



Supporting  
document 0.3

# 2020-2025 Draft Plan

2020-2025  
Regulatory Proposal  
August 2018





# SA Power Networks 2020–2025 Draft Plan

Delivering better outcomes at a lower price



### Acknowledgement of Country

SA Power Networks acknowledges the Australian Aboriginal and Torres Strait Islander peoples of this nation. We acknowledge the traditional custodians of the lands on which our company is located and where we conduct our business. We pay our respects to ancestors and elders, past and present. SA Power Networks is committed to honouring Australian Aboriginal and Torres Strait Islander peoples' unique cultural and spiritual relationships to the land, waters and seas and their rich contribution to society.

### Company information

SA Power Networks is the primary electricity distribution network operator in South Australia. For information about SA Power Networks visit [sapowernetworks.com.au](http://sapowernetworks.com.au)

### Disclaimer

This document is designed to promote early engagement on our expenditure plans for 2020–2025, prior to our formal proposal being lodged with the Australian Energy Regulator in early 2019. Unless otherwise stated, all monetary values are expressed in real 2020 dollars.

This document contains certain predictions, estimates and statements that reflect various assumptions concerning, amongst other things, economic growth and load growth forecasts that, by their nature, may or may not prove to be correct and are subject to ongoing change and development.

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# Delivering better outcomes at a lower price



**Rob Stobbe**  
Chief Executive Officer

## I am pleased to present our 2020–2025 Draft Plan. The Draft Plan outlines our expenditure and revenue forecasts for delivering electricity services to 860,000 homes and businesses across South Australia.

We developed this plan with comprehensive input from our customers and stakeholders. The consultation process began in early 2017 and three key themes consistently emerged. Our customers want us to:

- › do our part to keep a lid on prices, noting we represent approximately 26% of a typical residential customer's electricity bill;
- › maintain electricity supply reliability across the State; and
- › continue a managed transition to the 'network of the future'.

As we engaged with our customers and stakeholders, they consistently asked us to 'do more for less'. We strongly believe that this Draft Plan will achieve this; it will deliver better outcomes for our customers at a lower price.

During 2020–2025 we will continue to meet all of our regulatory obligations for safety, supply reliability and customer service outcomes, as we have during the current 2015–2020 period.

In addition, we will also deliver targeted improvements in:

- › supply reliability for poorly-served customers;
- › bushfire risk reduction;
- › management of our ageing network assets;
- › cyber security protections for customer and business information; and
- › enabling the transition to a distributed energy future.

These better outcomes will be made possible by:

- › listening to our customers and stakeholders;
- › industry leading productivity performance;
- › innovative asset management practices; and
- › leading national thinking as we transition to the network of the future.

We know that the cost of living, including electricity bills, is a major concern for many customers, and we have an important role to play in energy affordability. Since privatisation in 1999/00 on average the increase in our prices has been in line with CPI resulting in our component of residential bills falling from 50% to 26%.

This Draft Plan outlines how we will continue to keep the lid on prices below CPI for customers over the 2020–2025 period.

I am confident that our Draft Plan for 2020–2025 strikes the appropriate balance between customer service, network safety and price affordability. I firmly believe it is in the long term interests of our customers.

I am grateful for the time and contributions made by all of our customer representatives and stakeholders who have helped us get the 2020–2025 Draft Plan to this point.

I encourage you to review this document and send through your feedback so that we can further improve our Plan before it is lodged with the Australian Energy Regulator in early 2019.

You will find more information on how to provide your feedback at the back of this document.

I thank you for taking the time to review our 2020-2025 Draft Plan.



**Rob Stobbe**  
Chief Executive Officer

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# Delivering better outcomes at a lower price

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# 2020–2025 Draft Plan





TELSTRA  
PLAZA

# What this plan means for customers

## Delivering better outcomes at a lower price

### Keeping prices down



#### Reductions of \$37

in residential customer annual bills in 2020/21 and \$148 for small to medium business customers' bills



#### Delivered through

- › reducing network capacity investment by \$106m
- › avoiding and deferring other expenditure where possible
- › new technologies to keep spending at sustainable levels



#### \$280m total savings to customers

through efficient reductions in investment



#### Remain the #1 most efficient distribution business

in Australia on a state-by-state basis

### A safe and reliable network



#### \$726m

to keep our ageing network performing well



#### \$83m

to continue safety programs and reduce bushfire start risk



#### \$37m

to maintain average supply reliability and

#### \$36m

to improve supply reliability for 19,000 regional customers and 73,000 customers in storm-prone areas



Improved tree trimming through collaboration with councils and customers

✓ **No additional cost**



Better information to customers during storms and other outages

✓ **No additional cost**

## Transitioning to a new energy future



### **\$37m investment**

to ensure customers can continue to connect and export energy from their solar and batteries



### **Supporting more renewable energy**

on the network



### **Exploring alternatives to building network infrastructure**

\$28m non-network opportunities



### **\$4m**

for trialling new technologies and innovative solutions



### **Collaborating with government and industry**

to realise benefits to the community

# 1 Overview of 2020–2025 Draft Plan

**SA Power Networks is the primary electricity distribution network operator in South Australia. We supply energy to more than 860,000 homes and businesses.**

Our activities are regulated by the Australian Energy Regulator (AER) and we are required to submit our expenditure and revenue proposals to the AER every five years for their review and approval. Our plans for 2020–2025 have been informed by extensive engagement with customers, stakeholders and other interested parties.

We have consulted with metropolitan and regional customers, the business sector and various customer and stakeholder representatives. We also meet regularly with our Customer Consultative Panel as well as our business, renewables, community and arborist reference groups. Feedback from these groups continues to shape our plans.

Earlier this year we shared our preliminary plans and forecasts with customer representatives and stakeholders through a series of ‘deep dive’ workshops. We reviewed our plans after receiving their feedback and reduced capital expenditure (by \$90 million) and operating expenditure (by \$49 million). The revised forecasts are presented in this Draft Plan, which achieves an appropriate balance of:

- › keeping prices down;
- › maintaining a safe and reliable network; and
- › transitioning us to a new energy future.

## Keeping prices down



This Draft Plan will deliver an average annual price reduction of \$37 for residential customers in 2020/21 and a \$148 saving for a typical small to medium business.

These savings build on price reductions in 2015/16, when distribution prices were reduced by 25%. They are also well in excess of the \$13 savings in network (ie transmission and distribution) charges considered achievable by the Australian Competition and Consumer Commissions’ (ACCC’s) Inquiry into electricity retail prices.<sup>1</sup>



We are reducing prices by lowering expenditure in some areas, particularly in customer demand-driven investment in the network (which will reduce by net \$87 million). This is consistent with South Australia’s forecast economic conditions and associated network growth requirements during 2020–2025.

We are also investing wisely in targeted areas such as Information Technology (IT) systems and tools. These will increase our field staff’s use of mobile technologies to better collect and process customer and asset information as well as deliver work programs efficiently.



By the end of the current 2015–2020 period we will have reduced capital expenditure by around \$370 million through prudent and efficient management— whilst still meeting our obligations to connect customers, maintain reliability and meet service standards.

As a consequence, our regulated asset base (or RAB) will be smaller. This is good for customers, as a lower asset base reduces the allowed return on assets and helps keep a lid on future distribution prices. Customers will save around \$280 million in future network charges as a result of lower capital spending in the 2015–2020 period.



Since the AER’s Inaugural Annual Benchmarking Report in 2014, SA Power Networks has consistently been ranked the most efficient electricity distributor on a state-by-state basis when compared to other Australian electricity distribution businesses. SA Power Networks continues to work hard to remain at the efficient frontier of Australian distributors and our Draft Plan reflects our ongoing commitment to achieve this through 2020–2025.

<sup>1</sup> ACCC, *Restoring electricity affordability and Australia’s competitive advantage Retail Electricity Pricing Inquiry – Final Report, June 2018 (Page XV)*

## A safe and reliable network



In September 2016, South Australia experienced a total loss of electricity supply (a ‘black system’ event) precipitated by extreme storm damage to ElectraNet’s transmission lines. This state-wide blackout was a stark reminder to all South Australians that reliable and secure electricity is essential for our modern lifestyle.

SA Power Networks operates the oldest distribution network assets in the National Electricity Market (NEM) and the number of age related defects has been increasing in recent years. During 2020–2025 we will continue our 10-year asset management program — agreed with State regulators in 2015 to maintain the standard of all electricity assets to the legislated safety and technical requirements. We are developing new approaches to meet an increased workload, manage risk and keep the network performing well.

This Draft Plan proposes \$726 million to refurbish or replace aged and deteriorating assets to manage the ‘health’ of the network and ensure its safe and reliable performance well into the future. This forecast is \$49 million lower than that discussed with customers and stakeholders earlier this year. This reduction follows further asset management modelling refinement and analysis.



We propose \$37 million to maintain supply reliability expenditure at current levels to meet our ongoing average reliability targets (which exclude the impact of major storm events) set by the Essential Services Commission of South Australia (ESCoSA). We have also included \$36 million of expenditure to:

- › harden the network in the face of more frequent and increasingly severe weather events — improving reliability for 73,000 customers in storm prone areas; and
- › improve reliability for 19,000 of our poorly-served customers — those that experience excessively frequent or long power outages compared to other customers.

Our total reliability program is \$20 million lower than we discussed with customers and stakeholders earlier this year due to the removal of the Ceduna alternative power supply project, which is subject to the ESCoSA service standards review.



The 2018 St. Patrick’s Day bushfires in New South Wales and Victoria also remind us that extreme fire danger weather can have an impact on trees and powerlines with catastrophic consequences.

The Draft Plan proposes to continue our bushfire mitigation program with \$19 million expenditure planned for 2020–2025. This will help to maintain community safety by reducing the probability that extreme fire danger weather will cause fires to start from our powerlines. The Safety program also includes expenditure to continue ongoing programs to upgrade protection equipment (\$24 million) and substation infrastructure (\$40 million) to meet current Australian standards. This is \$24 million lower than discussed with customers and stakeholders earlier this year due to extending the time period of the program.



To create a more sustainable environment that minimises the need for tree trimming over time, we are working to:

- › reduce tree trimming costs over the longer term;
- › improve visual outcomes through partnering and collaborating with councils; and
- › improve public education/awareness.

Key initiatives include:

- › trials with councils to remove saplings and chemically regulate the growth of some tree species;
- › developing proposed amendments to the South Australian Vegetation Regulations to improve safety, reduce costs and deliver better community outcomes (with customer and stakeholder support);
- › developing processes to better assess the visual amenity, cost, and impact on tree health of different pruning or trimming techniques, in partnership with our vegetation clearance contractor and a local council; and
- › continuing a tree removal and replacement program to reduce the need for future tree trimming.

These improvements will be delivered at no additional cost to customers.



In 2020–2025 we will continue to refine and enhance our capability to improve how we communicate with customers, particularly those affected during storms and other outages.

We will modify our systems to provide more personalised and localised messaging to customers, including more accurate supply restoration times for affected customers, at no additional cost to them.

## Transitioning to a new energy future



Customer expectations and technology-driven changes are transforming the way customers use electricity. South Australia already has the highest per capita take-up in Australia of domestic rooftop solar. Retailers and other ‘aggregators’ are developing virtual power plants (VPPs) to aggregate customers’ energy resources and centrally dispatch them into the electricity market. The South Australian Government has plans which could see 90,000 batteries connect to our network in coming years, and the take-up of electric vehicles is also expected to increase.

The existing electricity network was designed and constructed over the past 100 years to transport energy, from large coal and gas-fired power stations connected to the transmission network, then through the distribution network to customers. We expect that more than 50% of all electricity generated in the next five to 10 years will be generated by customer equipment that connects into the electricity distribution network. This poses security and reliability challenges for our network.

Customers also want to have more control over how and when they use energy. The network of the future will need to provide the platform for customers to access new energy products and services and have more choice in how they buy, use and trade their energy.

During 2020–2025 we are proposing ‘no-regrets’ investment of \$37 million to continue to adapt the network to support increasing uptake of customers’ distributed energy resources (DER) like solar, battery storage and VPPs, and enable further value release from customer equipment under any of the models described in the recently released ENA/AEMO Open Energy Networks<sup>2</sup> consultation paper. This is \$20 million lower than discussed with customers and stakeholders earlier this year due to a revision in the scope of a new low voltage network operating model.



We are committed to supporting Government policy and the community’s desire for more renewable energy on the network.

We are working with:

- › **the South Australian Government** on its proposed program to support more customers adopting battery storage;
- › **retailers** who are considering VPPs that will further increase the amount of solar and batteries connected to the network;
- › **equipment manufacturers**, to agree on appropriate standards for any new equipment connecting to the network;
- › **developers** who are promoting new ‘greener’ residential developments; and
- › **industry** participants around operation and management of third party energy services.



We are also committed to adopting all viable alternatives to building network infrastructure to meet future network challenges. Non-network solutions such as batteries and solar generation can defer or eliminate the need to build traditional long-life network assets and result in lower prices for customers.

During 2015–2020 we implemented the following non-network solutions:

- › contracted third-party generation at Bordertown — deferring upgrade of a 33,000 volt powerline;
- › implemented the Salisbury residential battery project which deferred the need to build additional powerlines; and
- › connected a battery to the network at Cape Jervis, which helped defer the planned upgrade of the Cape Jervis 33,000/11,000 volt substation.

During 2020–2025 we will investigate non-network opportunities to:

- › use third party generation to avoid a network upgrade at Robe;
- › use systems and data to more actively manage our low voltage network and avoid or defer the upgrade of network assets;
- › use customer solar and battery systems to avoid network upgrades in the Aldinga area;
- › utilise customer resources to avoid replacing and upgrading long rural lines at Emu Bay on Kangaroo Island; and
- › defer a new Gawler East zone substation through customers in the Gawler East area adopting solar and storage options.

<sup>2</sup> AEMO and Energy Networks Australia, *Open Energy Networks*, July 2018



Additional solar and batteries on our network, and the emergence of VPPs and other new technologies, will drive further changes in the electricity industry. These changes will present new opportunities for customers and will require new ways for distribution businesses to operate and manage their networks.

The AER will provide us with a demand management incentive allowance of around \$4 million for 2020–2025 to help fund research and development of demand management projects. We expect to spend this allowance on a number of projects which will help us assess new technologies and their potential applications as well as customers’ likely responses to these technologies.

We will explore:

- › embedded networks with green schemes which facilitate peer-to-peer trading within the embedded network and reduce overall network demand;
- › the potential impact of electric vehicle charging and opportunities for demand management using smart vehicle chargers;
- › integrating future VPP market platforms; and
- › the impact and opportunities of emerging smart hot water systems.



The electricity industry will change profoundly over the next five to 10 years and we are currently working closely with key stakeholders to adapt to these changes and unlock value for customers and stakeholders. Specifically, we are working with:

- › **technology providers** (such as Tesla) to ensure we understand how the market is changing;
- › the **South Australian Government** to support and enable its energy policy directions;
- › the **Australian Energy Market Operator (AEMO)** to ensure power system security is not compromised;
- › the **Australian Energy Market Commission (AEMC)** to make sure that the rules under which we operate continue to serve the long-term interests of customers; and
- › the **AER** to ensure our plans are the most efficient way to deliver on our regulatory obligations and service standards.



### Tariffs

The AER will determine our total revenue allowance for 2020–2025. We will then recover this allowed revenue through distribution tariffs, which are approved by the AER each year.

This Draft Plan contains the tariff structures and options that we are proposing to include in our 2020–2025 Tariff Structure Statement. These tariffs are designed to empower customers to better manage their bills and keep overall costs down.



### Other customer-specific services

The AER will set prices for public lighting, customer connection and other customer-specific services for 2020–2025. These are discussed briefly in this Draft Plan.

We do not expect any marked change in the price or delivery of these services.

### Feedback

We now welcome feedback from all customers and stakeholders on this Draft Plan, to further improve our plans before we lodge our full 2020–2025 Regulatory Proposal with the AER in early 2019.

You can provide feedback in various formats. Please refer to the end of this document for more detail.

# Delivering services efficiently

**SA Power Networks  
is ranked as the most  
efficient distributor on  
a state-by-state basis.**





# About SA Power Networks

## Our performance



**#1 for efficiency**  
in the National  
Electricity Market

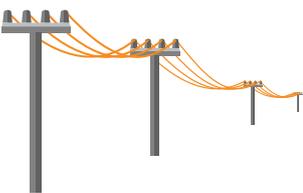


**Reliability and**  
customer service  
targets met



**Industry leader**  
in safety

## What we do



**Operate the oldest**  
**network** in the National  
Electricity Market



Provide network coverage  
over **178,000km<sup>2</sup>**



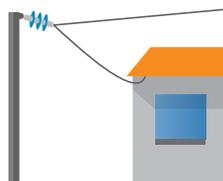
**Deliver power to 99%** of  
South Australia's population



**Supply 860,000**  
homes and businesses



**Connect the most rooftop**  
**solar per capita** in the  
National Electricity Market



**Enable 25,000** new  
or altered connections  
each year



**Read more than 1 million**  
**meters** and provide data  
to retailers



**Maintain 240,000 street**  
**lights** for councils and  
South Australian Government



Our prices in line with CPI since 1999



26% of residential customers' bills

### How we do it



Employ 1,800 South Australians

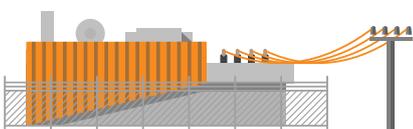


Located at 42 sites across the state

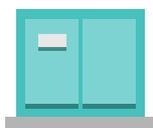


Deliver future-focused services that customers value

### What we manage



416 zone substations



77,800 transformers



647,000 stobie poles



Powerline route length: 82,000km ≈ 20% underground

## 2 Delivering services efficiently

### Our performance



The AER’s most recent benchmarking report released in December 2017 recognised SA Power Networks as the most efficient distributor on a state-by-state basis, based on ‘total factor productivity’.

Table 2.1: Total Factor Productivity state rankings

State	Ranking
South Australia	1
Victoria	2
Queensland	3
Tasmania	4
New South Wales	5
Australian Capital Territory	6

Table 2.2: Total Factor Productivity by distributor

Network	AER Ranking
CitiPower (VIC)	1
<b>SA Power Networks</b>	<b>2</b>
United Energy (VIC)	3
Jemena (VIC)	4
Powercor (VIC)	5
Engex (QLD)	6
Endeavour Energy (NSW)	7
AusNet Services (VIC)	8
TasNetworks (TAS)	9
Ergon Energy (QLD)	10
ActewAGL (ACT)	11
Essential Energy (NSW)	12
Ausgrid (NSW)	13

We rank number two on efficiency when all of the distribution businesses in the NEM are compared. We are second only to a unique distribution business that is responsible for a small footprint, including the Melbourne Central Business District (CBD).

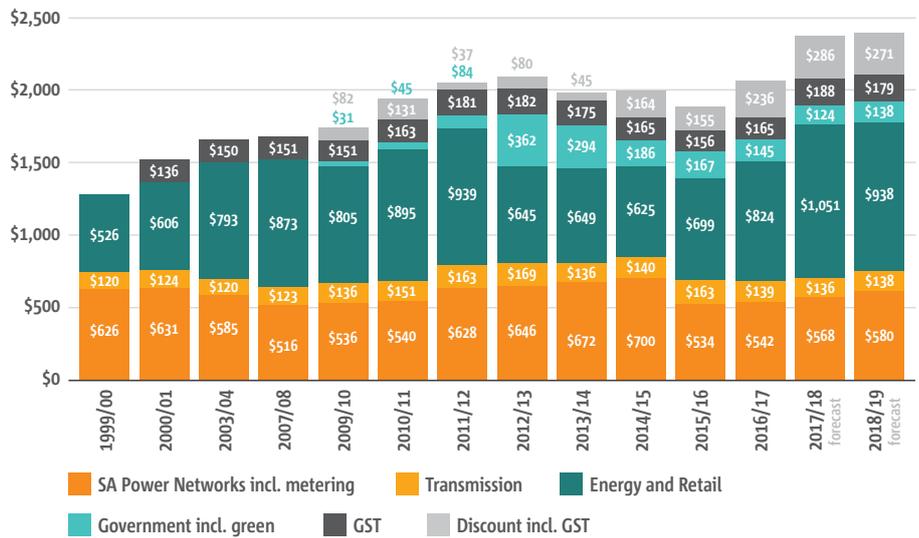


Figure 2.1: Average SA residential electricity bills

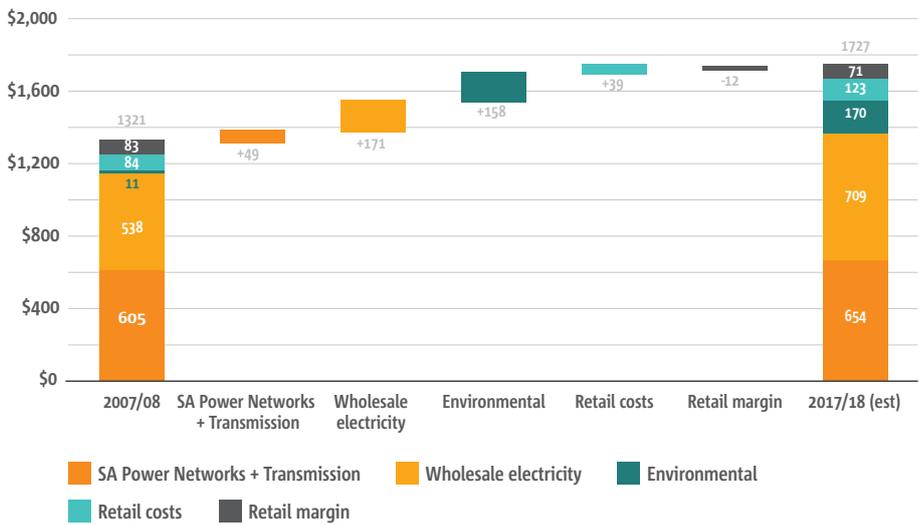


Figure 2.2: Change in average South Australia residential bill per customer 2007/08 to 2017/18 (\$ per customer, real \$2016/17, excluding GST)<sup>3</sup>

3 ACCC, Restoring electricity affordability and Australia’s competitive advantage Retail Electricity Pricing Inquiry – Final Report, June 2018

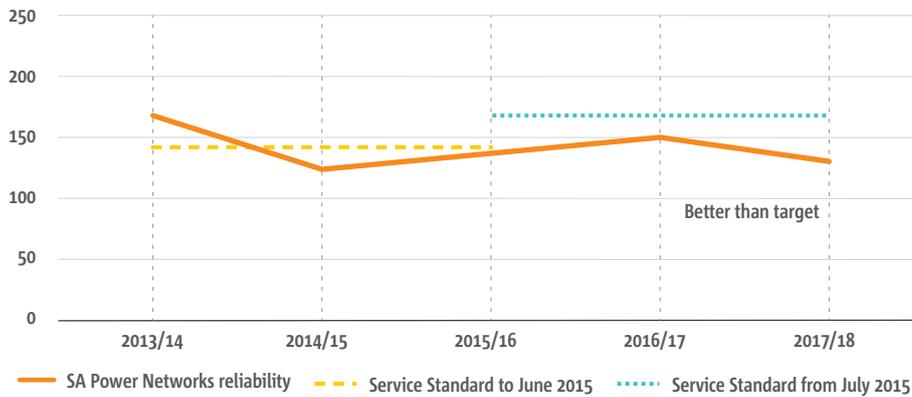


Figure 2.3: Electricity network system reliability<sup>2</sup> (excluding major event days) — average minutes of outages per customer



Providing a safe, reliable and secure electricity supply is our core business.

