



Supporting  
document 5.18

# LV Management Business Case

2020-2025  
Regulatory Proposal  
25 January 2019



SA Power Networks

# LV Management Business Case



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## Document Control

Version	Date	Author	Notes
0.5	18/12/18	BW	First draft
0.9	16/01/19	BW	Update from internal review
1.0	25/01/19	BW	Issued

## Summary

This business case recommends new expenditure in the 2020-2025 regulatory control period (RCP) to develop new operational systems and business processes to actively manage the integration of rooftop solar PV (rooftop PV), battery storage and virtual power plants (VPPs) into the distribution network. Total capital expenditure (capex) proposed is \$31.8 million over the 2020-2025 RCP, and there is an associated increase in operating expenditure (opex) of \$3.8 million over the period<sup>1</sup>.

This expenditure is in addition to ‘Business as Usual’ expenditure on Low Voltage (LV) network maintenance which will continue through the 2020-2025 RCP at a cost of \$8 million per annum. It also excludes the cost of continuing the targeted LV transformer monitoring program commenced in 2017, at a cost of \$5 million per annum.

## Context and related documents

This business case relates to the strategic initiatives described in chapter 5 of our Regulatory Proposal<sup>2</sup>, ‘Transitioning to a new energy future’ and the associated attachments 5 (Capital expenditure) and 6 (Operating expenditure). Full details of the methodology and analysis are provided in separate reports from KPMG<sup>3</sup>, EA Technology<sup>4</sup> and HoustonKemp<sup>5</sup>. Figure 1 below shows the relationships between these documents.

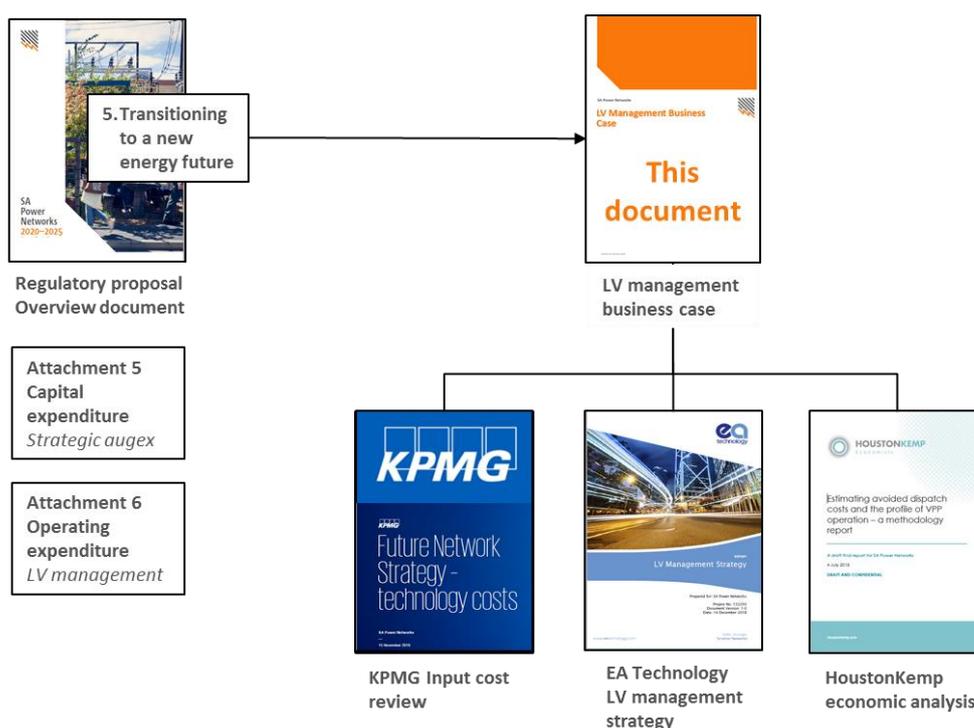


Figure 1. Context and related documents

<sup>1</sup> Figures are in June \$2020

<sup>2</sup> SA Power Networks, *Regulatory Proposal 2020-25, Overview Document*

<sup>3</sup> KPMG, *Future Network Strategy – technology costs*, report prepared for SA Power Networks, November 2018 (see Supporting Document 5.19)

<sup>4</sup> EA Technology, *LV Management Strategy*, report prepared for SA Power Networks, v1.0, December 2018 (see Supporting Documents 5.21, 5.22.1, and 5.22.2)

<sup>5</sup> HoustonKemp, *Estimating avoided dispatch costs and the profile of VPP operation – a methodology report*, January 2019 (see Supporting Document 5.20)

## Drivers for change

South Australia has the highest ratio of rooftop PV generation to operational consumption of all the NEM regions, and this is forecast to remain the case for the next ten years<sup>6</sup>. Installed rooftop PV capacity reached 1GW in 2018 and continues to grow strongly, driven in part by strong growth in the mid-sized (30 - 200kW) commercial sector as businesses respond to high energy prices. The rate of applications for new rooftop PV systems in this sector of the market tripled from 2016 to 2017.

At 1pm on 2<sup>nd</sup> December 2018, sunny and mild conditions saw South Australia record its lowest state-wide demand on record, at 520 MW. AEMO is now forecasting that state-wide minimum demand will reach zero at certain periods as early as 2024 as rooftop PV capacity continues to grow<sup>7</sup>.

The market for battery storage is also starting to accelerate. Retailers AGL and Simply Energy are currently rolling out VPP projects to more than 2,000 customers and, more significantly, 2018 saw the launch of two major Government VPP programs: a \$100 million home battery fund that offers subsidies of up to \$6,000 each for 40,000 customers to buy ‘VPP capable’ batteries, and the SA Government/Tesla Virtual Power Plant scheme, which aims to roll out up to 50,000 batteries in a single 250MW VPP. These two schemes combined could see 90,000 new batteries with up to 400MW of controllable storage connected to the distribution network in the next five years<sup>8</sup>.

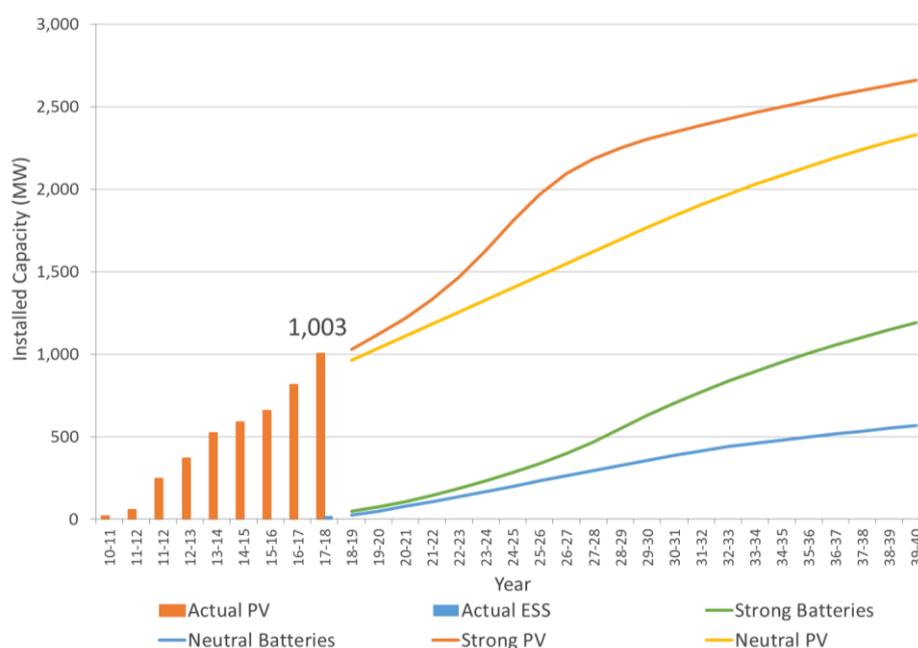


Figure 2. South Australia PV and battery (ESS) installed capacity, actual and forecast. Source: SA Power Networks, AEMO ISP2018

## Distribution network hosting capacity

The distribution network has a finite capacity to accommodate the connection of rooftop PV systems and batteries. This ‘hosting capacity’ is limited by two things:

### 1. Voltage constraints

SA Power Networks has a regulatory obligation to maintain supply at the customer connection point between 216V and 253V (the range specified in Australian Standard AS60038)<sup>9</sup>. Rooftop PV

<sup>6</sup> AEMO, *South Australian Electricity Report*, 2018

<sup>7</sup> Ibid

<sup>8</sup> See <http://www.renewablessa.sa.gov.au/> (accessed January 2019)

<sup>9</sup> South Australian Government, *South Australia Electricity (General) Regulations 2012*, version 17.10.2017, regulation 46 (a)

and battery inverters must raise voltage in order to feed energy ‘upstream’ back into the grid. This increases the dynamic range of voltage variation in the LV network as voltage drops at times of high demand and rises at times of low demand and high rooftop PV output (e.g. mild, sunny days). Once rooftop PV penetration exceeds around 25%-30% of households in a local area<sup>10</sup>, voltage at customer connection points can, at certain times, exceed the range specified in AS60038. This causes customer inverters to trip off and can cause quality of supply issues for other customers in the area (including those without rooftop PV), including damage to customer equipment.

## 2. Thermal constraints

As rooftop PV penetration grows in a local area, reverse current in the middle of the day (‘peak generation’) can become greater than the traditional summer afternoon peak current draw that the network was designed for. When reverse current exceeds the thermal rating of an asset like an LV transformer, fuses will operate, causing a supply outage for customers in the area.

These issues arise in part because the network was designed for peak demands that are reduced, in aggregate, by natural diversity in customer usage patterns, whereas rooftop PV output lacks this diversity; all rooftop PV systems in the same local area are generally exporting at full power simultaneously in the middle of the day.

VPPs that aggregate many customers’ individual distributed energy resources<sup>11</sup> (DERs) under central control present particular challenges in this regard, because a VPP operator who triggers the simultaneous discharge of multiple batteries in the same local area, for example in response to a market price signal, can cause a very large swing in energy flow in the local network.

Our understanding of these issues has been informed by our Salisbury VPP trial, which commenced in 2016. Every customer in this trial has a 5kW rooftop PV system and a battery. Figure 2 below shows an analysis of aggregated load data from a week in January 2017 for the 100 customers in this trial.

