditure. This type of constraint will be feasibly solved by upfront financial incentive or capacity purchasing after 2025, when the DER price is forecast to halve. This means in general substation constraints will need to be assessed on a case-by-case basis given the current low demand growth climate.

The traditional network solution of creating a new 11kV feeder tie, upgrading or construction may reduce the number of customers supplied by a single feeder or substation. This has SPS benefits (less customers interrupted for an 11kV fault) and provides additional operational flexibility for planned maintenance. These benefits are not realised through reduction of peak demand using DER. Contrastingly there are additional benefits in market participation, and active quality of supply management using DER when it is not utilised for peak reduction. These benefits however are highly dependent on market and network conditions.

Sub-transmission capacity upgrades

Sub-transmission lines are typically upgrade when one of the following are forecast to occur:

- a) The normal summer rating of the line is forecast to be overloaded during 10% POE summer conditions (a one in 10-year summer).
- b) The end of line voltage is forecast to be outside of standard during 10% POE summer conditions (a one in 10-year summer) due to voltage drop.
- c) There is a net economic benefit in the construction of an additional sub-transmission line to mitigate the risk posed by a failure of the existing sub-transmission line (based on Value of Customer Reliability).

In case a) and b) DER will need to be deployed at peak load times to avoid overloading the sub-transmission line being overloaded. In case c) DER will need to be deployed only for the loss of the sub-transmission line but may need to provide supply for all customers.

The amount of DER required for a sub-transmission line depends on the size of the line and load at risk. The DER required to avoid a sub-transmission overload could range from as small as 10kVA through to 40MVA depending on the size of the system supplied and the growth rate. The typical peak time is approximately four hours which determines the minimum energy required to be offset, estimated at 40kWh to 120MWh for cases a) and b). In case c), the load may be unsupplied by a faulted sub-transmission line for up to 12 hours and therefore considerably more DER would be required.

The typical solution for an overloaded sub-transmission line is to up-rate (increase ground to line clearance) or restring (larger conductor) the line. To mitigate the risk of radial sub-transmission lines, typically a new sub-transmission line is constructed.

The DER solution and implementation would depend greatly on the length of the line and works required and will need to be assessed on a case-by-case basis. Given the current low demand growth climate, some constraints are likely to be economically deferred using DER today.

For example, consider the current 300kW/600kWh overload on the Robe 33kV line. The network solution to up-rate the line is estimated to cost \$3,000,000 (\$160,000 per annum deferral benefit). A DER solution would need to provide 300kW/600kWh in the first year and 35kW/70kWh in subsequent years to cover load growth.

Preliminary analysis suggests there could be up to a \$100,000 per annum saving available for deferring the Robe 33kV line constraint with DER, but a more detailed study is required to validate this.

Infill distribution transformers

Infill distribution transformers are typically required for increased load in residential areas that have undergone redevelopment, (where customer numbers have increased but not fully catered for), which can result in LV fuse operation during periods of peak demand (heatwave conditions). These situations are typically resolved by either upgrading existing transformers or by installing infill transformers and altering the LV areas to share load.

Infill transformers typically require a new pole and may require both HV extension and LV re-conductoring. They are also subject to scrutiny to determine the best location electrically and aesthetically in already settled areas.

Peak load conditions may occur one to two days at a time, three to five times a year, for relatively short periods of four hours per day during the 6 to 10pm window. This sporadic short duration means a large proportion of the infill transformer capacity would be underutilized for the remaining part of the year.

The DER solution to replace the need for an infill distribution transformer would vary depending on the size of the existing transformer, number of customers, existing neighbouring capacity, LV reticulation, and growth rate. An example can be used to estimate the scale and feasibility of DER required in a typical case. Consider:

- a) A transformer with existing capacity: 315kVA
- b) Diversified peak load of each customer: 5kVA
- c) Peak load of 83 customers: 415kVA
- d) Overload component: 50kVA for 4 hours (Network Planning overload allowance 130% of the transformer rating)

In order to reduce the peak load on the transformer to within acceptable limits at least 50kVA of load will need to be offset. In order to cater for the 50kVA for 4 hours, a storage system of at least 200kWh is required. This can be installed as a single unit, fully controlled by SAPN, or as distributed residential storage.