In recent years, customers have experienced poor supply reliability because of major events including:

- › a state-wide power outage in September 2016 caused by cyclonic-force winds that damaged ElectraNet’s transmission system; and
- › significant outages at the distribution level caused by an unprecedented number of storms in 2016 and 2017.

Notwithstanding these events, we continued to meet our electricity supply reliability<sup>4</sup> standards and our customers remain satisfied with the level of customer service we provide.



A focus on safety underpins everything we do. Our recent safety performance shows us leading the industry and in 2017 we reduced our lost time injury frequency rate to almost zero.



We strive to deliver outcomes for customers at the lowest sustainable cost and we are conscious that every dollar we spend is paid for by customers.

We understand that customers’ electricity bills have grown over time due to a range of new charges that are not related to distribution costs; most recently due to large increases in wholesale/retail charges.

Our charges have remained in line with CPI since 1999/00 (refer to Figure 2.1). We have been able to achieve this by operating efficiently and considering the effects of our decisions on our customers’ electricity costs. This contrasts with wholesale generation costs that have nearly doubled over the same period.

<sup>4</sup> Measured using the system average interruption duration index (SAIDI) which reports the average minutes per annum that South Australian customers are without electricity supply (excluding major event days). Method of calculating target and outcomes amended by ESCoSA in 2015/16



SA Power Networks’ recovers its costs from the distribution component of customers’ bills. This component has reduced from 50% to 26% for residential customers since privatisation in 1999/00 and is now typically 28% for a small business.

The recent ACCC report into electricity pricing shows that the significant recent increases in electricity bills arise from retailer/wholesale and government scheme increases.

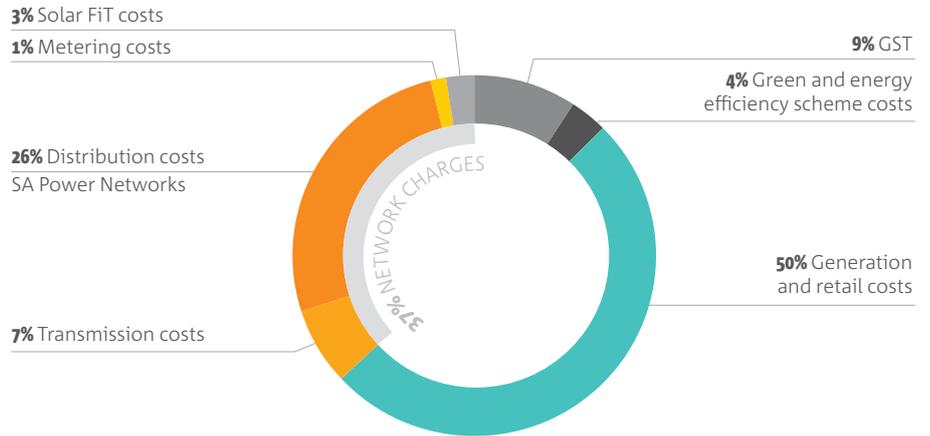


Figure 2.4: Residential customer bill breakdown

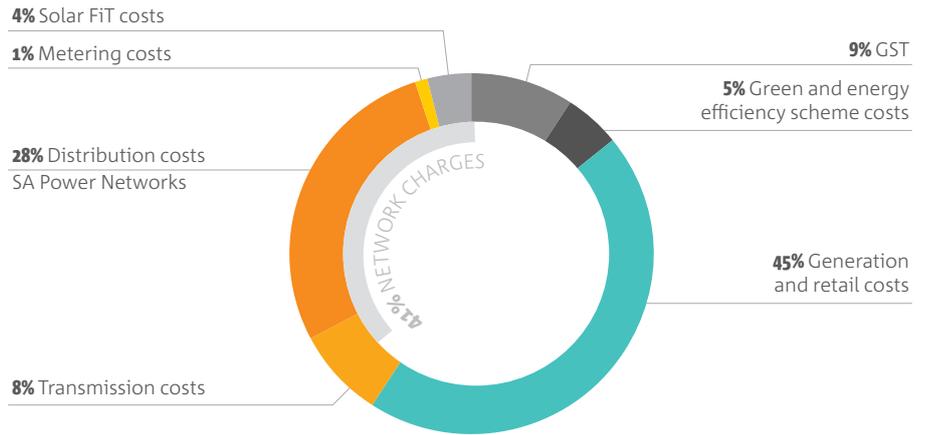


Figure 2.5: Business customer bill breakdown

## What we do

**Our primary responsibility at SA Power Networks is to maintain the safety and reliability of the electricity network for 860,000 residential and business customers, across a service area of 178,200km<sup>2</sup>.**

The majority of our assets were constructed in the 1950s, 1960s and early 1970s, and we now operate the oldest network in the NEM.

## How we do it

We apply prudent risk-based asset management strategies to ensure continued good performance from these ageing assets. We maintain, repair, refurbish and replace these assets as efficiently as possible based on their condition.

And we are not just doing what we have always done. We have future-focused strategies to ensure we adopt and increasingly deploy new technology and non-network alternatives from third parties where cost-effective – and we avoid investing in long-life assets when future technologies could prevent this expenditure entirely.

Since 2011, our Future Operating Model<sup>5</sup> has provided us with a perspective on what the future world looks like for our customers and our network. It helps us understand how our business will need to adapt to support the changing needs and choices of our customers. The Future Operating Model guides our broad decision-making and our strategies. We maintain and update this document every two years as our operating environment evolves.

**Our corporate vision is to be ‘a leader in delivering energy services that customers value’.**

Through direct engagement and surveys of our customers and key stakeholder groups, we make sure that what we do is valued by our customers and that we work together to deliver energy services they value.

As a privately-owned business that manages essential public infrastructure, we are funded to provide a specified level of service for a reasonable commercial return. These outcomes are overseen through economic and service standard regulation which are administered by the AER and ESCoSA respectively.

The South Australian Government’s Office of the Technical Regulator (OTR) also monitors our technical compliance with requirements of the *Electricity Act 1996 (SA)* and regulations, technical standards, and codes.

Our headquarters are in Adelaide and we are one of the State’s largest organisations. We employ more than 1,800 people throughout metropolitan and regional South Australia to support this network. We are also a major training organisation, with hundreds of apprentices becoming the next generation of powerline and electrical tradespeople.

We operate out of 42 depots and offices located in the metropolitan area and major country locations across the State.

We are proud of what we do for South Australians. We are particularly proud that we are recognised as a cost-efficient business, despite the challenges of a big State with a dispersed population.

<sup>5</sup> Future Operating Model document is available at [sapowernetworks.com.au](http://sapowernetworks.com.au)

# Customer engagement

Early, frequent and open engagement with customers and their advocates underpins this Draft Plan.





## Customer engagement program



**2,892**

participants



**43**

Engagement  
activities



**36**

Reference Group  
meetings



**13**

Locations across  
South Australia



**10**

Newsletters



**4,071**

talkingpower.com.au  
visits

## PHASE 1: Strategic Research and Early Engagement | Feb – July 2017

### Customer Research

**1,000** Residential and business customers

- 503 online
- 5 in-depth interviews
- 8 focus groups
- 402 telephone surveys

### Customer Priorities

- Outage Comms
- Sustainability
- Network reliability
- Future network options
- Self-reliant SA
- Electricity prices

## PHASE 2: In-depth Engagement | Aug – Dec 2017

### Directions Workshops

**134** Participants

202 questions answered

6 locations

54% residential | 46% business/government

- Reliability of the network
- Network of the future
- Network prices

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### talkingpower.com.au Online Engagement

**1,396** Registered

- Surveys
- Polls
- Forums
- Maps

- September: Network reliability
- October: Outage Comms
- November: Network of the Future

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### Culturally and Linguistically Diverse Focus Groups

**54** Participants

**4** Communities

30+ questions asked

- Reliability of the network
- Network prices
- Restoring power

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### Vulnerable Customer Conversations

**68** Participants

54% metro Adelaide | 46% regional townships and country

27 discussion topics raised

- Network prices

## PHASE 3: Draft Plan Development and Engagement | Jan – Sept 2018

### Deep Dive Workshops

**240** Participants

- Business advocates
- Arborist Reference Group
- Vulnerable customer advocates
- Local Government
- Renewable energy advocates
- Residential and business customers
- Retailers
- State Government
- AER, AEMO, AEMC
- Other specialist and representative groups

**10** Workshops

Tariffs	Levels of Service
Capex 1	Capex 2
Opex	Future Networks 1
Future Networks 2	Future Networks 3
Public Lighting	Information Technology

### 3 Our customer and stakeholder engagement

#### Designing our customer engagement

**Our Customer Engagement Program for our 2020–2025 Plan began in February 2017. It was designed as a progressive, phased program that would provide multiple and diverse opportunities for dialogue and engagement. Our goal was to better understand the expectations and priorities of our customers and stakeholders so we could make sure that our plans for 2020–2025 were in their longterm interests.**

Regular interactions with our Customer Consultative Panel and reference groups (which typically meet quarterly) have underpinned the program. The panel and reference groups were established in late 2015 and refreshed in late 2016 and include more than 60 customers and consumer advocates from diverse occupations and interest areas including arborists, renewables, business, community, and electricity advisory (refer to Figure 3.1).

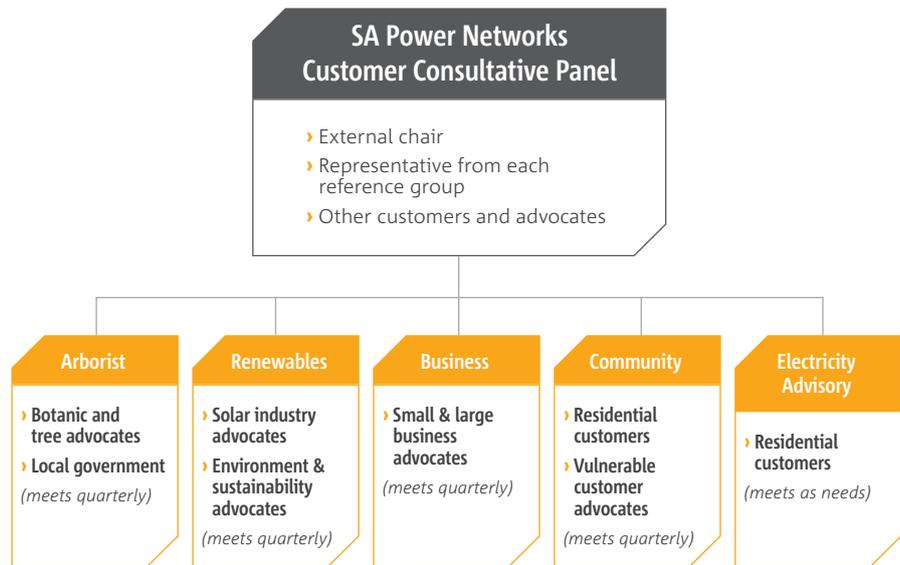


Figure 3.1: Customer Consultative Panel and Reference Groups

Our 2020–2025 Customer Engagement Program continued our business-as-usual engagement and also:

- › considered past engagement learnings;
- › was informed by our reference group members;
- › reflected our desire for continuous improvement;
- › was aligned to both AER and SA Power Networks' consumer engagement principles; and importantly
- › was guided by a 'no surprises' approach.

We have continued to evolve our program and adopt new engagement activities. For example, we established a dedicated website ([talkingpower.com.au](http://talkingpower.com.au)) that uses online engagement tools to reach a broad customer base through surveys, polls, and forums. We undertook other targeted activities such as consulting with vulnerable customer groups and culturally and linguistically diverse communities (CALD). These were developed and delivered in response to stakeholder feedback and in partnership with several of our stakeholder organisations (thanks to Multicultural Communities Council SA, Australian Refugee Association, Uniting Care Wesley Bowden, and Uniting Communities).

A summarised version of our engagement program can be found in Figure 3.2.

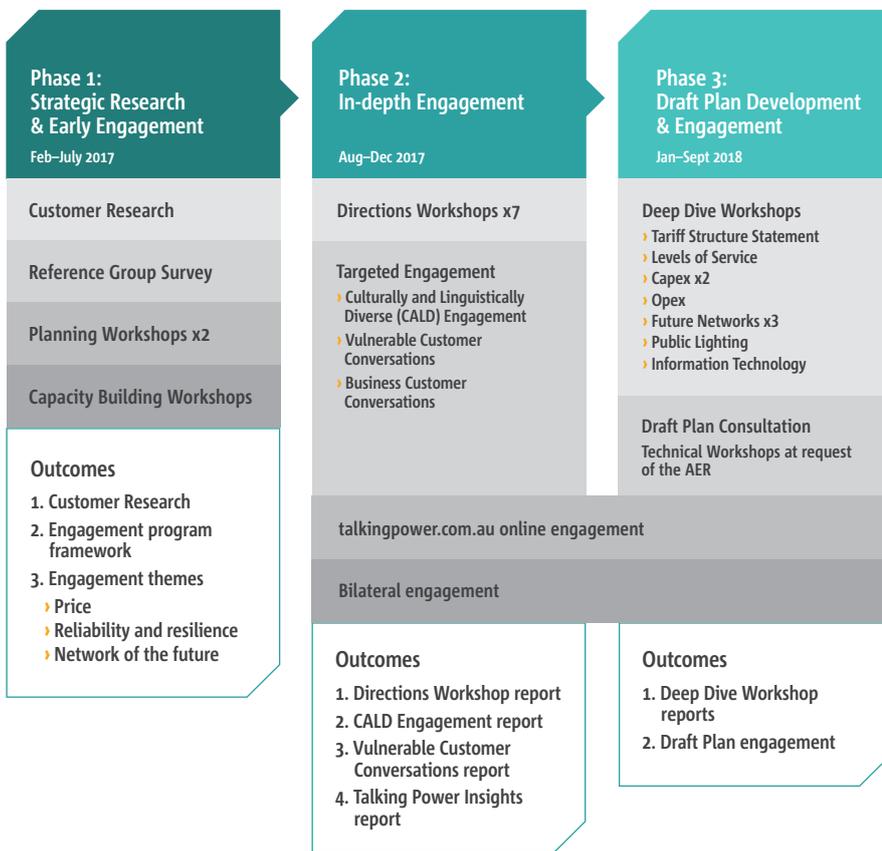


Figure 3.2: 2020–2025 Regulatory Proposal Customer Engagement Program

## Delivering our engagement

In 2017, our engagement was broad and we sought customer insights around three key themes that were identified in our preliminary customer research:

- › Network price
- › Network reliability and resilience
- › The network of the future

We considered the priorities emerging from this early engagement in our preliminary expenditure forecasting in late 2017. These preliminary forecasts were based on keeping expenditures as low as possible. They were then used in early 2018 to engage with stakeholders through a series of deep dive workshops, where we explored the capital and operating expenditure forecasts presented in our Draft Plan.

## Tariff Structure Statement (TSS)

Specific engagement on our 2020–2025 TSS is discussed in Section 9. The TSS outlines the more cost-reflective tariffs we are proposing for 2020–2025 and how these will empower customers to better manage their bills.

## ESCoSA's Service Standard Framework review

We have also worked closely with ESCoSA in its 2020–2025 Service Standard Framework review. We considered their requirements as we designed our engagement activities and we shared engagement outcomes. ESCoSA's research also assessed the extent of a customer's willingness to pay for improved reliability levels and this is reflected in its draft reliability standards for 2020–2025<sup>6</sup>.

## Engagement outcomes (summary)

Our comprehensive engagement program has provided rich, and at times diverse, feedback which we have used to refine our Draft Plan (refer to Table 3.1 overleaf). Broadly, customers have told us they value three areas:

- › Keeping prices down
- › A safe and reliable network
- › Transitioning to a new energy future



### Keeping prices down

Electricity price increases are hurting customers, particularly those who are vulnerable or running a business. SA Power Networks must do its part to keep a lid on electricity prices. As a result, everything proposed in this Draft Plan has been considered with affordability in mind.



### A safe and reliable network

Reliable energy remains a high priority for customers, particularly our business customers. In some regional areas, customers asked for improved reliability locally and recognised that those improvements may come at a cost.

It was also important to many customers that we continue to manage the increasing risk of bushfires starting from powerlines.



### Transitioning to a new energy future

Customers support SA Power Networks' responsible investment in the network to realise the potential benefits of distributed energy resources.

6 Essential Services Commission of South Australia, SA Power Networks reliability standards review — draft decision, August 2018

Table 3.1 Customer feedback and our response

Theme	What we heard	Our response
 <p><b>Keeping prices down</b></p>	<ul style="list-style-type: none"> <li>› Ongoing electricity bill increases are challenging for customers, particularly vulnerable customers and small business</li> <li>› Ensure network prices are affordable while maintaining satisfactory service levels</li> <li>› Actively look for efficiencies and innovate to stay at the efficient frontier and deliver price relief</li> <li>› Avoid or defer expenditure where possible</li> <li>› If expenditure is required, adopt a prioritised, staged approach to any programs</li> <li>› Instead of proposing step changes, absorb improvements where possible</li> <li>› Apply an additional productivity growth factor to reduce costs</li> <li>› “Do more for less”</li> </ul>	<ul style="list-style-type: none"> <li>› The Draft Plan will reduce customer’s bills in 2020/21 — a \$37 decrease for the average residential customer and a \$148 reduction for a typical small to medium business</li> <li>› Prudent approach to all expenditure forecasts to minimise investments in the Regulatory Asset Base (RAB)</li> <li>› Efficient deferrals and refurbishment of assets when possible, eg improved risk-based approach is enabling efficient deferral of \$200 million of asset replacement</li> <li>› Continuation of internal programs to drive efficiencies, while managing risk and retaining value</li> <li>› Expenditure programs only proposed when value outweighs cost</li> <li>› Staged, risk-based approach to capital programs, targeting areas of greatest need and/or value</li> <li>› We have not applied a productivity growth factor (but we continue to strive to achieve further efficiencies to deliver on our operating obligations at a cost lower than our allowances — sharing benefits with customers 70:30 as per incentive scheme regulations. We are also absorbing some cost increases and providing additional services for no additional cost)</li> <li>› Total reductions of \$90 million capital expenditure and \$49 million operating expenditure following customer and stakeholder feedback on preliminary forecasts in deep dive workshops (see sections 6 and 7 for details)</li> </ul>
 <p><b>A safe and reliable network</b></p>	<ul style="list-style-type: none"> <li>› Continued reliability of the network is a high priority</li> <li>› Some locations (Eyre Peninsula, parts of the Adelaide Hills) have indicated a desire for reliability improvements</li> <li>› Regular asset inspection, maintenance and repair or replacement is important</li> <li>› There is logic in our risk-based approach to asset management — but need to avoid ‘boom and bust’ cycles of expenditure</li> <li>› Customers expect SA Power Networks to operate safely, and balance safety, risk and affordability when managing the network</li> <li>› Bushfire safety is important, not only to those in bushfire risk areas, but to most customers</li> <li>› Customers value accurate, timely and tailored information about power outages</li> </ul>	<ul style="list-style-type: none"> <li>› Prudent expenditure plans to maintain current reliability and safety levels and meet service standards</li> <li>› Targeted program to improve reliability to ‘poorly served’ customers</li> <li>› Continuation of a targeted program to improve the resilience of storm-prone network areas</li> <li>› Prudent bushfire risk mitigation plan to reduce the risk of our network starting fires</li> <li>› Proposed asset replacement program at sustainable levels</li> <li>› Removal of the IT step change associated with more advanced customer engagement technologies proposed in the operating expenditure deep dive workshop — approach now focuses on progressive system enhancements to improve customer communications over time</li> </ul>

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**Theme****Transition to a new energy future****What we heard**

- › Enable continued uptake of renewable technologies
- › Allow customers to export to the network — but not at any cost
- › Ensure the network can support two-way energy flows
- › Consider ways of capturing and sharing data on distributed energy resources and network hosting capacity
- › Actively pursue non-network solutions and avoid capital expenditure
- › Future network plans should allow for a range of future scenarios
- › Consider how network tariffs and demand management opportunities could be used to delay capital investment
- › The AER's Consumer Challenge Panel (CCP14) provided advice to the AER on our approach to addressing the challenges of high penetration of solar and embedded generation on our network

**Our response**

- › Continued refinement of our industry-leading Future Network Strategy and related projects, pilots and trials
- › More detailed investigation into the options and opportunities that will enable increased take-up of new customer technologies
- › An integrated approach to managing the challenges and opportunities of new technologies and use patterns, including tariff design that is aligned to our Future Network Strategy (eg proposed Time of Use (ToU) residential tariff, VPP tariff)
- › Potential non-network solutions identified, valued at \$28 million
- › Integrated, measured, and staged strategy aimed at using the available data to dynamically manage flows on the network, rather than significantly augmenting the capacity of the network
- › Testing the market for potential demand management opportunities and other trials
- › We are adopting a 'no-regrets' approach to managing customer solar and embedded generation and accept CCP14 comments that further significant consideration of options will be beneficial

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**Evaluating our engagement program**

We are always seeking to improve our engagement and aim for best practice. We have reviewed our program's effectiveness and implemented improvements based on the customer and stakeholder feedback we received.

**Our Draft Plan**

Thank you to everyone who has talked to us so far. In the spirit of 'no surprises' we are pleased to have discussed our Plan with our stakeholders and are confident that this Draft Plan reflects what you've told us is important — for us to deliver a safe, reliable supply of electricity and begin the transition to the future, all while doing our part to keep a lid on costs.

We look forward to your feedback.

**Feedback**

Do you have any feedback on our customer engagement program and outcomes?

# Keeping prices down

A \$37 drop in annual residential bills and a \$148 drop in distribution charges for business.



wrapping by florist



## 4 Keeping prices down

**The number one priority for customers and stakeholders throughout our customer engagement program was affordability of electricity.**

We shared our preliminary plans and expenditure forecasts with key customer representatives and stakeholders earlier this year. At that time, we indicated a revenue outlook increasing at approximately 1% per annum above CPI over the 2020–2025 period.