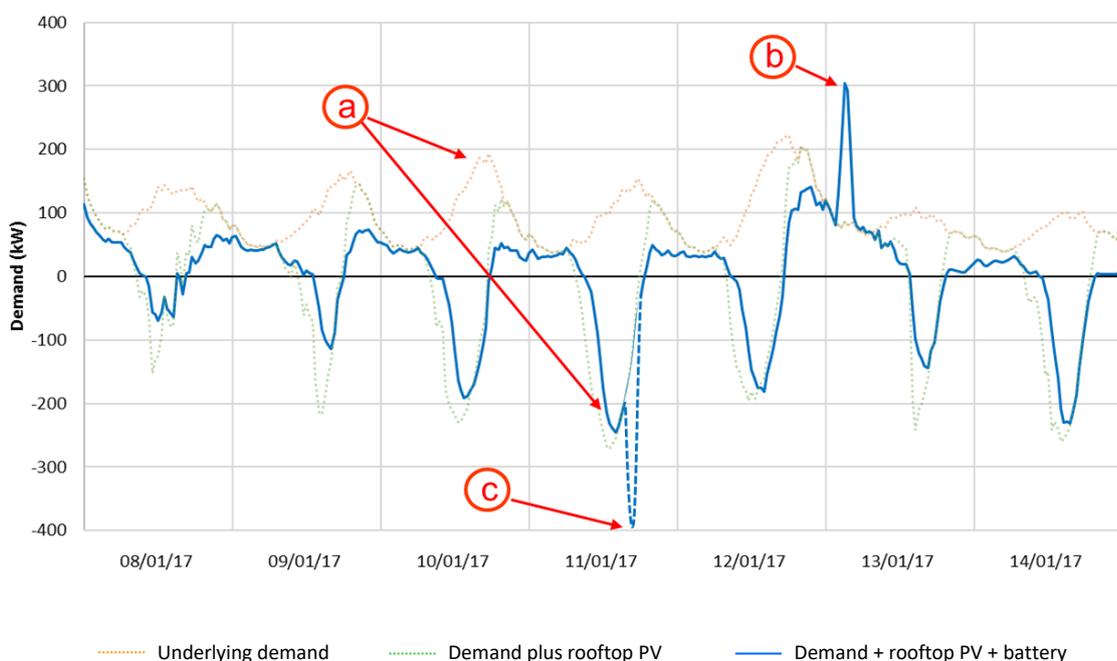


Figure 3. Salisbury battery trial, 100-customer aggregated demand data

<sup>10</sup> E.g. an area served by a single LV transformer

<sup>11</sup> This term is used by the electricity regulators and the industry to refer to all forms of generation and storage that is connected to a distribution network.

Figure 3 shows:

- a) The early afternoon peak ‘negative demand’ from rooftop PV exports (in this case, after the customers’ batteries are full), which is greater in magnitude than the traditional diversified peak demand due to afternoon air-conditioner load for which the network was designed (the brown dotted line);
- b) The spike in demand created on the 13<sup>th</sup> of January when the batteries were instructed to charge from the grid to maximise customers’ available backup power, as part of a pilot storm mitigation program. In this event the un-diversified load significantly exceeded normal afternoon peak demand; and
- c) The potential impact if the VPP were operated for wholesale market trading by a third party and the VPP operator chose to dispatch all batteries to discharge to the network at a time when rooftop PV exports are already high, e.g. in response to a wholesale price spike or contingent event.

In keeping with normal industry practice, SA Power Networks currently uses two methods to manage the impact of distributed generation on the network:

1. Static per-customer export limits, currently set at 5kW per customer<sup>12</sup>; and
2. Reactive investigation and remediation to address voltage and thermal capacity issues as they arise, e.g. when customers report voltage problems at their premises or fuses operate. Remediation methods range from relatively simple rebalancing of load and generation between phases, to expensive solutions involving upgrading transformers, replacing conductors or installing voltage regulation equipment, the cost of which is ultimately borne by all consumers through the network component of their bill.

## Modelling hosting capacity

In 2017 SA Power Networks engaged specialist UK electrical engineering consultancy, EA Technology to develop a statistical model to estimate the hosting capacity of different areas of the South Australian distribution network. This work built on and extended an earlier study undertaken in 2014 by local consultant PSC<sup>13</sup>. Full details of this modelling can be found in the LV Management Strategy document<sup>14</sup> but at a high level the methodology was as follows:

- The 75,530 LV areas in our network were classified into 15 categories
- Field audits were undertaken of a number of representative sample LV feeders in each category, to capture detailed electrical information and refine the category definitions.
- Detailed electrical models of the representative sample feeders were built using DigSILENT PowerFactory. These models were then used to simulate network conditions using representative customer load profiles at increasing levels of DER penetration, to determine the penetration levels at which voltage and thermal limits are reached.
- The outputs from this process were used to build an abstract whole-of-network hosting capacity model, taking into account statistical variability within each network category.

The results of this modelling are summarised in Figure 4 below and the notes that follow.

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<sup>12</sup> For a single-phase connected system

<sup>13</sup> PSC Consulting, *SA Power Networks Consultancy Services for Impact of Distributed Energy Resources on Quality of Supply*, report JA4679-4-0.1, Rev1, 12th May 2014

<sup>14</sup> EA Technology, *LV Management Strategy*, report prepared for SA Power Networks, v1.0, December 2018, Annexe 1: DER hosting Capacity Assessment (see Supporting Document 5.22.1)

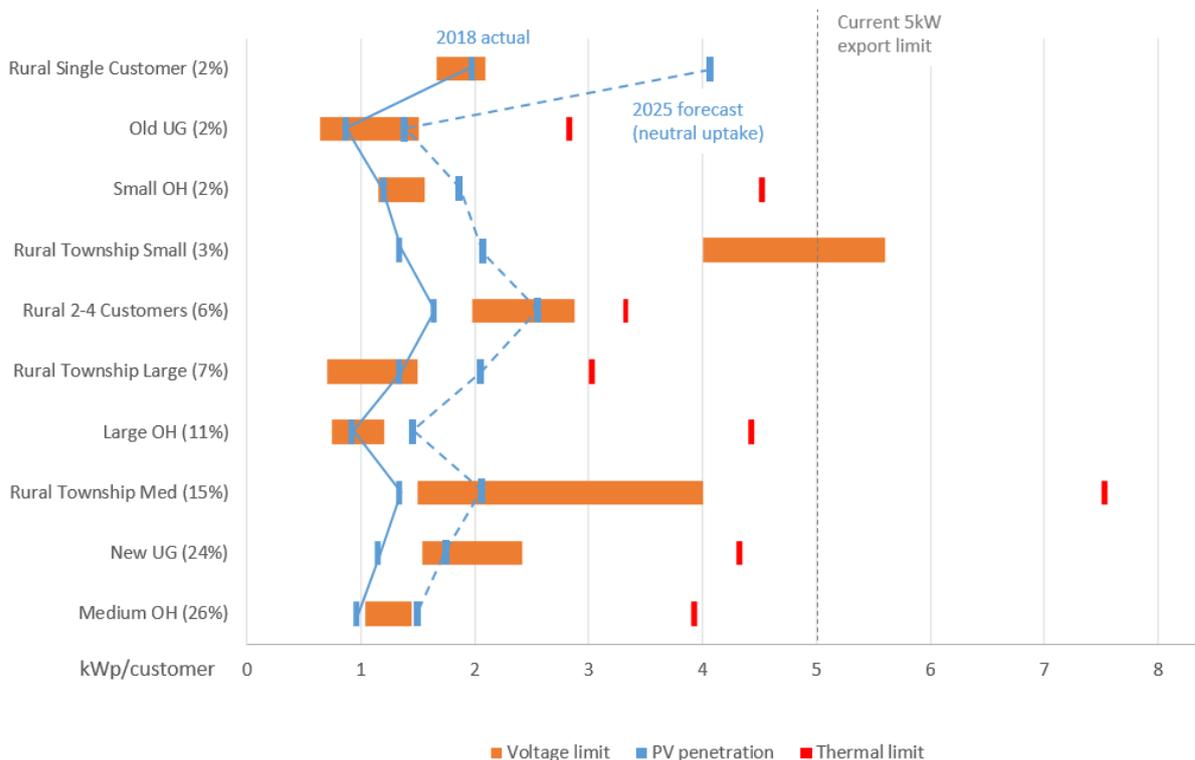


Figure 4. Hosting capacity modelling outputs

In Figure 4:

- The vertical axis shows the different categories<sup>15</sup> of overhead (OH) and underground (UG) LV network. The percentages in brackets show the proportion of customers connected to networks of these different types.
- The orange bars show the amount of rooftop PV, in kW per customer, that networks of each type can accommodate before voltage limits are exceeded<sup>16</sup>. The length of the bar reflects the statistical variability between individual networks of a given type. It can be seen, for example, that ‘Large OH’ (overhead construction) networks have generally lower hosting capacity than ‘New UG’ (underground) networks, due to the difference in construction standards.
- The red bars show the amount of rooftop PV per customer before thermal limits are reached, that is, before a transformer is overloaded by reverse current in the middle of the day.
- The blue bars show (a) the average level of rooftop PV penetration today for networks in each category, based on actual installed capacity at end Q1 2018, and (b) the forecast level of penetration per category in 2025 (the blue dotted line) based on AEMO’s ISP2018<sup>17</sup> neutral uptake forecast.

This modelling found that:

1. Today’s approach, which is to allow any rooftop PV system to connect that has a maximum export power of 5kW<sup>18</sup>, is not sustainable, or at least not without significant new investment in network infrastructure, as this exceeds the underlying hosting capacity of the majority of the network.

<sup>15</sup> This is a subset of the 15 categories modelled in which some categories have been combined to simplify the figure

<sup>16</sup> That is, the level of rooftop PV penetration at which at least one customer on the network would be expected to experience voltage variations outside the range required by regulation at certain times – typically over-voltage during mild, sunny conditions when there is low underlying demand.

<sup>17</sup> AEMO, *Integrated System Plan for the National Electricity Market*, July 2018

<sup>18</sup> For a single-phase connected system

2. Across all network types, voltage constraints arise before thermal limits are reached – for passive rooftop PV at least. VPP operation (not shown in Figure 4) can cause thermal limits to be breached at lower penetration levels, if batteries discharge in the middle of the day while passive rooftop PV output is already high, or charge during a peak summer afternoon.
3. Hosting capacity limits are already being exceeded in some areas of our network, in certain categories.
4. By 2025, if no action is taken, voltage limit exceedances are expected to be widespread in all network types other than small rural townships.

The outputs of the modelling were compared with empirical evidence from Quality of Supply investigations into voltage-related customer enquiries during 2017 and 2018 (e.g. inverters disconnecting in the middle of the day due to over-voltage) and were found to be consistent. Figure 5 below shows the number of rooftop PV-related customer voltage enquires since 2011. It can be seen that these enquiries are seasonal, peaking in spring when generally sunny but mild weather results in high rooftop PV output combined with low underlying demand, and have increased significantly in the last two years as rooftop PV penetration begins to exceed hosting capacity across more areas of the network.

