SA Power Networks

Attachment 5

Capital expenditure

2020-25 Regulatory Proposal

31 January 2019

This section outlines:

- › our proposed capital works program and expenditure for the 2020-25 Regulatory Control Period; and
- › where we have refined our plans in response to customer and stakeholder feedback.

Company information

SA Power Networks is the registered Distribution Network Service Provider (**DNSP**) for South Australia. For information about SA Power Networks visit www.sapowernetworks.com.au

Contact

For enquiries about this Revenue Proposal please contact:
Richard Sibly
Head of Regulation
SA Power Networks
GPO Box 77
Adelaide SA 5001
sapn2020proposal@sapowernetworks.com.au

Disclaimer

This document forms part of SA Power Networks' Regulatory Proposal (**the Proposal**) to the Australian Energy Regulator (**AER**) for the 1 July 2020 to 30 June 2025 regulatory control period (2020-25 **RCP**). The Proposal and its attachments were prepared solely for the current regulatory process and are current as at the time of lodgment.

This document contains certain predictions, estimates and statements that reflect various assumptions concerning, amongst other things, economic growth and load growth forecasts. The Proposal includes documents and data that are part of SA Power Networks' normal business processes, and are therefore subject to ongoing change and development.

Whilst care was taken in the preparation of the information in this Regulatory Proposal, and it is provided in good faith, SA Power Networks, its officers and shareholders accept no responsibility or liability for any loss or damage that may be incurred by any person acting in reliance on this information or assumptions drawn from it for a different purpose or in a different context.

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Note

This attachment forms part of our Proposal for the 2020-25 RCP. It should be read in conjunction with the other parts of the Proposal.

Our Proposal comprises the overview and attachments listed below, and the supporting documents that are listed in Attachment 18:

Document	Description
	Regulatory Proposal overview
	Customer and stakeholder engagement report
Attachment 1	Annual revenue requirement and control mechanism
Attachment 2	Regulatory asset base
Attachment 3	Rate of Return
Attachment 4	Regulatory depreciation
Attachment 5	***Capital expenditure***
Attachment 6	Operating expenditure
Attachment 7	Corporate income tax
Attachment 8	Efficiency benefit sharing scheme
Attachment 9	Capital expenditure sharing scheme
Attachment 10	Service target performance incentive scheme
Attachment 11	Demand management incentives and allowance
Attachment 12	Classification of services
Attachment 13	Pass through events
Attachment 14	Alternative Control Services
Attachment 15	Negotiated services framework and criteria
Attachment 16	Connection policy
Attachment 17	Tariff Structure Statement
Attachment 18	List of Proposal documentation

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5 Capital expenditure

5.1 Introduction

Our capital expenditure (**capex**) forecast incorporates the capital investment we propose to make in relation to the provision of standard control services (**SCS**) during the 2020-25 RCP. The return on capital through the regulatory asset base (**RAB**), is one of the building blocks that forms part of our total revenue requirement for the 2020-25 RCP.

This Attachment:

- outlines our regulatory obligations in relation to our capex forecast and capital work programs,
- discusses the capex outcomes in the 2015-20 RCP,
- describes our approach to forecasting capex for the 2020-25 RCP,
- details our forecast capex for the 2020-25 RCP,
- provides context and reasoning that support our capex forecasts (as appropriate); and
- discusses relevant customer and stakeholder feedback and how this has influenced our capex program for the 2020-25 RCP.

Table 5-1 sets out the structure of this Attachment to aid the reader.

SA Power Networks has also provided additional supporting documentation to the Australian Energy Regulator (**AER**) in support of this forecast in accordance with the requirements of clauses 6.5.7(b), 6.8.2(c)(2) and 6.8.2(d) of the National Electricity Rules (**NER**) and the Regulatory Information Notice (**RIN**) dated 31 October (Supporting Document – RIN Cross reference table)

All dollars in this Attachment are June 2020, million unless specified otherwise.

Table 5-1: Capex attachment structure

Section	Title	Context
5.1	Introduction	An introduction to capex and the NER requirements
5.2	Overview	An overview of the key components of our capex proposal for the 2020-25 RCP
5.3	The key challenges we face	What we need to respond to, what is shaping our needs and how capex needs to respond
5.4	Customer and stakeholder engagement	The customer and stakeholder engagement process and feedback in respect to capex plans, and how customer feedback has shaped those plans
5.5	Rule requirements	The NER requirements relating to capex
5.6	Our electricity distribution network	An overview of our network and its operating environment
5.7	Performance during the 2015-20 RCP	Our network financial and benchmarking performance during the 2015-20 RCP
5.8	Capex categories	An outline of how we have set out the categories of expenditure in accordance with Expenditure Forecast Assessment Guidelines
5.9	Documentation hierarchy	Sets out the documentation hierarchy for our capex
5.10	Capex development process	A summary of how we have developed our capex forecasts

5.11	Key assumptions	A summary of the key assumptions underpinning our capex proposal
5.12	Summary of capex forecast for the 2020-25 RCP	A summary of our proposed capex for the 2020-25 RCP compared to the current and previous RCPs
5.13	Replacement expenditure forecast	An outline of the replacement and refurbishment capex forecasts that renew and repair our network for the 2020-25 RCP
5.14	Augmentation expenditure forecast	An outline of the augmentation capex forecasts responding to changes in conditions and demand for the 2020-25 RCP
5.15	Customer connections expenditure forecast	An outline of the connections capex forecasts and the expected customer contributions for the 2020-25 RCP
5.16	Non-network expenditure forecast	An outline of the non-network capex forecasts for the 2020-25 RCP
5.17	Contingent projects	Our proposed contingent projects for the 2020-25 RCP
5.18	Deliverability	An outline of our deliverability plan for the capex program
Appendix A	Capital expenditure profile 2010-25	Sets out the capex for the previous, current and forecast RCPs.

5.2 Overview

Although SA Power Networks' distribution charges make up less than 30% of the typical average residential electricity bill, we are committed to ensuring that our customers continue to get value for money from the services we provide.

Our network is one of the most efficient in the country and has been for many years. This means we have to work harder to find further improvements, particularly when:

- our network assets have an average age ranging between 42 years, the oldest in the National Electricity Market (**NEM**);
- an increasing numbers of assets need maintenance or replacement to minimise the risk of blackouts and other reliability or safety issues;
- some of our rural and remote customers experience significantly worse reliability than others, which customers have asked us to address; and
- new technologies, customer demands and deteriorating weather patterns are making us think about how we operate our ageing network and prepare for the future without overcommitting resources to short term solutions.

Compromise is a necessary reality given the diverse needs of our customers and the changing role of our network. We seek to strike a balance by constraining our expenditure to put downward pressure on electricity prices for our customers, while still meeting all our regulatory obligations and maintaining good customer service levels.

Our capex forecasts have a long-term focus – while we are mindful of current affordability concerns of our customers, we do not want to inequitably impose additional costs on future generations. Our forecasts also acknowledge and address new and emerging challenges faced from transitioning the oldest network in the NEM to the new energy future.

When developing our capex forecasts, we have considered a range of challenges facing our industry and distribution networks in particular. We have engaged broadly with customers and stakeholders to ensure we understand their perspectives. This extensive engagement program commenced early in 2017 and included customer surveys, workshops and focus group research to first identify what was important to customers.