The typical traditional solution cost is in the order of \$40,000 to 50,000, installed with an expected lifetime of 50 years, with potential to cater for future load growth at little to no extra cost. This is equivalent to \$2,000-\$2,500 in deferral benefit per year.

It is conceivable network sided DER never reaches a price low enough to be cost competitive with a traditional network solution. At this stage customer sided solutions do not look like they would be cost productive unless significant expenditure was required – far more than the typical cost to install an in-fill transformer.

Installing an in-fill transformer reduces the number of customers supplied by a single transformer, however the SPS impact of this is expected to be negligible.

SWER Capacity Upgrade

Increasing load on SWER systems from increased urbanisation of rural areas and increased commercial activity has been recorded in some areas. SWER's are very radial in nature, often built in remote regions, with little to no opportunity to tie load to other SWER feeders, or to create new SWER's from existing 11 or 33kV feeders.

The largest SWER isolating transformer is 200kVA, non-typical solution allows for paralleled 150kVA isolating transformers, (300kVA capacity) - not recommended practice. Traditional network solutions include 11 or 33kV extension, (anything from one span to several kilometres), to new SWER isolating transformer and SWER 19kV construction to a suitable tie point on the existing overloaded SWER, in order to transfer part load to proposed SWER.

Typically, peak load conditions may occur for several, one to two days at a time, three to five times a year, for relatively short periods of four hours per day during the 6 to 10pm window.

Recent SWER split projects have ranged in price from \$150,000 to \$750,000 and would provide a deferral benefit from \$8,000 to \$40,000.

The DER solution to replace the need for a traditional SWER upgrade would vary greatly depending on the localised conditions. Consider:

- a) Existing SWER isolating transformer is 200kVA
- b) SWER is radial and no viable tie-point with no localised 11 or 33kV feeder available
- c) Isolating transformer peak load measured at 140%, or 280kVA for 2 hours per day during peak load periods. Network Planning allowable overload limit set to 30%, exceeding this limit triggers an upgrade requirement.
- d) Overload component is 80KVA for 2 hours.

It is conceivable that this type of solution is feasible today under favourable conditions and under most conditions from 2025 given slow load growth.

F NETWORK IMPACTS OF ELECTRIC VEHICLES

CSIRO and Energeia have modelled the potential bill impact on electricity consumers arising from the forecast uptake of EVs, taking a whole-of-system approach that considers the impact on generation as well as transmission and distribution networks and also takes into account the expected growth in solar and battery storage [3]. CSIRO modelled two different scenarios: a ‘slow tariff reform’ scenario in which flat tariffs continue to be the norm for the majority of customers through 2035 and beyond (Scenario 2), and a ‘rapid tariff reform’ scenario in which the majority of customers transition to demand-based tariffs by the mid-2020s (Scenario 4)²⁸.

In the flat tariff scenario CSIRO assumes that EV owners will prefer more powerful chargers (7.2kW in the CSIRO modelling, consistent with the current generation of products aimed at home use) and charge at times of convenience. In the demand-tariff scenario they assume that EV owners will choose smaller chargers (3.6kW) for home use and manage their charging to occur outside peak demand periods, predominantly overnight.

CSIRO found that, given the slow rate of EV uptake forecast for Australia, EV charging is unlikely to have a material impact on customer bills prior to 2030. In the longer term, however, it will tend to reduce customer bills, as the benefit of increased energy throughput outweighs the cost of increasing peak demand. This benefit occurs in both tariff scenarios, but is significantly greater when customers transition rapidly to demand-based tariffs, because peak demand growth is greatly reduced. In scenario 4, CSIRO found that the average household bill would be 20 percent lower than their base-case by 2050. In the ‘slow tariff reform’ scenario (Scenario 2) where EV charging is not well managed, most of this benefit is lost due to the cost of growing peak demand, and customer bills are reduced by less than 4%.