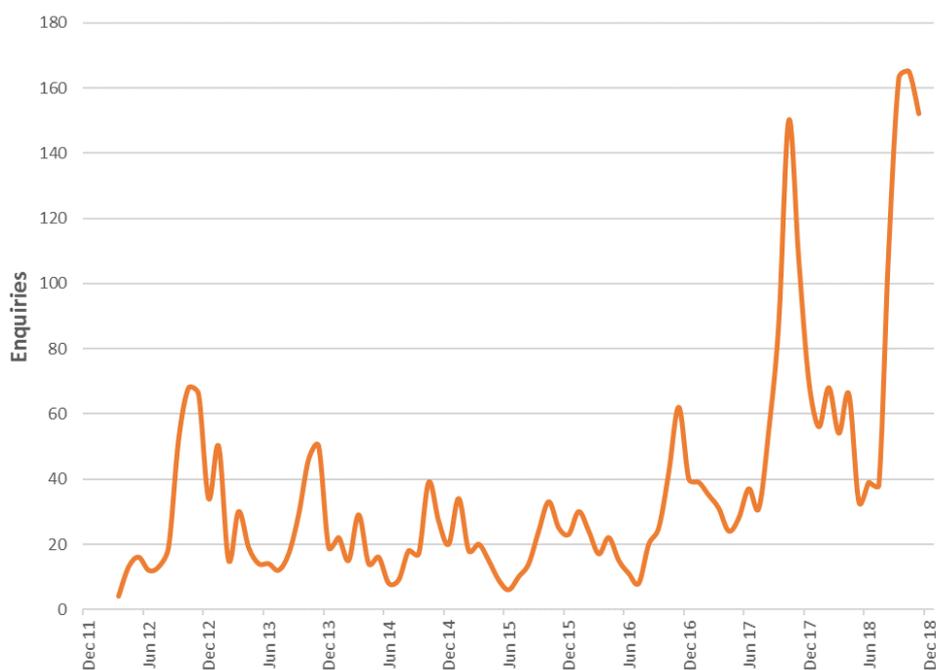


Figure 5. SAPN Customer high-voltage enquiries

## Limitations of the modelling

It is important to understand the limitations of this modelling. The EA Technology model is necessarily an abstract, statistical model of different categories of LV network. It is based on field-scoping and electrical modelling of a very small number of sample networks in each category and then estimating the statistical variation within each category. It is an economic model, not an operational model, insofar as it can inform, in general terms, the average likelihood of capacity constraints being exceeded in networks of a particular type for a given penetration of DER, but it does not understand the specific characteristics of any individual network, nor the dynamic state of the network at any point in time.

We are not able to construct a more detailed operational model of our LV network at this time as we do not have sufficient data on the electrical characteristics (e.g. conductor types) or state (e.g. open points) of this part of our network, and we have almost no active monitoring in the LV network. A key focus of our

proposed investment in the 2020-25 RCP is to capture the data we require to develop a more granular and complete model that can be used operationally to estimate and manage hosting capacity in individual LV networks.

## Integrated strategies to increase hosting capacity (what we've done so far)

Our overall strategy is to take an integrated approach to managing the network through a combination of efficient network-side solutions, demand-side (non-network) solutions and price signals<sup>19</sup>. In accordance with this approach we have already put in place some initial measures to help to increase the amount of DER our network can accommodate:

- **Inverter settings.** In November 2017 we updated our connection standards to require all new rooftop PV and battery inverters connected to our network to be configured with the Volt-VAr and (if available) Volt-Watt response modes defined in AS4777.2<sup>20</sup>. Our modelling suggests that Volt-VAr, in particular, can be effective in reducing local voltage rise issues with minimal impact to real power export. The effectiveness depends on a reasonable proportion of inverters on an LV circuit having the feature enabled, and so the benefit of the new standard will grow over time, as new inverters are installed and old ones are replaced.
- **Tariffs.** Our Tariff Structure Statement (TSS) for the 2020-2025 RCP<sup>21</sup> proposes new network tariffs that are designed to encourage customers to shift load to the middle of the day during times when there is a surplus of rooftop PV generation.
- **Shifting hot water loads.** We undertook a small trial in 2017 where we shifted hot water load from the night to the middle of the day. Following from this, we are considering using the Demand Management Innovation Allowance (DMIA) to fund further trials in this area in the 2020-2025 RCP<sup>22</sup>.
- **Transformer monitoring.** In 2017 we installed 200 LV transformer monitors in targeted areas with high levels of rooftop PV and/or high demand, as the first phase of a progressive rollout that we propose to continue from 2018 through to 2025<sup>23</sup>. This is a first step in achieving a basic level of visibility of our LV network.

## The identified need

SA Power Networks is required under:

- regulation 46(a) of the Electricity (General) Regulation (**Electricity Regulations**) to ensure that its network is designed, constructed, operated and maintained so that at a customer's point of supply the voltage is as set out in AS 60038;
- clause 5.2.1(a)(3) of the National Electricity Rules (**NER**) to maintain and operate its network in accordance with good electricity industry practice and relevant Australian Standards; and
- clause 5.2.3(b) to comply with the quality of supply standards described in schedule 5.1 of the NER and set out in its connection agreement with customers.

<sup>19</sup> SA Power Networks, *Future Network Strategy 2017-2030*, v1.0, November 2017 (see Supporting Document 5.17)

<sup>20</sup> SA Power Networks, *Technical Standard – TS 129, Small Inverter Energy Systems (EIS) – Capacity not exceeding 30kW*, November 2017

<sup>21</sup> SA Power Networks, *Regulatory Proposal 2020-25*, Attachment 17, Tariff Structure Statement

<sup>22</sup> SA Power Networks, *Regulatory Proposal 2020-25*, Attachment 11, Demand Management Incentive Scheme

<sup>23</sup> SA Power Networks, *Asset Plan 1.1.01 Distribution System Planning Report*, section 19

In addition, SA Power Networks' forecast capex and opex expenditure for the 2020-2025 RCP must comprise the forecast expenditure that SA Power Networks considers is required in order to:

- meet or manage the expected demand for standard control services over the 2020-2025 RCP;
- comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
- maintain the quality, reliability and security of supply of standard control services (where there are no applicable regulatory obligation or requirement); and
- maintain the safety of the distribution system through the supply of standard control services.

To meet these obligations we must ensure that the ongoing uptake of rooftop PV and batteries, and the synchronised operation of batteries by third party VPP operators, do not lead to unacceptable degradation in quality, reliability or security of supply for customers.

Our modelling shows that if we continue to apply our current connection rules, in which all embedded generating units of 5kW export capacity or less are approved for connection, many areas of our network will exceed their hosting capacity in the 2020-25 RCP as rooftop PV and battery storage uptake continues to grow. This is the case:

- even after taking into account the impact of static measures such as inverter settings and new tariffs; and
- across a range of rooftop PV and battery growth scenarios, including low-uptake sensitivity cases.

If we do not manage this effectively, the distribution network may become a bottleneck that severely curtails the ability for customers and new energy services providers to participate in the market and contribute effectively to the energy system in South Australia.

A specific challenge that we face is that we currently have almost no visibility of our LV network, which is where issues due to embedded generation arise first. We are significantly behind other DNSPs in this respect. For example, Victorian distributors benefit from ubiquitous monitoring of customer voltage through distributor-owned smart meters, and Energy Queensland and, to a lesser extent, Networks NSW, have already made significant investments in the deployment of low voltage network monitoring equipment. In South Australia, we only find out about a LV network issue when a customer reports it. We then install temporary monitoring to investigate the problem and determine the necessary remediation work. While this simple, reactive approach has been effective for many years, and has helped to keep costs down for customers, it is no longer sustainable.

In considering how to manage this, we need to weigh the benefits to the community as a whole from enabling greater DER uptake against the network expenditure required to enable this. In accordance with the NER and the national electricity objective (NEO) we must ensure that any changes we make to the way we manage DER connections or operate the distribution network are prudent, efficient and in the best long-term interests of all customers in South Australia – including those who do not have their own distributed energy resources and may never be participants in new energy markets.

## Options considered

In 2017 we engaged EA Technology to determine options for managing network hosting capacity through the 2020-2025 RCP, undertake a cost/benefit analysis in relation to identified options and recommend an

approach which is consistent with and achieves the NEO and the expenditure objectives<sup>24</sup>. This work identified and compared the following three options:

1. **Option 1 - Static limits:** when part of the network reaches its technical capacity we could require all new DERs connected to the network in that area to be configured as ‘zero export’ – i.e. customers can generate energy to use in-house, but cannot feed energy into the network. This approach is relatively straightforward to implement through changes to our connection rules, and is already being implemented by some DNSPs, e.g. PowerCor in Victoria, in areas of high rooftop PV penetration. It obviates the need for network capacity upgrades but means that these DER customers cannot access feed-in tariffs, participate in network support schemes or VPPs or export electricity to the NEM. This reduces the value to the DER customers themselves and also reduces the broader market benefits enabled by rooftop PV and VPPs.
2. **Option 2 - Dynamic limits:** this is a variation on option (1) in which we offer a new dynamic export limit option to DER customers and VPPs whose systems have the technical capability to self-manage. This would enable us to signal the true capacity of the network on a locational and time-varying basis, so customers’ exports would only be limited at those times and in places where there is a capacity constraint. This requires expenditure on new systems to (a) improve visibility of LV network performance, (b) calculate LV network hosting capacity and (c) extend the kind of dynamic limit signals we provide today for generators larger than 200kW down to smaller DERs and VPPs.

We have considered two variants of option 2:

- **Option 2(a)** uses a ‘template’-based model of hosting capacity, in which performance of every circuit is calculated by reference to a representative sample set of around 10% of LV circuits that are modelled in detail and actively monitored.
  - **Option 2(b)** uses a full electrical model of our LV network to calculate hosting capacity. This allows for greater accuracy than option 2(a), and hence has the potential to enable greater utilisation of network capacity, but requires significantly more expenditure in capturing data and building the network model.
3. **Option 3 - Add capacity:** if we retain the current export limit of 5kW per customer<sup>25</sup>, this will require ongoing expenditure to increase the capacity of the network to allow customers to continue to connect new DERs and export energy to the network at any time. This expenditure would include a mix of both network augmentation (**augex**) and non-network (**market-based, opex**) solutions such as demand management. Under this approach all customers bear the cost of increasing network hosting capacity. As constraints typically occur infrequently during the year, network augmentation under this approach tends to lead to a reduction in network asset utilisation (i.e. the increased network hosting capacity is only required for a small part of each year).

