SA Power Networks

Supporting document 5.14

DER Management Expenditure Overview

2020-25 Revised Regulatory Proposal

10 December 2019

SA Power Networks

DER management expenditure overview

Contents

Document Control

Version	Date	Author	Notes
0.1	5/11/19	BW	First draft
0.2	17/11/19	BW/MN	Complete draft
1.0	27/11/19	BW	Updated to incorporate external stakeholder feedback

Summary

This document is intended to summarise several programs in SA Power Networks 2020-25 Regulatory Proposal (**Original Proposal**) relating to (a) managing the impact of increasing uptake of Distributed Energy Resources (**DER**) such as rooftop solar during the period, and (b) managing and maintaining the Low Voltage (**LV**) part of the network, from street transformer to customer premises.

This document considers the following elements of our Original Proposal:

- Our three 'core' LV network management programs:
  - Ongoing Business as Usual (**BAU**) LV augmentation work to maintain Quality of Supply (**QoS**) within prescribed service standards
  - Our new 2020-25 Strategic LV management program
  - Ongoing installation of permanent LV transformer monitors
- A targeted capital program to address substation voltage control issues in five substations
- A contingent project relating to upgrading our Under-Frequency Load Shedding (**UFLS**) scheme, if we are directed to do so by the Australian Energy Market Operator (**AEMO**)
- Other aspects of our Original Proposal that form part of our overall strategy for managing DER but do not give rise to specific capital (**capex**) or operating (**opex**) expenditure requirements in the 2020-25 regulatory control period (**RCP**), eg our proposed new tariffs.

These plans are 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. This Future Network Strategy[1] is summarised in Figure 1 below.

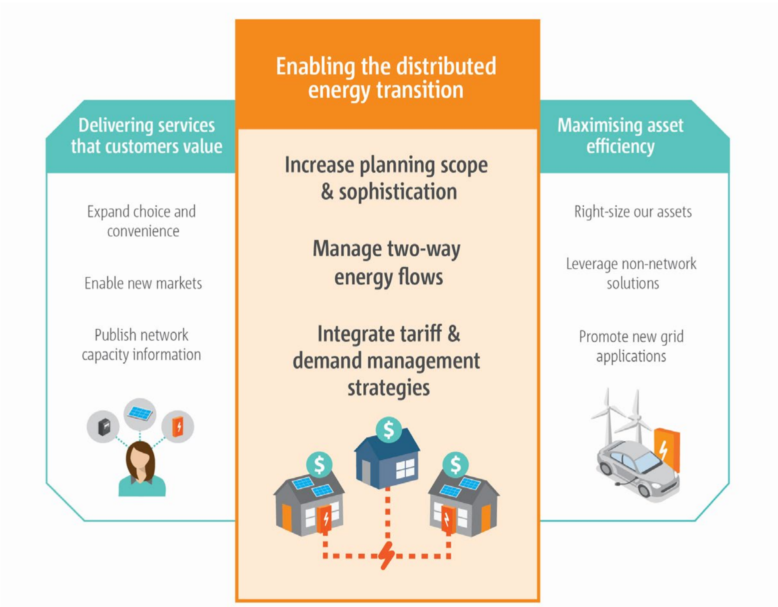

Figure 1. SA Power Networks' Future Network Strategy (2017)

[1] SA Power Networks, *Future Network Strategy 2017-2030*, v1.0, November 2017

In AER's Draft Decision—SA Power Networks Distribution Determination 2020 to 2025 (**Draft Decision**), they were unable to support SA Power Networks' full proposal for Quality of Supply, Low Voltage Transformer Monitoring and Voltage Regulation. The AER asserted that SA Power Networks failed to identify how the combination of programs could work together to manage voltage issues and that though the interrelationships were considered, they were not fully recognised in the Original Proposal. This document seeks to summarise these aspects of our SA Power Networks 2020-25 Revised Regulatory Proposal (**Revised Proposal**) and clarify the interrelationships between them. The capital expenditure related to these programs is summarised in the table below.