While most customers and stakeholders were generally understanding of our plans, it was clear that the majority were seeking average price increases of no more than CPI, and preferably below CPI. We have refined our plans which has enabled a reduction to our proposed capital and operating expenditure in certain areas to better meet the expectations of customers. We have also adopted a rate of return consistent with the AER's draft Rate of Return Guideline published in July 2018 and calculated a 5.55% weighted average cost of capital (WACC) which compares with our current WACC of 6.13%. This also contributes to lower prices for customers.

### Revenue<sup>8</sup>

**Our Draft Plan will deliver a real reduction in distribution charges in the first year of the 2020–2025 period with no real increases in charges in subsequent years.**

We propose a revenue path whereby revenue will reduce by CPI-3.9% in 2020/21 and only increase by CPI in the remaining four years of the period. We have used the AER's revenue model to determine this revenue path but varied from the AER's standard approach to deliver no real increases in the remaining four years of the period. The AER's standard approach would deliver a slightly bigger reduction in 2020/21 but would see distribution charges increase above CPI in subsequent years. We have adopted our approach as we understand that while customers and stakeholders want reductions in their bills in 2020/21, they also want no real price increases in subsequent years. The final revenue path is set in consultation with the AER.

Table 4.1: Achievable average annual residential bill savings by 2020/21<sup>7</sup>

Region	2017/18 Bill	Networks <sup>*</sup>	Wholesale	Environment	Retail	Reduction	2020/21	% Reduction
Victoria	1457	39	192	34	26	291	1166	20
New South Wales	1697	174	155	43	37	409	1288	24
South East Queensland	1703	147	192	18	62	419	1284	25
<b>South Australia</b>	<b>1727</b>	<b>13</b>	<b>227</b>	<b>89</b>	<b>42</b>	<b>371</b>	<b>1356</b>	<b>21</b>
Tasmania	1979	113	226	75	–	414	1490	21

<sup>\*</sup> Networks includes both distribution and transmission costs

<sup>7</sup> ACCC, *Restoring electricity affordability and Australia's competitive advantage Retail Electricity Pricing Inquiry – Final Report, June 2018 (Page XV)*

<sup>8</sup> The 2020–2025 revenue and pricing outcomes exclude any incentive carry-over amounts that may be determined by the AER

## Electricity bills

**Under our approach, the average residential customer's annual distribution charges will reduce by \$37 in 2020/21.**

For a typical small to medium business, distribution charges will fall approximately \$148. This significantly exceeds the ACCC view that networks should be able to deliver a \$13 reduction in electricity bills (see Table 4.1).

These savings build on the significant reductions in our network charges delivered in 2015/16. Figure 4.1 illustrates the price change for an average residential customer.

The detail behind the indicative price and revenue forecasts is explained in the following sections of this Draft Plan.

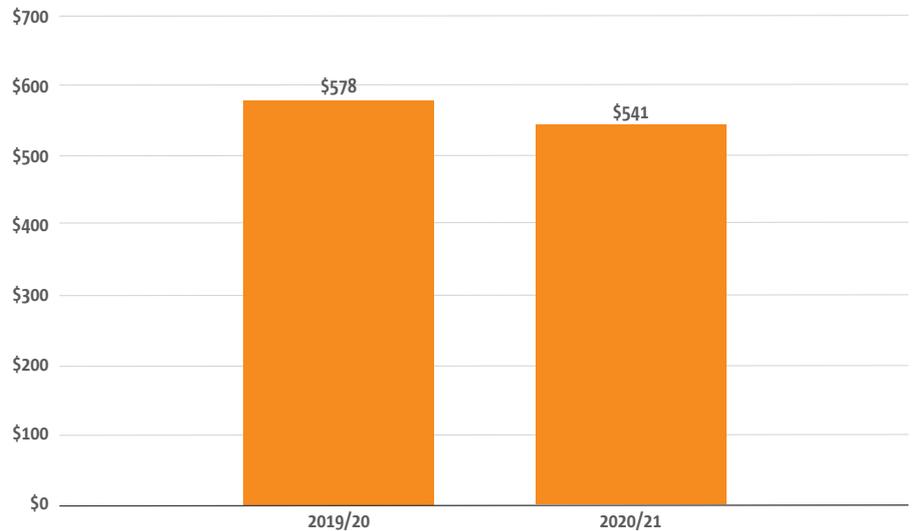


Figure 4.1: Average annual residential distribution bill comparison (nominal \$)

### Feedback

- › Do you have any feedback on our proposed revenue plans or electricity bill impact?
- › Do you support our revenue path approach?

# Enabling the distributed energy transition

Transitioning from centralised to de-centralised generation.

## **This section outlines:**

- › the impacts that more solar systems and batteries will have on our distribution network;
- › the strategies we use to manage these impacts; and
- › our plans to enable further distributed energy resources to connect to our network.





## 5 Enabling the distributed energy transition

### The changing role of the distribution network

It is easy to forget that as recently as ten years ago it was extremely unusual to see a solar panel on a roof in South Australia. At that time, the role of the distribution network was as it always had been: to take energy generated in the state's large coal and gas-fired generators, delivered at high voltage to our zone substations via ElectraNet's transmission network, and distribute it to homes and businesses across the state.

In 2018, the role of the distribution network is very different. One in four premises now has solar on the roof. Taken together, these 200,000 rooftop systems can now generate 940 megawatts (MW) of electricity in the middle of the day — more than any other single generator in the state — much of which is fed back into the distribution network to be re-distributed to other homes and businesses.

Rooftop solar capacity continues to grow strongly, and significantly ahead of AEMO's most recent forecasts (November 2017), 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 systems in this sector of the market tripled from 2016 to 2017.

By 2026, AEMO is forecasting that there will be enough installed rooftop solar to supply the entire State's energy needs at periods of minimum demand.

As we continue through this transition from centralised to de-centralised generation, the role of the distribution network changes and becomes more critical. Individual customers with solar now rely on our network not only to supply their energy needs at times of high demand, but also to export their surplus energy in the middle of the day. As rooftop solar continues to make up an ever-larger proportion of the state's generation mix, the whole state energy system is becoming increasingly reliant on SA Power Networks' electricity network to supply and redistribute this energy.

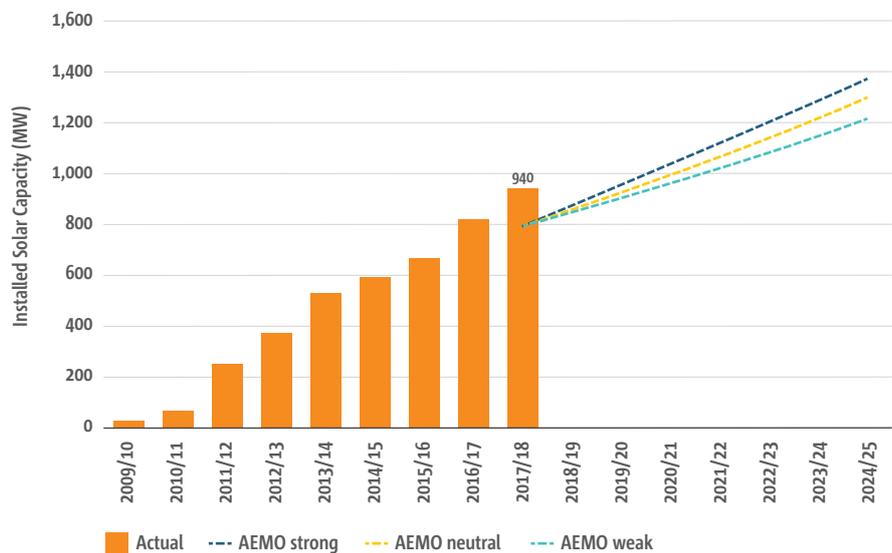


Figure 5.1: Installed Solar capacity and future forecasts

### Battery storage and VPPs

The market for residential battery storage in South Australia is poised to accelerate, driven by falling battery prices, discount schemes from major retailers and, most significantly, two major new South Australian Government programs. The programs, commencing in 2018, include a \$100 million home battery fund that will offer subsidies of up to \$2,500 each for 40,000 customers to buy residential batteries, and the South Australian Government/Tesla Virtual Power Plant scheme, which aims to roll-out up to 50,000 batteries, initially targeting Housing SA properties. These two schemes could see 90,000 new batteries connected to our distribution network in the coming years.

The value of home storage is multiplied when many individual batteries are aggregated under central control to form a VPP. Such VPPs can be dispatched rapidly to supply energy to the wholesale market or to provide ancillary services (eg services that balance demand and supply) to the market operator. They are expected to play an important role in dynamically balancing supply and demand in energy networks throughout the world as the energy mix becomes increasingly dominated by intermittent generation sources like solar and wind.

South Australia is at the forefront of VPP use globally. In 2018, we already have:

- ▶ the 100-battery (300kW) VPP established by SA Power Networks in Salisbury in 2016 to provide support to the network in that area;
- ▶ AGL's 1,000-customer, five megawatt VPP, which is currently being implemented;
- ▶ Simply Energy's newly-announced 1,200 customer (6MW) VPP, which will commence later this year; and
- ▶ the South Australian Government/Tesla VPP. This first phase of the rollout, to 1,200 premises, will be complete in mid-2019. The Government plans to expand this VPP to a final size of 50,000 households, which would make it the largest VPP in the world, and at 250MW, a very significant resource in the South Australian energy market.

Many of the 40,000 batteries subsidised under the Government's \$100 million grant program might also be enrolled in VPP schemes, as this will offer greater savings to the householder than if they use as a stand-alone battery.

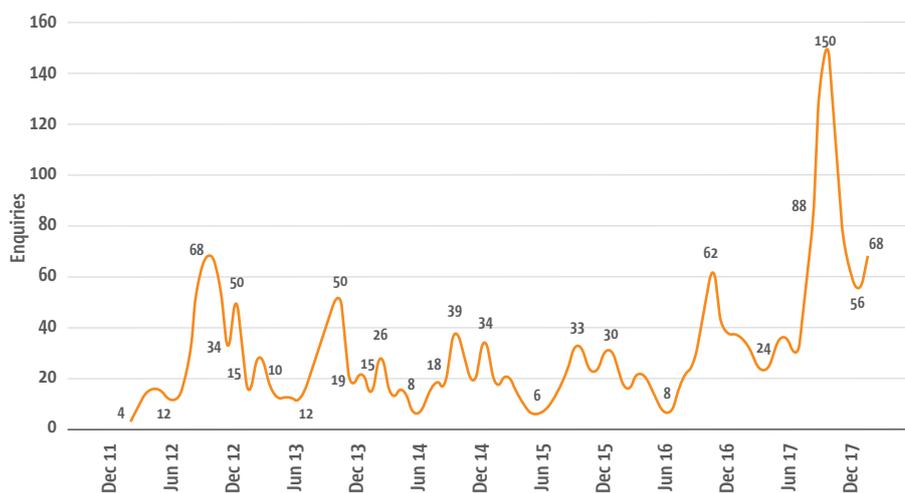


Figure 5.2: Voltage related enquiries

### Network ‘hosting capacity’ for distributed generation

Our distribution network was not designed to transport energy in two directions, and every powerline has a finite hosting capacity to accommodate the connection of distributed energy resources (DER) like solar and batteries before technical issues arise.

As DER penetration increases in a local area the first issue that arises is normally over-voltage at times of high export, as customer inverters must raise local voltage to feed energy ‘upstream’ into the network. This causes customer inverters to trip off and it can cause damage to the customer’s and their neighbours’ equipment. We have seen a sharp increase in the number of customer enquiries about voltage-related issues in the last 12 months (Figure 5.2), as solar penetration begins to exceed hosting capacity limits across increasingly large areas of our network.

In areas of very high solar penetration, reverse energy flow in the middle of the day can eventually become high enough to exceed the thermal rating of distribution transformers or other assets. This can interrupt supply to multiple customers.

These issues can be exacerbated by the operation of VPPs that enable customer energy resources to be dispatched in a coordinated manner in response to market signals and cause very large swings in energy flow within our local network.

These issues arise first in localised areas of our low voltage (LV) network. This is a challenge because there has not been a historical need to invest in any means to monitor or actively manage this part of our network. We currently only find out about an LV network issue when a customer enquires and then we install temporary monitoring equipment to investigate the problem and determine the necessary remediation work.

While this simple, reactive approach to managing the LV network has served us well for many years — and helped to keep costs down for customers — it is no longer sustainable. As solar and battery storage uptake continues to grow, many areas of our network will reach or exceed their hosting capacity in the 2020–2025 period. We will need to transition to a more flexible and active approach to managing our LV network if we are to continue to maintain power system security and supply quality for all of our customers while permitting the continued uptake of solar and batteries.

### Strategies for managing change

The clear feedback from customers through our customer engagement program, was that they expect us to prudently plan for the future and explore efficient network and non-network solutions to manage these emerging issues. However, the future is uncertain and technology is evolving rapidly. Customers and stakeholders did not support large expenditure on items which could quickly become redundant. The expenditure proposed in this Draft Plan therefore represents a minimum ‘no regrets’ approach to both manage the issues that are emerging now and establish a foundation to deploy more sophisticated future solutions if and when needed.

## What we have done so far

**We have already put in place some initial measures to help increase the amount of energy resources the network can accommodate and lay the foundation for our transition to more active management of the LV network.**

### Inverter settings

In December 2017 we updated our connection standards so that all new solar and battery inverters connected to our network must be configured with the Volt-VAR and (if available) Volt-Watt response modes as defined in Australian Standard 4777.2. Our modelling shows that Volt-VAR, in particular, can reduce local voltage rise issues very effectively if a reasonable proportion of inverters have the mode enabled. The benefits of this new standard will increase over time as new inverters are installed and old ones are replaced.

### Tariffs

We are proposing new network tariffs for 2020–2025 to encourage customers to shift their load to the middle of the day, when there is a surplus of solar generation.

### Shifting hot water loads

In 2017 we undertook a small trial where we shifted hot water load from the night to the middle of the day and we are considering using the AER's Demand Management Innovation Allowance to fund further investigation of this area.

### Transformer monitoring

In 2017 we installed 200 distribution transformer monitors in high-solar and high demand areas, as the first phase of a progressive rollout that we propose will continue from 2018 to 2025. This is a first step to achieve visibility of our low voltage network.

## Our plan for 2020–2025

**While passive measures such as tariffs and inverter settings will help to extend the hosting capacity of the network, we expect the present hosting capacity limits to be exceeded in up to 20% of the network by 2025<sup>9</sup>, even with these measures in place.**

We will continue to use our existing processes to remediate these issues as they arise through the 2020–2025 period. We will also put in place the new systems, processes and capabilities that will help us to transition to a more active, sustainable approach to management of the LV network towards the end of the period.

Our plan for 2020–2025 includes \$37 million in new capital expenditure and a corresponding \$2 million increase in annual operating expenditure to develop the following system features:

- › an operational model of the LV network;
- › DER database; and
- › dynamic export limits.

### An operational model of the LV network

We will develop an LV network model to determine the hosting capacity of each LV powerline circuit. We intend to use a template-based model, where the performance of every circuit is calculated by referring to a representative sample set of around 10% of the LV circuits that are modelled in detail and actively monitored.

An operational model of the LV network will help us to identify problem areas in the network for investigation and remediation before customers have a problem, and to more efficiently plan and schedule remedial works. It will also help us to provide better information to customers who want to connect both small and large embedded generators to the network.

We will implement structured monitoring in targeted areas of the LV network. This will include a combination of LV transformer monitors, continuing the program that began in 2017, and end-of-line and mid-line voltage monitoring, which we intend to procure as a service from retailers and other third parties with smart meters and similar devices. We will also invest in systems to store and process this data as well as a data interface for third-party providers.

### DER database

We will put in place a database to store information on the distributed energy resources connected to our network and create new processes for installers to register the systems electronically, improving the accuracy of our records and compliance with our connection standards<sup>10</sup>.

<sup>9</sup> Modelling based on current forecast uptake rates for solar and batteries

<sup>10</sup> This component could also be used to support the proposed national battery register, currently the subject of a rule change proposal before the AEMC

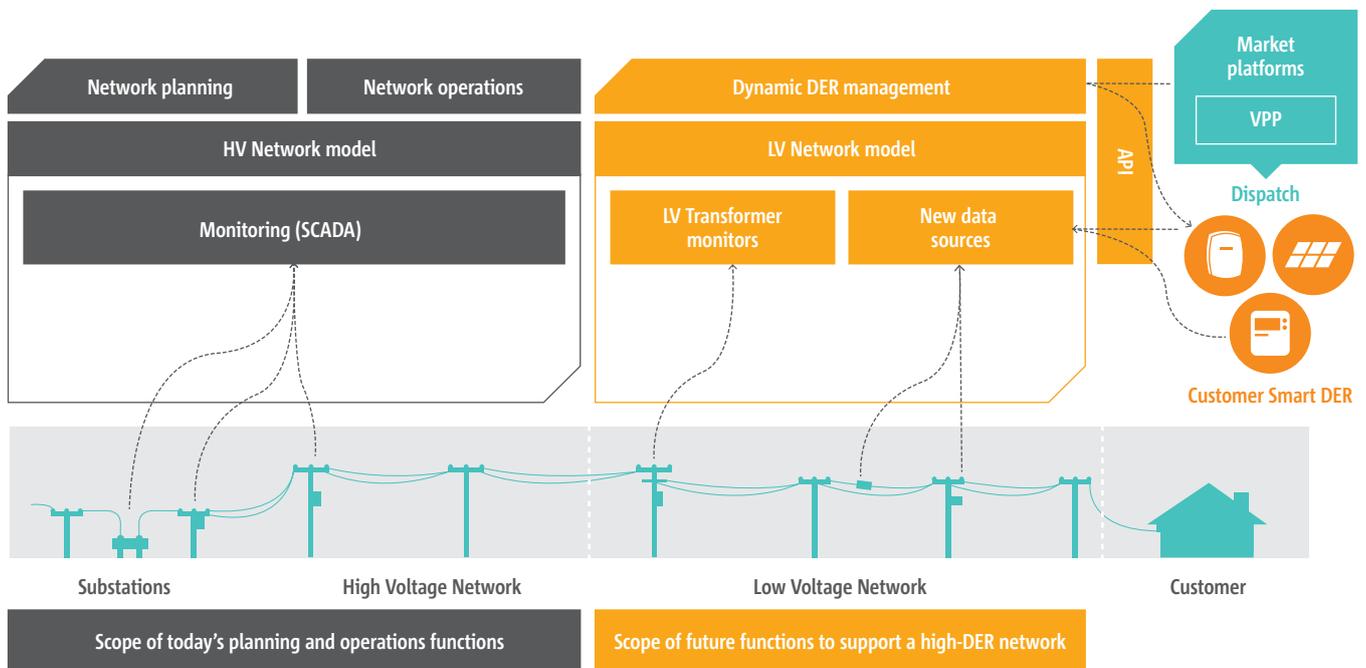


Figure 5.3: Present and proposed network capabilities

### Dynamic export limits

We will implement new systems and interfaces to enable us to set DER export limits dynamically, so that customer equipment can reduce export levels at times when the network is under stress. This ‘feed-in-management’ approach is already used for large embedded generators connected to our network<sup>11</sup>, and is used in other jurisdictions with high penetration of solar (eg Germany). This will allow more DER to connect, and more energy to be exported, while maintaining the security, reliability and quality of supply.

We considered three alternatives to this approach: continue to upgrade and augment the network to increase hosting capacity (as we do today), seek to procure network support services from the market, or limit new DER connections to a circuit once hosting capacity has been reached.

Our economic modelling indicates that implementing a dynamic export limit scheme in South Australia for small embedded generators will enable the least-cost long-term solution from a whole-of-market perspective. This is because it will enable us to defer significant future LV network augmentation expenditure, while continuing to increase the amount of solar energy that can be supplied to the market. This will keep overall power system costs down and benefit all electricity customers.

Compared to investing in long-lived network assets, our non-network approach has greater flexibility; will increase, rather than decrease, asset utilisation; and is adaptable to a broad range of future scenarios.

More active monitoring and control of the distribution system also presents long-term opportunities to reduce overall power system costs for customers and will help us to protect the overall integrity of the State’s energy system during contingent events. We have been working with AEMO since late 2017 to explore these opportunities.

### Feedback

What feedback do you have on our proposed approach to enabling ongoing uptake of customer distributed energy resources like solar and batteries?

11 As of August 2018 this includes all systems of more than 200kW

# Capital expenditure

Investing capital prudently in our network and systems.

## This section outlines:

- › our capital works program for 2020–2025 by category;
- › how we forecast expenditure in each category; and
- › where we have refined our plans in response to customer and stakeholder feedback.





## 6 Capital expenditure

### Capital expenditure is undertaken to create or replace assets.

Based on feedback from customers and stakeholders we have refined our plans and now forecast capital expenditure of \$1,850 million for 2020–2025.

This is a \$90 million reduction from our preliminary plans shared with stakeholders.

Table 6.1 compares expenditure for the 2015–2020 period with our 2020–2025 preliminary plans and this Draft Plan, by expenditure category.