## Other options that were identified but rejected during initial investigations

Several alternative approaches were also identified but were not included in the detailed cost/benefit analysis because initial investigations suggested that these were unlikely to become viable in the timeframe required to address the forecast rate of DER uptake in South Australia:

- **Connection pricing for DERs:** we could seek to recover the cost of any network augmentation required to enable exports directly from the customer at the time that they connect their DER to the network. This would be a change from the current regulatory approach: consistent with clause 5A.E.1(b) of the NER<sup>26</sup> we do not require retail customers who apply to receive a basic connection service to make a capital contribution towards the cost of augmentation. The AEMC has considered

<sup>24</sup> The capital expenditure objectives set out in clause 6.5.7(a) of the NER and the operating expenditure objectives set out in clause 6.5.6(a) of the NER.

<sup>25</sup> For single phase customers

<sup>26</sup> AEMC, *National Electricity Rules*, version 117, December 2018

this issue in its 2018 Network Economic Regulatory Framework Review<sup>27</sup> and Distribution Market Model project<sup>28</sup>, and has formed the view that the current connection charging arrangements are appropriate and that dynamic management of exports is likely to be a more efficient approach<sup>29</sup>. The AEMC's work has considered that the current charging arrangements complement an 'open access' model for network connections and that changes to connection charges were unlikely to be suitable to manage DER given that the challenges and opportunities presented by DER vary on a locational and temporal basis.<sup>30</sup>

- **Export tariffs:** we could seek to apply a network tariff that includes a demand component for export energy, reflective of the long-run marginal cost of providing the necessary network capacity. This is currently prohibited under clause 6.1.4 of the NER<sup>31</sup>, and would require quite significant changes to the current regulatory and market frameworks, which are designed to recover network costs only via tariffs on import energy and which do not provide for firm network access for generators to export energy. The AEMC considered this issue in both its Distribution Market Model final report<sup>32</sup> and also in its Economic Regulatory Framework review<sup>33</sup> and did not consider that any change to the current framework was warranted, preferring instead that active DER management strategies be pursued initially. We note that even if current restrictions on export tariffs were removed, such tariffs would likely be developed to mirror those for energy consumption. That is, these would seek to signal long-term network cost drivers to encourage efficient use (long run marginal cost)<sup>34</sup> rather than signal short-run network constraints (short run marginal cost) and, therefore, could not be solely relied upon for operational constraint management.
- **Changes to standard voltage levels:** in 2018 Queensland introduced a change to reduce the nominal voltage level in that state from the legacy standard of 240V +/- 6% to the AS60038 standard nominal voltage of 230V +10%/-6%, in part in response to high-voltage issues arising from rooftop PV<sup>35</sup>. Some stakeholders have asked whether voltage-related issues in South Australia could be mitigated by a change to standards to allow a wider range of voltage variation. It is important to note that, unlike Queensland (and Western Australia), South Australia already uses the 230V +10%/-6% standard, having adopted it when it was first introduced in 2000. We consider it unlikely that the voltage range specified in AS60038 will change in the 2020-2025 RCP as it is aligned with international appliance standards. We also note that any such change to the standard would only prevent voltage problems if there were widespread replacement of legacy customer equipment to support the new standard.

## Recommended option

The analysis undertaken by EA Technology identified that option 2(a), implementing greater LV network visibility and dynamic export limits using a template-based hosting capacity model, is the option that best promotes the NEO and reflects the expenditure criteria<sup>36</sup>. The modelling shows that option 2(a) increases utilisation of existing network assets and provides the best long-term outcome for all customers (both with and without DERs) under a range of possible future scenarios. This option and the associated cost/benefit analysis are set out in detail in the remaining sections of this business case.

<sup>27</sup> AEMC, *2018 Final report, Economic regulatory framework review*, 26 July 2018

<sup>28</sup> AEMC, *Distribution Market Model – Final report*, 22 August 2017.

<sup>29</sup> Ibid, section 5.4.2

<sup>30</sup> AEMC, *2018 Final report, Economic regulatory framework review*, 26 July 2018, pp.89-90

<sup>31</sup> AEMC, *National Electricity Rules*, version 117, December 2018

<sup>32</sup> AEMC, *Distribution Market Model – Final report*, 22 August 2017.

<sup>33</sup> AEMC, *2018 Final report, Economic regulatory framework review*, 26 July 2018

<sup>34</sup> As reflected in the current Pricing Principles in the NER, in particular, clause 6.18.5(f).

<sup>35</sup> Queensland Government, Department of Natural Resources, Mines and Energy, *New Statutory Voltage Limits for Queensland*, advisory at <https://www.dnrme.qld.gov.au/energy/initiatives/statutory-voltage-limits> (accessed January 2019)

<sup>36</sup> The capital expenditure criteria are set out in clause 6.5.7(c) of the NER and the operating expenditure criteria are set out in clause 6.5.6(c) of the NER.

## Features of option 2(a)

Option 2(a), implementing greater LV network visibility and dynamic export limits, includes the following elements:

- **Visibility of LV network hosting capacity**

We will implement mid-line and end-of-line monitoring in targeted areas (approximately 10%) of the LV network, primarily through procurement of ‘data as a service’ from smart meter providers and other third parties. This will require new systems to receive, store and process this data.

We will also develop a ‘template’-based LV network model to estimate the hosting capacity of each LV circuit, using the monitoring data as input.

As well as supporting dynamic export limits, this will enable us to identify problem areas in the network for investigation and remediation before customers become impacted, and to more efficiently plan and schedule remedial works. It will also enable us to provide better information to customers seeking to connect both small and large DERs to the network.

- **DER register**

We will put in place a database to store information on the DERs connected to our network, and implement new processes for installers to register installed DERs electronically. This is necessary to support the new regulatory obligations and requirements introduced in the AEMC’s 2018 Rule change<sup>37</sup> for provision of data to a national DER register.

In the context of option 2(a), this will improve the completeness and accuracy of our DER data to a level that can be used operationally as an input to the hosting capacity model. Electronic registration has the additional benefit that it will improve compliance with our connection standards, in particular the application of the correct inverter Volt-VAR settings, which will help to mitigate local voltage rise issues over time.

- **Open interfaces (APIs)**

We will implement the new systems and interfaces required to publish dynamic export limits to DER customers and DER aggregators such as VPPs.

These elements are shown in Figure 6 below.

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<sup>37</sup> AEMC, *National Electricity Amendment (Register of distributed energy resources) Rule 2018 No. 9* made by AEMC on 13 September 2018.

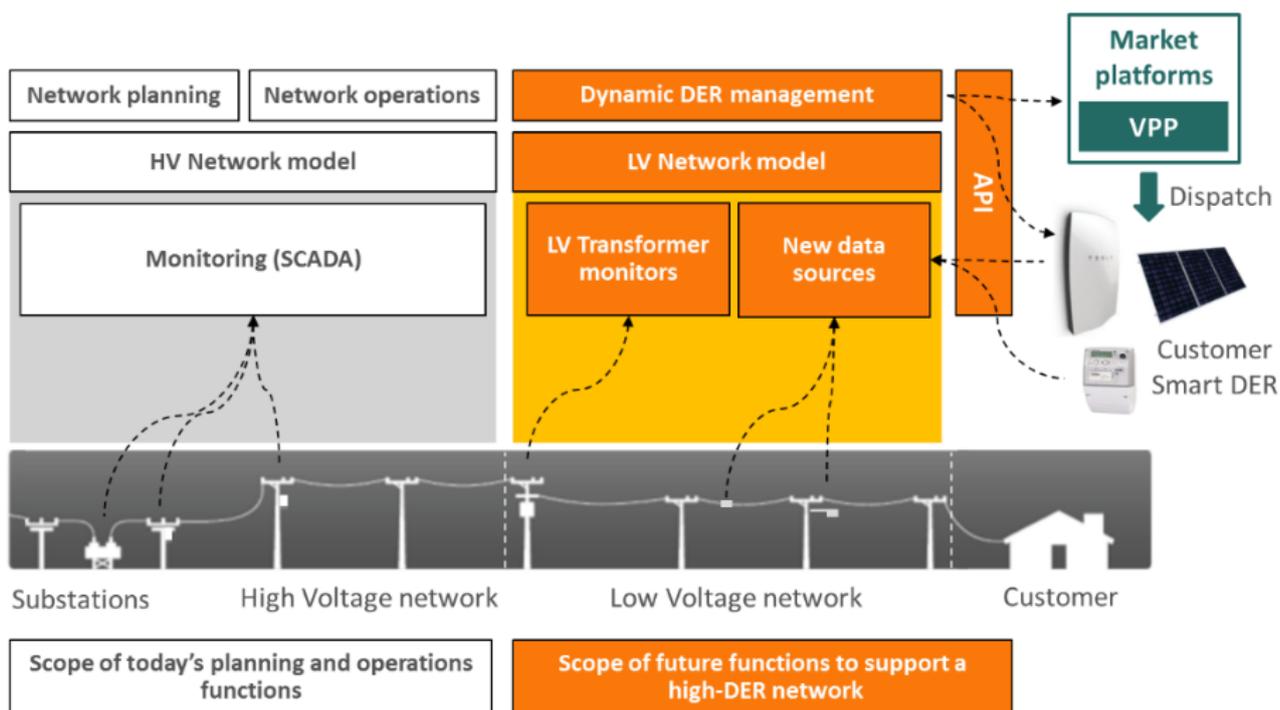


Figure 6. Functions required to enable LV visibility and dynamic export limits

## Estimated costs

### CAPEX

The estimated capital cost to implement option 2(a) is \$31.8 million over the 2020-2025 RCP (\$2020), as shown in the table below and the explanatory notes that follow.

#### CAPEX (\$'000, \$2017, inc. overheads)

Work package	20/21	21/22	22/23	23/24	24/25	Total	Note
LV monitoring	2.43	3.11	2.12	2.71	1.63	<b>11.99</b>	(1)
Build LV hosting capacity model	2.04	3.08	1.47	0.65	0.52	<b>7.76</b>	(2)
DER database	0.69	1.25	0.68	0.53	0.47	<b>3.62</b>	(3)
Dynamic export limit calculation	0.28	1.14	1.82	1.60	0.63	<b>5.46</b>	(4)
Transition & program management	0.89	0.89	0.89	0.89	0.89	<b>4.46</b>	(5)
<b>Totals (\$2017, inc. overheads)</b>	<b>6.33</b>	<b>9.47</b>	<b>6.98</b>	<b>6.37</b>	<b>4.14</b>	<b>33.30</b>	
<b>Totals (\$2020)</b>	<b>6.05</b>	<b>9.04</b>	<b>6.67</b>	<b>6.09</b>	<b>3.96</b>	<b>31.80</b>	(6)

Notes:

1. Implementation of an open interface (**API**) for data transfer, and systems for data storage and processing of time-series voltage data to attain visibility of voltage variations in the LV network. Data will be primarily procured from third parties e.g. smart meter providers.
2. Development of a template-based model of LV network topology and hosting capacity limits, and new processes to centrally manage LV switching.
3. Establish DER database and electronic registration process, and data sharing arrangements with AEMO, consistent with the new regulatory obligations arising from the AEMC's 2018 rule change for a national DER register<sup>38</sup>.