Table 1. Capital expenditure related to DER Management

CAPEX category	Original Proposal	AER Draft Decision	Revised Proposal	Difference vs original proposal	*Note*
LV Management program	30.3	30.3	30.3	-	*(1)*
Quality of Supply BAU	44	38.1	41.4	-6%	
LV transformer monitoring	18	0	5.1	-72%	
Voltage regulation	14.3	7	7	-51%	

Contingent project	Original Proposal	AER Draft Decision	Revised Proposal	Difference vs original proposal	*Note*
Potential underfrequency load shedding (UFLS) scheme remediation	75.4	0	38.2 to 75.4	-49 - 0	*(2)*

Notes:

1. All figures in this table are shown in $2019-20 with <u>business overheads excluded, escalations included</u>, to allow for comparison with the AER's summary table 5.4 in its Draft Decision. The corresponding figures in the associated business cases may differ from those shown here as they include business overheads.
2. This is a <u>contingent project</u>, which means that this expenditure is not included in our 2020-25 revenue proposal, but may be incurred during the 2020-25 period if the relevant trigger conditions arise. Should this eventuate, SA Power Networks must apply to the AER under clause 6.6A.2(d) of the NER to amend its revenue determination to include the required revenue.

Relationships Between Core DER Management Programs

The relationships between our three core LV management programs are shown in Figure 2 below. The programs and the inter-relationships are summarised in the notes that follow.

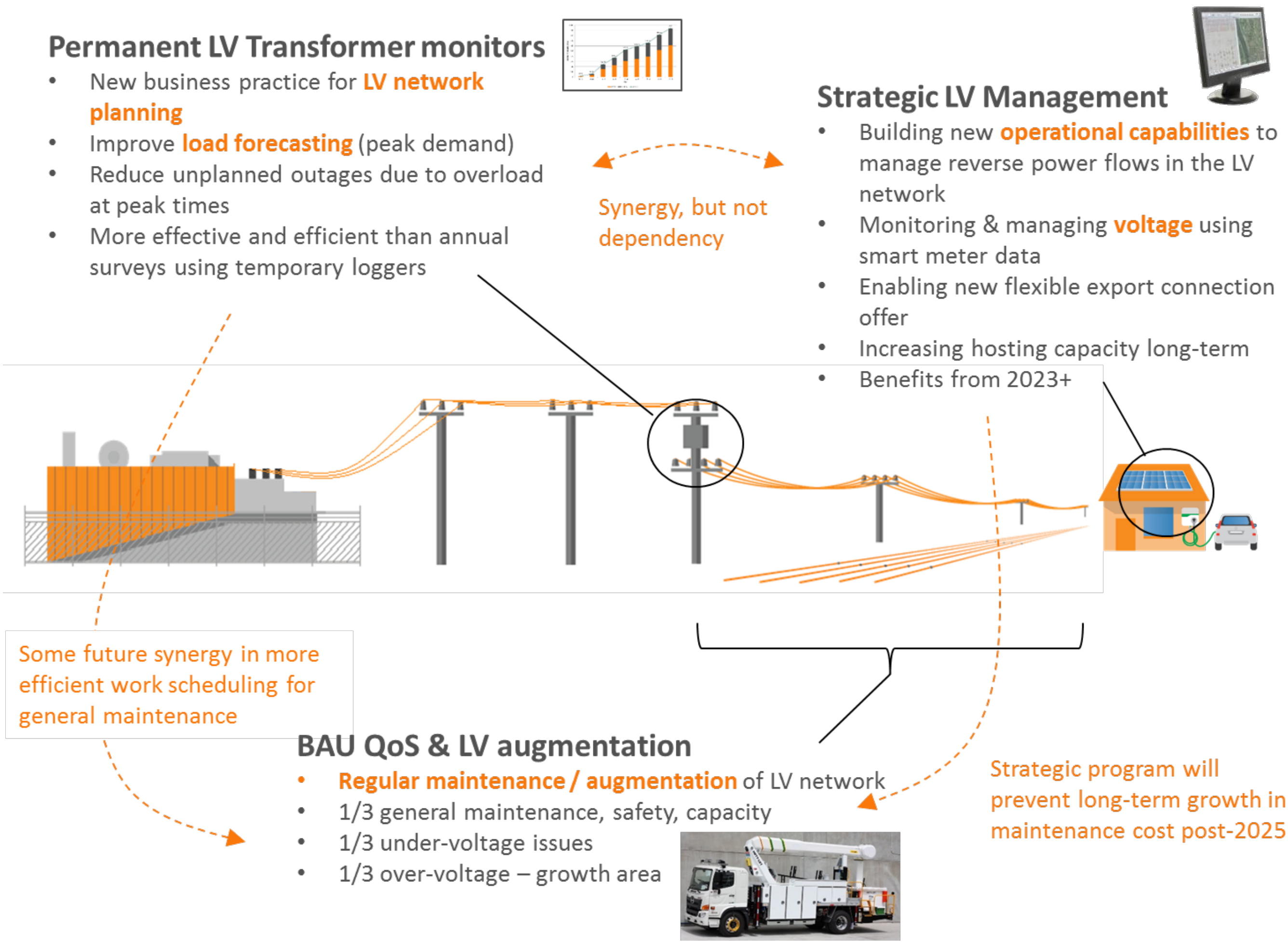

Figure 2. Relationship between core DER management programs

BAU QoS & LV augmentation is a continuation of our normal augmentation expenditure required to maintain the services standards on the LV network and to address customer Quality of Supply issues arising, such as over- or under-voltage. It comprises a capital program of enhancement, infill and upgrade works to LV transformers and related assets, and annual operating costs to undertake regular load surveys in the LV network for capacity planning purposes (ie load growth) and to investigate customer-reported Quality of Supply issues.