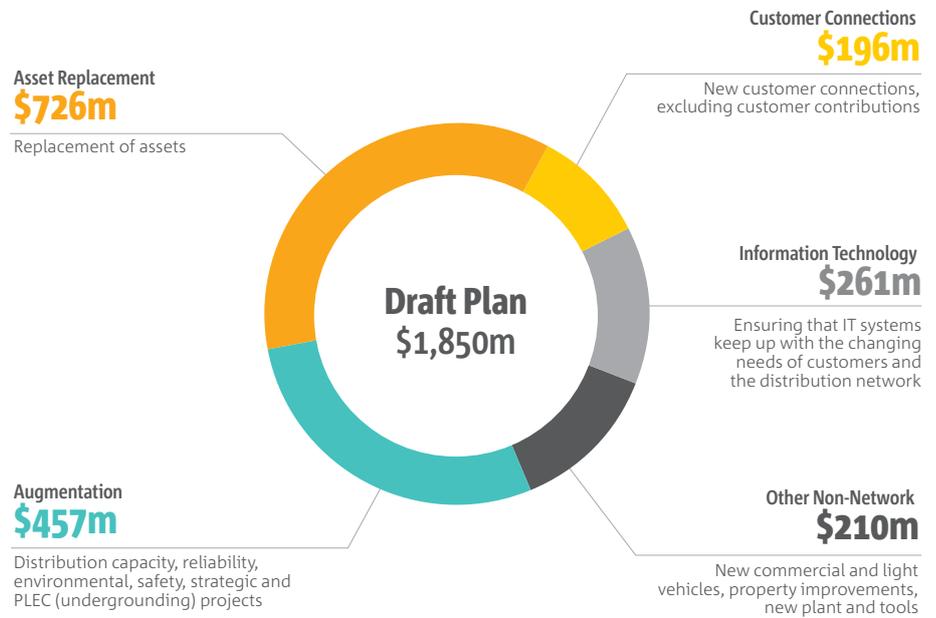


Figure 6.1: Capital expenditure for the 2020–2025 regulatory period by category

Table 6.1: Capital expenditure summary for the 2015–2020 and 2020–2025 periods

Expenditure category (all values in \$ million)	Expenditure actual/forecast 2015–2020	Preliminary plan (Nov 2017) 2020–2025	Draft Plan 2020–2025	Change from preliminary plan	What has changed from the Preliminary plan?
<b>Replacement</b>	<b>614</b>	<b>775</b>	<b>726</b>	<b>(49)</b>	<ul style="list-style-type: none"> <li>› Refinement of Repex modelling inputs to develop a forecast that represents only the amount we need to meet our obligations</li> </ul>
Powerline overhead		406	402	(4)	
Powerline underground		112	73	(39)	
Substation		152	142	(10)	
Other		37	37	0	
Safety		68	72	4	
<b>Augmentation</b>	<b>453</b>	<b>528</b>	<b>457</b>	<b>(71)</b>	<ul style="list-style-type: none"> <li>› Deferred some augmentation projects due to overall lower state demand than previously forecast, this enables the consideration of non-network solutions in the future</li> <li>› Reduced expenditure for developing an operational model of the LV network</li> <li>› Developed a more efficient approach to obtain visibility of our LV network</li> <li>› Removed the Ceduna alternative power supply project as this is subject to the ESCoSA service standards review</li> <li>› Extended the protection compliance program from 10 to 15 years</li> </ul>
Capacity	255	174	168	(6)	
Strategic	62	88	68	(20)	
Reliability	36	93	73	(20)	
Safety	45	107	83	(24)	
Environmental	10	10	10	0	
PLEC	45	56	55	(1)	
<b>Connections (Net)</b>	<b>167</b>	<b>164</b>	<b>196</b>	<b>32</b>	<ul style="list-style-type: none"> <li>› Increased to reflect the most recent economic outlook that includes an uplift in localised major customer connections compared to our preliminary plan</li> </ul>
Gross expenditure	489	500	589	89	
Customer contribution	(322)	(336)	(393)	(57)	
<b>Non-network</b>	<b>479</b>	<b>474</b>	<b>471</b>	<b>(3)</b>	<ul style="list-style-type: none"> <li>› Maintain a business as usual approach</li> </ul>
IT	313	263	261	(2)	
Fleet	92	108	108	0	
Property	51	76	76	0	
Telecomms	2	8	8	0	
Plant and tools	21	19	19	0	
<b>Total*</b>	<b>1,713</b>	<b>1940</b>	<b>1850</b>	<b>(90)</b>	

\* Totals may not add up due to rounding

## 2015–2020 expenditure performance

**With our continued focus on only spending on what is necessary we have achieved a reduction in planned spend of \$367 million in 2015–2020.**

The primary reasons for this are:

- › actively deferring some work programs, in particular asset replacement work. This was achieved by a change in our approach to managing risk (refer to Valuing and Visibility approach on page 41);
- › the development of additional methods to defer the high cost of replacement, eg by refurbishing mechanical reclosers and re-plating stobie poles that had previously been plated;
- › actual customer demand being lower than forecast, which allowed prudent deferral of a number of augmentation (substation and sub-transmission) projects; and
- › lower than forecast costs for the Kangaroo Island cable project following a competitive tender process and prudent reduction in capacity of the undersea cable due to lower customer demand.

While we are obligated to meet service levels and manage risk appropriately, we are also encouraged by the AER's capital expenditure sharing scheme (CESS) to improve efficiency of our capital expenditure and to prudently defer expenditure where circumstances permit. Our prudent lower expenditure of the capex allowance in 2015–2020 of \$367 million<sup>12</sup> will result in a lower regulated asset base (RAB) and lower prices to customers in 2020–2025 and later periods. The AER's CESS scheme ensures that 70% of the reduction in capex is returned to the customers over the life of the proposed assets. The reduction in capex in 2015–2020 equates to around \$280 million of savings to customers when calculated using the AER's CESS model.

## Replacement

**\$726 million**

Asset replacement (repex), comprises around 40% of the total capital expenditure forecast. This expenditure is necessary to maintain the current service levels and achieve an appropriate asset risk profile. The expenditure addresses an increasing number of asset defects occurring due to age, use and environmental conditions. It is based on rigorous modelling and methodologies.

Figure 6.2 compares the average asset age of distribution businesses and shows we have the oldest electricity network in the NEM.

Many assets were built in the 1950s, 1960s and early 1970s. The age profile reflects our asset management practice to repair and refurbish assets to extend their useful life wherever it is cost-effective, rather than replace them with new, more expensive assets. Figure 6.3 shows when the majority of the current assets were installed, and where we have invested in new assets in recent years.

Other distribution businesses in the NEM have had a more significant investment period during 2005–2012, whereas our investment has been low in comparison. This has resulted in our RAB growing at a much lower rate (1%) compared to other distributors (an average of 5%) over the 2006–17 period (Figure 6.4).<sup>13</sup>

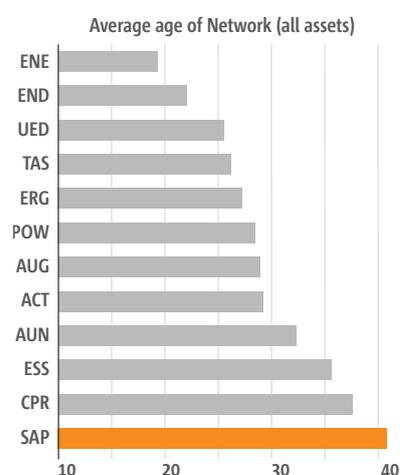


Figure 6.2: Distribution network service providers aged asset profile<sup>14</sup>

To continue to keep overall costs down and continually improve, we have evolved our asset management practices. Initially we replaced assets on failure. We then inspected the condition of our assets and prioritised their replacement based on condition. Next, we adopted a risk based replacement approach. Currently we have evolved to use a more refined and economic 'value-based replacement' approach.

Where cost-effective, we will extend asset life by refurbishing rather than replacing new assets. This is an efficient way to manage the ageing asset base.

We are also encouraged through the CESS and the Demand Management Incentive Scheme (DMIS) to adopt non-network alternatives where possible. Such alternatives may be feasible for large network projects. However, the majority of asset replacement involves like-for-like replacement of individual network components (poles, conductors, transformers, and switchgear) as we are yet to find suitable non-network alternatives.

<sup>12</sup> Based on the actual/forecast expenditure for the 2015–2020 period

<sup>13</sup> Source: AER Distribution Economic Benchmarking data and roll forward models

<sup>14</sup> Analysis of distribution businesses data published by the AER

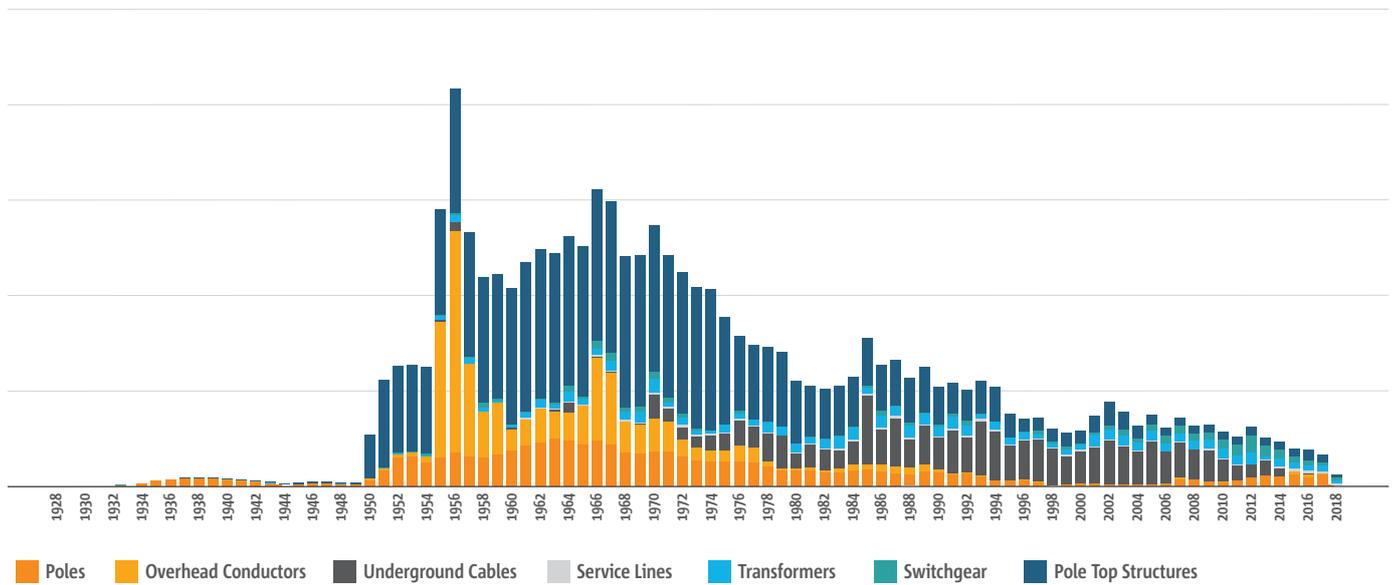


Figure 6.3: SA Power Networks asset investment profile

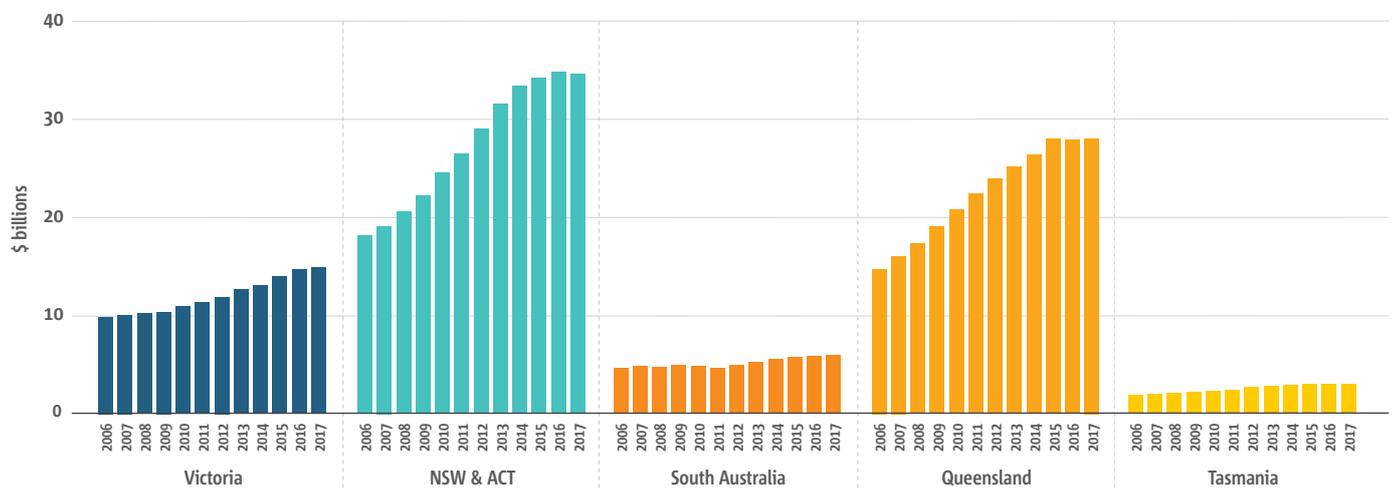


Figure 6.4: Regulatory asset base from 2006 to 2017, by NEM region, real \$2016/17<sup>15</sup>

15 ACCC, *Restoring electricity affordability and Australia's competitive advantage Retail Electricity Pricing Inquiry – Final Report*, June 2018 (Page ix)

**Expenditure profiles**

Figure 6.5 shows our past, current and forecast repex allowance and spending profiles.

**Previous period expenditure**

From 2010, we increased our inspection program across the entire network and introduced more rigour in the way we inspect assets and collect asset data. This enabled us to develop a comprehensive database on the condition of all network asset components.

Our inspections found more age-related defects than anticipated and in the 2010-2015 period we spent more than the AER allowance for repex to correct these defects.

**Current period expenditure**

In 2014 we agreed with the Office of the Technical Regulator (OTR) and ESCoSA to address and rectify outstanding defects using a risk-based approach — with the objective to return overall asset condition and risk to more satisfactory levels over a 10 year period (2015–2025). The teal line in Figure 6.6, shows the forecast risk level in 2014 at the time of our last Regulatory Proposal to the AER (for the 2015–2020 period), consistent with OTR expectations. The risk is expressed in terms of Maintenance Risk Value (MRV) which measures the condition of an asset and its criticality on the network. The orange line represents the MRV risk trajectory with repex maintained at the current levels allowed by the AER.

However, it has become evident that the actual level of risk on our network is far greater than we forecast in 2014, and this is shown by the grey line in Figure 6.6. This is because our inspections focused initially on Bushfire Risk Areas which are patrolled annually, and we have since found a higher volume of defects than initially forecast in Non-Bushfire Risk Areas.

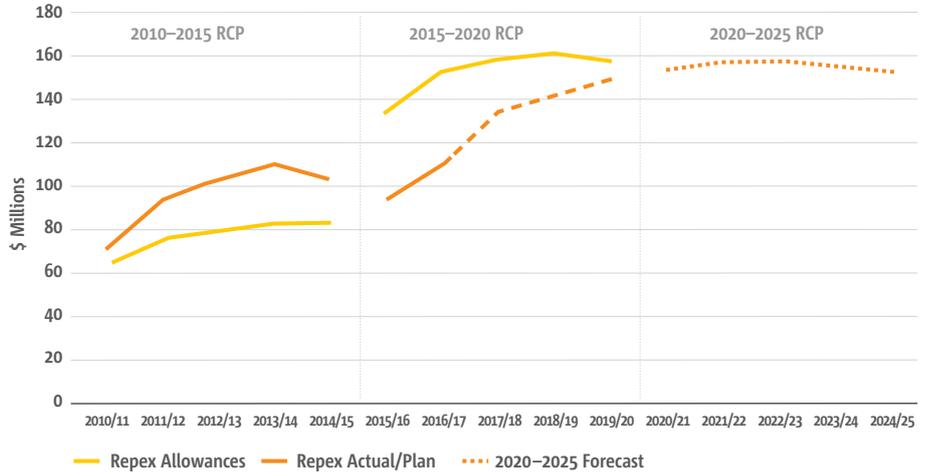


Figure 6.5: SA Power Networks replacement regulatory allowance and actual spend

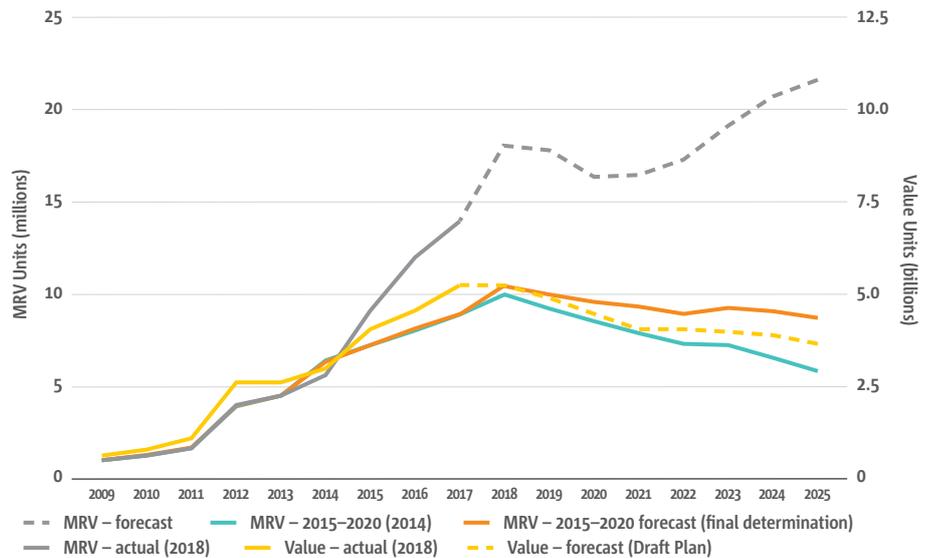


Figure 6.6: Network asset risk profile in Maintenance Risk Value and Value

We increased our resources to manage the larger volume of defects being identified. Under the MRV approach, the forecast expenditure required in 2020–2025 to address these defects and return network risk to levels expected by the OTR is \$920 million. However, in the first part of the 2015–2020 period, we developed a new approach to remove risk more prudently and efficiently. This ‘Valuing and Visibility’ approach was implemented in 2017 and allows us to:

1. More accurately identify and quantify the value of risk associated with an asset defect — calculate the return on investment for rectifying a defect by assessing a wider range of risk parameters (eg bushfire risk, safety, environment, customer value, compliance risks, expenditures, probabilities and consequences of failures); and
2. Employ new work planning approaches using geographic information systems to make all work visible to work planners so they can efficiently bundle work programs in similar geographic areas. This will avoid costs, such as fewer truck visits and fewer labour hours employed and reduce the number of planned outages customers would experience due to bundling of works.

By using our Valuing and Visibility approach (supported by our IT Assets and Works Program, see page 45), we will return risk to the levels expected by the OTR at a significantly lower cost than under our previous asset management approach — we now forecast we will spend \$726 million over 2020–2025 rather than \$920 million.

To further minimise repex costs we have extended our asset refurbishment and life extension programs where possible.

For example, many of our ageing stobie poles are corroded at ground level. In these situations it is more cost-effective to bridge the gap between sound portions of steel by ‘pole-plating’<sup>16</sup> and extend the pole’s life rather than replacing the whole pole. Pole refurbishment is very efficient. It only costs 15% of pole replacement costs and can extend pole life by up to 50%. Customers benefit from this efficiency. In 2017 we refurbished around 5,300 poles at an average cost of \$1,270 each. The average pole replacement costs \$10,000 — this saved \$46 million in capital expenditure.

During 2015–2020 we extended the pole plating program to re-plate poles that had been plated previously — resulting in further savings. We also undertook other refurbishment programs, such as refurbishing mechanical reclosers.

Customers and stakeholders supported these more efficient approaches.

By the end of 2018 we will have completed the full cycle of asset inspections as agreed with the OTR and ESCoSA. This will provide the data we need to plan for the efficient replacement or refurbishment of assets into the future.

### 2020–2025 Repex proposal

Our replacement expenditure program for the 2020–2025 period is based on more accurate information and improved modelling techniques. We have established the systems and trained additional field staff to ensure the program is delivered efficiently.

Our 2020–2025 Draft Plan builds on the efficiency and productivity gains made in the current period. To make sure we do not always replace all assets like-for-like, we:

- › refurbish rather than replace assets where it is efficient to do so;
- › consider customers’ future energy needs and install appropriate assets to fit into longer term plans; and
- › consider all viable demand management and non-network alternative options.

Our ageing asset base means that ongoing investment is essential to maintain regulated safety and service levels. Failure to invest sufficiently in the network will ultimately lead to unacceptable safety and service level outcomes — and lead to higher expenditure in the future.

Our customers have said it is important to keep prices down, but that it is equally important that we don’t leave a cost burden for future generations. Our 2020–2025 repex program appropriately balances these aims.

<sup>16</sup> Pole-plating involves partial excavation of the pole base and welding steel plates across the corroded sections

## Augmentation

### \$457 million

#### Overall augex

Augmentation expenditure (augex) relates to the expenses we incur to provide network capacity and meet quality of supply requirements.

These requirements are driven by:

- › regulatory obligations and service standards to maintain a safe and reliable network;
- › customer driven changes (such as growth in demand or take-up of solar systems);
- › environmental factors (such as climate or changes in standards); and
- › risk management.

We plan for these changes and implement solutions ‘just in time’ to ensure augmentation work is delivered efficiently and seamlessly.

Our augmentation expenditure is made up of several categories:

- › Capacity driven augmentation
- › Strategic programs
- › Reliability
- › Safety
- › Environmental
- › PLEC

#### Comparison of augex

A comparison of our historical augex, our forecast for the remainder of the current period, and our forecast for the next period is set out in Figure 6.7.

Our expenditure was lower than our allowance in the first two years of this period but we are on track to meet our allowance for the remainder of the current period (Figure 6.7). Customers share in the savings in the early years.

Our total augex forecast for 2020–2025 responds to changing requirements.

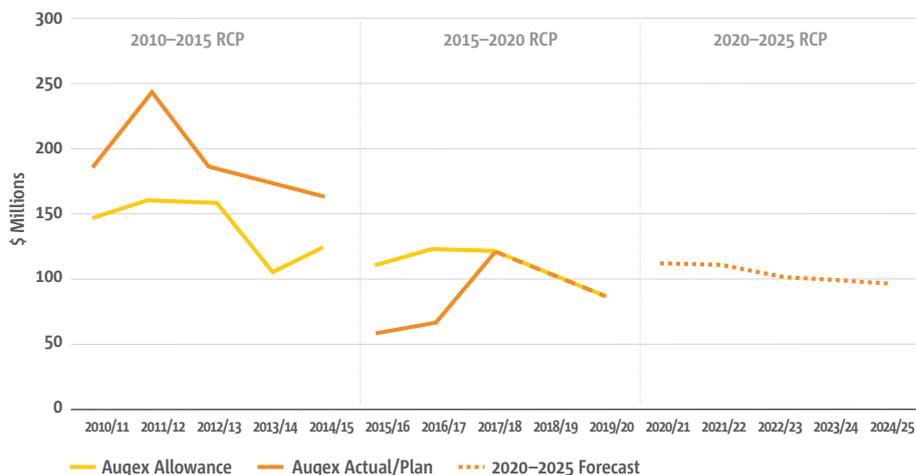


Figure 6.7: SA Power Networks augmentation regulatory allowance and actual spend

#### Capacity

AEMO’s 2017 South Australian electricity demand forecasts predict that the net summer demand (after solar and batteries) will decrease at an annual average rate of 1% over 2020–2025, as traditional drivers of peak demand growth (summer air-conditioning load) continue to be offset by solar; increasingly efficient appliances and housing stock; and slow economic growth.

Correspondingly, we forecast a continued reduction in our capacity-driven augmentation capital expenditure for 2020–2025.

Notwithstanding this reduction in peak demand at the overall system level, there are still geographic pockets of customer demand growth in newer suburbs like Munno Para, Gawler East and Mt Barker West as well as in higher density developments of older areas like St Clair and Bowden.

The AER’s regulatory investment test for distribution (RIT-D) process requires us to engage with the market to seek non-network alternatives prior to undertaking any large capital investment in network assets. Gawler East, which requires a new zone substation, falls into this category. The use of non-network solutions is also encouraged more broadly through the Demand Management Incentive Scheme (DMIS).