<sup>38</sup> AEMC, National Electricity Amendment (Register of distributed energy resources) Rule 2018 No. 9 made by AEMC on 13 September 2018

4. Establish system for LV network constraint calculation and publication of dynamic export limits to DER operators and aggregators and VPP operators via an open API.
5. 3 x FTE transition team (transition manager, change management and administration) to manage program of work, transition to BAU operations and business process change.
6. All input cost estimates in this business case are in \$2017 and include business overheads. The equivalent costs in \$2020 (as included in our Regulatory Proposal) are also shown.

## OPEX

There is a necessary step change in operating costs associated with implementing option 2(a) of \$3.8 million over the 2020-2025 period RCP (\$2020) as shown in the table below and the explanatory notes that follow.

### *OPEX (\$'000, \$2017 inc. overheads)*

<b>Work package</b>	<b>20/21</b>	<b>21/22</b>	<b>22/23</b>	<b>23/24</b>	<b>24/25</b>	<b>Total</b>	<i>Note</i>
LV monitoring	0.00	0.37	0.77	0.84	0.89	<b>2.86</b>	(1)
LV hosting capacity model	0.00	0.07	0.14	0.14	0.14	<b>0.50</b>	(2)
DER database	0.00	0.00	0.10	0.20	0.20	<b>0.51</b>	(3)
Dynamic export limit calculation	0.00	0.00	0.00	0.00	0.19	<b>0.19</b>	(4)
<b>Totals (\$2017, inc. overheads)</b>	<b>0.00</b>	<b>0.44</b>	<b>1.01</b>	<b>1.18</b>	<b>1.43</b>	<b>4.06</b>	
<b>Totals (\$2020)</b>	<i>0.00</i>	<i>0.41</i>	<i>0.95</i>	<i>1.11</i>	<i>1.34</i>	<i>3.80</i>	(5)

Notes:

1. Procurement of data from competitive smart meter providers and other third parties, and operating costs associated with the systems and process to enable this. This operating cost is an efficient non-network (opex based) alternative to capital expenditure on SAPN-owned monitoring devices at mid-line and end-of-line. It therefore represents a capex-to-opex trade-off.
2. Ongoing staff and other costs associated with maintaining the model of LV network topology and hosting capacity limits.
3. Staff and system operating costs associated with ongoing operation of the DER register in accordance with the requirements of the AEMC's 2018 rule change for a national DER register<sup>39</sup>.
4. Ongoing system operating costs associated with LV network constraint calculation and publication of dynamic export limits to DER operators, aggregators and VPP operators via an open API.
5. All input cost estimates in this business case are in \$2017 and include business overheads. The equivalent costs in \$2020 (as included in our Regulatory Proposal) are also shown.

## Cost estimation methodology

SA Power Networks engaged KPMG to assist with development of capex and opex estimates for this business case. KPMG undertook this work in two phases:

1. **Co-creation of initial cost estimates.** KPMG worked directly with SA Power Networks' subject matter experts from IT, network management and network strategy teams to develop initial cost estimates and, in a series of co-design workshops and meetings, iteratively elicit, challenge and refine costs and assumptions. KPMG brought its own in-house expertise and experience from

<sup>39</sup> AEMC, *National Electricity Amendment (Register of distributed energy resources) Rule 2018 No. 9* made by AEMC on 13 September 2018

similar projects in other organisations and used its own cost models to undertake top-down validation of cost estimates as they were developed.

2. **Review of final cost estimates.** Following further refinement of the initial cost estimates and expected benefits, KPMG undertook a final review of the estimation process and final estimates against the NER, to assess whether the proposed expenditure is efficient, prudent and reflects a realistic expectation of the demand forecast and cost inputs to achieve the expenditure objectives.

Specific methods used in developing and refining these cost estimates included:

- Use of standard labour costs in pricing internal and contract resources.
- Insights from EA Technology on the template-based approach to LV network modelling, based on experience in the UK.
- Market engagement to seek quotes for specific technology components (e.g. OSI Soft) and for provision of data from smart meter providers.
- Industry working groups to seek industry input, share learnings and leverage other DNSP's experience in particular in the area of LV network monitoring.

Further details of the costs and the estimation methodology are included in KPMG's report<sup>40</sup>.

## Estimated benefits

As shown in the table below, option 2(a) has an estimated positive net benefit of \$39.68 million (NPV<sup>41</sup> to 2035) under base case (neutral) DER growth assumptions when compared to the 'do nothing' option (option 1) in which expenditure is avoided by limiting all new DERs connecting to constrained areas of the network to zero-export at time of installation.

<b>NPV (\$'000)</b>	
<b>Item</b>	<b>NPV to 2035</b>
Cost of preferred option (capex + opex)	-\$47.87
Value of additional exported energy	\$87.55
<b>Net outcome</b>	<b>\$39.68</b>

The following section describes how these benefits are calculated.

## Comparison of options

### Cost/benefit analysis

The Transform Model<sup>42</sup> developed by EA Technology was used to model and compare long-term (to 2035) economic outcomes of each of the options for a range of different input assumptions (e.g. high vs low DER uptake forecasts). The resulting cost/benefit comparison is shown in Figure 7 below.

<sup>40</sup> KPMG, *Future Network Strategy – technology costs*, report prepared for SA Power Networks, November 2018 (see Supporting Document 5.19)

<sup>41</sup> Discount rate of 2.89%

<sup>42</sup> Originally developed in 2012 by a consortium including EA Technology and Frontier Economics, in collaboration with UK distribution networks and the UK regulator Ofgem, the Transform Model is a comprehensive techno-economic model specifically developed to model different distribution network investment strategies. The model is now licenced to all UK distribution network operators (DNOs), and has been used as the basis of all UK networks' regulatory submissions for the UK 2015-23 regulatory period (RIIO-ED1), underpinning some £500m of planned network investment. Ofgem has described the model as "world leading" in its approach to this complex issue. The model is now being used by networks outside the UK, including in New Zealand and Australia.

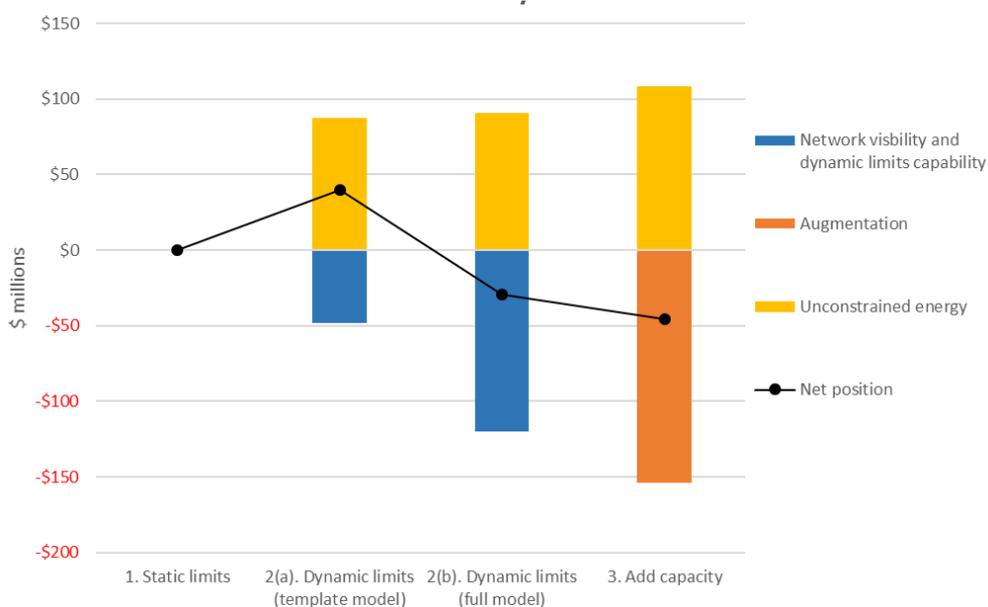


Figure 7. Cost/benefit analysis: base case

In Figure 7, option 1 (static limits) is considered as the 'do nothing' or 'baseline' option. The costs and benefits of the other options are presented relative to this baseline as follows:

- For option 3 (add capacity) the negative orange bar represents the total expenditure that would be required (NPV to 2035) to add enough capacity to the network to allow all new DER systems to connect with the current export limit of 5kW per customer. This is calculated by the Transform Model based on the least-cost series of investments required year-on-year to mitigate hosting capacity constraints as they arise, drawn from a set of known technical solutions that includes 'traditional' network augmentation options (e.g. changing transformer taps, installing voltage regulation equipment, upgrading transformers, etc.), as well as non-traditional solutions such as grid-connected batteries, demand management and third-party network support contracts. For each candidate solution, the model knows the cost of the solution (capex and opex), the expected technical efficacy in increasing hosting capacity 'headroom', the lifetime of the solution, and so on. The model also takes into account the positive impact of new inverters with Volt-VAr response modes, which become progressively more prevalent through new DER system installations and end-of-life inverter replacements, and the potential impact of load shifting due to new distribution network tariffs.
- The positive yellow bar for option 3 represents the total value of the additional energy exported to the NEM that would, under option 1, have been curtailed due to zero export limits. This energy arises both from passive rooftop PV and from battery exports due to VPPs dispatching in response to wholesale market price signals. The future value of this export energy is estimated using a separate wholesale market model developed by economic consultants HoustonKemp<sup>43</sup>. HoustonKemp have estimated this value using a methodology consistent with the AER's RIT-T and RIT-D guidelines<sup>44</sup> that seeks to identify value that represents additional benefit to the NEM rather than a transfer between parties. The model considers the cost of the next-best generating system that would be displaced by the exported energy in each time interval, taking into account South Australia's present and future generation mix. This approach focusses on underlying resource costs and not the wholesale price forgone or the value forgone by the customer or VPP operator,

<sup>43</sup> HoustonKemp, *Estimating avoided dispatch costs and the profile of VPP operation – a methodology report*, January 2019 (see Supporting Document 5.20)

<sup>44</sup> Regulatory Investment Test – Transmission and Regulatory Investment Test – Distribution; refer <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018> (accessed January 2019)

consistent with the RIT market benefit category of ‘changes in fuel consumption arising from different patterns of generation dispatch’<sup>45</sup>.