The figure below illustrates the difference in DNSP network capacity required (NEM-wide) to meet peak demand under the two scenarios.

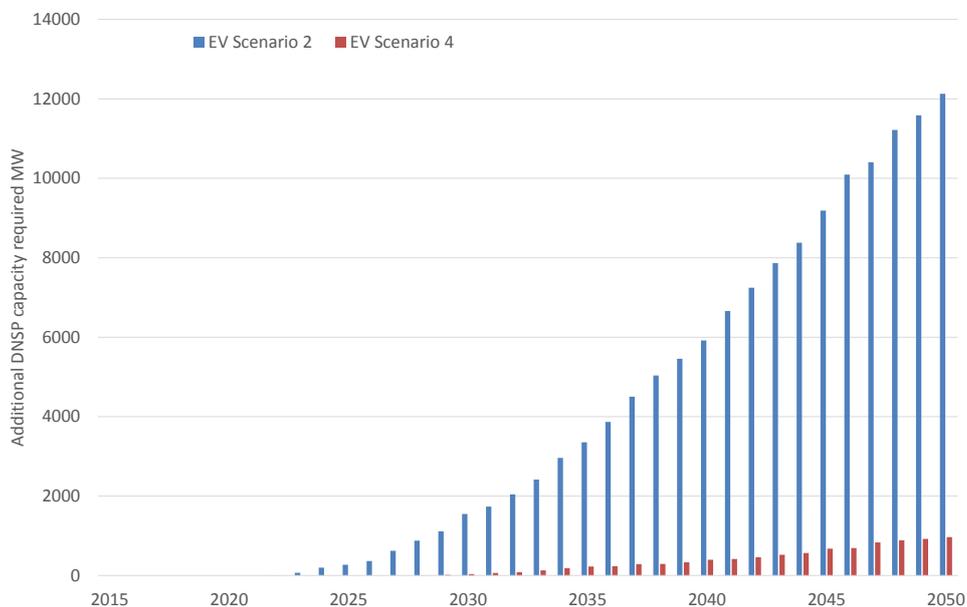
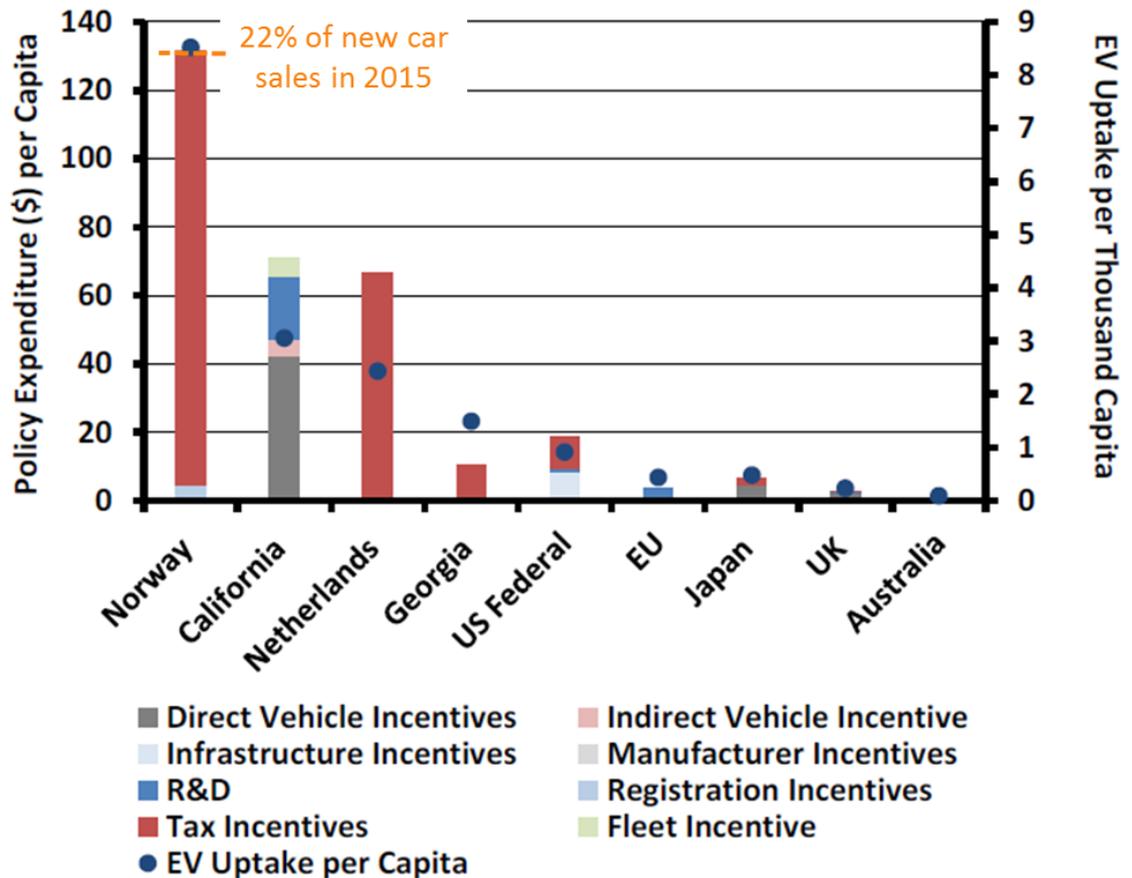