In 2020–2025 we will also seek to procure non-network alternatives for lower-value projects that fall below the RIT-D

threshold. We are looking to pilot this process with an initial approach to market later in 2018. Our initial assessment of network augmentation projects planned for the 2020–2025 period has identified projects worth around \$28 million that are candidates for a non-network solution.

Capacity related augex is also required to manage our quality of supply obligations. Some customers are experiencing technical supply issues with voltage instability and spikes exceeding the standards as the number of solar systems on our network increases. Our current practice is to manage these issues reactively. After receiving information from customers about quality of supply concerns, we undertake field investigations, install temporary voltage monitoring devices and then determine the best way to fix the problem.

We have started a program to proactively monitor our low voltage network and we have targeted areas with high solar penetration. Low voltage monitoring helps us to collect better information on how the network is performing. This will improve network planning and operation and defer large augmentation remediation works.

We plan to spend \$19 million over the five years to 2025 to help more customers connect and export energy from their solar and battery systems so they can realise the full benefits of their investment while maintaining a safe and reliable quality of supply.

## Strategic

As discussed in Section 5, South Australia is leading the nation with the installation of customer solar systems.

We are proposing a \$37 million program during 2020–2025 to develop:

- › an operational model of the LV network;
- › a DER database; and
- › dynamic export limits.

We will also spend \$31 million on network control related expenditure including:

- › continuation of the Supervisory Control and Data Acquisition (SCADA) rollout to country substations;
- › hardware and software upgrades for the Advanced Distribution Management System (ADMS) and the Outage Management System (OMS).

## Reliability

We need to maintain a reliable network to meet our prescribed service standards, and to meet our customers' expectations. We will spend \$37 million on measures that will maintain our underlying<sup>17</sup> reliability performance standards to 2025.

In 2015 we commenced a 10-year program to 'harden the network' and reduce the impact of major storms on customers in storm prone areas. We have included \$17 million to finalise this program during 2020–2025. When this program is completed we will have reduced outage durations for 73,000 customers by two hours per annum.

We are also planning to improve the service levels for 19,000 of our poorly served customers. We propose \$19 million to improve the reliability of poor performing powerlines and reduce total average outage times by three hours per year for customers who are serviced by these powerlines. Both these programs do not impact underlying reliability performance.

## Safety

We actively monitor the safety of our network and will continue work programs to maintain the network's safety and manage risks to our customers, employees, contractors and the wider community.

Forecast expenditure is based on our historic expenditure levels and specific programs that arise due to a change in our obligations or risk.

This period we plan to continue our bushfire mitigation program and our protection equipment compliance program.

The effect of fires in High Bushfire Risk Areas (HBFRA) can be catastrophic for our customers and with extreme weather events increasing, we need to manage this risk.

The bushfire mitigation program includes replacing some outdated network components and installing fast operating switches to reduce the risk of fires starting in HBFRA.

We began the mitigation program in the current period and spoke to our customers about continuing the program during the customer engagement process. Our customers supported the program provided that the benefits to the community exceed the costs.

Further to our \$16 million program in the current 2015–2020 period, we propose an expenditure of \$19 million in the 2020–2025 period to continue to reduce bushfire risk. Preliminary modelling results indicate significant community benefits will accrue from reduced bushfire start risk. Specifically, the results indicate that a \$35 million capital investment (ie \$16 million in 2015–2020 and \$19 million in 2020–2025) will reduce bushfire risk by approximately \$62 million over the life of the assets, and will provide a significant net benefit to the community.

Extensive wind and solar generation sources have resulted in greater instability of the high voltage (HV) electricity network.

The metropolitan HV compliance program is a new program that addresses vulnerabilities in the HV protection systems that have become unacceptable.

We also have parts of our network in rural areas where the back-up protection is no longer compliant with the current rules. Therefore, additional protection equipment must be installed in these areas to ensure the safety of customers' supply.

In our preliminary plan we proposed to complete these protection programs by 2025 at a cost of \$48 million. In order to manage the price impact on our customers, we have reprioritised these programs and will now complete them over a longer period, by 2030. In this Draft Plan we have included \$24 million for protection compliance during 2020–2025 and deferred \$24 million of expenditure to the subsequent period.

<sup>17</sup> Underlying reliability excludes supply outages that occurred during a Major Event Day (MED), ie. widespread outages that occurred during major storms

## Environmental

Ongoing environmental capital expenditure is required to comply with current Environmental Protection Authority (EPA) legislation requirements and helps us manage environmental risks, primarily oil containment in substations.

Our plans reduce the risk of substation transformer oil leakage in the community. This is a continuation of a long-term program that commenced when the EPA's Bunding and Spill Management Guideline came into effect.

It is costly to install oil containment equipment in existing substations so we have chosen to manage the highest risks first within the constraints of affordability. Oil containment equipment will be installed in all high and medium risk sites by 2025.

The \$10 million expenditure in the 2020–2025 period is consistent with expenditure in the current period.

### Power Line Environment Committee

The Power Line Environment Committee (PLEC) operates under a charter assigned by the Minister, and focuses on strategic undergrounding of powerline infrastructure. PLEC coordinates these projects and the costs are shared with state and local governments. This is a legislated requirement which sets the amount of expenditure — \$55 million for the 2020–2025 period. PLEC benefits customers through safety and aesthetic improvements to cultural, heritage and tourist regions.

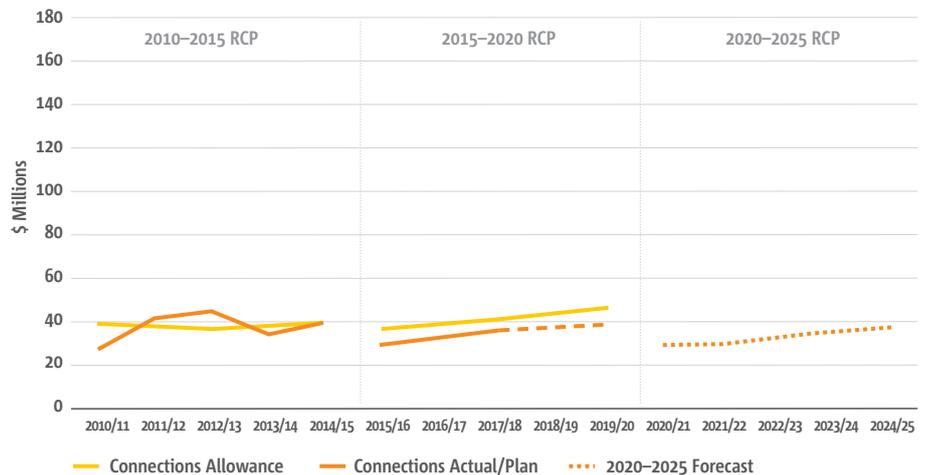


Figure 6.8: SA Power Networks connections regulatory allowance and actual spend

## Connections \$196 million

Connections expenditure is incurred to connect new customers or upgrade the connections of existing customers on our network. The cost of customer connections is partially offset by customer contributions.

The National Electricity Rules require a customer to contribute to connection costs. This provides a pricing signal to allow the customer to consider the locations and the associated costs of their connections. It also reduces cross subsidisation from other customers.

Our 2020–2025 Connections Policy will be submitted to the AER for approval. We are not proposing any material changes from our current policy.

The forecast for this expenditure category is driven by new and existing customer growth — a function of economic conditions in the state and underlying confidence in the economy.

The expenditure was slightly above allowance for the previous 2010–2015 period (Figure 6.8) and slightly below the allowance for the current 2015–2020 period (due to lower than forecast economic growth).

The connections expenditure forecast is the net connections expenditure incurred by SA Power Networks. That is, expenditure after customer contributions. We expect the forecast connections expenditure for 2020–2025 to closely follow the expenditure of the current period.

We engaged an independent economics forecasting consultant to help us develop our forecast. They advised us on the economy's expected growth; in particular the components of the economy that translate to new and upgraded connections. This gave us the best possible idea of our connection commitments for the next five years.

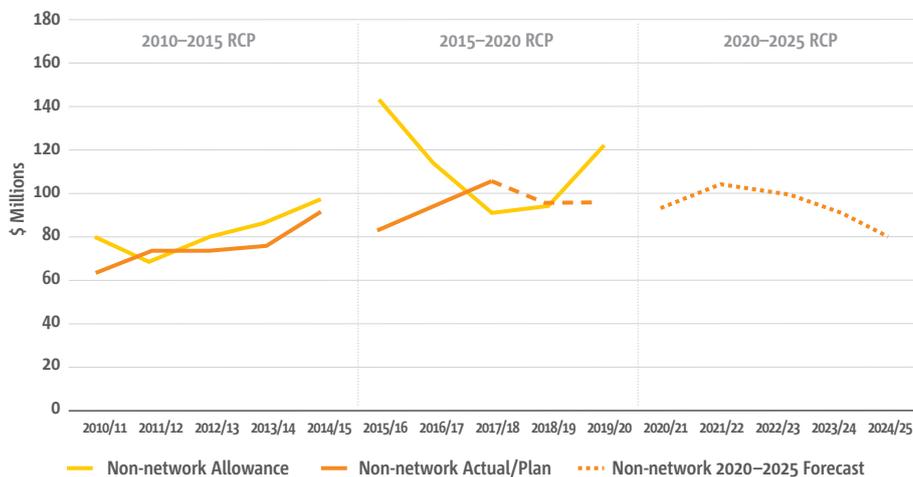


Figure 6.9: SA Power Networks non-network regulatory allowance and actual spend

## Non-network \$471 million

Non-network capital expenditure includes expenditure for:

- › information technology;
- › fleet (vehicles);
- › property;
- › communications; and
- › other.

Figure 6.9 shows the trend of our non-network expenditure.

We spent less than anticipated on non-network expenses in the current period. This is largely due to the standardisation of our fleet vehicles; a highly competitive fleet market; and the deferral of some property projects (until we have greater clarity and certainty on the future use and function of some properties).

## Information Technology \$261 million

Our IT systems are fundamental to enabling the provision of energy services to customers. They capture electricity usage data and are used for billing retailers and customers; enable new customer connections; assist with the management of our network assets, schedule people and resources to deliver energy services; and provide administrative functions across the entire business.

They provide information to customers through Power@MyPlace™ and our outage map applications. They allow customers to report faults and street lights that are not working and help us to interact with customers and electrical contractors on new connections and land developments.

Our IT systems improve the efficiency of capital expenditure and energy service delivery as they allow us to collect information on and understand our millions of network assets such as their age and condition and how the performance of the network asset affects our customers. This helps us to manage network reliability and risk while avoiding unnecessary network replacement, efficiently respond to a rapidly changing environment and provide the level of services that customers demand.

We also gain an understanding of how our customers are using the network (eg solar installations) and the impact of this use on the network. Our improved data and technology have allowed us to forecast a replex expenditure \$200 million lower than it would have been had we used our preceding methodologies.

### 2015–2020 performance

Over the 2015–2020 regulatory period we focused on providing cost effective IT services whilst business and customer needs rapidly evolved.

The biennial KPMG survey<sup>18</sup> consistently shows that SA Power Networks' IT is one of the lowest cost — often the lowest cost — of Australian distribution businesses.

During 2015–2020 we will have successfully delivered a large IT program of works, including:

- › substantially completing the replacement of our obsolete customer and billing systems and enabled improved outcomes for customers aligned with Power of Choice reforms;
- › modifying systems to meet regulatory obligations for metering contestability, customer access to data and regulatory reporting;
- › progressing our Asset and Works management improvement journey to enable us to efficiently manage the increasing risks associated with an ageing network. This will help us to manage network reliability and risk without significantly increasing replacement capex (\$200 million efficient deferral and cost reduction);
- › remediating and replacing more systems than planned (including our Outage Management System) to satisfy increased customer demand for timely and accurate information;
- › developing an enterprise information security capability in response to the increasing prevalence and sophistication of cyber security threats; and
- › initiating SAP as our core enterprise platform for most new capabilities, to help simplify our complex applications environment.

18 KPMG, KPMG Utilities IT Benchmarking – SA Power Networks – March 2018 (with updates June 2018)

We delivered IT services more cost effectively by:

- › implementing a new IT operating model to improve operational performance and respond to variations in demand and skills required across projects;
- › embedding 'LEAN' and 'AGILE' as standard methods in our work;
- › implementing an improved organisation-wide investment governance process; and
- › starting to move to cloud technologies so we can respond to the needs of the business in the most cost-efficient manner.

#### **Customers and businesses increasingly demand and depend on IT systems**

Managing the transition to a distributed energy future is presenting significant challenges for the management of our network (see Section 5). IT systems are replacing traditional technologies to manage our operational networks. They will allow us to better predict and proactively manage emerging issues, and it means our customers can continue to connect solar and new technologies to the network and realise the benefits of their investment.

The numerous and widespread power supply outages of 2016 raised customer expectations for timely and accurate information so that they could make more informed decisions. Our data is becoming more accurate and our systems are becoming smarter, so we can offer more responsive and better-quality communications to customers.

#### **2020–2025 IT proposal**

We are proposing a smaller program of work (\$261 million) during 2020–2025 than in the current period (\$313 million). This will ensure we can continue business as usual and manage the following challenges.

#### **We must maintain reliable, secure and responsive IT systems**

Core systems must continue to be updated and patched to ensure they are reliable, secure and maintain our current levels of service. We depend on these systems to deliver energy services to customers and support critical business activities that are increasingly facing new evolving adverse cyber security threats.

Key systems which will need a major upgrade or will need to be replaced, include our core enterprise business system SAP and our Geospatial Information System (GIS).

#### **We must continue to manage IT costs while meeting evolving customer needs**

Increasingly, technology is expected to enable efficiencies in the delivery of energy services. Our customers have indicated that they would like us to use technology to effectively manage the network, specifically customers have asked us to:

- › improve reliability in poor performing areas;
- › make prudent investments to enable us to keep electricity prices down;
- › enable the energy transition with appropriate preparation;
- › balance current network investment with future uncertainty;
- › provide accurate, reliable and timely outage communication; and
- › improve outcomes in vegetation management.

We will respond to these needs with an appropriate level of IT expenditure.

Through our customer engagement program our customers and stakeholders told us they wanted to understand the value of IT expenditure. The value of IT expenditure is in the benefits and customer outcomes the investment provides. IT investment is only undertaken after appropriate cost benefit analysis is conducted to ensure the expenditure is of value.

This prudent approach is fundamental to us continuing to deliver improved customer outcomes and efficiencies across the business over the next five years.

Furthermore, the demand for IT services is continuing to grow as our organisation uses technology to manage workloads and deliver customer services more efficiently.

#### **We must continue to meet our regulatory and legal obligations**

To better manage cyber security threats, the Australian Government Critical Infrastructure Centre best practice guidelines now place restrictions on our ability to source support from overseas. We need to return that support back onshore but this comes at a higher cost.

There are also new requirements to comply with the AEMC's five-minute settlement rule change. This will multiply the amount of interval meter data we need to manage six-fold.

Some of the outcomes from our IT expenditure include:

- › improving our understanding of our asset data in areas of the network where customers are experiencing poor performance to enable appropriate solutions to be designed and delivered;
- › optimising our service delivery model through improvements in planning and scheduling of work to ensure we are delivering the work that is of the highest value to customers;
- › increasing the use of mobile technologies for field crews so that they can manage jobs and crews more efficiently and reduce response times for customers;
- › improving cyber security to reduce the potential for significant disruptions to customers from attacks on our network and to meet requirements imposed by the new *Security of Critical Infrastructure Act 2017 (Cth)*; and
- › replacing or upgrading computer systems before vendor support on older systems is withdrawn.

## Fleet

### \$108 million

We maintain a pool of specialised vehicles that provide a safe and efficient work environment for our field crews. These vehicles enable them to work at heights and on energised components of the network to reduce customer power outages and restore power quickly and safely.

Our field employees respond to damaged equipment brought down by storms, fallen trees, vehicles and other events. With over 82,000km of powerlines, more than 77,800 street transformers, and a service area of 178,000km<sup>2</sup>, we need a fleet that can reach all of the assets that service our customers — often under harsh physical and environmental conditions.

Our fleet includes elevated work platforms (EWPs), excavators, borers and cranes; light trucks and passenger vehicles.

Fleet expenditure is incurred as we replace assets on a cyclical nature, based on their age and condition. As the fleet ages, maintenance costs increase as do the risks associated with performance. Our fleet has an average life of approximately 10 years, so almost half of the fleet needs to be replaced in each five-year regulatory period.

We have standardised fleet specifications and have managed to achieve a lower overall fleet cost in the 2015–2020 period; this is also reflected in our unit cost forecasts for the next period.

Our forecasts vary from period to period due to the cyclical nature of replacements (Figure 6.10).

We are proposing to spend \$108 million on fleet expenditure during 2020–2025.

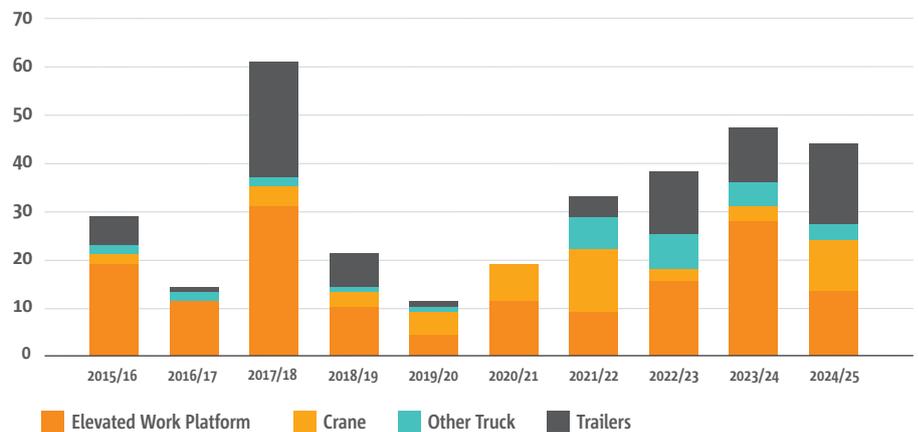


Figure 6.10: SA Power Networks commercial and heavy vehicle replacements

## Property

### \$76 million

In order to support our electricity network, we need property for offices, depots, warehousing, training, and servicing equipment. We need to maintain the property in accordance with current building regulations and safe and secure work practices.

Our depots house the vehicle fleet when not in the field. They contain the servicing equipment that keeps the network going and they hold the materials (such as cable, transformers, poles, insulators) that allow us to repair the network following an outage; expand the network; replace worn components; and make new connections.

We need these materials and vehicles distributed around the network to make sure that we can respond to any operational and maintenance needs quickly to meet service standards. We have 42 sites in metropolitan and regional areas.

Within our property portfolio we have the following property types:

- › commercial;
- › industrial;
- › metropolitan depots; and
- › regional depots.

There is also a small component of land and easement expenditure.

We are proposing to spend \$76 million on property during 2020–2025.

## Telecommunications

### \$8 million

We spend money to maintain and manage our telecommunications network. This allows us to remotely operate parts of the network, monitor load and condition, and capture data from more than 400 zone substations.

The communications network allows us to dispatch crews to investigate and rectify the faults identified by our systems and by our customers. These communication systems help us schedule work efficiently and respond dynamically to new customer information, while maintaining a safe work environment for our people in the field.

We are proposing to spend \$8 million on communications during 2020–2025.

## Plant and tools

### \$19 million

Minor plant and tools support our field and workshop staff to install, maintain and repair the electricity network.

We plan to spend \$19 million on plant and tools during 2020–2025. This is the same level of expenditure as in the current period.

## Capex Summary

Key capex work programs for the 2020–2025 regulatory period are summarised in Table 6.2.

Table 6.2: Capital expenditure summary for the 2020–2025 period

Category	2020–2025 Forecast \$ million	Key work programs in 2020–2025
<b>Replacement</b>	<b>726</b>	<ul style="list-style-type: none"> <li>› Continue 10-year asset management program to maintain asset health by refurbishing and replacing aged and deteriorating network assets. For higher value assets, the forecast is based on actual asset condition information, rigorous modelling and risk assessments, and for lower value assets the forecast is based on historical trend analysis</li> </ul>
<b>Augmentation</b>	<b>457</b>	
Capacity	168	<ul style="list-style-type: none"> <li>› Reduced works program from the current period by \$106 million, reflecting subdued economic conditions and lower network demand</li> <li>› \$19 million low voltage network monitoring program to manage the impact of solar and battery systems</li> </ul>
Strategic	68	<ul style="list-style-type: none"> <li>› \$37 million new expenditure to transition to the network of the future (as outlined in Section 5)</li> <li>› \$31 million for network control related expenditure</li> </ul>
Reliability	73	<ul style="list-style-type: none"> <li>› \$37 million program to maintain average supply reliability levels to all customers</li> <li>› Continuation of a 10-year program to harden the network in storm prone areas reducing outages by two hours on average per annum for 73,000 customers — \$17 million</li> <li>› \$19 million program to improve reliability to 19,000 poorly served customers by three hours on average per annum</li> </ul>
Safety	83	<ul style="list-style-type: none"> <li>› Continuation of bushfire risk mitigation program — \$19 million</li> <li>› Continuation of protection equipment upgrade program to meet legislated requirements — \$24 million</li> <li>› \$40 million to continue upgrading substation infrastructure (fencing, lighting) to current standards and replacing unsafe/inoperable switchgear</li> </ul>
Environmental	10	<ul style="list-style-type: none"> <li>› Continuation of substation oil containment program and substation noise abatement</li> </ul>
PLEC	55	<ul style="list-style-type: none"> <li>› Legislated undergrounding program administered by ESCoSA</li> </ul>
<b>Connections</b>	<b>196</b>	<ul style="list-style-type: none"> <li>› Forecast expenditure reflects most recent independent economic outlook</li> </ul>

Category	2020–2025 Forecast \$ million	Key work programs in 2020–2025
<b>Non-network</b>	<b>471</b>	
IT	261	<ul style="list-style-type: none"> <li>› Recurrent \$201 million — manage and update (patch, upgrade/replace) existing software and hardware for: <ul style="list-style-type: none"> <li>- 80+ applications (\$75 million);</li> <li>- end user devices (\$24 million);</li> <li>- servers and operating infrastructure (\$30 million); and</li> <li>- IT management, cyber security tools and products (\$16 million).</li> </ul> </li> <li>› Specific large replacements: <ul style="list-style-type: none"> <li>- Complete the billing system replacement (\$13 million)</li> <li>- Upgrade SAP platform to enable continued vendor support (\$27 million)</li> <li>- Consolidation of GIS systems (\$14 million)</li> </ul> </li> <li>› Non-recurrent \$60 million: <ul style="list-style-type: none"> <li>- Continue Assets and Works program (\$48 million)</li> <li>- Modifications to systems for ring-fencing and five minute rule change compliance (\$11 million)</li> </ul> </li> </ul>
Fleet	108	› Ongoing cyclic replacement program of heavy and light vehicles
Property	76	› Ongoing property refurbishment program
Telecomms	8	› Manage and upgrade communications network
Plant and tools	19	› Support field staff to install, maintain, and repair equipment
<b>Total</b>	<b>1,850*</b>	

\* Totals may not add up due to rounding

## Feedback

What feedback do you have on our proposed capital expenditure program? We are particularly interested in your thoughts on our:

- › replacement expenditure program;
- › reliability expenditure, including our programs to improve reliability to storm-prone areas and poorly served customers;
- › capacity augmentation expenditure, including our low voltage network management program;
- › safety augmentation expenditure, including our bushfire mitigation program; and
- › our IT expenditure.