- The positive yellow bars for options 2(a) and 2(b) show that these options also enable additional energy to be exported compared to the baseline option 1, because under these options export limits are only applied for a small proportion of the year (e.g. in the middle of a mild, sunny day when rooftop PV export is very high relative to underlying demand), when and where required.
- The negative blue bars for options 2(a) and 2(b) represent the total cost (capex and opex) of the new operational systems required to enable dynamic export limits. The higher cost for option 2(b) reflects the higher cost of building a full LV network model under this option as compared to the template-based model used in option 2(a).
- All amounts are NPV to 2035

The figure shows that, under the base case input assumptions, the preferred option 2(a) has the highest net value (NPV to 2035) of all options considered. By managing DER exports largely within existing asset capacity, this option avoids the significant cost of network augmentation associated with option 3, while still enabling the majority of the market benefits from passive rooftop PV exports and active dispatch of VPPs.

## Sensitivity analysis

To test the options against a range of plausible future scenarios, the cost/benefit modelling was repeated for a number of sensitivity cases representing different uptake forecasts for rooftop PV, battery storage and electric vehicles (EV), and different VPP participation rates for battery customers. The economic modelling undertaken by HoustonKemp also considered a range of sensitivities in relation to the future generation mix<sup>46</sup>.

In constructing the sensitivity cases our approach has been:

- a) to focus on credible future scenarios;
- b) to explore changes in those input variables most likely to affect the performance of credible options; and
- c) to consider variables most likely to affect the ranking of net economic benefits across the options under consideration.

The sensitivity cases included neutral, weak and strong forecasts from AEMO’s 2018 Integrated System Plan<sup>47</sup>, supplemented with additional lower-bound cases based on low and weak uptake curves drawn from AEMO’s 2017 insights report<sup>48</sup> to test whether the options were robust should DER uptake rates regress below 2018 weak forecasts.

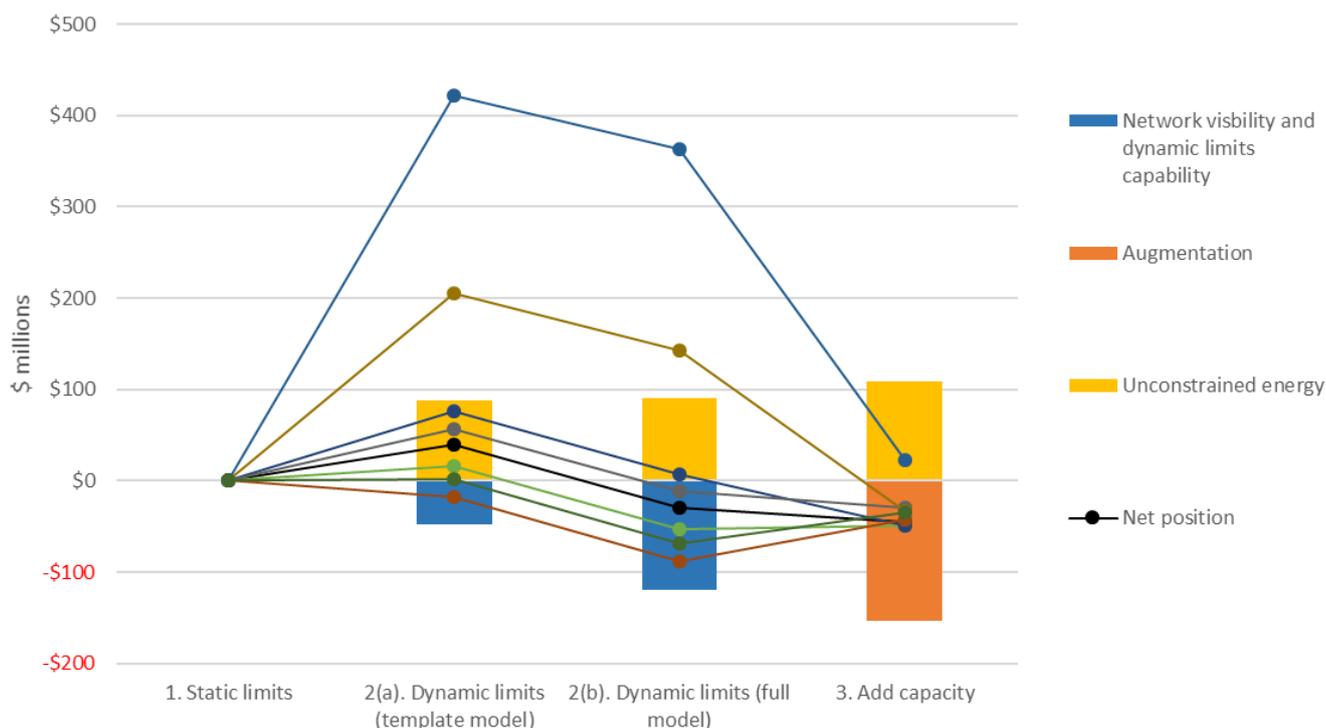
Figure 8 below shows the relative economic performance of the four options over the range of scenarios modelled, overlaid on the base case.

<sup>45</sup> This is a category of market benefit that has, to date, existed as part of the RIT-T framework and which the AER now accepts as relevant to the RIT-D; refer AER, *Application Guidelines—Regulatory Investment Test for Distribution*, p.33

<sup>46</sup> For details refer HoustonKemp, *Estimating avoided dispatch costs and the profile of VPP operation – a methodology report*, January 2019

<sup>47</sup> AEMO, *Integrated System Plan for the National Electricity Market*, July 2018

<sup>48</sup> AEMO, *Electricity forecasting insights for the National Electricity Market*, June 2017



**Figure 8. Cost/benefit analysis: sensitivity analysis**

This analysis found that option 2(a) gave a net positive outcome compared to the ‘do nothing’ case (option 1) for all but one of the modelled sensitivities and outperformed options 2(b) and 3 in all cases. The benefit of option 2(a) as compared to option 1 (the ‘do nothing’ case) increases with stronger DER growth and VPP participation scenarios.

Option 2(a) was preferred over the alternative approach to implementing dynamic export limits, option 2(b), in all sensitivity cases. Although option 2(b) unlocks slightly greater benefits through more accurate modelling of LV network hosting capacity than option 2(a), the cost to develop the full electrical model of the LV network upon which this option depends are significantly higher than the costs to implement the simpler template-based model used in option 2(a). In the analysis, the additional benefits did not outweigh the higher costs. It is worth noting that the cost to implement a complete LV network model will reduce over time as we capture more accurate field data on the network through ongoing maintenance works. Importantly, the recommended option 2(a) retains the optionality to progress to a full network model in future, so we may re-assess towards the end of the 2020-25 RCP whether there is a case for further investment to improve the accuracy of the network model.

The specific combinations of input assumptions used in the sensitivity cases are summarized in appendix A. Full details of the Transform Model, methodology and input data sets are included in EA Technology’s report<sup>49</sup>.

## Non-quantified benefits

The cost/benefit analysis presented above is based on a single measure of economic benefit: the future market value of the additional energy able to be exported by customer DERs when they are not constrained by export limits. The methodology used by HoustonKemp to calculate the value of this exported energy, based on the avoided dispatch cost of other forms of generation, is consistent with the ARE’s RIT-T and RIT-D guidelines and is intended to reflect the long-term value to consumers, assuming the market is efficient. This approach gives a more conservative estimate of future benefits than other methods that consider

<sup>49</sup> EA Technology, *LV Management Strategy*, report prepared for SA Power Networks, v1.0, December 2018 (see Supporting Document 5.21)

factors such as wholesale market price or customer benefits arising from feed-in tariffs or avoided retail costs.

The RIT guidelines allow for consideration of certain other benefits such as avoided transmission costs, the impact of avoided or deferred investment in new generation and reduction in network losses. Our analysis does not seek to quantify these additional benefits, nor does it include any market benefits arising from increased competition in the SA market from VPP operators, which was a key element of the analysis undertaken by Frontier Economics in 2018 on the potential market benefits of the SA Government/Tesla VPP<sup>50</sup>.

Within the limits of the modelling, we consider, therefore, that the market benefits quantified in the analysis are conservative, and more likely to understate the actual value than to overstate it.

There are additional non-market benefits associated with option 2(a) that have not been quantified, but which strengthen the case for this as the preferred option:

- The majority of the capex and opex associated with this option is spent in the establishment of a platform for monitoring targeted areas of the LV network and modelling hosting capacity across the network. This capability will enable a range of other benefits:
  - It will facilitate the publication of more accurate ‘opportunity maps’ of available network capacity, and facilitate better investment decisions by customers considering connecting DERs to the network.
  - It will enable more effective network planning and operations, including more proactive management of Quality of Supply (detecting and resolving potential issues before customers are impacted, which is not generally possible today).
  - It will establish the commercial relationships and technical interfaces necessary to leverage network functions of third party smart meters. This has the potential to enable a range of other benefits beyond voltage monitoring such as outage detection and detection of neutral faults at customer premises, delivering on a key outcome intended by the AEMC’s Power of Choice review<sup>51</sup> and the Competition in Metering rule change<sup>52</sup>.
  - It will avoid the need for future capital expenditure on network-side monitoring by enabling access to the market for third-party data sources.
  - It will provide the data necessary to identify opportunities for non-network solutions to network capacity constraints, and facilitate engagement with energy service providers for the broader range of non-network solutions that are beginning to emerge as new technology platforms enable aggregation of flexible loads such as hot water, pool pumps, air-conditioning and EV chargers.
- By enabling greater access to available network capacity and avoiding unnecessary curtailment of ‘surplus’ solar energy via static export limits, the preferred option will:
  - Reduce CO2 emissions.
  - Potentially enable customers to exceed current 5kW export limits at certain times, increasing the value of larger rooftop PV systems and, in particular, VPPs.

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<sup>50</sup> Frontier Economics, *South Australia’s Virtual Power Plant*, Frontier Economics Assessment, February 2018, <https://frontier-economics.com.au/documents/2018/02/south-australian-virtual-power-plant-summary-note.pdf>, accessed January 2019

<sup>51</sup> AEMC, *Power of choice review – giving consumers options in the way they use electricity*, Final report, November 2012

<sup>52</sup> AEMC, *National Electricity Amendment (Expanding competition in metering and related services) Rule 2015*

- In a time of rapid technological change and uncertainty, option 2(a) has greater optionality and flexibility than either option 1, which imposes inflexible static export limits on customers, or option 3, which commits capital expenditure to long-lived network assets that may never be fully utilised. It is a staged approach that allows for a range of future scenarios without the risk of stranded investment.
- The preferred option is aligned with recommendations of AEMC’s 2018 Economic Regulatory Framework Review for efficient distribution network investment<sup>53</sup>, and is compatible with all future distribution market models currently being investigated through the AEMO/ENA Open Energy Networks industry consultation process<sup>54</sup>.