Historically around 1/3 of this expenditure has been associated with general maintenance, safety and capacity work; around 1/3 has been associated with addressing under-voltage and other QoS issues; and 1/3 has been associated with addressing customer-reported over-voltage issues. In recent years the amount of expenditure on customer over-voltage issues has been increasing as rooftop solar penetration begins to reach the technical limits of the local network in many areas, and over-voltage conditions become more common in the middle of the day.

In our Revised Proposal we forecast that the growth in BAU expenditure observed through the 2015-20 period will continue on trend until 2023, with modest reductions in capex for 2023/24 and 2024/25 due to operational efficiency savings arising from our LV monitoring program.

Strategic LV management is a new program of work proposed for the 2020-25 period to build new operational capabilities to manage reverse power flows in the LV network. It comprises two key elements: (a) establishing a level of visibility of voltage in the LV network that we do not have today, using data from smart meters and other customer devices and (b) developing a new 'template-based' model of LV network performance using this data in order to provide a flexible (dynamic) export limit for solar customers with smart inverters, so that inverter output can be moderated at times when the network is under stress to avoid local over-voltage. This will deliver long-term benefits to all consumers (not just solar customers) by enabling more DER to connect, and more solar energy to be exported through the network, while avoiding the cost of extensive network augmentation. This program is described in detail in the associated business case, see Supporting Document 5.18 - LV Management Business Case, Original Proposal (**Supporting Document 5.18)**.

Permanent LV transformer monitors extends a pilot program commenced in 2017 to roll out permanent monitoring to around 2,000 metropolitan LV transformers for load forecasting purposes. The aim is to establish permanent load monitoring at a representative sample of 10% of our multi-customer metropolitan LV areas. This will enable the current method used for load forecasting and capacity planning in the LV network, which is based on an annual program of temporary transformer load surveys, to be discontinued and replaced with a more efficient, accurate and modern load forecasting method. This new load forecasting method uses a combination of permanent transformer monitoring data and customer load profiles from smart meters, yielding a long-term reduction in operating expenditure.

Synergies

As shown in Figure 2, above, while these three programs relate to three different business functions – BAU maintenance, operational voltage management and capacity planning – there are natural synergies between them that are reflected in adjustments to the associated capex and opex items in our Revised Proposal:

- Our strategic LV management program will change the way DER connects to, and integrates with, the network by enabling smart inverters to reduce their level of export dynamically when required. The aim is to arrest the increasing prevalence of local over-voltage issues that we see today from the continued connection of un-managed solar inverters. In the long term this will cause a reduction in both BAU capex and opex associated with managing these issues. These new capabilities will not become operational until the latter part of the 2020-25 period, however. We forecast that the current trend of increasing over-voltage issues will continue in the first three years of the 2020-25 RCP as rooftop solar uptake continues to grow, necessitating an ongoing increase in BAU expenditure, before flattening as our new flexible connection service comes into effect for new solar customers.

- As described in the associated business case, the operational hosting capacity model we propose to develop under our strategic program to support the calculation of flexible export limits will rely primarily on end-point voltage data sourced from smart meters, see Supporting Document 5.18. We can, however, also incorporate voltage data from other sources, including the permanent transformer monitors deployed as part of our capacity planning program. If we can improve the accuracy of the voltage model using this additional data, we can potentially reduce the amount that customer export limits are reduced in constrained areas, unlocking additional latent export capacity in the network.

- The 2,000 permanent LV transformer monitors deployed for our load forecasting project will also enable us to avoid some of the costs of investigating customer-reported quality of supply issues, in cases where the customer is in an area that has a permanent monitor installed. This will provide savings in both BAU capex and opex in the last two years of the 2020-25 period that have been factored into the expenditure forecasts in our Revised Proposal.

Finally, it should be noted that, while there are synergies between the strategic LV management program and LV transformer monitoring program that enhance the respective benefits, these two programs are not interdependent; either could be undertaken without the other.