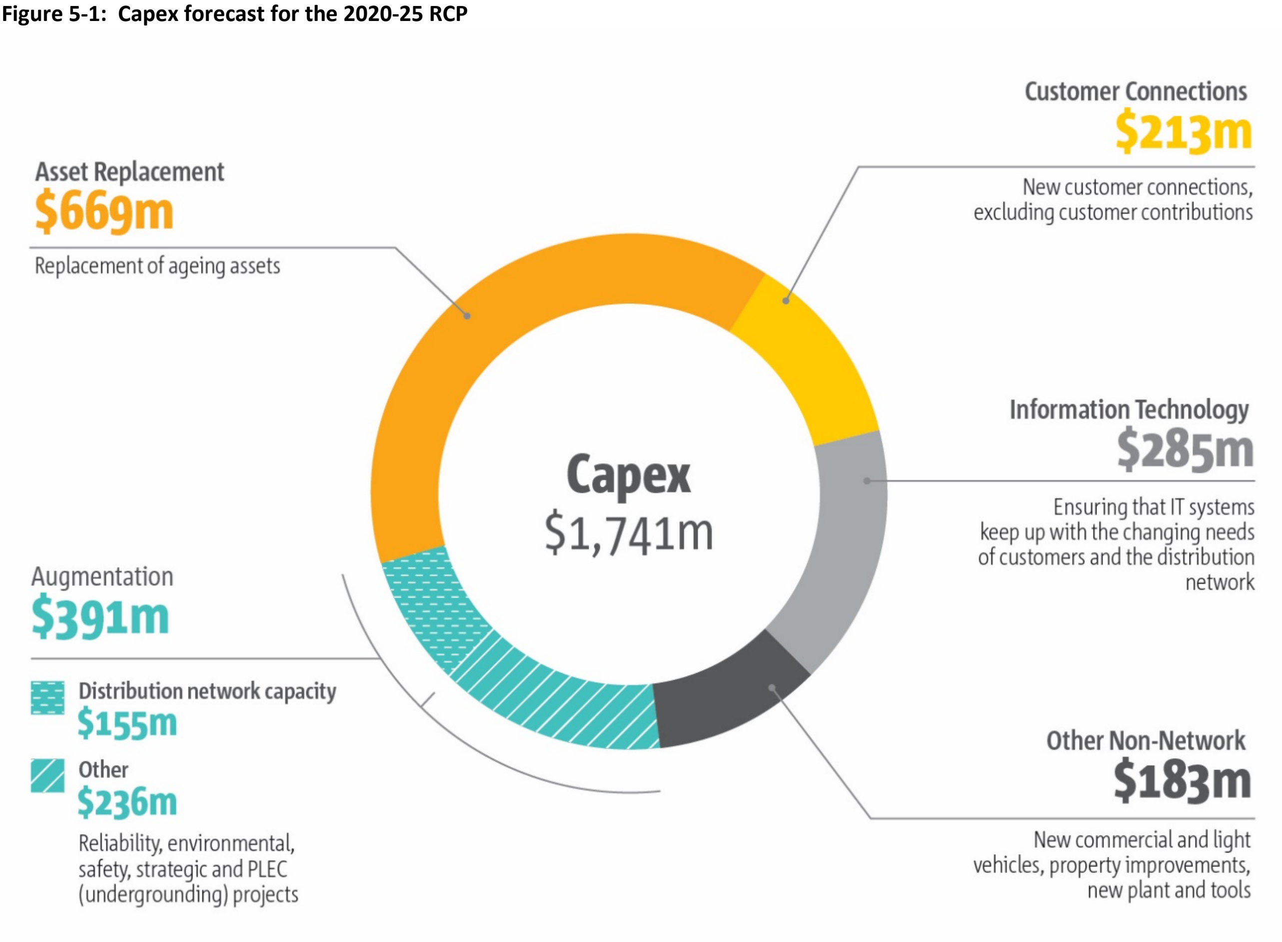
In 2018, we consulted in-depth with customers and stakeholders on the detail of our preliminary expenditure proposals to make sure that our customers are at the centre of our plans, and have refined our plans accordingly.

Throughout our engagement, our customers and stakeholders have reinforced the importance of:

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

Our capex forecast for the 2020-25 RCP is represented in Figure 5-1.

Figure 5-1: Capex forecast for the 2020-25 RCP



5.3 The key challenges we face

Our challenge is to prudently and efficiently balance the following requirements:

- ensuring our ageing network remains safe, reliable and fit for the future;
- responding to the demand from customers to reduce prices; and
- supporting ongoing customer demand for renewable energy technologies and new services.

These challenges have been the subject of intensive engagement and discussion with our customers and stakeholders over the past two years. We have heard varying views but there is consistent support for the objectives of holding down prices, maintaining reliability and safety, and investing wisely for the future.

We are focused on efficient investment to maintain reliability and safety, renew ageing network assets, invest in technology to maintain our ability to deliver our existing services and to deliver new and different services that customers demand, and ensure the network is in a fit state to support customers as they make future choices about how they meet their energy needs.

Table 5-2 below summarises the key challenges we are facing and how we propose to respond to them.

Table 5-2: The key challenges we face

Challenge	How we have responded
Managing an ageing asset base We have the oldest asset base in the NEM. The age and condition of the assets increases the risk of defects impacting on safety and reliability. Replacements and refurbishments are necessary but need to be managed within the constraint of affordability.	We have developed industry leading capabilities using IT systems and tools to manage our assets more efficiently utilising innovative value-based approaches. We have also determined the sustainable levels of expenditure required to keep our network operating safely and reliably. The largest single component of our proposed 2020-25 capital program is expenditure on replacing and refurbishing our ageing network assets so they can continue to provide safe and reliable services to the current and future generations of customers.
Managing rising energy costs Our customers are very concerned about electricity prices.	We are continuing prudent investment in the core network assets providing our traditional distribution services – to manage community risk and maintain customer supply reliability. We have made modest investments to improve reliability to customers on very low reliability feeders; improve bushfire risk management and cyber security protections – but only where support has been received from customers and stakeholders. We are also making modest investments to develop the capabilities to manage and enable the new energy choices of consumers and resultant transition occurring on our network.
The challenge of customer solar and the future network One in four customers in South Australia now has their own rooftop solar generation. Taken together, these customers can generate 1000 mega-watts (**MW**) which is more energy than any other single generator in the State. In addition, the market for residential battery storage is accelerating. Retailers are rolling out 'virtual power plant' (**VPP**) projects and, more significantly, 2018 saw the launch of two major State Government VPP programs that could see 90,000 new batteries with up to 400 MW of controllable storage connected to the distribution network in the next few years.	Our network will be key to enabling customers to access more efficient energy solutions and services, and it must be able to deal with the system impacts of distributed energy resources (**DER**). We have escalating 'quality of supply' (**QoS**) enquiries typically due to voltage levels rising above technical standards, often related to DER on our network, and we are proposing a sensible and prudent approach to manage this challenge.

5.4 Customer and stakeholder engagement

We have engaged extensively with our customers and stakeholders on our plans for the 2020-25 RCP, and this engagement will continue. The breadth of our engagement program has helped to ensure that we understand, and have given appropriate consideration to, the diverse range of views of our customers and stakeholders.