## Stakeholder engagement

We have undertaken a comprehensive stakeholder engagement program for our 2020-2025 Proposal involving over 5,000 participants across more than 100 workshops and other activities around the state since the program commenced in February 2017. Our approach to managing increasing DERs in the grid has attracted significant interest from stakeholders, and hence has been a significant area of focus in our engagement program. Our stakeholder engagement in this area is summarised in Figure 9 below and the text that follows.



Figure 9. Future network stakeholder engagement timeline, 2017 - 2018

## Customer engagement

Following a series of customer workshops around the State in late 2017, we held three ‘deep dive’ workshops in Adelaide in early 2018 to communicate and consult on this aspect of our Proposal in detail. We also solicited feedback from industry stakeholders and consumer groups through our Renewables Reference Group and Customer Consultative Panel.

The clear feedback from customers through these activities was that they expect us to prudently plan for the future to ensure that the distribution network can continue to support the transition to a low-carbon, decentralised energy system. However, customers recognise that the future is uncertain and technology is evolving rapidly, and did not support large expenditure on items which could quickly become redundant.

To further test community attitudes to network investment in enabling greater uptake of distributed energy resources, we engaged independent market research firm Newgate Research to undertake an online survey of 1,000 residential customers across our distribution area<sup>55</sup>. The survey was designed specifically to canvas community feedback on the three possible approaches of static export limits, capacity investment and dynamic export limits. It described the three options and provided information on both the

<sup>53</sup> AEMC Economic Regulatory Framework Review report “Promoting Efficient Investment in the Grid of the Future”, July 2018

<sup>54</sup> AEMO and Energy Networks Australia, *Open Energy Networks, consultation paper*, 2018

<sup>55</sup> Newgate research, *Community attitudes towards potential solar infrastructure investment*, research report, December 2018 (see Supporting Document 0.16)

overall cost and the predicted bill impacts for each option for a range of customer segments including solar and non-solar households.

In an initial contextual question the survey found that 76% of customers felt positively about “SA Power Networks spending money on its network to enable more solar in South Australia,” with just 4% feeling negative about this. The dynamic export limit approach was the most popular of the three options among the customers surveyed, with 54% selecting this as their preferred option. It was also the option that was considered most in the long-term interests of customers, by 48% of participants.

There was also moderate support for upgrading network capacity to enable more embedded generation, even though this was identified as the most expensive of the options for customers. 33% of customers surveyed selected this as their preferred option, and 40% believed that this was most in the long-term interest of customers. Support for static export limits was low, with only 13% preferring it and 12% believing it to be most in the long-term interest of customers, even though it was identified as the least expensive option for customers. See more in the full report (Supporting Document 0.16 – Newgate Research Community attitudes towards solar).

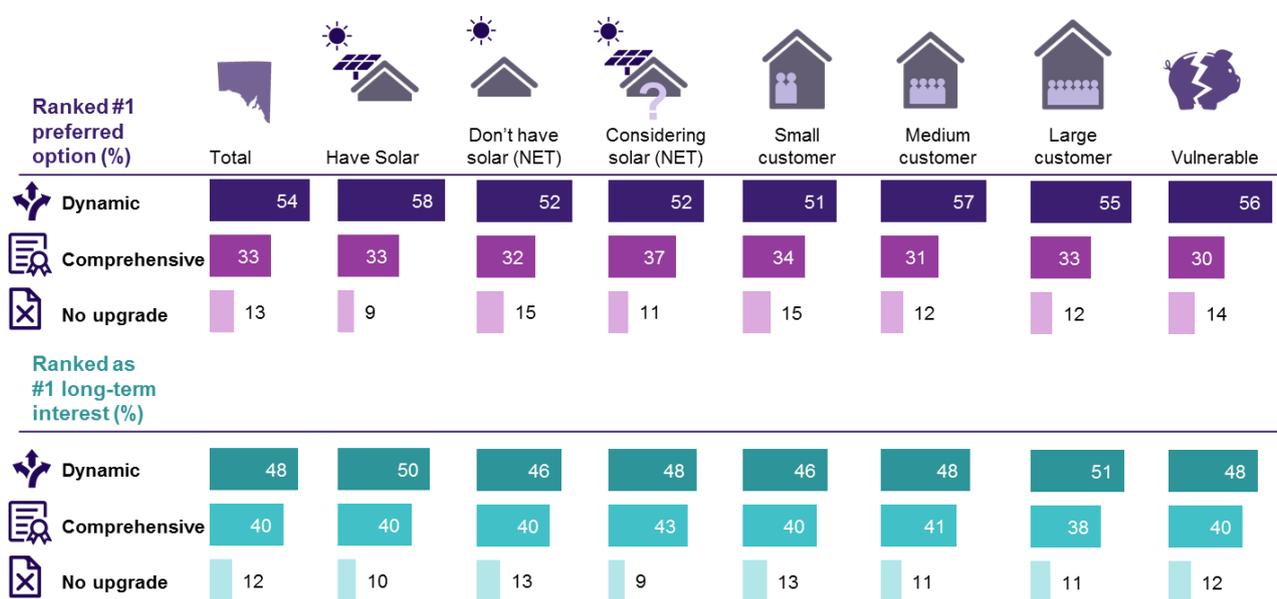


Figure 10. Customer survey results: relative preferences by key customer segments for dynamic export limits ('dynamic'), upgrading network capacity ('Comprehensive') and static limits ('No upgrade')

As illustrated in Figure 10 above, these preferences were consistent across all customer segments including those with and without rooftop PV, small, medium and large households, as well as vulnerable customers, and are consistent with the feedback received from customers and stakeholders through other engagement activities.

## Industry engagement

We have also engaged extensively with industry throughout 2018 in developing our proposed approach:

- We have actively engaged with AGL, Simply Energy and Tesla in relation to their new VPPs in South Australia, both in terms of ensuring effective grid integration and to explore opportunities to use these systems for network support. We are a financial partner in Simply Energy’s ARENA-funded VPP project<sup>56</sup> and have been working closely with both Simply Energy and platform provider Greensync during the design phase of this project over the last 12 months.

<sup>56</sup> Refer <https://arena.gov.au/projects/simply-energy-virtual-power-plant-vpp/>, accessed January 2019

- We tested the market in two specific areas through two separate Expression of Interest (EOI) processes, one in relation to procurement of network data from smart meter providers and the other seeking non-network solutions for upcoming network constraints that fall below the RIT-D value threshold, including voltage and thermal constraints at the LV network level.
- We hosted an industry workshop in Melbourne on 17 May which brought together key stakeholders from across the DER industry nationally (including retailers, solar and battery companies, inverter manufacturers, technology vendors, new energy services companies, platform providers and aggregators) to discuss and seek industry advice on future approaches to grid integration of DERs and VPPs in Australia.
- Following the 17 May workshop we issued a formal consultation paper to this DER Industry Technical Reference Group<sup>57</sup>, and convened further technical workshops with the group on 28 August and 11 October, specifically to seek industry input into a suitable interface (**API**) specification for exchanging data between the distribution network and DER platforms. This work culminated in the publication of a draft interface specification in October 2018, and has informed our development of cost estimates for this aspect of our proposal.
- Following a recommendation by the AER’s Consumer Challenge Panel (**CCP14**), we also convened a separate ‘DER Integration Working Group’ comprising a mix of senior DER industry stakeholders as well as representatives from Energy Consumers Australia, the Total Environment Centre, Clean Energy Council, the South Australian Government and AEMO. The purpose of this group was to provide a forum to seek stakeholder input to two complementary questions to inform our 2020-25 Proposal: what are the key services the distribution network must provide to enable and support the developing market for DERs over the 2020-2025 timeframe, and what services can the emerging DER industry offer to the distribution network to enable non-network solutions? This working group met in August, September and October 2018, and these sessions were also attended by representatives from AER and CCP14.
- Also following recommendations from CCP14 and AER technical advisors, we hosted a DNSP Future Network Forum in Adelaide in October 2018. Attended by all Australian DNSPs, the ENA and AEMO, this whole-day event provided a unique opportunity to share and align approaches to managing the transition to distributed energy across the NEM. Further meetings are planned in 2019 to continue to promote a consistent approach nationally to DER/network integration and the use of common standards.

These industry engagement activities and working groups are summarised in Figure 11 below:

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<sup>57</sup> SA Power Networks, *Improving integration of distributed energy in South Australia – consultation paper*, August 2018

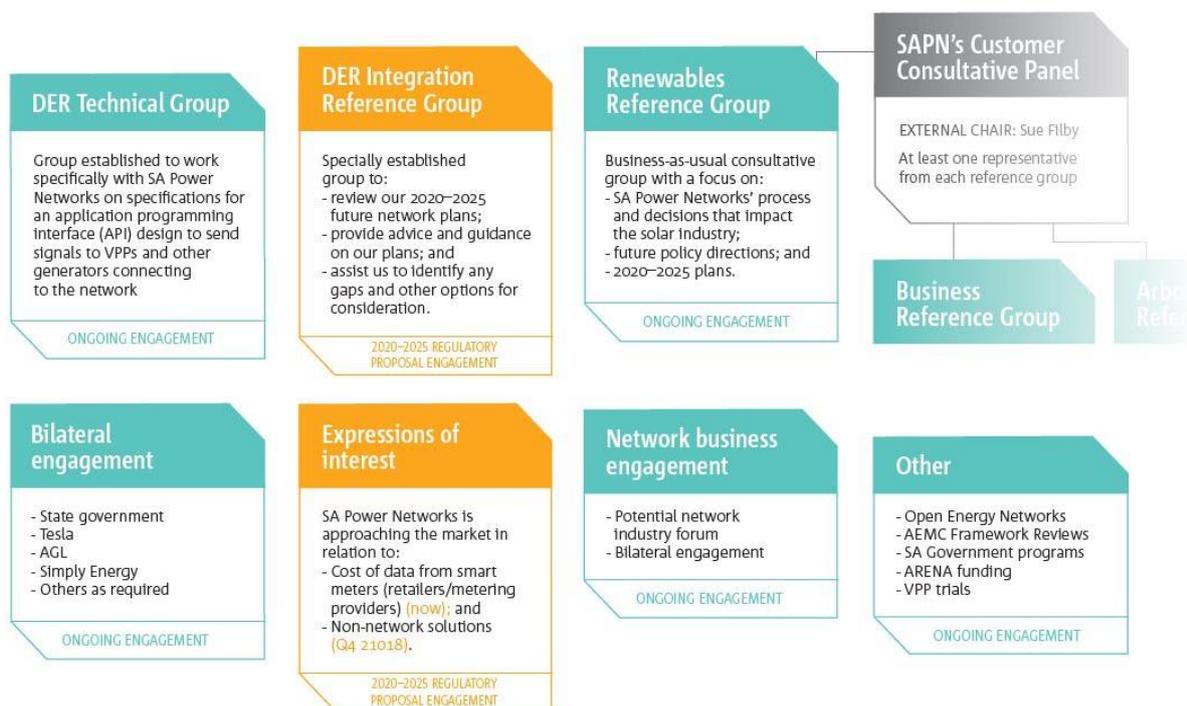


Figure 11. Future network stakeholder engagement activities, 2017 - 2018

## Engagement with regulators, policymakers and AEMO

During 2018 we have engaged directly with the AER’s senior technical advisors and the Consumer Challenge Panel to seek feedback on our proposed approach to introducing dynamic export limits. This has included provision of detailed technical information on the modelling approach used in the options comparison, and a written response to questions raised in CCP14’s feedback on our Draft Plan, published in August 2018.