One specific point that is worth clarifying in this regard is that the smart meter data required for the strategic LV management project is voltage data which we will procure from metering coordinators; whereas smart meter data used for load forecasting is simply customer interval energy data, which we already receive from customers with smart meters as a matter of course through the normal market systems and, therefore, we do not have to procure.

Relationship with Substation Voltage Regulation

Our 2020-25 Revised Proposal includes a capital program to address voltage regulation issues identified with eight of our oldest substation transformers that have inadequate tapping range. In our original submission we proposed the accelerated replacement of these aging transformers for a modern equivalent with extended tapping range. Our Revised Proposal includes a lower-cost capital program that includes the installation of voltage regulators in some locations to avoid the need for transformer replacement, as recommended by the AER in its Draft Decision.

This program is specific to addressing this asset limitation in the five affected substations. The expenditure in question does not fall under the BAU QoS line item as it relates to the high voltage (**HV**) substation, and it is unrelated to the broader issues of DER management across the network that are targeted by our core programs.

Relationship with Under Frequency Load Shedding

Our proposal contains a contingent project[2] that recognises the likelihood that we may be directed by AEMO to undertake necessary measures to maintain system security. It is expected that these measures will include an upgrade to our UFLS scheme in the 2020-25 period.

The ULFS scheme is a facility that we own and administer on behalf of AEMO, who are responsible for system security. It is an autonomous emergency system intended as a last resort to restore the balance between demand and supply in the event of a major system-wide disturbance such as sudden loss of a large generator or major damage to infrastructure. It does this by rapidly disconnecting load in the event of a sudden fall in system frequency.

In practical terms, the UFLS capability is enabled within certain zone substation circuit breakers, which monitor local frequency. They are armed to trip off whole HV feeders (each connecting thousands of customers) automatically within milliseconds if frequency drops below safe levels. The system is illustrated in Figure 3 below. The system, although extensively deployed throughout our distribution network, is largely an unsophisticated system that will immediately interrupt feeders

[2] As noted above, this means that this expenditure is not included in our 2020-25 revenue proposal but may be incurred during the 2020-25 period if the relevant trigger conditions arise. Should this eventuate, SA Power Networks must apply to the AER under NER 6.6A.2(d) to amend its revenue determination to include the required revenue.

without consideration to the directional flow of energy (ie regardless of whether the feeder is importing or exporting energy at the time).