As explained above, there is general agreement from our customers that we must strive to achieve three key objectives:

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

Our customer and stakeholder engagement program is summarised in Section 2 of the Overview document and discussed in detail in the Customer and stakeholder engagement report submitted with this Regulatory Proposal. The feedback provided throughout our customer and stakeholder engagement program, and how we have responded in preparing our capex forecasts is summarised below.

Table 5-3: Summary of customer and stakeholder feedback relating to capex and our response

Theme	What we heard	Our response
Keeping prices down	Make affordability a higher priority – ensure not a dollar more than necessary is spent	Capex has been further reduced by $109 million since the 2020-25 Draft Plan, taking the total capex reduction to $199 million since sharing preliminary forecasts in deep dive workshops in early 2018. Our prudent approach is embedded in how we do business, for example: ›› Our approach to replacement expenditure which involves managing risk by focusing on work that delivers the most value for customers, based on the likelihood and impact of consequence ›› Our approach of actively managing network constraints rather than building new assets to increase capacity ›› Moving IT services away from in-house assets to cloud location paid services
	Refine programs so proposed expenditure is in line with current period expenditure	Capex reductions have been achieved by revising the scope of works for some programs, extending the timeframes of some programs, and removing some programs altogether ›› Capex programs are now largely aligned to current period expenditure
	Actively look for efficiencies and innovate to stay at the efficient frontier and deliver price relief	We have taken a prudent approach to all expenditure forecasts: ›› Expenditure programs have only been proposed when value exceeds cost

	Avoid or defer expenditure where possible but do not under-invest now and pass costs on to future generations If expenditure is required, adopt a prioritised, staged approach to any programs	›› Efficient deferrals and refurbishment of assets is undertaken when possible. For example, our improved value-based approach is enabling efficient deferral of ~$200 million of asset replacement, and the new substation originally planned for Gawler East has been deferred into a future RCP ›› We have a staged, risk-based approach to capital programs, targeting areas of greatest need and/or value ›› Prudent capex in the 2020-25 Regulatory Proposal (**Proposal**) results in a 1% growth in the RAB over the 2020-25 RCP
	IT expenditure is high, a full cost-benefit analysis must be undertaken, and the value of IT investment needs to be justified from the perspective of the customer	All our IT programs are supported by detailed cost-benefit analyses and business cases that explore alternative options. Value has been characterised in terms of customer benefit, for example benefits are framed in terms of what it means for our ongoing abvility to service customers
A safe and reliable network	Continued reliability of the network is a high priority	Prudent capex plans are proposed to maintain current reliability and safety levels and meet service standards
	Improving reliability for some parts of the network (eg Eyre Peninsula, Adelaide Hills) is important to customers. This is also supported by councils and Business SA	›› We have a targeted program to improve reliability to customers connected to low reliability feeders ›› We are continuing a targeted program to improve the resilience of storm-prone network areas (note the scope and costs of these targeted programs have been reduced following customer and stakeholder feedback on the 2020-25 Draft Plan)
	Regular asset inspection, maintenance and repair or replacement is important, and customers want us to continue to find efficiencies	›› In addition to our value-based approach to asset management (which focuses on the risk and value analysis of comprehensive asset data), we will continue to look for more innovative ways to manage our assets, such as the use of drones and other new technologies
	There is logic in our value-based approach to asset management — but we need to avoid ‘boom and bust’ cycles of expenditure	›› We are proposing an asset replacement program to continue at current levels. Even though ultimately these levels will need to increase, we think we can maintain these levels at least until 2025

	Customers expect SA Power Networks to operate safely, and balance safety, risk and affordability when managing the network	Ongoing focus on safety in our work practices and innovation in our value-based asset management approach to ensure we continue to deliver value for customers
	Bushfire safety is important, not only to those in bushfire risk areas, but to most customers	We are continuing our prudent bushfire risk mitigation plan to reduce the risk of our network starting fires (note the scope and cost of this program has been reduced following customer and stakeholder feedback on the 2020-25 Draft Plan)
	Customers value accurate, timely and tailored information about power outages	We will continue to improve our capability (through ongoing IT system enhancements) to provide customers with accurate and timely information
	Managing the risk of cyber security is important to customers	Prudent cyber security protections for customer and business information and network integrity are proposed
Transitioning to the new energy future	Customers, both with and without solar, support the ongoing uptake of rooftop solar and new technologies like home batteries and electric vehicles Enable continued uptake of renewable technologies – but not at any cost	›› We are proposing targeted investment in new systems to monitor and manage our low voltage network more actively, and to offer the option of variable, rather than fixed, export limits for customers with solar and other embedded generation ›› This will enable us to make available more of the existing asset capacity for solar exports, avoiding expensive network asset upgrades. It also enables greater flexibility so we can adapt to future change ›› This approach will vary dynamically based on when and where the constraints arise
	In a time of change when technology is evolving rapidly, avoid large expenditure on items that might become redundant Our plans should allow for a range of future scenarios – not lock us in to one version of the future Actively pursue third-party non-network solutions and demand management to avoid capital expenditure	›› Continued refinement of our industry-leading Future Network Strategy and related projects, pilots and trials. This integrated, measured and staged strategy focuses on market-based solutions, including purchasing and using available data from smart meters and third-party providers to reduce expenditure on grid-side monitoring devices ›› We are actively testing the market for demand management opportunities. So far we have identified around $28 million of capital projects that could be candidates for non-network solutions ›› Our approach of sending DER export limits is adaptable to whoever is receiving the message. DER services will continue to evolve but our approach does not 'pick a

		winner' in terms of how the market will evolve
	Work closely with industry to ensure national alignment Do not forget non-solar and vulnerable customers 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. CCP14 asked that we share more details of our network capacity modelling, and challenged us to seek least-cost solutions	›› Detailed customer research across all segments, including non-solar and vulnerable customer groups, as well as extensive and ongoing engagement with industry and other distribution networks, to ensure our plans are aligned with customer expectations and broader industry direction. All feedback, both qualitative and quantitative, supports our proposed approach of enabling more DER through active capacity management and variable export limits ›› By enabling more lower cost renewables to be connected to the network, the entire community will benefit from downward pressure on wholesale electricity prices and cleaner energy solutions while also avoiding more costly increases in additional network capacity

5.5 Rule requirements

Clause 6.5.7(a) of the NER provides that SA Power Networks must submit a building block proposal for the 2020-25 RCP that includes a forecast of the capex it requires in order to achieve each of the following capex objectives:

- meet or manage the expected demand for SCS over the 2020-25 RCP;
- comply with all applicable regulatory obligations or requirements associated with the provision of SCS;
- maintain the quality, reliability and security of supply of SCS (where there are no applicable regulatory obligations or requirements);
- maintain the reliability and security of the distribution system through the supply of SCS (where there are no applicable regulatory obligations or requirements); and
- maintain the safety of the distribution system through the supply of SCS.

Clause 6.5.7(c) of the NER provides that the AER must accept the proposed capex forecast that SA Power Networks includes in its building block proposal if the AER is satisfied the total forecast capex reasonably reflects each of the following capex criteria:

- the efficient cost of achieving the capex objectives;
- the cost that a prudent operator would require to achieve the capex objectives; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives.

Further, clause 6.5.7(e) of the NER requires that, in deciding whether or not it is satisfied that the total of our forecast capex reasonably reflects the capex criteria, the AER must have regard to the capex factors which include (but are not limited to) benchmarking, prior period performance and importantly the extent to which the capex forecast addresses the concerns of electricity consumers as identified in the course of SA Power Network's engagement with electricity consumers.