Figure 43 – Additional DNSP capacity required for EV charging under two tariff scenarios (Source: CSIRO)

²⁸ Scenario 1 and Scenario 3 were counterfactuals to model baseline price evolution under the two tariff scenarios in the absence of any EV uptake.

G ELECTRIC VEHICLE POLICY LANDSCAPE

Experience in other jurisdictions has been that Government incentives have been the single most significant factor in determining the rate of uptake of EVs. The figure below shows per-capita government policy expenditure on EV incentives for a number of different countries and illustrates the correlation with EV uptake rates.



Source: International Council of Clean Transportation, Inside EVs website

Figure 44 – Impact of government incentives on EV uptake overseas

As can be seen in the chart, Australia today lacks any significant government incentives for EVs, although opportunities exist to stimulate the EV market at local, state and federal levels of government.

Local government schemes

Adelaide City Council, with its ‘Carbon Neutral Adelaide’ agenda, is the ‘most active proponent of electric vehicles among the South Australian councils. In 2015 ACC introduced an incentive scheme to encourage private car park owners, building owners and others to install chargers in the CBD (within the metropolitan boundary) in which the council will pay 50% of the price of each charger, up to a maximum of \$1,000 for an AC Level 2 charger (5-20kW) and \$5,000 for a fast charger (20kW+). As noted in section 8.2, ACC has also recently announced plans to install 30 public AC chargers in CBD car parks and 10 for on-street parking in 2017.

Kangaroo Island council has also been active in promoting EVs. The council has installed public charging infrastructure on the island, and is seeking to work with other councils to install AC

chargers in public locations to establish an 'EV friendly' tourist corridor through the Fleurieu Peninsula and into the hills and wine regions.

State government incentives

The SA Government has had a Low Emission Vehicle Strategy since 2012 [16] that seeks to promote EVs, but to date has not implemented any specific financial incentives to stimulate the market. The most generous incentives at the state and territory level in Australia are in the ACT, where EVs are exempt from stamp duty, which saves approximately \$1,000 on the cost of a \$35,000 vehicle, and also attract a 20% reduction in annual vehicle registration fees [15]. Similar measures could be introduced in South Australia.