# Operating expenditure

Maintaining our operating expenditure at efficient levels.

## This section outlines:

- › the key components of our 2020–2025 operating expenditure forecast;
- › how we develop a total forecast using the AER’s ‘base-step-trend’ methodology; and
- › how we have reduced our forecast expenditure in response to customer and stakeholder feedback.





## 7 Operating expenditure

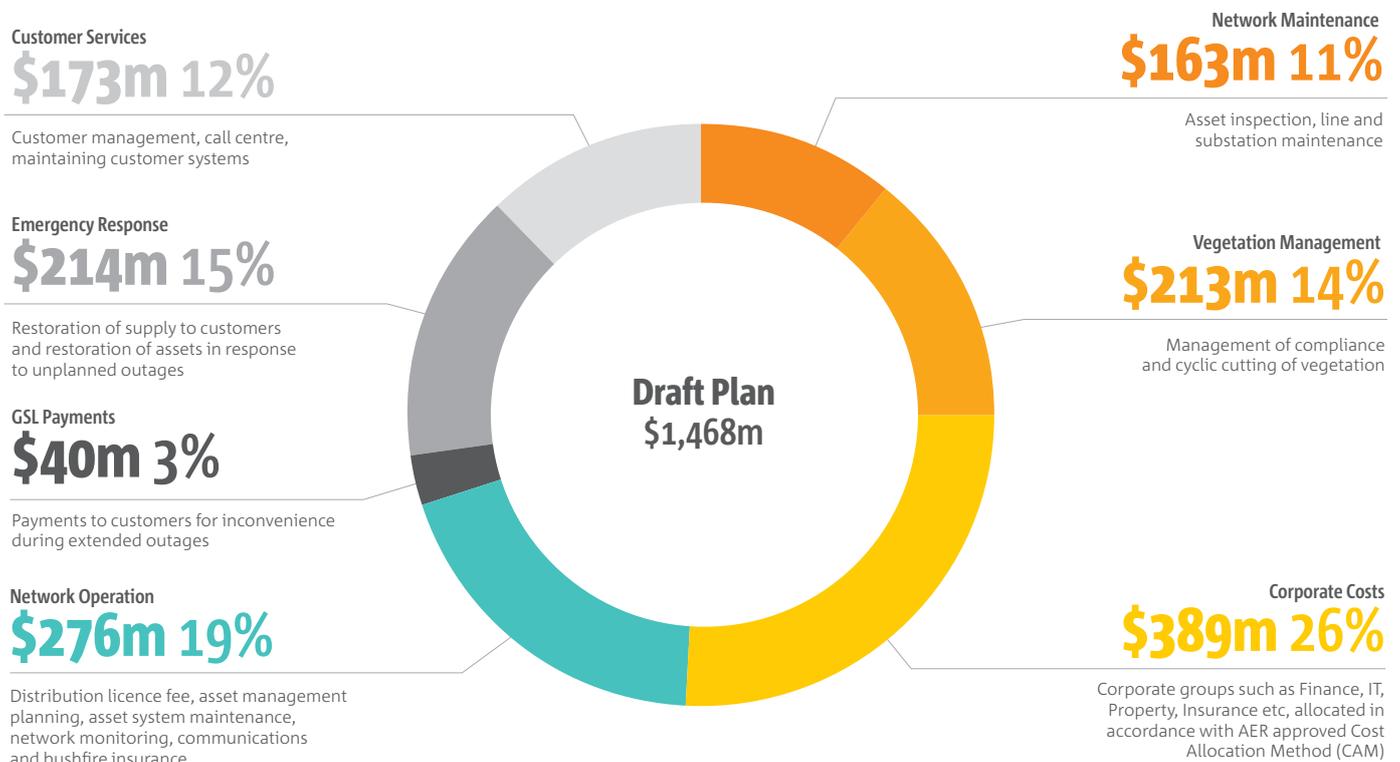


Figure 7.1: Opex expenditure for the 2020–2025 regulatory period by category

### Operating expenditure (opex) relates to money spent maintaining and operating the assets that make up and support the electricity distribution system.

At a high level, opex includes costs associated with:

- › operating the network, including network monitoring and asset management planning;
- › maintaining powerlines and substations to enable a safe and reliable distribution system;
- › managing vegetation around powerlines to mitigate bushfire risk and maintain reliability;
- › restoring supply for unplanned power outages caused by weather events, equipment failure or third-party damage;

- › guaranteed service level (GSL) inconvenience payments to customers when outages exceed the levels of service prescribed in ESCoSA's Service Standard Framework;
- › customer service costs; and
- › business support costs, including costs for corporate groups such as information technology, property management and financial services.

A summary of the opex components and their cost forecasts for the 2020–2025 regulatory period is contained in Figure 7.1.

Operating costs generally recur each year, but some programs are cyclical. For example, vegetation is cleared around powerlines over a three-year cycle in non-bushfire risk areas.

Additionally, costs may fluctuate from year to year because of severe weather events, which can directly affect emergency response costs and GSL inconvenience payments.

External factors also arise over time that can increase operating costs. For example, in the 2010–2015 regulatory period:

- › the breaking of the 'millennium drought' (2010) in South Australia led to substantially more vegetation growth which increased the volume of work required under our vegetation management program to meet our regulatory obligations;
- › an unprecedented take-up of solar system installations, largely driven by the State Government Feed-In Tariff, significantly increased administrative costs. It also increased the costs associated with investigating, managing and maintaining voltage levels within specified standards<sup>19</sup>; and
- › the volume and severity of extreme weather events increased, leading to higher emergency response costs and GSL inconvenience payments.

<sup>19</sup> The export of energy into the low voltage network at low load times can result in higher voltage levels which are outside the standard

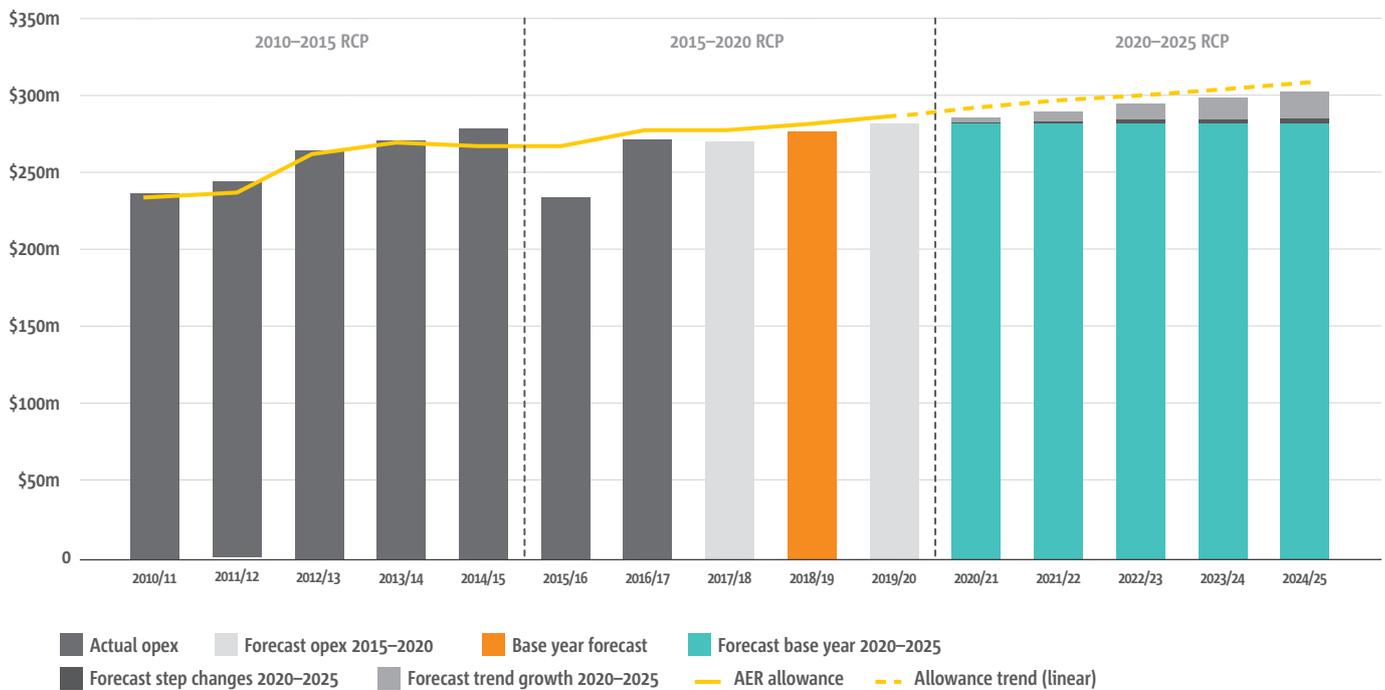


Figure 7.2: SA Power Networks historical and forecast operating expenditure

The AER prefers to forecast opex for each five-year period using a base-step-trend methodology.<sup>20</sup> This involves the distribution business nominating an efficient year. That is, a year where operating costs are considered to be representative of the normal costs associated with meeting the distribution network operator’s regulatory obligations and requirements (subject to adjustments for an one-off events or where base year costs are not representative of future costs).

The AER then uses its own assessment techniques to assess the efficiency of the proposed base year. If the base year is not efficient, the AER will determine an alternative forecast of the base opex.

‘Step’ changes may be added to the base opex for new, changed or removed non-discretionary or regulatory obligations or requirements that will result in the distribution business incurring increased (or decreased) costs during the period. Changes may also be made for any trade-offs that require additional opex which is offset by lower capital costs to achieve overall business efficiencies. A ‘trend’ rate of change will also be applied to account for changes in:

- › opex for forecast growth in outputs (eg circuit length, customers, demand);
- › real price growth of labour and non-labour inputs (eg materials); and
- › industry productivity and efficiency improvements.

Once opex allowances are set, the AER may apply its Efficiency Benefit Sharing Scheme (EBSS) to incentivise distribution businesses to find ongoing operating efficiencies and therefore incur less opex. Businesses that can maintain and operate the electricity network at a lower cost than their allowance (and still meet applicable service standards), may retain the benefit of the lower costs for five years. After this time the customers will gain through lower opex allowances in the subsequent regulatory period. Effectively, the EBSS allows distribution businesses to retain around 30% of the benefit of lower costs, with the remaining 70% passed back to customers.

SA Power Networks’ current operating expenditure forecast for the 2020–2025 regulatory period is \$1,468 million. This is \$49 million lower than the forecasts first discussed with customers and stakeholders earlier this year. These reductions are due to reductions in step changes and a lower labour price growth. Our historical and forecast operating expenditure is shown in Figure 7.2.

<sup>20</sup> AER, *Expenditure assessment guideline for electricity distribution*, November 2013, p22

In developing our opex forecast, we have:

- › considered our historical and current performance;
- › identified regulatory and environmental factors in the 2020–2025 regulatory period that will require changes to the current opex level; and
- › considered feedback from customers and stakeholders on preliminary plans that we shared with them earlier this year.

Expenditure for the 2010–2015 regulatory period was largely in line with allowances. Costs escalated over the period due to the external factors previously described.

In the current 2015–2020 regulatory period, our operating expenditure is forecast to be lower than our allowances in each year, the benefit of which will be passed on to customers as lower base year costs in the forthcoming 2020–2025 regulatory period.

2015/16 did not reflect a normal regulatory year, with abnormally low expenditure resulting from several factors. We reprioritised work programs and actively deferred some work programs while taking into consideration the AER’s draft decision (of April 2015). Vegetation management expenditure was also lower due to timing of the cutting cycle and there was a low incidence of extreme weather events.

Conversely, in 2016/17 extreme weather events were at a record high, with nine Major Event Days<sup>21</sup> recorded (compared to a historical average of three to four per year), which meant increasing costs to repair and reinstate the network. Additionally, more than \$25 million in GSL inconvenience payments were made to customers whose supply was interrupted as a result of weather-related system outages.

2017/18 had a low incidence of extreme weather days, resulting in lower emergency response costs and GSL payments.

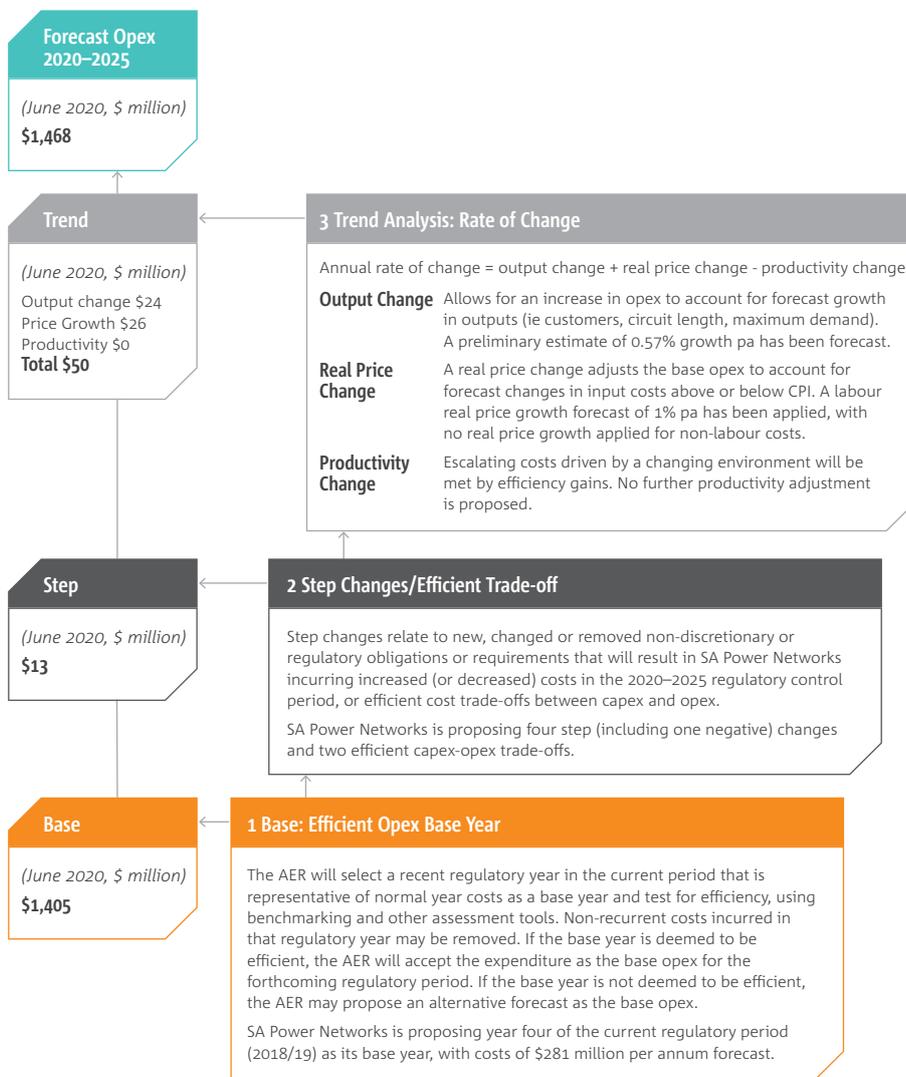


Figure 7.3 Opex base-step-trend methodology

SA Power Networks forecasts that operating expenditure will be sustained at levels lower than the AER’s regulatory allowances due to efficiencies delivered over the period. The last two years of the current regulatory period are forecast to be equivalent to 2017/18, but with a ‘normal’ year of GSL payments included<sup>22</sup>.

We have applied the AER’s preferred base-step-trend method to prepare our forecast for the 2020–2025 regulatory period (Figure 7.3).

21 Major Event Days (MEDs) are defined by the AER as extreme weather or events that interrupt power to a significant number of customers for extended periods  
22 Based on an average of payments for the first three years of the current regulatory period, which equates to regulatory allowances in total

We have nominated 2018/19 as our base year.

The base year must reflect a suitable foundation for the future period. We believe that 2018/19 best represents this as it:

- › will be the most recent year for which actual audited data will be available for the AER’s final decision;
- › will best reflect the costs required to efficiently maintain and operate the electricity network;
- › is forecast to be approximately two percent below our current regulatory allowances; and
- › incorporates efficiency gains that we will have achieved up to 30 June 2019.

Expenditure levels in earlier years of the current regulatory period do not adequately provide a base for the forthcoming period due to the atypical factors we highlighted earlier. Our revised Regulatory Proposal will be submitted to the AER in December 2019 and will incorporate actual expenditure for 2018/19.

One of the primary techniques the AER will use to assess the efficiency of our base year will be their benchmarking of SA Power Networks against other distribution businesses.

Benchmarking is a quantitative, or data driven, approach used to measure how productive (or efficient) firms are at producing outputs compared with their peers.

The AER releases an annual benchmarking report<sup>23</sup> to “provide consumers with useful information about the relative efficiency of the electricity networks”<sup>24</sup>. SA Power Networks consistently benchmarks in the top quartile of distribution businesses for a range of opex measures.

In the AER’s 2017 Annual Benchmarking Report, SA Power Networks ranked third in terms of Opex Multilateral Partial Factor Productivity (MPFP) for the 2016 regulatory year (Table 7.1).

Our opex MPFP declined during the 2010–2015 regulatory period, largely due to the increase in opex described earlier.

Despite the decline, SA Power Networks has remained in the upper quartile of distribution businesses in terms of opex efficiency. This decline in opex MPFP is similar to the industry trend, but has now stabilised, as our efficiency has increased in the past two years.

SA Power Networks continually strives to reduce opex and to improve benchmarked outcomes. We believe that our delivery of operating costs below our regulatory allowances while we continue to meet service standards in the current period, and our benchmarked position as an efficiency leader, confirms that our base year opex for 2020–2025 is efficient.

**Table 7.1: AER opex MPFP benchmarking 2016**

<b>Network</b>	<b>AER Ranking</b>
<b>Powercor (VIC)</b>	<b>1</b>
<b>CitiPower (VIC)</b>	<b>2</b>
<b>SA Power Networks</b>	<b>3</b>
<b>TasNetworks (TAS)</b>	<b>4</b>
<b>ActewAGL (ACT)</b>	<b>5</b>
<b>Energex (QLD)</b>	<b>6</b>
<b>United Energy (VIC)</b>	<b>7</b>
<b>Essential Energy (NSW)</b>	<b>8</b>
<b>Jemena (VIC)</b>	<b>9</b>
<b>Endeavour Energy (NSW)</b>	<b>10</b>
<b>AusNet Services (VIC)</b>	<b>11</b>
<b>Ergon Energy (QLD)</b>	<b>12</b>
<b>Ausgrid (NSW)</b>	<b>13</b>

We have added three material step changes to our base year expenditure for new or changed regulatory obligations that will require additional operating expenditure in the 2020–2025 regulatory period.

These relate to:

- › costs to support new ways for customers to get value from our network — by obtaining better visibility of new customer technologies and managing our low voltage network to ensure the quality and continued supply to all electricity customers;
- › costs to comply with new national critical infrastructure cyber security legislation; and
- › additional incremental software licence and cloud subscription costs associated with the replacement of the customer billing system.

A further material step-change has also been applied which will reduce opex for 2020–2025. The proposed change by EScOSA to cap GSL reliability duration payments to customers at a maximum annual level in the 2020–2025 regulatory period is expected to lower opex costs by \$22 million.

At our Future Networks deep dive workshop, stakeholders asked SA Power Networks to seek lower-cost alternatives to obtain visibility of new customer technologies. We have been actively exploring alternative technical approaches to enable dynamic export limits and now propose a simplified solution that will enable us to estimate performance impacts to an 80% degree of accuracy. This has reduced the forecast opex for this step change by more than 60%.

An additional step change to implement enhanced customer engagement technologies was removed from our Draft Plan on the advice of customers and stakeholders following our opex deep dive workshop.

We have also included two trade-offs to transition internally-capitalised IT infrastructure to externally-owned (cloud) systems. The trade-offs require additional opex to be incurred, but are offset by lower capital costs that will drive overall business efficiencies and reduce costs to customers.

23 [aer.gov.au/system/files/AER%202017%20distribution%20network%20service%20provider%20benchmarking%20report.pdf](http://aer.gov.au/system/files/AER%202017%20distribution%20network%20service%20provider%20benchmarking%20report.pdf)

24 AER, *Annual Benchmarking Report Electricity distribution network service providers, November 2017, page 22*

A summary of the proposed step changes and trade-offs is contained in Table 7.2.

Finally, we have applied trend increases for growth in the electricity network and real input price increases.

Our network growth is small as overall customer demand is forecast to decline, with only marginal increases in customers and powerline length for localised demand growth. We have applied the AER's preferred formula in determining network growth.

Customers and stakeholders did not support any increase above CPI for price inputs in our opex engagement workshop. We only accept this view for non-labour costs.

Electricity distributors operate in a dynamic industry to deliver services to customers. Much of the work is performed on or near energised assets in a high-risk environment, where safety to both the public and workers is of paramount importance.

A real labour price increase reflects the high skill levels, contribution to ongoing productivity improvement, and adaptability to technological change for workers in our industry. We have applied labour escalation costs based on an average of independent forecasts for the utility industry in South Australia, to reflect the real increase in costs that will be incurred. This is consistent with the AER's accepted approach.

The third factor in the trend calculation is productivity growth.

SA Power Networks, responding to the incentive-based regulatory framework, constantly strives to achieve efficiency gains. This is challenging in an environment where external factors drive increases in operating costs, including:

- › ageing assets;
- › increasing customer solar and battery enquiries and applications;
- › delivery of better quality information to customers;
- › higher aesthetic vegetation management expectations;
- › increasing safety and design standards;
- › climate change and increased frequency and severity of major storm events; and
- › more onerous regulations (eg traffic management restrictions).

In the current period we have also absorbed significant new costs associated with changes to regulatory obligations not provided for in current allowances, such as metering contestability, ring-fencing and distribution annual planning report rule changes.

In our engagement program earlier this year, customers and stakeholders sought to apply an additional productivity growth factor to reduce costs.