SA Power Networks is of the view that its proposed capex forecast meets the capex objectives and capex criteria, taking into account the capex factors and therefore should be accepted by the AER as part of its distribution determination for the 2020-25 RCP. In addition, our proposed capex forecast reflects a balanced approach that best achieves the national electricity objective (**NEO**) to promote efficient investment in, and efficient operation of use of, our electricity services for the long term interests of our customers,[1] and meets the revenue and pricing principles to provide us with a reasonable opportunity to recover at least the efficient costs we incur in providing those services and complying with our regulatory obligations.[2]

5.6 Our electricity distribution network

The electricity distribution network in South Australia is vast, covering more than 178,000km^2 along a coastline of over 5,000km. The network extends across difficult and remote terrain, operates in demanding conditions and stretches for over 82,000 route km, including over 400 zone substations, 77,800 street transformers, more than 640,000 Stobie poles and 200,000km of overhead conductors and underground cables. Our assets also include switches, meters, and many ancillary systems as well as fleet and depot facilities located across the State.

We supply electricity to more than 860,000 customers ranging from isolated farms in rural areas to industry precincts, regional and metropolitan residential homes, businesses and city centres.

With the exception of much of the coastal area, South Australia is very sparsely settled. Approximately 70% of SA Power Networks' customers reside in major metropolitan areas, including the great majority of business and commercial customers. However, the extensive area serviced by our distribution system results in 70% of the network infrastructure (in terms of circuit length) delivering energy to the remaining 30% of customers. Compared with other states, South Australia has relatively few regional centres, and they are generally small and sparsely located. As a result, the average customer density per kilometre of distribution line in South Australia is the lowest among the NEM distribution network service providers (**DNSPs**).

5.6.1 Network configuration

Our distribution network is predominantly a three-phase system, with some single-phase components used mostly in rural and remote areas. The sub-transmission network supplies and connects zone substations, operating at 66kV and 33kV. In rural and remote areas, the single-phase system predominantly operates at 19kV. Thirty percent of our network is comprised of these long 'single wire earth return' (**SWER**) lines. In higher density rural and urban locations, the three-phase distribution feeder system most commonly operates at 11kV, however some older 7.6kV distribution feeders still exist. The standard nominal low voltage customer supply is 230V at 50Hz.

[1] *National Electricity Law, section 7.*
[2] *National Electricity Law, section 7A.*

5.6.2 Our network operating environment

Figure 5-2: SA Power Networks' service area

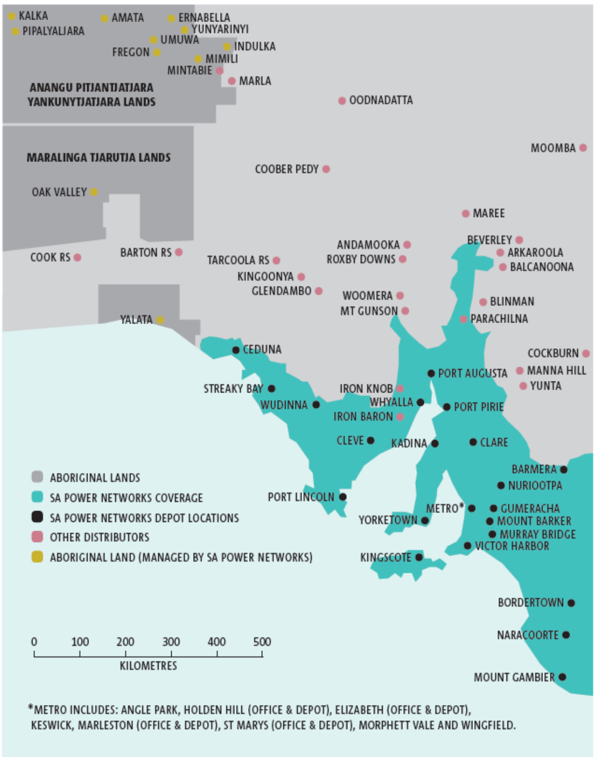
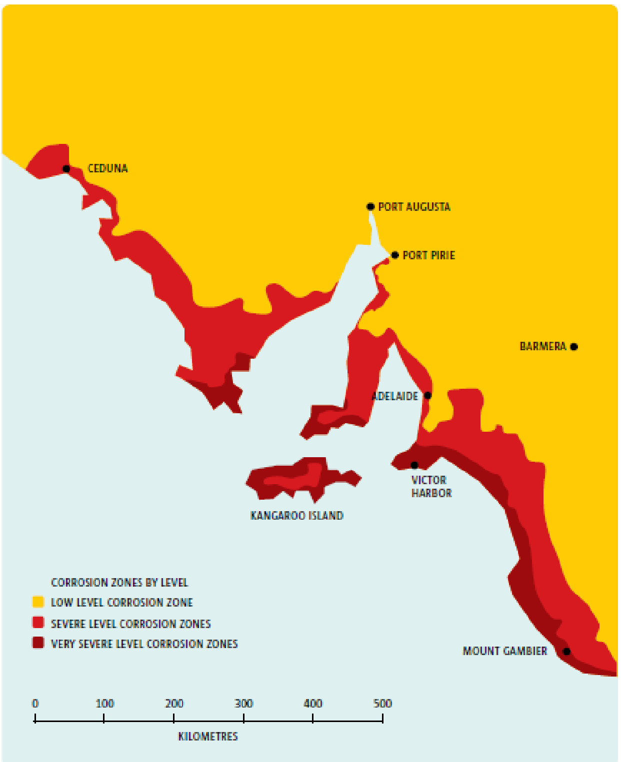


Figure 5-2 illustrates the extent of our overhead network in South Australia. The network is centred on Adelaide and supplies electricity to the south-east coastal region of South Australia and north towards inland South Australia.

As can be seen in Figure 5-2, SA Power Networks' overhead powerline network has a significant amount of assets situated along the coast, resulting in high exposure to a corrosive marine environment. As a consequence, corrosion of network assets is a major cause for concern to SA Power Networks. We have acknowledged the impact of corrosion on the assets in the overhead powerline network, including poles and conductors, by identifying different corrosion zones within South Australia. Figure 5-3 details the levels and location of the atmospheric corrosion zones in South Australia.

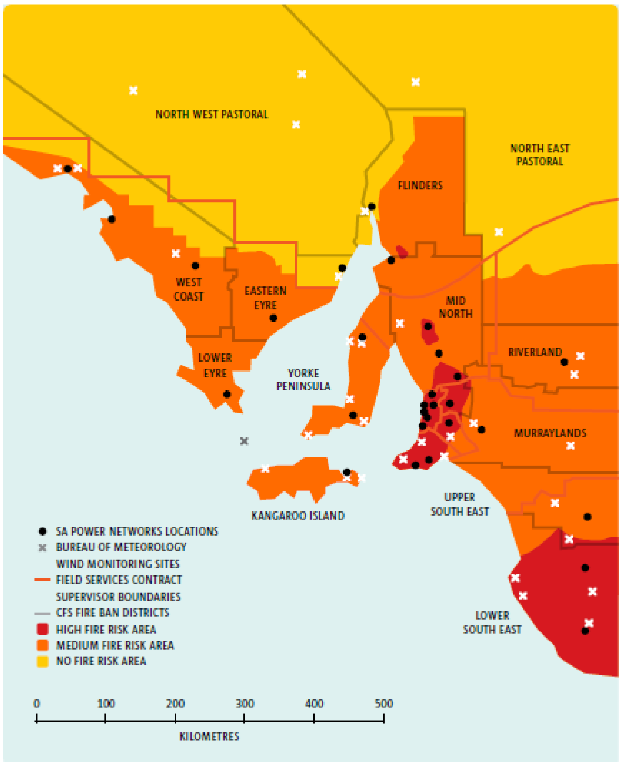
There are three levels of corrosion zones: low; severe; and very severe. The severe corrosion zones extend further inland due to the transfer of airborne salts by the atmosphere. Comparison of Figure 5-2 with Figure 5-3 identifies that a large proportion of the distribution network is located in the severe and very severe corrosion zones.