Commonwealth government opportunities

In addition to direct incentives, CSIRO has found that other policy change most likely to stimulate EV and PHEV uptake in Australia is the introduction of European-style vehicle emissions standards [3]. This is an area where Australia lags behind the rest of the developed world. The Commonwealth Government established a Ministerial Forum on Vehicle Emissions in late 2015 to consider future fuel efficiency and emissions standards for Australia, and has been consulting on this issue during 2016. The associated interdepartmental working group is to report in 2017 with recommendations for Australian standards.

Some industry participants, including Ergon, ActewAGL and AGL have been active participants in this debate, and lobby actively in other areas to advocate for government incentives to encourage EV adoption in Australia. The South Australian government and Adelaide City Council, having both set aggressive greenhouse gas emissions reduction targets, are also public advocates of EVs and favour greater Commonwealth Government support.

H STRATEGIC PROJECTS 2017 – 2018

1. Expand customer choice and convenience

1.1 Customer solutions process improvements

Steve Jolly

Implement process improvements in order to improve customer experience, increase productivity and release capacity to offer enhanced service.

Deliverables – by end 2017:

- Simplified offer letter (version 1 complete)
- Electronic and credit card payment facility
- Electronic invoicing
- Review standard charges
- OH rate review
- SIR review
- Simplified embedded generation connection process
- Update/create info pack for infill developers
- Communication plan for major projects
- Customer service training develop & deliver to NPOs
- Contract management training
- Review adequacy of customer feedback mechanisms

Deliverables – by end Q2 2018

- Update standard charges to offer more choice
 - Improve transparency of workflow with FS
 - Simplified indicative offer process
 - Approved PROEST development plan
-

1.2 Self-service strategy

Steve Jolly

Determine priorities, develop a staged implementation plan, and gain approval to increase customer self-service capabilities

- Review overseas/other self-service portals
- Develop spec for our self service capability/portal and roadmap for development and implementation
- Features may include access to information, self-service quotations, online feasibility assessment and tracking progress of connections
- Consider relationship with standard visibility platform (e.g. geocortex)

Deliverables – by end 2017

- Develop direction & indicative scope & cost for self-service portal

Deliverables – by end of Q2 2018:

- Self-service specification and business case approved

1.3 New services consultation

Steve Jolly

Consult with customers to determine priorities for establishing new types and/or grades of service

- Potential new products inc. payment terms for major CAPEX projects
- Alternative connection types etc
- (interaction with standard levels of service e.g. shopping centres, CBD)
- Engage with CR to align with their consultation process
- Engage industry / customer groups

Deliverables – by end 2017

- New services development plan to 2020, including prioritised list of proposed new services
- Annual review process & governance

1.4 Customer advisory function

Steve Jolly

Develop a function in Customer Solutions to offer customers broader energy services advice.

Deliverables – by end 2017

- Service implementation & change management plan

Deliverables – by end Q2 2018

- Identify specific team of network managers/CSMs/SNPOs for advisory role
 - Training materials & internet resources
 - Work instructions
-

2. Increase planning scope and sophistication

2.1 Strategy & tools for enhanced planning

David Pritchard

Determine a strategy to expand the scope of current planning processes to integrate DER and extend into the LV network. Determine role of ADMS in meeting future network planning needs.

The goal is to establish a roadmap for tool and process enhancements that will, by the end of the 2020-25 period:

- embed DER into NP
- Integrate LV NOM into planning tools

Deliverables – by end 2017

- Network planning capability roadmap to 2025 + inc. role of ADMS in short term and medium term
- Recommendations for new tools and timeframe for acquisition
- Draft specifications for new network planning tools

Deliverables – by end 2018

- Procure enhanced network planning tools for short term
 - ADMS data extraction capability
 - Clear direction for medium term
-

2.2 Hosting capacity analysis and strategies

David Pritchard

Engage consultant to undertake modelling of hosting capacity of the LV network (with consideration of HV). Determine and gain agreement to least cost strategies to increase hosting capacity.