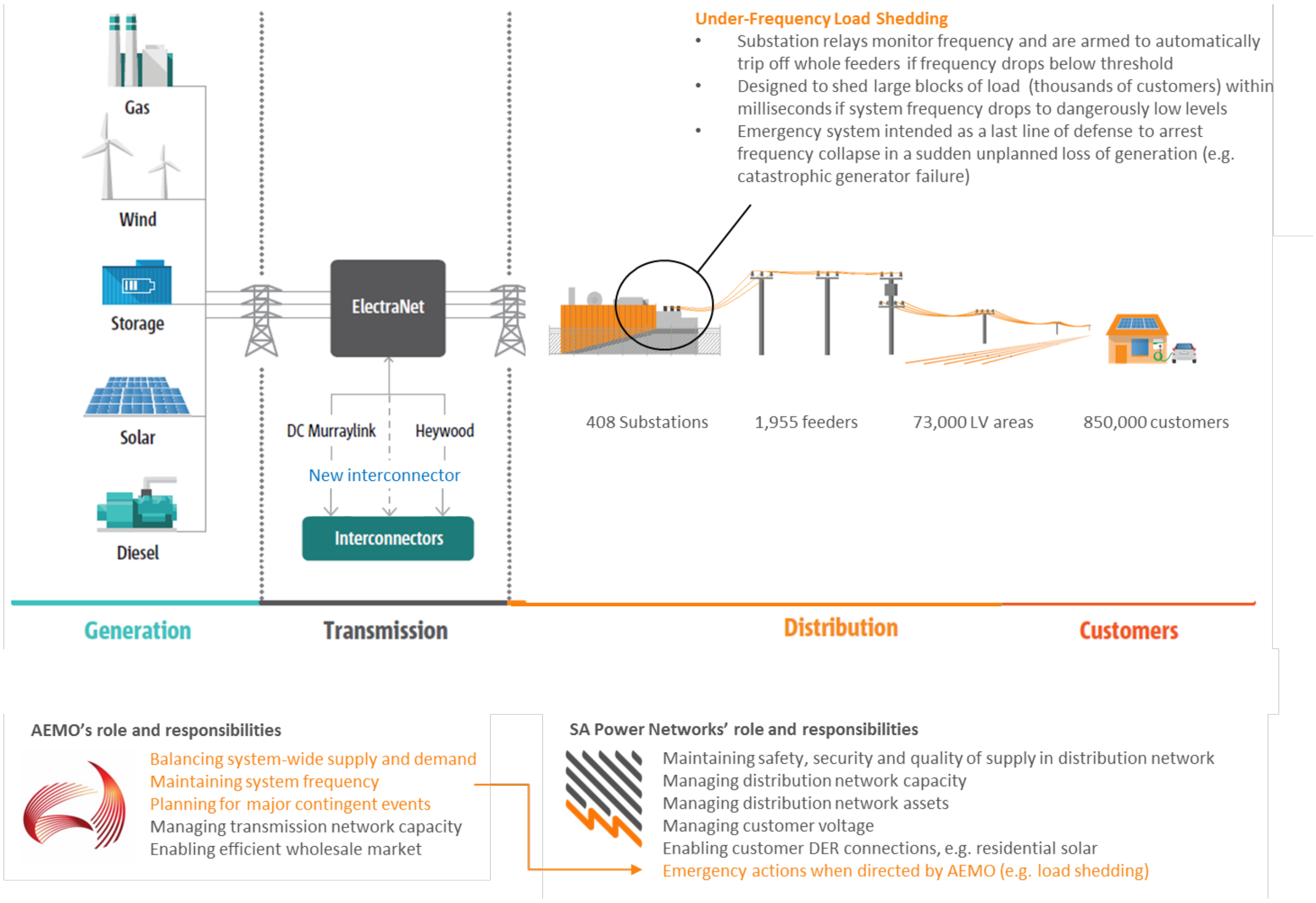

Figure 3. Under-frequency load shedding

With the increase in DER, there are now times of the day, particularly during mild, sunny weather, where whole HV feeders on our network are exporting energy, ie they are acting as a net generation source. Tripping these feeders during an underfrequency event will actually exacerbate the issue, creating further network instability and increasing the likelihood of a System Black event.

AEMO has identified this issue as a risk to system security. To address this, the UFLS system will need to be upgraded so that the substation relays can validate the direction of energy flow before disconnecting, so that the scheme does not shed feeders that are actually a source of generation.

As an emergency system designed to operate in extreme circumstances, the UFLS scheme is not directly related to the other systems and processes described herein which are used to manage DER in the distribution network from day-to-day. It is unrelated to the dynamic management of exports enabled through our strategic LV management program insofar as (a) its primary function is to shed load, not to manage export energy from DER and (b) it must operate within milliseconds, which is far beyond the capability of the systems we propose to publish variable export limits to smart inverters via internet interfaces.

Relationships with Other Activities

As described above, 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[3]. In accordance with this approach our plans for 2020-25 include some other measures intended to help to increase the amount of DER our network can accommodate:

- **Inverter settings**. In May 2019 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[4]. Our modelling suggests that the Volt-Var feature 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 hence will increase over time as new inverters are installed and old ones are replaced.

- **Tariffs.** Our Tariff Structure Statement for the 2020-2025 RCP[5] 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 to fund further trials in this area in the 2020-2025 RCP[6], and we are currently consulting with retailers and other stakeholders on this.

We have taken into account the expected impact of these other measures on reducing the underlying incidence of local voltage issues through the 2020-25 period in the forecast capex and opex for our BAU QoS and LV maintenance program, and in estimating the future benefits attributable to both our strategic LV management program and LV transformer monitoring program.

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[3] SA Power Networks, *Future Network Strategy 2017-2030*, v1.0, November 2017
[4] SA Power Networks, *Technical Standard – TS 129, Small EG Connections – Capacity not exceeding 30kW, May 2019*
[5] *SA Power Networks 2020-25 Regulatory Proposal, Attachment 17: Tariff Structure Statement*
[6] *SA Power Networks 2020-25 Regulatory Proposal, Attachment 11: Demand Management Incentive and allowance*

Shortened Forms

AEMO	*Australian Energy Market Operator*
capex	*capital expenditure*
DER	*Distributed Energy Resources*
HV	*high voltage*
LV	*low voltage*
opex	*operating expenditure*
Original Proposal	*SA Power Networks 2020-25 Regulatory Proposal*
RCP	*Regulatory Control Period*
Revised Proposal	*SA Power Networks 2020-25 Revised Regulatory Proposal*
Supporting Document 5.18	*Supporting Document 5.18 - LV Management Business Case SA Power Networks 2020-25 Regulatory Proposal*
UFLS	*Under-Frequency Load Shedding*