Figure 5-3: Atmospheric corrosion zone map of South Australia



SOURCE: SA POWER NETWORKS

Figure 5-4: Bushfire risk areas in South Australia



SOURCE: SA POWER NETWORKS

There is a significant risk of liability from fire starts in South Australia, due to the presence of bushland tracts in the vicinity of urban development areas and our 'Mediterranean' climate. The *Electricity (General) Regulations*

2012 (SA) (**Electricity (General) Regulations**) defines South Australia geographically into two zones, according the the degree of bushfire risk. Those zones are:

- non-bushfire risk areas (**NBFRAs**); and
- bushfire risk areas (**BFRAs**).

We have recognised the importance of minimising any risk associated with operating the distribution network in BFRAs by identifying the levels and location of bushfire prone areas. Figure 5-4 illustrates the three bushfire risk areas designated by SA Power Networks within South Australia.

The areas identified are high bushfire risk areas (**HBFRAs**), medium bushfire risk areas (**MBFRAs**) and NBFRAs. HBFRAs include most of the protected natural reserves, conservation parks and forestry plantations. MBFRAs reflect the risk to developments on the fringe of dense bushland. NBFRAs consist of metropolitan, suburban, and country districts.

In order to effectively manage our asset portfolio, SA Power Networks specifies and considers the corrosion zone level and the bushfire risk area category for each asset in our Asset Management Database.

In managing our assets and planning our network, a number of other factors that impact on the electricity needs of South Australian business and residential customers are taken into account including:

- changes in spatial demand and consumption diversity;
- impacts of DER;
- hot and dry climate;
- severe weather events;
- quality of supply; and
- rapid changes in emerging technology.

5.7 Performance during the 2015-20 RCP

5.7.1 Financial performance

In the 2015-20 RCP, we undertook a significant investment program. In addition to augmentation and connections expenditure, we undertook a significant step increase in asset replacement and refurbishment expenditure to manage the condition of our ageing and deteriorating infrastructure, refurbishing or replacing defective assets to maintain the safety, quality, reliability and security of supply in delivering SCS.

For our 2015-20 RCP, the AER determined an efficient capex allowance of $2,024.4 million (June 2020). The allowance was based on total gross capex less capital contributions. Our forecast total net capex for the 2015-20 RCP is $1,728.2 million (June 2020) as outlined in Figure 5-5 and Table 5-4. Appendix A sets out our detailed 15-year actual and forecast capex trend by category for the period from 2010 to 2025.

Figure 5-5: Comparison of capacity expenditure, AER allowance to actual/forecast for the 2015-20 RCP (June 2020, $ million)

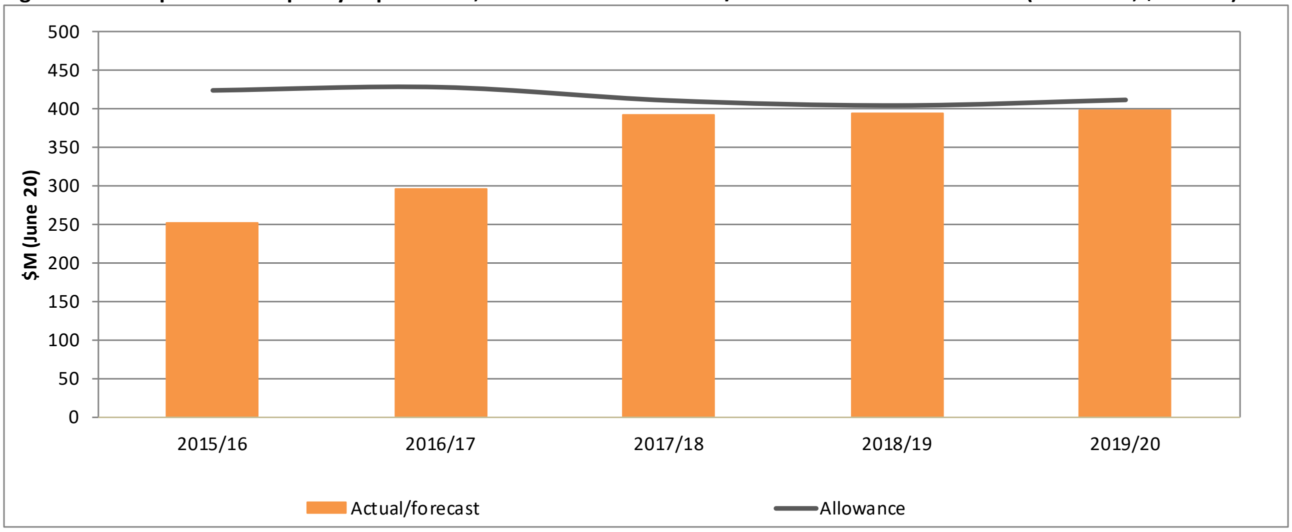


Table 5-4: Total net capex AER allowance and actual/forecast capex for the 2015-20 RCP (June 2020, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	TOTAL
Allowance	412.9	417.3	400.0	393.5	400.7	**2,024.4**
Actual and forecast	251.0	295.2	391.2	393.8	397.0	**1,728.2**

SA Power Networks has invested prudently and efficiently in network and non-network assets in the 2015-20 RCP spending $1,728.2 million, being $296.2 million or 15% less than the AER approved capex allowance for the 2015-20 RCP. Much of this underspend occurred in the first two regulatory years of the 2015-20 RCP.

Regulatory year one (2015/16) had abnormally low expenditure resulting from several factors. For example, we reprioritised some work programs to later in the 2015-20 RCP while the uncertainty concerning our revenue allowance for the 2020-25 RCP was being resolved.[3]

We also delayed some replacement expenditure (**repex**) where possible to allow us to change our 'risk-based replacement' approach to a more efficient and prudent 'value-based replacement' approach using our Valuing and Visibility Tool for a number of asset categories (including poles, power transformers, circuit breakers and protection relays).

This new ‘value based replacement’ approach has enabled us to remove more network risk during the 2015-20 RCP than we otherwise would have, had we spent in line with the AER allowances using the ‘risk-based replacement’ approach. Our ‘value-based replacement’ approach also results in less forecast repex for the 2020-25 RCP. Our ‘value-based approach’ is discussed further in Section 5.13.2.

In regulatory year two (2016/17) extreme weather events were at a record high, with nine Major Event Days (**MEDs**)[4] recorded (as compared to a historical average of three to four per year).This lead to:

- a diversion of resources to repairing and reinstating the network and away from implementing our capital program for the 2015-20 RCP; and
- a resulting increase in operating expenditure (**opex**) and decrease in capex during this regulatory year.