- Survey other DBs for best practice
- Determine granularity of whole network model (Transformer / suburb / ...) and approach
- Determine prototypes, classify whole network into those types
- Model prototypes
- Determine mitigation strategies & costs (input from Transmission/Substation voltage management project)
- Approach should target allowing forecast DER uptake with no caps or limits

Deliverables – by end 2017:

- Hosting capacity analysis report
- Detailed models of prototypes
- Initial whole-of-network model
- Refined QoS management strategies & costs for 2020-25
- Estimated time horizon for hosting capacity limits across the network based on DER uptake forecasts
- High-level remediation cost forecasts for reset

Deliverables – by Q2 2018

- Refined whole-of-network model
 - Detailed assessment of remediation strategies and costs for identified 2020-25 issues
 - Detailed reset proposal
-

2.3 High-DER protection review

David Pritchard

Consider the protection implications of AEMO's and CSIRO's future network forecasts. Engage with Electranet and consider AEMO needs & future UFLS, leverage ENA work.

Deliverables – by end 2017

- High DER protection review report, identifying any specific remedial action required in 2020-25 period
 - Refine reset expenditure forecast
-

2.4 Network automation expansion strategy

Mark Vincent

Determine strategy and business case to expand feeder automation

Deliverables – by end 2017

- Feeder automation expansion business case
-

3. Manage two-way energy flows

3.1 LV transformer monitoring trial

David Pritchard

Roll out LV transformer monitoring for 200 LV transformers in areas of very high summer peak demand, to assess load profiles, dynamic range and capacity constraints. Trial several equipment vendors to inform approach to broader rollout.

Deliverables – by end 2017

- 200 transformer monitors installed and operational
-

3.2 Diverse LV monitoring trial – prototype areas

David Pritchard

Targeted deployment of additional transformer monitors and other data sources to saturate a small number of prototypical areas, and negotiation of access to third-party data sources, to:

- establish a common data model and platform to integrate LV monitoring data from different sources
- inform optimal mix of transformer monitoring & other data sources e.g. smart meters, smart streetlights, smart DER
- inform the optimum balance between modelling and monitoring to estimate hosting capacity and identify local constraints to a sufficient level of accuracy at least cost
- Consider future control requirements.

Deliverables – by end 2018

- Monitoring deployed to prototype areas
 - Common data platform
 - Negotiated access to 3rd party data
 - Strategy for optimal monitoring mix
-

3.3 Inverter voltage control trial

David Pritchard

Utilise grid and residential energy storage systems to trial innovative new voltage control techniques:

- Use assets deployed in Salisbury and Cape Jervis
- Explore technical capabilities of residential vs. commercial inverters
- Explore optimal 'passive' configuration: real vs. reactive power response curves (max benefit for least customer impact)
- Test VPP voltage raise/lower services
- Test practical issues with use of customer equipment as a solution

Use modelling and trial results to recommend standards and requirements for smart inverters, and to inform solution options for LV hosting capacity constraints.

Seek to undertake this work as part of an ENA/API ASTP project.

Deliverables – by end Q3 2017

- Scope and plan
- Consider upcoming commercial installs
- Specifications for Reposit
- Initial settings for domestic inverters

Deliverables – by end 2017

- Salisbury & Cape Jervis pilot solution
- Determine target area for high-saturation trial (considering constraint list in DAPR)

Deliverables – by end Q2 2018

- High solar area trial in place (high saturation of enabled inverters)
- Revised settings / standards for domestic inverters

Deliverables – by end 2018

- Trial complete, report & conclusions
-

3.4 LV Management Strategy

Matthew Napolitano

What level of capability do we need in order to manage the LV network to support future needs? How to develop this capability and at what cost? How might this be staged?