We do not support this approach as further productivity growth must represent industry-wide efficiency gains. As a leader in efficiency, it will be more difficult for SA Power Networks to achieve additional, across-the-board productivity gains than less efficient distribution businesses, and we will be penalised if we cannot meet those gains.

We have not applied any further productivity growth factor in our Draft Plan, but we will continue to strive to achieve further efficiencies to deliver on our operating obligations at a cost lower than our regulatory opex allowances and share those benefits with customers through the EBSS.

We will continue to explore ways to respond efficiently to any current or new drivers of our operating expenditure, through cost saving initiatives such as:

- › exploring further outsourcing opportunities to deliver lowest cost services;
- › continuing to improve work processes by adopting methodologies such as 'LEAN' and 'AGILE' programs to improve efficiency and minimise waste;
- › streamlining supply chain management activities to maximise value; and
- › continuing to implement technology and system improvements to improve work practices, reduce costs, defer capital projects where prudent, and reduce asset redundancy.

Through the EBSS, 70% of any savings realised from delivering services at a lower cost than the AER's allowance will be returned to customers.

## Summary

We have applied the AER's preferred base-step-trend process to develop an efficient and prudent opex forecast for the 2020–2025 regulatory period. We will continue to strive to reduce opex and improve our benchmarked outcomes by delivering operating costs below our regulatory allowances and continuing to meet service standards. This will deliver ongoing benefits to our electricity customers. We have considered feedback from our customer and stakeholder engagement workshops and have reduced our Draft Plan opex by almost \$50 million from that originally proposed.

In total, we are forecasting \$1,468 million for the 2020–2025 regulatory period to maintain and operate the electricity distribution network. This will enable us to continue to meet our regulatory obligations and maintain the quality, reliability, safety and security of its electricity supply and distribution network for South Australian electricity customers.

## Feedback

What feedback do you have on our proposed operating expenditure?

Table 7.2: Draft proposed step changes and trade-offs 2020–2025

Step change/ trade-off	Driver	Detail	Total (June 2020, \$ million)	Capex savings (June 2020, \$ million)	Customer engagement feedback
LV management future networks	Opex associated with new capex program driven by need to comply with regulatory obligations in changed operating environment	Increase in operating costs to obtain data, procure IT platforms and operate and maintain the capabilities required to obtain visibility of and manage our low voltage network in response to new DER connecting to our network.	\$10.1		Requested that SA Power Networks seek a lower-cost alternative. A simplified solution that will provide performance impacts to approximately 80% accuracy has now been proposed with a \$16 million cost reduction.
Cloud transition – cloud hosting	Capex/opex trade-off	Efficient trade-off between capitalised infrastructure owned by SA Power Networks, to 'infrastructure-as-a-service' via a cloud-managed service provider.	\$7.5	(\$8.7)	Acceptance that 'Cloud' is a sound strategic option to deliver IT services in a flexible and cost-efficient way, but expect AER to thoroughly review efficiency of trade-off.
Cloud transition – work scheduling	Capex/opex trade-off	Efficient trade-off between capitalised major upgrades of a critical IT software package managed by SA Power Networks to 'software-as-a-service' via a cloud-managed service provider.	\$3.1	(\$3.1)	Acceptance that 'Cloud' is a sound strategic option to deliver IT services in a flexible and cost-efficient way, but expect AER to thoroughly review efficiency of trade-off.
Critical infrastructure compliance	Change in regulatory obligations	SA Power Networks is required to comply with the <i>Security of Critical Infrastructure Act 2018 (Cth)</i> which imposes restrictions on the location and ownership of IT functions that support critical infrastructure businesses in Australia, and will increase the costs of these functions.	\$10.6		Acceptance that this change will cause SA Power Networks to incur additional costs. Build-up of forecast to be clearly outlined in Regulatory Proposal's supporting documents. Costs have reduced slightly from those originally presented due to confirmation of support costs by our external provider.
Billing replacement	Opex associated with ongoing capex program for legacy billing system replacement	SA Power Networks has commenced replacing its customer billing system due to its age and to provide additional capability to meet regulatory obligations. An operational step change for additional costs was approved for the current regulatory period. A further step change is required for additional incremental software licence and cloud subscription costs to be incurred in the 2020–2025 regulatory period, as detailed in our 2015–2020 Regulatory Proposal.	\$3.4		Acknowledged that change is a result of previously approved program of work where regulatory obligations are a key driver. Evidence of revised costs for the 2020–2025 period to be supplied with Regulatory Proposal.
GSL reliability duration payments	Compliance with proposed change to regulatory obligation	South Australia currently has the most costly GSL reliability scheme of all states, with higher payments and an uncapped liability, which continues to apply during uncontrollable severe weather events. ESCoSA is proposing to cap GSL reliability duration payments to customers for the 2020–2025 regulatory period at maximum annual levels. This will reduce overall GSL costs, but they will remain onerous as payments will continue to apply during severe weather events.	(\$22.0)		Not discussed at engagement workshops. Customers have been engaged as part of the ongoing review by ESCoSA.
Customer engagement technologies	Capex / Opex trade-off for improved customer information	Opex associated with implementation of a customer experience management system.	\$2.5		Not supported by customers and stakeholders. No longer proposed.
<b>Total step changes and trade-offs</b>			<b>\$12.7</b>		

# Revenue building blocks

The revenue building blocks are developed using AER approved processes.

## **This section outlines:**

- › other building blocks which comprise the total regulated revenue allowance (depreciation, return on capital, income tax and outcomes from incentive scheme arrangements). We have forecast these building blocks in accordance with AER approved processes.



## 8 Revenue building blocks

This section provides forecasts of the remaining revenue building blocks (prepared in accordance with the AER's established guidelines) and depreciation (using the AER's 2015–2020 approved approach).

Revenue needs to be set at a level that enables SA Power Networks to recover its efficient costs and provide an adequate return to investors as it invests in the network and maintains a safe, reliable and secure supply.

The National Electricity Rules establish a building block method for determining our revenue requirements. The building block method recognises the different types of costs that we need to recover through network charges, namely:

- › return on capital to recover inherent costs of debt and a return to investors on their equity invested;
- › return of capital or depreciation;
- › operating expenditure;
- › outcomes from incentive scheme arrangements; and
- › corporate income tax.

Our indicative forecast capital and operating expenditures contribute to our total revenue requirement in the next regulatory period, but most of our revenue is determined by the following financial factors and historic expenditure:

- › the value of the existing asset base, reflecting historic investment in the network;
- › the remaining life of our assets;
- › the financial market data, which is used to assess the current cost of capital; and
- › the corporate income tax rate.

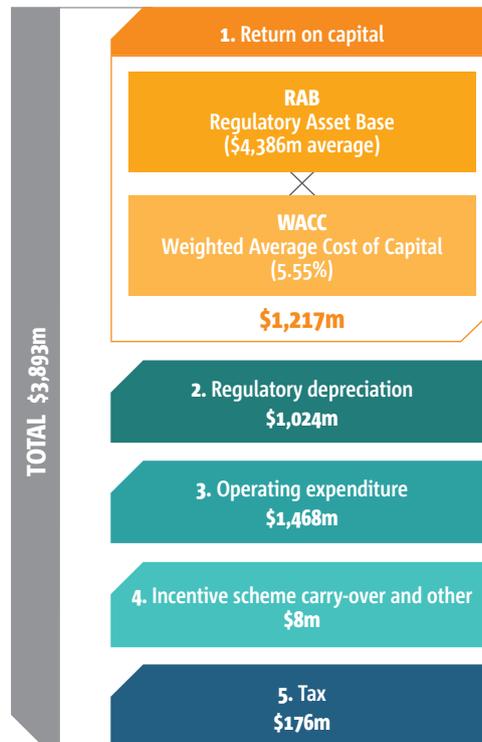


Figure 8.1: Draft Plan revenue

### 1. Return on capital

The rate of return is an estimate of what it costs a business to fund capital investments.

The AER's Rate of Return Guideline sets out how it will determine the return that all regulated energy network businesses in Australia can earn on their investments. This is done using a method called a weighted average cost of capital (WACC).

The WACC is made up of the cost of the two investment funding sources — equity and debt. The cost or return that investors expect on their investments is known as the return on equity.

The cost or interest rate that a business pays to borrow money to invest is known as the return on debt. The WACC is a weighted combination of these two costs.

The AER calculates the WACC as:  
 $WACC = \text{return on equity} \times 40\% + \text{return on debt} \times 60\%$

In July 2018, the AER released a Draft Rate of Return Guideline.<sup>25</sup> While still subject to further review, we have used the draft guideline to provide an estimate of the WACC for 2020–2025 and will continue to engage with the AER on this matter.

For this Draft Plan, our indicative rate of return on capital, or WACC, is set out in Table 8.1. Each of these parameters has been determined in accordance with the AER's Draft Rate of Return Guideline.

### 2. Depreciation (return of capital)

Depreciation is designed to return capital investment to investors over the expected useful life of the assets.

We have calculated depreciation using the year-by-year tracking approach approved by the AER at our 2015 determination. We continue to apply the same standard asset lives and straight-line depreciation approach approved by the AER in 2015.

<sup>25</sup> AER, Draft Rate of Return Guidelines, July 2018

Table 8.1: Draft Plan parameters for weighted average cost of capital

Component	Draft Plan	Comment
Risk free rate	2.70%	Based on the average Australian Government bond rates in the six months to end April 2018
Equity beta	0.6	As per draft AER rate of return guideline
Market risk premium	6.00%	As per draft AER rate of return guideline
Return on equity	6.30%	Adopting AER method
Return on debt	5.05%	Adopting AER method
Gearing ratio	60%	As per draft AER rate of return guideline
Nominal vanilla WACC	5.55%	

### 3. Operating expenditure

Our operating expenditure requirements were discussed in section 7.

### 4. Incentive scheme arrangements

The AER has developed the following incentive arrangements in accordance with the National Electricity Rules:

- › Service Target Performance Incentive Scheme (STPIS) — this provides incentives to maintain or improve operational performance. Outcomes that are better/worse than target receive revenue rewards/penalties up to 5% of total revenue;
- › the Efficiency Benefit Sharing Scheme (EBSS) — this provides incentives to achieve and maintain operating expenditure efficiency improvements. Operating expenditure below/above allowance results in savings/additional costs that are shared approximately 70% with customers and 30% with the distribution business;
- › the Capital Expenditure Sharing Scheme (CESS) — this provides incentives to make capital expenditure efficiency gains. Similar to the EBSS, capital expenditure below/above allowance results in savings/additional costs that are shared approximately 70% with customers and 30% with the distribution business; and

- › the Demand Management Innovation Scheme (DMIS) — this provides incentives to implement non-network solutions over network solutions for an ‘identified need’.

The STPIS, EBSS and CESS are symmetrical incentive schemes, that is, while improved performance is rewarded, reduced performance is penalised.

The AER is proposing<sup>26</sup> to apply all these schemes in the forthcoming regulatory period in accordance with the AER’s prevailing guidelines.

### 5. Corporate income tax

The corporate income tax allowance is calculated using the corporate tax rate of 30% (30 cents in the dollar) reduced by a forecast benefit to owners of imputation credits. The AER has estimated an imputation benefit of 50%, resulting in a tax allowance calculated using an effective tax rate of 15%.

We note the AER is also currently reviewing the regulatory tax approach. Any outcomes from that review will be incorporated into our Regulatory Proposal.

### Forecast inflation

For the purposes of this Draft Plan, we have applied a forecast inflation of 2.5%. This has been calculated using the AER’s approach to forecasting inflation which uses a combination of the Reserve Bank of Australia’s short-term forecast of inflation and the mid-point of its longer-term target range for inflation.

#### Feedback

Do you have any feedback on these revenue building blocks?

26 AER, Preliminary Framework and Approach SA Power Networks regulatory control period commencing 1 July 2020, March 2018

# Tariff structure statement

Empowering customers to better manage their bills.

## This section outlines:

- › how tariff reform helps keep future distribution costs down;
- › the challenges on our distribution network that we are trying to address;
- › the principles underpinning the development of our tariff structures;
- › stakeholder engagement and feedback adopted in developing our tariff proposals; and
- › our proposed tariff structures for 2020–2025.





mart

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ARCADE

G.W. COX  
MY JEWELLER

prorealty  
PROPERTY CONSULTANTS  
FOR LEASE  
EDUCATION/OFFICE SPACE  
Level 3, Walter Place 2,375sqm  
Level 2, 3 to 5 "Block" Adelaide  
Level 2, Rooms from 50sqm  
GENEROUS INCENTIVES APPLY

ADELAIDE FRINGE  
BOX OFFICE

Pizzeria  
Cotto

COTTO

## 9 Tariff structure statement

### Electricity tariff reform in South Australia

#### Why

Tariff reform helps to keep future distribution network costs down by improving the use of the existing network and reducing the need to increase network capacity in the future.

#### What

Our pricing needs to better signal, via more cost-reflective tariffs, the cost of building and maintaining a network to better manage demand peaks and troughs. Increasingly the troughs are formed by surplus energy being generated by solar on South Australian rooftops.

Our tariffs also need to equitably share network service costs amongst all users.

#### Who

We already have cost-reflective demand-based tariffs for our largest customers. The tariff reform process is now looking to influence how households and smaller businesses use energy. Our charges are billed to customers' retailers and it will be up to retailers how they pass on our charges to their customers.

#### Proposed Tariff Structures

'Time-of use' tariff structures are proposed for residential and small business customers, who have interval meters. Interval meters measure electricity consumed at half-hourly intervals and enable more cost-reflective tariffs than the old 'accumulation' meters which only record total consumption, generally over a 90-day period.

A 'demand' tariff structure will also be available to residential and small business customers as an optional tariff.

#### When

About 10% of residential and small business customers now have interval meters and we expect this to grow to 45% by 2025 as all new and replacement meters must be of the new interval meter type. All existing customers with interval meters will be assigned to the new cost-reflective tariffs as will other customers when they get a new or replacement meter.

#### How customers will benefit

If retailers pass these tariffs through to customers, some customers will be motivated to change consumption patterns and reduce their individual bills. This will help to lower the future electricity price for all customers by helping to manage the impact of demand peaks and troughs. This will reduce network expenditure in the longer term.

### Background

Tariffs represent the pricing structure by which SA Power Networks recovers the revenue allowed by the AER.

Tariffs set the price for services that are provided by the electricity distribution network and are differentiated for customers who use the network in different ways.

There is some cost reflectivity within the current tariff structures as the tariff reflects the size of the customer's electricity usage and how much of the network they use. There is some cross subsidy as well. Whilst it costs more to provide electricity to customers in country areas compared with urban areas, State Government policy requires a state-wide price for each small customer within the same customer group.

Our tariffs also consider various attributes such as the density of customers within a network, the type and size of the electricity supply, when electricity is used, the peak demand and the metering that is available to collect information on a customer's use of the network. These matters influence the tariffs that can be offered to customers.

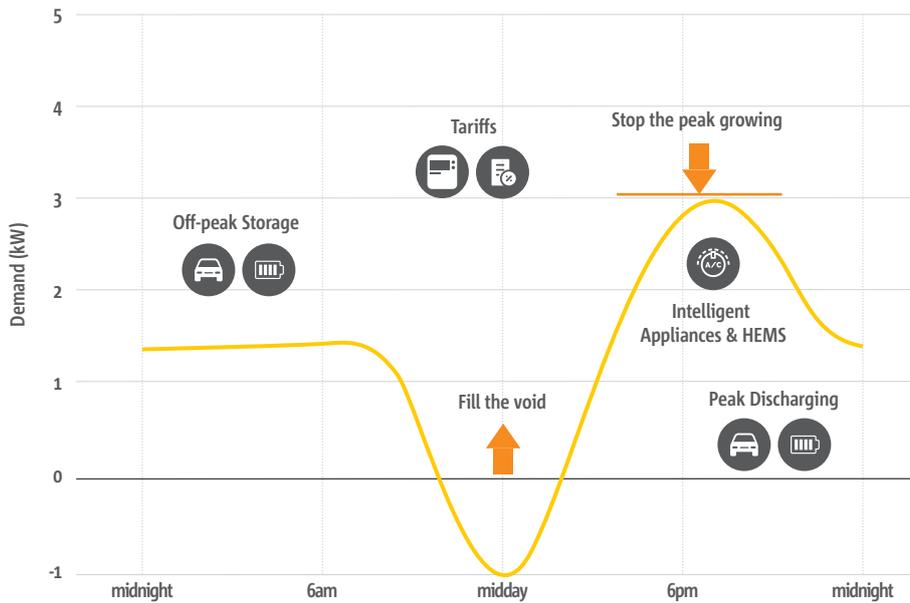


Figure 9.1: Network peak load curve for a day

### Key challenges we are trying to address

Until recently, ever-increasing customer demand required us to build more network capacity, primarily to meet increased residential air-conditioning loads on relatively few very hot summer days. The demand for electricity from our network peaked in 2009. Since then, overall system demand has remained relatively flat or declined slightly, largely due to the amount of rooftop solar systems now connected to our network.

As a consequence, the time of peak demand on our network has shifted from mid-afternoon on hot sunny days into the evenings, when the sun has gone down but air-conditioning is still in use. There is so much solar on our network now that on mild sunny days, residential suburbs are exporting significant quantities of energy into the network.

This excess generation is creating a demand void or ‘solar trough’ on our network in the middle of sunny days, while we must still manage the demand peaks a few hours later in the evenings. Without more cost-reflective pricing and other mechanisms (discussed in Section 5), we will need to increase network capacity to cater for the localised coincident peak of extra solar generation during the ‘solar trough’ (Figure 9.1).

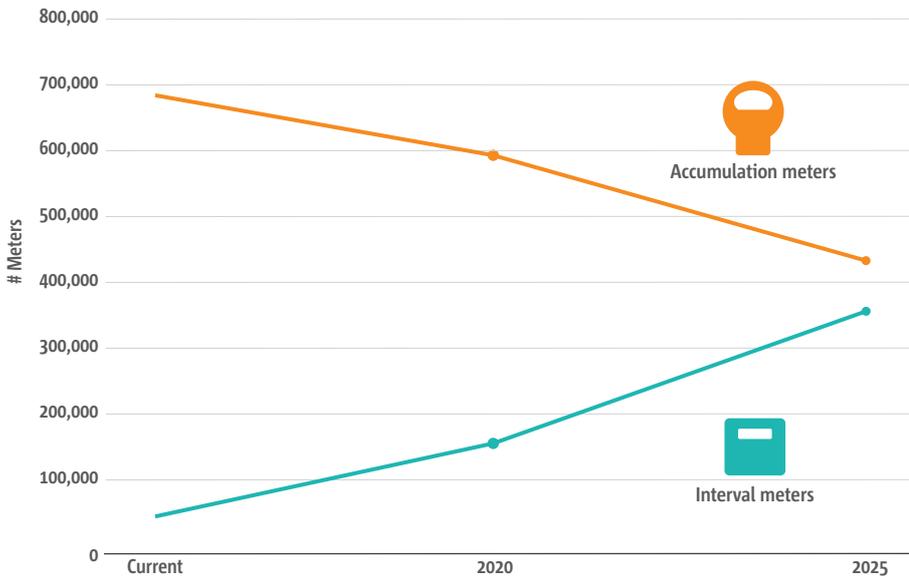


Figure 9.2: Change in the population of electricity meters

More cost-reflective tariff structures can help address this trend but they are dependent on the type of metering that customers have at their premises. ‘Time-of-use’ tariff structures are proposed for residential and small business customers who have interval meters to provide better pricing signals that encourage desired usage behaviours.

Only 10% of meters currently connected to our network are interval meters, but we expect this to move to 45% by 2025 (Figure 9.2). All new and replacement meters must now be remotely read interval meters (Type 4 meters) under the metering contestability rule changes that applied from December 2017.

More cost-reflective tariffs (on average) give customers a lower average price and provide opportunities for customers with flexible loads to shift some of their energy use to lower-priced periods such as the residential solar trough.

Moving loads like pool pumps, washing machines, clothes dryers and hot water heating to lower price periods can help customers manage the cost of electricity. In the future, these times would also be ideal to charge electric vehicles and batteries.

Our tariff structures are designed to empower customers to make informed choices by:

- › **providing better price signals** — our tariffs reflect what it costs to use electricity at different times of the day so that customers can make informed decisions to better manage their bills. Where customers have flexible loads (including batteries, electric vehicles and hot water storage heating) they may move the timing of those loads to a lower price time available every day;
- › **transitioning to greater cost reflectivity** — we will give customers (and their retailer) a choice on the speed to which they will make the transition to cost-reflectivity; and
- › **managing future expectations** — we will continue to guide retailers, customers and suppliers about services such as local generation, batteries, and demand management by setting out our tariff approaches for the 2020–2025 regulatory period.

## Customer impact principles

When developing our 2017–2020 Tariff Structure Statement (TSS), we conducted a deliberative process with a representative customer group. As a result of this process a series of principles were developed to guide decision-making around future tariff structures:

- › **Principle 1** — empower the consumer
- › **Principle 2** — fairness and equity
- › **Principle 3** — simplicity (to inform decision making)
- › Underlying principle — compliance

We continued to apply these principles as we developed our tariff proposals for 2020–2025 as set out in this Draft Plan.

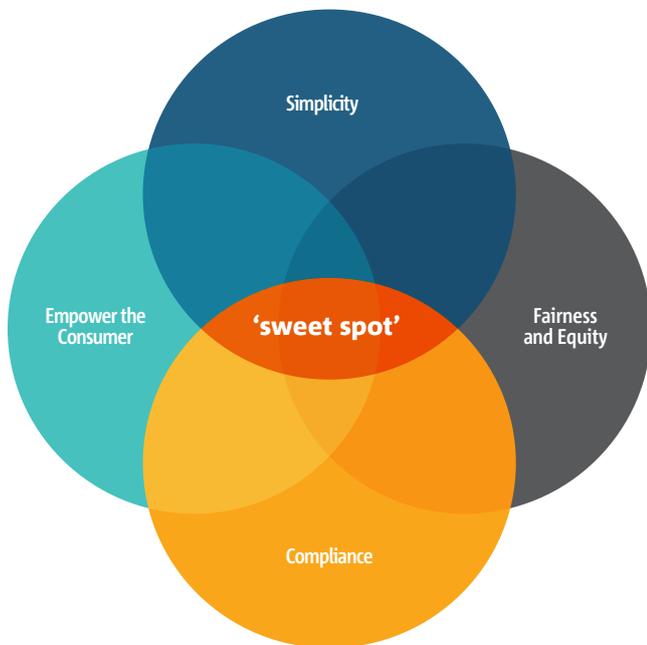


Figure 9.3: Customer impact principles

## AER directions

When the AER approved our 2017–2020 TSS, it indicated it expected to see the pace of transition increase over the 2020–2025 period. In particular it wanted to see:

- › pricing, network planning and demand management interaction;
- › a lift in the pace of tariff reform and customer assignment to cost-reflective tariffs (such as moving away from opt-in tariffs to opt-out tariffs if suitable metering is available);
- › improved quality of long run marginal cost estimates;
- › a reconsideration of the use of a 30-minute window to measure demand; and
- › more refined pricing windows and methods for determining the charging window time.