Variations in SA Power Networks’ capex in the 2015-20 RCP have also resulted from a number of other factors including:

- The lower than forecast growth in global demand resulted in us prudently deferring some augmentation projects. This lower than forecast demand was due to external factors beyond our control, including continued general economic downturn that resulted in the closure of some major

[3] The AER’s final distribution determination for the 2015-20 RCP was not published until 29 October 2015.

[4] MEDs are defined by the AER as extreme weather or events that interrupt power to a significant number of customers for extended periods.

commercial and industrial businesses in South Australia (eg the Holden manufacturing plant), and a slowdown in the new housing industry and agricultural industry. In addition, the continued significant uptake of solar (which exceeded the forecasts in our 2015-20 RCP) has reduced demand on our network.
- Lower customer connection work driven by lower customer growth and subdued housing market trends.
- Adopting cost-efficient alternatives to full asset replacement (ie refurbishment) where such actions are feasible, such as pole plating.
- Achieving cost efficiencies through improved business processes, one-off design improvements and a continued focus on equipment and service costs.

The incentive based regulatory regime encourages DNSPs to focus on efficiency in the delivery of capital investments undertaken throughout a RCP. Furthermore, there is a recognition that circumstances are likely to change during a RCP and where it is prudent to defer capex whilst still meeting service standards then DNSPs are encouraged to do so. This results in a lower RAB and lower costs to consumers in the next RCP.

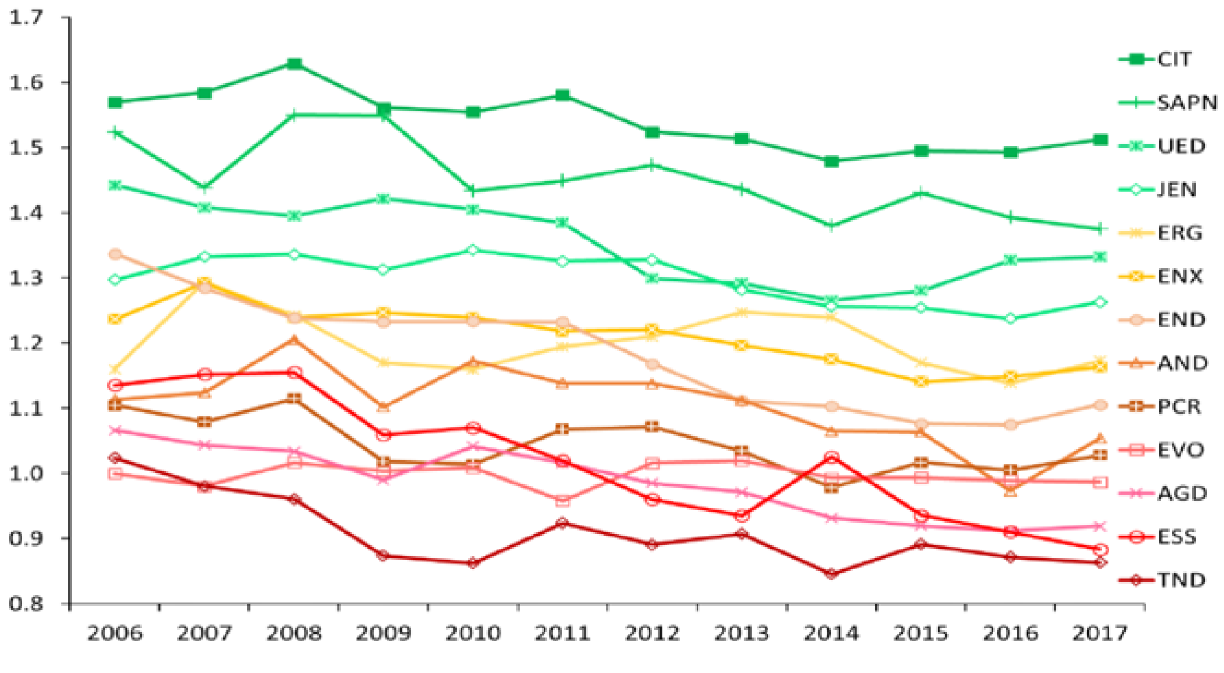
The actual/forecast level of capex in the 2015-20 RCP has resulted in SA Power Networks operating our network safely, complying with all obligations, and meeting our regulated service standards.

5.7.2 Benchmarking performance

Historical benchmarking of SA Power Networks' performance in the AER's annual benchmarking reports has shown that we are consistently in the top quartile of all DNSPs on almost all measures.

On a State-wide multi-lateral total factor productivity (**MTFP**) basis, SA Power Networks, as the sole DNSP in South Australia, benchmarks as having the highest distribution productivity level over the 2006-2017 period[5]. On an individual DNSP basis, we rank second behind CitiPower[6], which has the relatively small footprint of the Melbourne central business district. For capital multi-lateral partial factor productivity (**MPFP**) we rank second as shown in Figure 5-6 below.

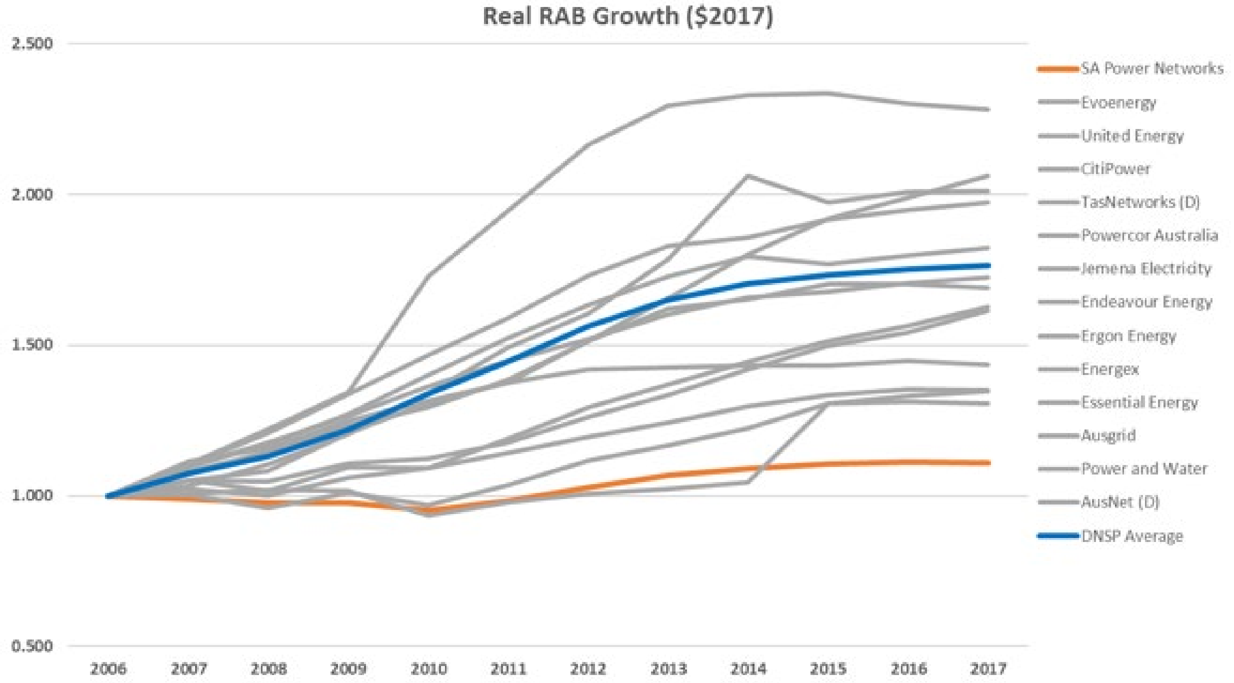
Figure 5-6: Capital MPFP by individual DNSP, 2006-17