- Connectivity
- LV electrical model (NOM)
- LV monitoring
- Non-traditional data sources
 - Requirements, value, systems, sources
- Customer & DER information

Deliverables – by end 2017

- LV management strategy document
- Reset proposal (preliminary)

Deliverables – by Q3 2018

- Reset proposal (refined)
-

3.5 DSO foundations

Matthew Napolitano

Foundations for DER orchestration

- General principle: all new DER must be controllable or control-ready
 - Could be though inverter or EMS
- Consider incentives vs mandate
- Standards & protocols
- Related to inverter project
- DSO trial
 - AEMO and/or Simply Energy

Deliverables – by end 2017

- Controllable DER plan – ‘no regrets actions’

Deliverables – by mid 2018

- Establish DER registration and incentive scheme (implement plan)
- Define and commence DSO trial

Deliverables – by Q3 2018

- DSO trial initial findings to refine reset story
-

3.6 DER forecasting in operational systems (Solcast)

Mark Vincent

Participate in ARENA/ANU/Solcast project to develop their real-time solar forecasting tool and integrate with ADMS. Project runs to July 2019.

Deliverables – by Q3 2017:

- Provide GIS data to Solcast and establish beta-test API

Deliverables – by Q3 2019

Demonstrate integration with operational systems (ADMS)
Transition plan for transition to BAU

3.7 Tariff strategy to minimise DER impact

James Bennett

Determine and lobby for incentives to encourage energy management system/battery vendors to implement algorithms that minimise network cost.

- Engagement in AEMC Distribution Market Model process
- Export tariffs and NER clause 6.1.4

Deliverables – by end 2017:

- Tariff strategy paper
-

4. Right size our assets

4.1 ADMD review

Jehad Ali

Propose and implement new ADMD standards:

- Review other utilities' approach to ADMD
- Make ADMD more specific to the application
- Consider 'bespoke' or negotiated options – what kinds of risk mitigations would we accept, what standard interfaces, how would we cap load?

Deliverables – by end 2017

- Updated table in SIR / TS100
- Develop proposal and standard rules for 'negotiated ADMD' process
- Trial application in place at Emu Bay
- Establish annual review process

Deliverables – by end Q2 2018

- Include negotiated process in SIR and rollout to Customer Solutions & industry
-

4.2 LV design standards

Jehad Ali

Gather info from other utilities and update LV design standards, to include:

- Trial and implement 240mm² sectored cable & different underground joint / fuse options.
- Develop 500kVA transformer design for LV URDs.

Deliverables – by end Q3 2017:

- Pilot sectored construction
- Report, cost/benefit comparison vs traditional design and recommendations

Deliverables – by end 2017:

- New standards in place

4.3 Non-network solutions for network constraints

David Pritchard

Review current processes to consider non-network alternatives to network augmentation, including for projects of < \$5 million. Make recommendations to amend processes in light of outcomes from project 3.5, 'DSO foundations', changing regulation (e.g. DMIS) and new opportunities (e.g. new market platforms). Consider partnership with specialist non-network solution provider.

Deliverables – by end 2017

- Publish annual 5-year constraint forecast in DAPR per NER and AER guidelines for <\$5 million

Deliverables – by end 2018

- Develop and implement new BAU process for evaluating non-network solutions

4.4 Non-network solutions for resilience

Jehad Ali

Options for generators, generator connection points and/or other DER to improve resilience in particular in rural networks. Consider design to enable solar to remain online.

Deliverables – by end 2017

- Proposal for reset
- Decision whether to proceed with Alternative Power Supply strategic initiative

4.5 **Size opportunity for SWER decommissioning**

Steve Wachtel

Determine criteria for SWER lines or line segments with high potential for decommissioning

- Engage with Horizon and others and consider Western Power/Horizon analysis
- Assess regulatory barriers, size of opportunity and candidate projects
- Determine criteria and method to pick candidate SWERs and recognise opportunities (e.g. function of load, customer numbers, condition, length, risk, etc.)