In addition, the AER has been asking distribution businesses to advise them of:

- › the consultation process undertaken to develop pricing proposals, and how we made the distinction between consultation with customers, customer representatives, retailers and State Government;
- › the effect of emerging technologies and market changes that will impact the network by 2025 and how our proposals consider these changes; and
- › how we balance simplicity and affordability with cost-reflectivity in tariff structures.



Figure 9.4: Tariff Structure Statement engagement

## How we have engaged on our 2020–2025 proposals so far

We undertook a multi-stage engagement process specifically on tariffs from November 2017 to March 2018. This engagement process was designed to:

- › **build understanding** of the current challenges, context and obligations in relation to tariff setting;
- › **explore allocation preferences** between residential and business customers; and
- › **explore customer impacts and gather feedback** on residential, small business and large business tariff proposals.

We have consulted with customers and stakeholders from:

- › our standing reference groups including:
  - Arborist
  - Business
  - Community
  - Renewables
  - Customer Consultative Panel;
- › South Australian Government;
- › Energy Consumers Australia;
- › Australian Energy Market Commission;
- › Australian Energy Market Operator;

- › Australian Energy Regulator;
- › AER Consumer Challenge Panel;
- › Energy Networks Australia and other distribution businesses; and
- › retailers:
  - Australian Energy Council
  - Alinta Energy
  - AGL
  - Lumo Energy
  - Origin Energy
  - Simply Energy.

This engagement has involved reference group discussions, bilateral meetings, and a dedicated tariff deep dive workshop, which brought together the diverse views of different stakeholder cohorts. Table 9.1 outlines what we heard and our response.

Table 9.1: Customer and stakeholder feedback and our response

What we heard	Our response
<ul style="list-style-type: none"> <li>› “Business shouldn’t have to bear the costs for services not provided to them.”</li> </ul>	<ul style="list-style-type: none"> <li>› \$35 million of GSL costs shifted from business to residential customers</li> </ul>
<ul style="list-style-type: none"> <li>› “The proposed tariff structures are very complex. Simplicity please.”</li> <li>› “The Critical Peak Pricing tariff is too complex.”</li> </ul>	<ul style="list-style-type: none"> <li>› Reduced the number of tariff elements from initial proposals</li> <li>› Simplified anytime blocks to only address critical issues</li> <li>› Ensured consistency between time blocks where possible</li> <li>› No longer proposing the Critical Peak Pricing tariff</li> </ul>
<ul style="list-style-type: none"> <li>› “Tariffs should be designed with retailers in mind.”</li> <li>› Retailers asked to be informed of the most important tariff elements.</li> </ul>	<ul style="list-style-type: none"> <li>› We will continue to engage with retailers on tariff design</li> <li>› We have reduced the off-peak residential time-of-use to those periods best suited to daily network issues</li> </ul>
<ul style="list-style-type: none"> <li>› “Customers need 12 months of data to understand their usage before moving to a new tariff.”</li> </ul>	<ul style="list-style-type: none"> <li>› We expect retailers will offer tariff choices</li> <li>› If retailers don’t offer a choice of tariffs, the network price impact on small customers should not be significant</li> </ul>
<ul style="list-style-type: none"> <li>› “Stage the transition through pricing within tariff structures.”</li> </ul>	<ul style="list-style-type: none"> <li>› We will transition all small customers to a new structure evenly over a five-year period</li> </ul>
<ul style="list-style-type: none"> <li>› “How will desired behaviour changes result in outcomes and how will these impact future planning?”</li> </ul>	<ul style="list-style-type: none"> <li>› Largely the customer response is unknown at this stage, but we expect that daily and summer congestion will reduce or at least not increase, which should result in lower future capex from avoiding or deferring augmentation and expansion of the network</li> <li>› We will continue to work collaboratively to ensure network planning and tariff structures are complementary</li> </ul>
<ul style="list-style-type: none"> <li>› “Moving to greater fixed costs removes any incentive or possibility for customers to modify behaviour to reduce costs.”</li> <li>› “Fixed charges are regressive and do not encourage energy conservation.”</li> </ul>	<ul style="list-style-type: none"> <li>› We acknowledge concerns raised on fixed supply charges</li> <li>› We believe our plans to increase supply charges are more cost-reflective and remove some cross-subsidy. They align with a world-wide trend to increase the fixed charged component</li> </ul>
<ul style="list-style-type: none"> <li>› “An appropriate recovery of revenue for the next regulatory period would be roughly 1/3 each for fixed, variable and demand charges.”</li> </ul>	<ul style="list-style-type: none"> <li>› We propose to limit any supply charge increase to \$10 per annum. Supply charges will recover approximately 25% of our overall costs by 2025, heading towards, but well within, the one third suggested in consultation</li> </ul>

## Our proposed tariff structures for 2020–2025

Our proposed tariff structures for 2020–2025 are set out below and balance the diverse feedback we have heard from all stakeholders, while addressing the AER’s expectations.

Table 9.2: Residential tariffs

Residential tariff	Tariff structure	Metering	Key features and considerations
Residential – Single rate	Supply charge + flat usage rate	Accumulation meter (Type 6)	<ul style="list-style-type: none"> <li>› Supply charge will increase &lt;\$10 per annum</li> <li>› Single rate reverts to a single block in July 2019</li> <li>› Only option for a residential customer with type six metering</li> <li>› Companion tariff available for controlled load (hot water) for customers with existing off-peak controlled load metering</li> </ul>
Residential – Time-of-use	Supply charge + peak and off-peak usage rates	Interval meter, either: <ul style="list-style-type: none"> <li>› remotely read (Type 4); or</li> <li>› manually read (Type 5).</li> </ul>	<ul style="list-style-type: none"> <li>› Default mandatory tariff for 2020–2025 for residential customers with type four or five metering. Same supply charge as single rate</li> <li>› Companion tariff available for controlled load (hot water). Customers may access lower network prices by managing the time-of-use of such appliances</li> <li>› Two, five-hour off-peak blocks every day:               <ul style="list-style-type: none"> <li>- 1am to 6am (early morning); and</li> <li>- 10am to 3pm (when solar export is at its highest). The price is approximately 35% of the single-rate usage price</li> </ul> </li> <li>› Price for the other 14 hours will be approximately 130% of the single rate usage price</li> </ul>
Residential – prosumer	Supply charge + time-of-use + average summer peak demand charge	Remotely read interval meter (Type 4)	<ul style="list-style-type: none"> <li>› New opt-in tariff for 2020–2025 for residential customers with type four metering. May suit customers with new technologies such as solar, batteries, electric vehicles and home energy management systems and households with less energy-intensive air-conditioning needs such as evaporative air-conditioning</li> <li>› The tariff has the same supply charge as single rate</li> <li>› A companion tariff is available for controlled load (hot water). Customers may access lower network prices by managing the time-of-use of such appliances</li> <li>› The tariff will comprise:               <ul style="list-style-type: none"> <li>- supply charge — 25% of the average residential bill;</li> <li>- usage charges — 35%, split into a peak and off-peak usage; and</li> <li>- peak average demand charges in summer — 40%.</li> </ul> </li> <li>› Price for off-peak usage would approximate the off-peak price used in the time-of-use tariff (35% of single-rate) but peak usage price would be much lower than time-of-use tariff, around 50% of the single-rate</li> <li>› Summer demand measured each month, November through March at the highest average level over the four-hour period, 5:30pm to 9:30pm, for that month. Designed to encourage battery owners to discharge at this time on hot days to offset their in-house use (air-conditioning in particular) and allow customers to use appliances as necessary during the four-hour period</li> <li>› We are investigating spreading the summer average demand charge (around 40% of the year’s network charges) more evenly across the year. This makes the tariff more complex, but provides a better cash flow for the customer, retailer and distribution businesses and should help many consumers who choose this option</li> <li>› During our engagement program we presented a Critical Peak Pricing option for discussion but customers, advocates and retailers felt that this failed to deliver on the simplicity objective, so we are only proposing the simpler time-of-use and the less complex prosumer tariffs</li> </ul>

Table 9.3: Companion controlled load (hot water) tariffs

Tariff	Tariff structure	Requirements	Key features and considerations
Off-peak controlled load	Flat rate	Accumulation meter (Type 6)	<ul style="list-style-type: none"> <li>› The time clock is managed by SA Power Networks, and typically involves supply usage between 11:00pm to 7:00am and from 10:00am to 3:00pm. (The solar sponge option is not available for those customers receiving the 44 c/kWh premium FIT payments)</li> <li>› The usage network price will be the same as the residential time-of-use off-peak network price</li> </ul>
Off-peak controlled load	Peak and off-peak rates	Interval meter (Type 4 and Type 5)	<ul style="list-style-type: none"> <li>› For Type 5 meters, the time clock is managed by SA Power Networks</li> <li>› For Type 4 meters, the time clock is managed through the meter by the retailer and the metering coordinator</li> <li>› The preferred time periods of use are from 11:00pm to 7:00am and from 10:00am to 3:00pm with a randomised start time of at least one hour for such equipment (to reduce the coincident peak start load)</li> <li>› The off-peak network price of the residential time-of-use tariff applies for preferred usage times. Usage outside these times is at the same price as the residential time-of-use peak network price</li> </ul>

Table 9.4: Small and medium business tariffs

Business Tariff	Tariff structure	Requirements	Comments
Small business – Single rate	Supply charge + flat rate	Accumulation meter (Type 6)	<ul style="list-style-type: none"> <li>› The only tariff option for a small business with single-rate Type 6 metering</li> <li>› The tariff has the same supply charge as residential tariffs</li> <li>› The companion tariff for controlled load (hot water) is available for those consumers currently using controlled load</li> </ul>
Small business – Two rate	Supply charge + peak and off-peak rates	Accumulation meter (Type 6)	<ul style="list-style-type: none"> <li>› The only tariff option for a small business with two-rate Type 6 metering. The peak and off-peak times are determined by the metering, which may be peak 7:00am to 9:00pm five days a week (Monday to Friday) or possibly all days of the week. Off-peak at all other times. The pricing will be similar to or the same as the small business time-of-use tariff</li> <li>› The companion tariff for controlled load (hot water) is available for those customers currently using controlled load on Type 6 metering</li> </ul>
Small business – Time-of-use (ToU)	Supply charge + time-of-use rates	Interval meter, either: <ul style="list-style-type: none"> <li>› remotely read (Type 4)</li> <li>› manually read (Type 5)</li> </ul>	<ul style="list-style-type: none"> <li>› Default tariff for small business with Type 4 or Type 5 metering. The same supply charge applies as small business single rate: <ul style="list-style-type: none"> <li>- peak is 7:00am to 9:30pm local time on work days (excludes public holidays), plus from November through March on non-work days, 5:30pm to 9:30pm; and</li> <li>- off-peak is all other times.</li> </ul> </li> </ul>
Small and medium business – Demand	Supply charge + actual/agreed demand rates + time-of-use rates	Interval meter (Type 4)	<ul style="list-style-type: none"> <li>› Mandatory tariff for customers with current-transformer (CT) connected meters (typically &gt;70kVA connection capacity)</li> <li>› Opt-in tariff for other small business customers with Type 4 meters</li> <li>› These arrangements enable cost-reflective tariffs to a significant subset of larger (typically &gt;70kVA demand) small business customers and provide time and choice for smaller customers as type four metering is rolled out by retailers</li> <li>› We considered other criteria for small and medium business demand tariff eligibility to manage the progressive implementation of more cost-reflective network tariffs to small business. Options considered included no threshold, thresholds based on annual consumption (MWh pa) or maximum demand (kVA), or when a business customer alters their supply arrangement. These other options have equity issues and involve complexity for consumers, retailers and the distribution business. Our small business stakeholders indicated a strong preference for simpler tariff options and tariff assignment rules</li> </ul>

Table 9.5: Large business\* tariffs

Tariff	Tariff structure	Requirements	Key features and considerations
CBD – Demand	Supply charge + actual/agreed demand rates + time-of-use rates	Remotely read interval meter (Type 4)	<ul style="list-style-type: none"> <li>› New mandatory tariff for large business in the CBD</li> <li>› Demand charge based on the highest daily average maximum demand during 11:00am to 5:00pm on work days only from November through March</li> <li>› Anytime demand charged on the highest half-hour demand during the year</li> <li>› Peak and off-peak usage rates apply at the times used for small business ToU, but at much lower rates</li> </ul>
Non-CBD – Demand	Supply charge + actual/agreed demand rates + time of-use rates	Remotely read interval meter (Type 4)	<ul style="list-style-type: none"> <li>› New mandatory tariff for large business outside the CBD</li> <li>› Demand charges based on the highest daily average maximum demand during 5:30pm to 9:30pm any day from November through March</li> <li>› Anytime demand charged on the highest half-hour demand during the year</li> <li>› Peak and off-peak usage rates apply at the times used for small business ToU, but at much lower rates</li> </ul>

\* The reason for this distinction between CBD and non-CBD is because the solar penetration in the CBD is different to the rest of South Australia, resulting in a different peak demand profile. The CBD includes the area surrounded by the parklands, including the River Torrens precinct, but excludes the North Adelaide area, north of the River Torrens.

## Potential additional tariffs under consideration

### Riverland trial

We are also trialling an agreed demand tariff for six large customers in the Riverland. This tariff trial is designed to:

- › target peak demand usage on extreme summer days (eg the peak demand is only measured on days when the temperature at Renmark is forecast to be 40 degrees Celsius or higher);
- › test the approach to measuring separate charges for peak demand and for anytime demand that we are proposing in the 2020–2025 period;
- › test the consumer experience with this opt-in tariff, and whether a tangible change in regional demand can be achieved by a consumer demand response; and
- › test our ability to implement a bespoke tariff.

We are trialling this as a consumer-rebate tariff: the consumer continues to be billed by their retailer under the standard agreed demand tariff, but SA Power Networks will rebate the consumer directly at the end of the year if the bespoke tariff is to their advantage. If successful, this tariff may be retained in the 2020–2025 period.

### Potential combination tariff

In the 2017–2020 period, our demand tariffs for small business and residential customers are a monthly actual demand charge. For large business customers, it is an annual agreed demand charge. Both tariffs have their good points and their lesser points.

For this reason, we are considering the merit of offering a combination actual/agreed demand tariff for general use by all customers. Such a tariff results in more equitable outcomes amongst customers. However, the combination tariff is more complex and it may be difficult to integrate into billing systems. If we cannot adequately develop this tariff, we will retain the existing monthly actual demand tariffs for smaller customers and the annual agreed demand tariffs for larger customers.

### What do these tariffs mean for customers?

If retailers pass these tariffs through to customers, customers may be motivated to change consumption patterns to try to reduce their individual bills. This behaviour should also help to lower the future price of electricity for all customers over the longer-term.

For residential customers with Type 4 or Type 5 interval meters, the mandatory time-of-use network prices will change the amounts paid by retailers for each customer. We do not expect that the network price will vary by more than five percent of the current retail price, which should be manageable for retailers and residential customers.

For the residential ‘prosumer’ who opts-in to the more complex summer demand tariff, the use of the four-hour window will help to correctly incentivise a demand response. The demand on our network is relatively flat over the four hours from 5:30pm to 9:30pm on extreme days, so it is more reasonable to measure across a four-hour window rather than bill on a single half-hour spike which may just be a combination of air-conditioning and meal preparation, for example.

The average use over the four-hour period is more relevant to the network than the highest half-hour that we have previously proposed, and which residential customers and retailers did not prefer. Figure 9.5 shows the average extreme summer day profiles for households with and without solar.

Figure 9.5 shows the difference in typical residential profiles on extreme days with and without solar. During the day, the solar profile is lower (red line). During the early evening when demand is highest, the two profiles are similar. Further benefit could be gained if batteries exported during this time after the solar panels have ceased generating electricity but air-conditioning is still required. Whilst this tariff will not be suitable for most residential customers, it will meet the needs of a niche group of prosumers seeking to improve the management of their electricity demand.

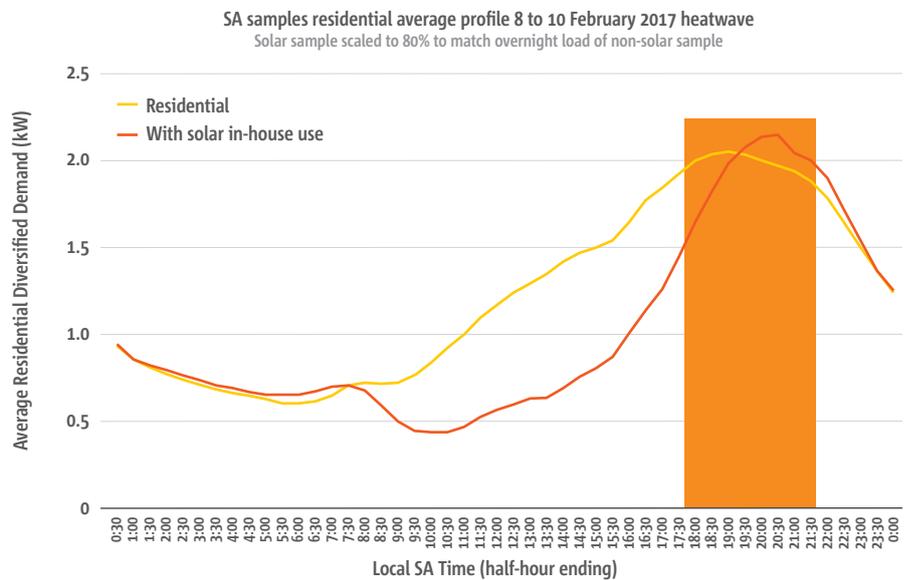


Figure 9.5: Residential demand profile with and without solar

### Other considerations

SA Power Networks does not determine the value of energy that customers export to the network. In the past, ESCoSA has set minimum prices for generation export but this price is now set by retailers.

Victoria’s state-regulator (Essential Services Commission) has proposed a time-of-export minimum price which has a low price near solar noon, a medium price prior to and after solar noon (and overnight) and a higher price in the late afternoon/early evening. Such a price structure for retailer feed-in-tariffs (FiT) would signal the ideal times for customers to be exporting their surplus energy.

This is not a pricing initiative that SA Power Networks can introduce nor influence. However, we would welcome any initiative to amend retailers’ FiT single-rate into a time-of-export rate where the price is lower at times of high export/lower local demand (solar noon) and is higher at times of low export/higher local demand (early evening).

### Feedback

What feedback do you have on our proposed tariff structures for 2020–2025?

- ▶ How well do you think our proposed tariff structures meet our guiding principles of simplicity, fairness and equity, and customer empowerment?
- ▶ For retailers: what impact will our proposed tariff structures have on retail product innovation and choice for customers?
- ▶ Are there other options we should be considering?

# Alternative control services

The prices of other customer-specific services will be set by the AER.

## This section outlines:

- › The range of other customer-specific services we provide where costs are recovered directly from individual customers. At the moment we determine the price of these services and they are listed in our Tariff Manual, but the AER will set prices for these services for 2020–2025.





VEHICLES EXEMPT

VEHICLES EXEMPT

PRIVATE PARKING AREA  
NO STOPPING  
VEHICLES EXEMPT

© HONEY JONES  
DORRISON  
ART

## 10 Alternative control services

The preceding sections of this Draft Plan set out our plans and expenditure forecasts to build, maintain and operate the shared electricity network during 2020–2025; to deliver services to customers and meet regulated obligations and service standards.

This section summarises the range of other customer-specific services we provide.

The costs of providing these services are recovered directly from individual customers. These services include public lighting services for councils and the South Australian Government; certain metering services, connection and alteration services; and a range of ancillary network services.

The prices for metering services are currently set by the AER whereas prices for the other services are currently determined by us and published in our Tariff Manual.<sup>27</sup>

For 2020–2025, the price of all customer-specific services will have greater regulatory oversight. We will develop a pricing proposal for each of these services and the AER will set the prices we can charge.



### Connections and supply alterations

- › 25,000 new connection and supply alterations each year
- › Costs are fully or partly funded by SA Power Networks based on future additional revenue to be earned from the customer. These costs are included in our capital expenditure forecasts. The balance of the costs charged to customers are in accordance with our AER-approved Connection Policy



### Public lighting services

- › Around 240,000 streetlights managed on behalf of councils and the South Australian Government Department of Planning, Transport and Infrastructure
- › Charges vary depending on the service package selected by customers



### Legacy metering services

- › More than 1,000,000 manually-read meters
- › On 1 December 2017, retailers became responsible for all new and altered metering arrangements. All new and replacement meters must now be remotely read interval meters (smart meters)



### Ancillary network services

- › Non-routine services which may have a fixed fee for more standard works or a quoted fee for non-standard works
- › Examples include network asset relocation work, energisation/de-energisation and special meter reading services

<sup>27</sup> Available at [sapowernetworks.com.au](http://sapowernetworks.com.au)

## **New public lighting services in 2020–2025**

**We continue to innovate our public lighting service offerings while keeping overall costs down: average public lighting costs have reduced 38% since 1999/00.**

In 2015–2020 we developed new service offerings including long-term contracts that provide a large degree of price certainty and helped to roll out new energy efficient street lights (LEDs).

Through ongoing discussions and workshops held with our public lighting customers, we are developing new service offerings that we believe our customers wish to see over 2020–2025, including choices on:

- › service packages;
- › asset responsibility and funding model;
- › asset technology and information;
- › price certainty; and
- › new/emerging public lighting services.

The AER will approve the pricing of all public lighting services from 2020.

### **Feedback**

- › Do you have any feedback on the arrangements for Alternative control services?



# Feedback

## We would love to hear from you.

**We welcome your responses to the questions throughout this Plan, or any other feedback you wish to provide.**

Your feedback will help us shape and refine our approach as we continue to prepare our 2020–2025 Regulatory Proposal, due to the AER in early 2019.

Please submit your feedback by **5:00pm Wednesday 19 September 2018.**

### **You can provide feedback by:**

**Emailing your feedback to:**  
[talkingpower@sapowernetworks.com.au](mailto:talkingpower@sapowernetworks.com.au)

**Visiting us online at:**  
[talkingpower.com.au/DraftPlan](http://talkingpower.com.au/DraftPlan)  
and completing the online form

**Sending your feedback to:**  
Richard Sibly, Head of Regulation  
SA Power Networks  
GPO Box 77  
Adelaide SA 5001

**Calling us on 1800 572 229**

*Submissions will be published on [talkingpower.com.au](http://talkingpower.com.au)*