[5] *AER, Annual benchmarking report, Electricity distribution network service providers, November 2018, page 12.*
[6] *Ibid, page 13.*

Additionally, over the 2006-17 benchmarking period, SA Power Networks' RAB growth has been the lowest of all DNSPs. Data for this has been sourced from the performance data released by the AER in November 2018[7], refer to Figure 5-7 below:

Figure 5-7: Figure 5 7: RAB growth by DNSP, 2006-17[8]



The above graphs demonstrate that our capex spend has been efficient. As a result, we have been recognised by the Grattan Institute[9] and the ACCC[10], for not over investing in our network. This is further supported by the AER's performance data released for network utilisation, which compares maximum demand to the total capacity of the distribution network at the zone substation level, which shows SA Power Networks as having one of the highest utilisation levels against our peers[11].

5.8 Capex categories

The AER categorises capex for SCS into four high level categories by primary driver.[12] These categories are as follows:

- **repex** — capex incurred to address deterioration in condition of existing network assets;
- **augex** — capex typically triggered by a need to build or upgrade network assets driven by changes in customer demand and/or non-demand factors;
- **connection and customer driven works** — capex necessary to connect new customers to the network or alter existing connections arrangements and other customer related works; and
- **non-network** — capex for activities not directly associated with the distribution network, including information technology (**IT**), network operational IT, fleet, property and other investments.

[7] *AER, Electricity distribution network service provider performance data 2006-2017, 2. RAB, 5 November 2018.*
[8] *AER, Electricity distribution network service provider performance data 2006-2017, 5 November.*
[9] *Grattan Institute, Down to the Wire: A sustainable electricity network for Australia, Technical, Supplement, March 2018, page 4.*
[10] *ACCC, Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry – Final Report, June 2018, recommendation 11.*
[11] *AER, Electricity distribution network service provider performance data 2006-2017, 10. Utilisation, 5 November 2018.*
[12] *AER, Expenditure Forecast Assessment Guideline, November 2013, p 17.*

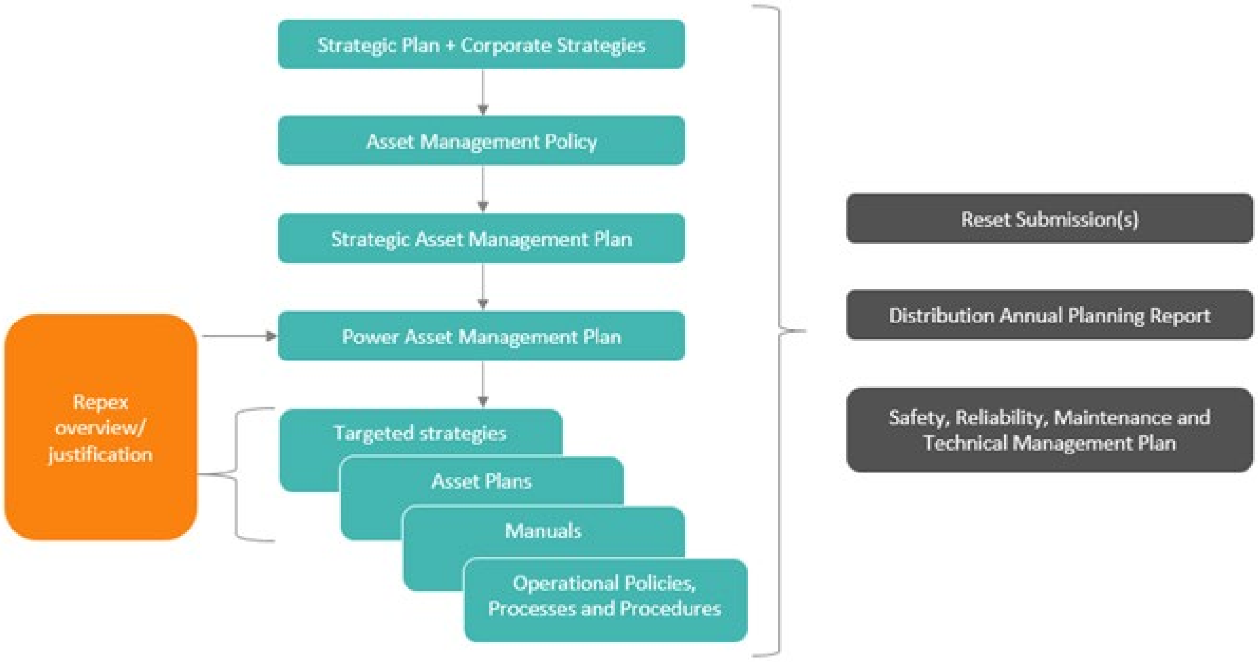
5.9 Documentation hierarchy

Several of our plans and strategies are related and collectively form part of the Asset Management System documentation that are incorporated by reference into the Office of the Technical Regulator (**OTR**) approved Safety, Reliability, Maintenance and Technical Management Plan (**SRMTMP**). These documents are as follows, the hierarchical relationship is shown in Figure 5-8:

- **Strategic Plan and other corporate strategies** – details our strategic direction, key priorities and core areas of focus, and sets the overarching direction for the organisation. Includes the Customer Engagement Strategy (Supporting Document 18.4), Future Network Strategy (Supporting Document 5.17) and Digital Strategy (available on request).
- **Asset Management Policy** – sets out the principles applied to asset management activities – Supporting Document 5.6.
- **Strategic Asset Management Plan** – outlines the operating environment and the challenges faced by SA Power Networks in delivering the service now and into the future, and the overarching strategies implemented to deliver a valuable service to customers – Supporting Document 5.7.
- **Power Asset Management Plan** – details the levels of service delivered, the assets required to deliver these levels of service, the risks faced, asset life-cycle strategies, historical and forecast expenditure to deliver the levels of service and/or to address identified risks – Supporting Document 5.8.
- **Distribution Annual Planning Report** – informs NEM regulators, participants and stakeholders about the existing and forecast system limitations on our distribution network, our network performance and our proposed distribution related investment for the forward planning period. Preparation of this document is a regulatory requirement (available on SA Power Networks' website[13]).
- **SRMTMP** – details the management framework, key procedures and associated performance indicators for the safety and technical management of our electricity infrastructure through its life cycle. Preparation of this document is a regulatory requirement – Supporting Document 5.3.
- **Detailed strategies, plans, manuals, policies, processes and procedures** – gives detailed guidance for maintenance and day-to-day operation activities – these documents are available on request by the AER.
- **Repex overview** – outlines the methodologies considered in developing the forecast repex and justification of the proposed methodology for determining the forecast repex for the 2020-25 RCP – Supporting Document 5.9.