Deliverables – by end 2017

- Detailed case studies based on forthcoming (and/or recent) SWER restring projects, including cost/benefit analysis
- Engage with other utilities
- Recommendation for timeframe for further work

Deliverables – by end Q1 2018 (or as determined)

- Determine scale of opportunity
- Plan and recommendations, including any lobbying or regulatory change required to enable

Deliverables – by end 2018 (or as determined)

- If appropriate, implement process and tools to recognise potential opportunities and assess as part of BAU
-

5. Promote new grid applications

5.1 Finalise and execute EV strategy

Mark Vincent

Determine and gain endorsement for strategies to accelerate EV take-up and position to maximise long-term benefits of EVs. Consider leveraging ENEnergi ARENA proposal & syndicating Ergon/other.

Deliverables – by end 2017

- EMG endorsed EV strategy (public document)
- Agreed approach to advocacy
- New web site / on-line resources
- Join appropriate industry association(s) e.g. EV Council

Deliverables – mid-2018

- Standard PLEC EV charging solution

5.2 EV charger pilot

Mark Vincent

Trial of public on-street EV chargers in partnership with a local council.

- Establish a platform to monitor and control smart chargers as a foundation for future demand management.
- Develop a standard turnkey managed EV charger solution for councils and others.

Deliverables – by end 2017:

- Trial established, solution defined, first on-street charger installed

Deliverables – by end Q2 2018:

- Network of 8 or more smart on-street chargers installed and operational
- Standard offering available for councils and other customers

5.3 New applications opportunity assessment

Mark Vincent

Undertake a more detailed assessment of future opportunities for new grid applications, and position to develop these:

- Develop opportunity maps for preferred locations for grid-scale DER and fast EV chargers
- Engage consultant to undertake a fuel substitution opportunity study
- Consider dedicated 'business development manager' role

Deliverables – by end 2017

- Decision on dedicated role
- Establish process for developing, publishing and maintaining opportunity maps
- Formalise DuOS treatment for grid-connected batteries

Deliverables – by end 2018

- Opportunity maps published

Deliverables – by end 2019

- Fuel substitution study

6. Enable new markets

6.1 Microgrid trial

Mark Vincent

Establish a community microgrid project to assess the opportunity to utilise community level optimisation of DER to:

- minimise connection point demands
- minimise local network costs
- reduce electricity costs to customers
- inform future network standards
- establish new standard offerings for developers
- informing regulatory approach.

Deliverables – by end 2017:

- ARENA agreement
- Participant agreements in place
- High level design complete
- Stage 1 local network build complete

Deliverables – by end 2018

- Embedded network established
 - First customers connected
 - Community-level optimisation in service
-

6.2 Standalone power system trial

Mark Vincent

Deploy 3 x standalone power systems to gain insights into the market with a view to:

- determining applicability for offering such systems to high cost existing customers, e.g. on low customer-density SWERs
- providing advice to customers on suitability in greenfields situations
- informing regulatory approach.

Deliverables – by end 2017

- 3 x standalone power systems deployed
- Agreed research plan

Deliverables – by end of Q2 2018:

- Preliminary data
- Advisory collateral established

Deliverables – by end 2020

- Handover to customers (end of 3 year maintenance period)
 - Final report
-

6.3 Off-grid community research

Mark Vincent

Undertake research into hybrid solar/battery/diesel microgrids in remote communities (e.g. Horizon, SA Govt.) to gain insights into the market.

- determining applicability for offering such systems to high cost existing communities, e.g. on long rural lines
- providing advice to developers on suitability in greenfields situations
- providing advice to communities who are considering going off-grid
- informing regulatory approach and business strategy.

Deliverables – by end 2018

- Report with findings
 - Advisory collateral
-

6.4 Position for peer-to-peer trading

Mark Vincent

Educate ourselves on p2p, form a position, inc. whether to advocate for rule changes to allow VNM. Could be undertaken by external consultants, either for us or through ENA.

Deliverables – by end 2018

- Written research scope and plan to progress
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