We are also engaging actively with the South Australian Government on the question of DER integration, including providing input to the technical specifications for the Government Home Battery Scheme. The Government’s vision is that VPPs will play an important part in South Australia’s future energy mix and hence it is supportive of prudent investment in measures that will ensure that the South Australian distribution network does not become a bottleneck that constrains the ability of VPPs to operate to their full potential and thereby constrains the development of competition in the NEM<sup>58</sup>.

We have been active participants in the broader public discourse around managing the transition to a high-DER energy system in Australia, including recent reviews by AEMC and the AEMO/ENA Open Energy Networks consultation process, and we have aligned our proposed approach with these broader industry directions. For example, the AEMC undertakes an annual review of the economic regulatory framework for electricity networks to assess whether the economic regulatory framework is robust, flexible and continues to support the efficient operation of the energy market in the long-term interest of consumers as the energy system evolves towards more decentralised energy resources. The most recent review, published in July 2018, considered economically efficient approaches to managing hosting capacity constraints in distribution networks and recommended that distribution networks transition to a dynamic approach to export limits, finding that:

*“...static strategies such as network tariffs can minimise overall electricity network costs...however, price signals and incentives alone will not prevent some technical issues arising at the network and system level”*

<sup>58</sup> Government of South Australia, Department of the Premier and Cabinet, letter to ARENA in support of SA Power Networks’ proposed trials, May 2018

and

*“Static export limits on export are a blunt approach to addressing the impact of distributed energy resources on the network...”*

*“prohibiting new DER systems from exporting where local hosting capacity has been reached or imposing broad restrictions is unlikely to be efficient or to meet customer expectations...”*

*“The Commission considers a more sophisticated and dynamic approach such as managing output to meet security, reliability and safety needs of the network would be better suited to managing the increasing penetration of DER.”<sup>59</sup>*

As noted earlier, our proposed approach is also compatible with all future distribution market models currently being investigated through the AEMO/ENA Open Energy Networks industry consultation process<sup>60</sup>. The core elements of LV network visibility, monitoring and the estimation of network constraints are foundational capabilities that are required to enable *any* future distribution market model. In the near term, the publication of these constraints to market participants via an open API will enable VPPs and aggregators to operate safely within the technical limits of the network within the current regulatory framework, while the future market framework is developed.

## Alignment with strategy

Our preferred approach is part of a comprehensive, integrated strategy that aims to manage the changing role of the distribution network through an efficient combination of price signals (tariffs), network-side and demand-side (non-network, market-based) solutions. Our broader Future Network Strategy<sup>61</sup>, developed in 2017, is summarised in Figure 12 below.

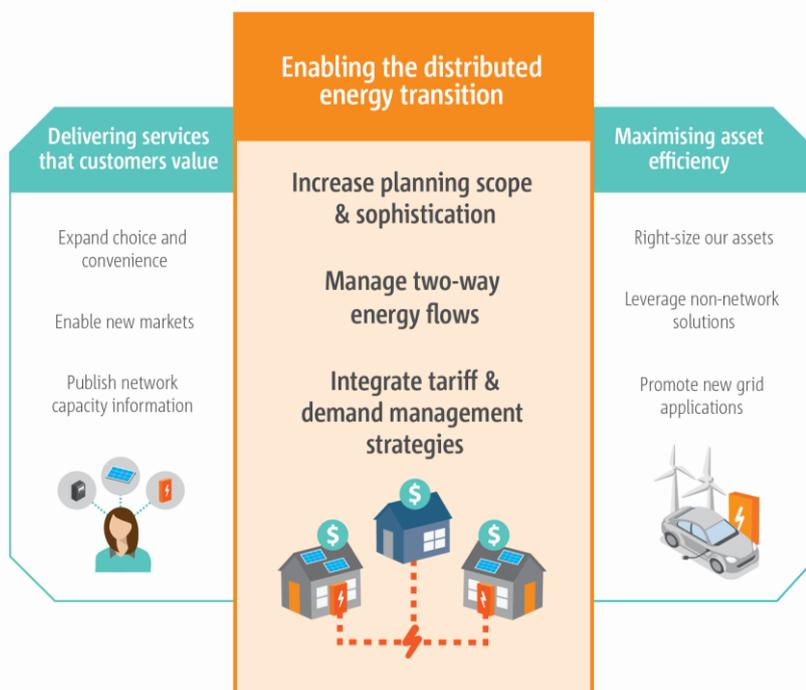


Figure 12. SA Power Networks’ Future Network Strategy (2017)

<sup>59</sup> AEMC, *Economic Regulatory Framework Review report “Promoting Efficient Investment in the Grid of the Future”*, July 2018

<sup>60</sup> AEMO and Energy Networks Australia, *Open Energy Networks, consultation paper*, 2018

<sup>61</sup> SA Power Networks, *Future Network Strategy 2017-2030*, v1.0, November 2017 (see Supporting Document 5.17)

The Future Network Strategy sets out a number of high-level strategic principles, and our preferred approach aligns fully with these:

- **Enable customer choice.** We need to understand the new ways customers want to connect and use the network, including participation in VPPs and future energy trading schemes, and provide sufficient information to customers to enable informed choices around buying and using DERs, and where to connect large resources to the network.
- **Maximise long-term value for all customers.** We must carefully consider the impact of our choices on both DER and non-DER customers to ensure that non-DER customers share in the benefits of the transition to distributed energy.
- **Plan for uncertainty.** In a time of rapid change in our industry, we accept that the future is difficult to predict, and we need approaches that are robust to a range of possible futures.
- **Encourage improved utilisation of existing asset capacity** before spending on network augmentation; deferring network investment in a time of change reduces the risk of stranded investment.
- **Use market-based solutions in lieu of network-side solutions where possible** (to the extent this is prudent and efficient) as this generally gives increased optionality and creates new value from DERs<sup>62</sup>.
- **Enable efficient market outcomes.** We need to ensure that the distribution network is an open platform for DERs to access and participate in the energy market.
- **Keep the lights on.** Above all, we must not compromise our ability to maintain safety, security and quality of supply for all customers, however the future unfolds.

## Conclusions

Our industry is undergoing its most significant transformation since its inception, and if we do not respond accordingly and adapt, the distribution network may become a bottleneck that severely curtails the ability for customers and new energy services providers to participate in the market and contribute effectively to the energy system in South Australia. As we respond to this transition we need to ensure that any changes we make to the way we manage and operate the distribution network are in the best long-term interests of all customers in South Australia.

This business case has considered four options for managing the forecast uptake of DERs in South Australia in the 2020-2025 RCP. Our economic modelling indicates that option 2(a), implementing a dynamic export limit scheme in South Australia, is likely to deliver the greatest value to consumers in the long-term from a whole-of-market perspective. Compared to investing in long-lived network assets it is lower cost, has greater optionality, and will provide a foundation for the most efficient management of available network capacity in a broad range of future scenarios.

The business case recommends that option 2(a) be pursued at a cost of \$31.8 million capex and \$3.8 million opex over the 2020-2025 RCP.

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<sup>62</sup> This is evident in option 2(a) in our approach to end-of-line and mid-line monitoring in the LV network, which is not to invest capex in deploying SA Power Network monitoring devices but rather to invest in setting up a market interface that will enable us to engage with third parties who already have smart meters and other devices able to provide the data streams we require. As noted above we have also issued an RFP to the market to assess the feasibility of non-network solutions for some upcoming network capacity projects that fall under our RIT-D threshold, including LV network hosting capacity constraints.

## A. Sensitivity cases

### SENSITIVITY CASES

Case	PV installed capacity (MW)	EV penetration (vehicles)	Energy Storage (MW)	VPP participation
Neutral-45	AEMO ISP 2018 <b>neutral</b> growth forecast	AEMO ISP 2018 <b>neutral</b> forecast	AEMO ISP 2018 <b>neutral</b> with the assumption of 40,000 state government batteries staged as per current plans	45%
PV Strong-45	As above	AEMO ISP 2018 <b>weak</b> forecast	AEMO insights 2017 <b>weak</b> with the assumption of 40,000 state government batteries staged as per current plans	45%
VPP Strong-45	AEMO ISP 2018 strong growth forecast plus additional PV to be installed under the Tesla VPP project	AEMO ISP 2018 neutral forecast (electric vehicles on the road)	AEMO ISP 2018 <b>weak</b> plus 40,000 state government batteries and 50,000 Tesla batteries staged as per current plans	45%
Weak Uptake-45	AEMO insights 2017 <b>low</b> - shifted forward 2 years to reflect actuals for FYE 2018	AEMO ISP 2018 weak forecast	AEMO insights 2017 <b>weak</b> with the assumption of 40,000 state government batteries staged as per current plans	45%
Neutral-90	AEMO ISP 2018 <b>neutral</b> growth forecast	AEMO ISP 2018 <b>neutral</b> forecast	AEMO ISP 2018 <b>neutral</b> with the assumption of 40,000 state government batteries staged as per current plans	90%
Neutral-10	AEMO ISP 2018 <b>neutral</b> growth forecast	AEMO ISP 2018 <b>neutral</b> forecast	AEMO ISP 2018 <b>neutral</b> with the assumption of 40,000 state government batteries staged as per current plans	10%
VPP Strong-90	AEMO ISP 2018 strong growth forecast plus additional PV to be installed under the Tesla VPP project	AEMO ISP 2018 neutral forecast (electric vehicles on the road)	AEMO ISP 2018 <b>weak</b> plus 40,000 state government batteries and 50,000 Tesla batteries staged as per current plans	90%
Base	Blend of Neutral-45 (70%), Neutral-10 (15%), VPP strong-45 (15%)			