[13] https://www.sapowernetworks.com.au/industry/annual-network-plans/

Figure 5-8: Documentation hierarchy

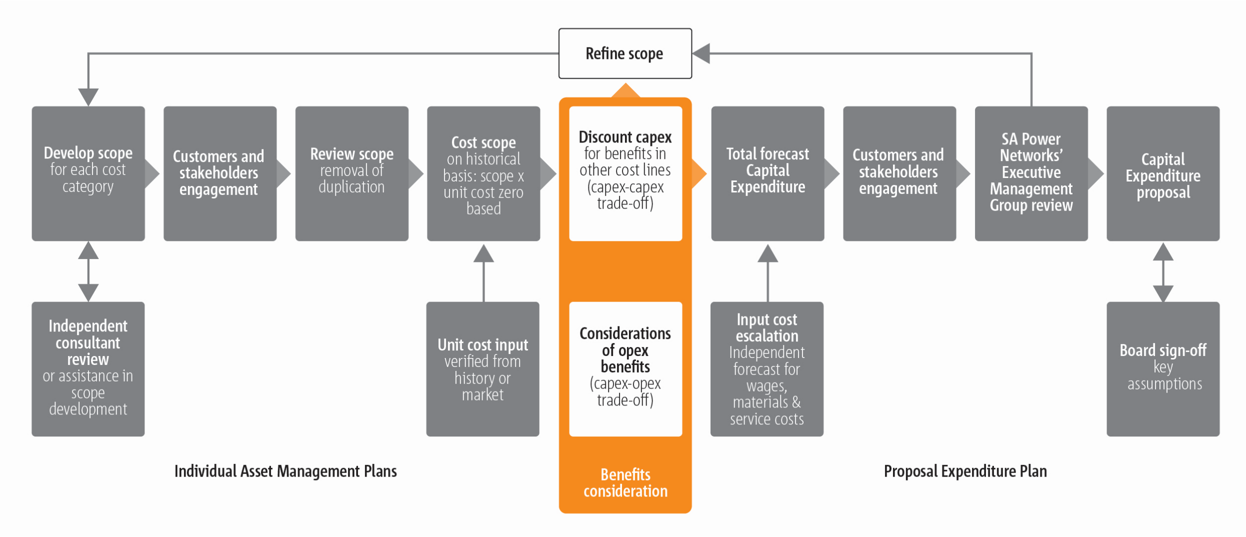


5.10 Capex development process

This section outlines the process, inputs and governance used in developing our capex plans and forecasts for network infrastructure for the 2020–25 RCP. Figure 5-9 illustrates the process utilised for the development of network capex plans.

Non-network categories (IT, network operational IT, property, fleet and other) have their own individual processes and are described in detail in Section 5.16 of this Attachment.

Figure 5-9: Network capex planning and forecasting process



We have undertaken extensive customer and stakeholder engagement which has influenced our capex program, this process is discussed in detail in our Overview document and Customer stakeholder and engagement report.

The scope of each capex plan has been developed using a risk-based approach that aligns with SA Power Networks' capital governance procedures (refer Supporting Document 5.2 – Capital Governance Process). This approach ensures that we can:

- meet forecast demand over the 2020-25 RCP;
- comply with all applicable regulatory obligations or requirements associated with the provision of SCS;
- deliver levels of customer service to meet our jurisdictional service standard obligations;
- achieve acceptable levels of business risk; and
- achieve acceptable levels of safety risk to the public and employees.

Key inputs into the development of our asset plans and forecasts for repex and auges include:

- regulatory obligations and requirements;
- jurisdictional service standards — essentially requiring that SA Power Networks maintain reliability and customer service at historic levels of performance;
- customer preference and expectations from our customer engagement program;
- condition and economic (value based) risk assessments for asset replacements and refurbishments;
- network planning criteria which deals with the response to changes required in the network;
- spatial peak demand forecasts which respond to the customer driven demands on the network; and
- customer connection forecasts which identify our response to the increase in customers connecting to the network.

The approach to developing forecasts for capex uses a 'bottom-up approach' whereby the network needs are identified and costed using historical building block estimates based on delivery of similar programs and projects.

It is incumbent on us as a DNSP that we develop prudent and efficient expenditure plans. In the process of developing our capex forecasts, we have considered the substitution possibilities between opex and capex to ensure that a consideration of whole of life costs forms part of the process of developing a solution. We have also ensured there is no 'double up' of expenditure in multiple categories. The development of expenditure plans incorporates a process of considering the 'trade-off' or benefits review between:

- capex and opex;
- refurbishment and replacement of assets; and

- network and non-network solutions.

5.10.1 Drivers

Table 5-5 summarises the drivers behind each capex category.

Table 5-5: Summary of categories of drivers of capex

Category	Driven by
Repex	• Condition • Defects • Age of asset components – some components require replacement as they have exceeded their serviceable life • Risk 'value' – a defect with a higher value of consequence of failure is prioritised ahead of other defects
Augex	• Growth in demand • Changes in the way power is used and generated • Compliance with reliability standards • Compliance with regulations (such as environmental standards)
Customer connections expenditure	• Growth in the number of customers • Changes to customer's connection requirements
Non-network expenditure	• Age and condition of underlying assets (such as fleet and property) • Ability to continue to perform and support assets (such as replacement of IT) • Changes to business requirements and environmental conditions (such as the development of depots and property issues) • Changes to the way energy is used (such as IT for 'network of the future' needs)

5.10.2 Escalations

Our forecast capex is built up using current values of costs in 2017 dollars. The costs are then escalated for forecast changes in the real input costs anticipated over the 2020-25 RCP. These escalators are consistent for both capex and opex. The methodologies used are outlined below:

Labour – SA Power Networks has escalations from the BIS Oxford Economics (**BISOE**) report titled 'Utilities and construction wage forecasts to 2024/25 for SA Power Networks'. Consistent with recent AER determinations, we have adopted an average of BIS Oxford Economics and Deloitte Access Economics' (**DAE**)[14] utilities sector labour price growth forecasts.

A copy of BIS Oxford Economics' full report is included as Supporting Document 6.6. Our DAE forecasts are based on the report prepared for the AER and applied in the final determination for ElectraNet's 2018-23 RCP (as relevant to South Australia),[15] with the final two years an average of the 2020 to 2023 period.

- **Contracted construction and labour services** – SA Power Networks has applied escalations from the BISOE report titled 'Utilities and construction wage forecasts to 2024/25 for SA Power Networks.

[14] *Deloitte Access Economics, Labour price forecasts prepared for the Australian Energy Regulator, 7 February 2018, page 74. Noting: DAE forecast only provides escalations to 2022/23, an average of the forecast for the regulatory years between 2020-2023 has been applied for the remaining two regulatory years.*

[15] *Deloitte Access Economics, Labour Price Forecasts prepared for the Australian Energy Regulator, 7 February 2018, page 74. Note that forecasts are only reported up to 2022/23; AER, ElectraNet Transmission final determination 2018-23, Overview, April 2018, page 26.*

- **Materials** – SA Power Networks is forecasting that non-labour costs will increase in line with CPI (ie no real price increase).
- **Land** – SA Power Networks has not applied a real land cost escalation.

A summary of the cost escalation rates discussed above and applied to capex is outlined in Table 5-6 below. Further detail regarding the approach used to develop these escalation rates is presented in Attachment 6 – Operating expenditure.

Table 5-6: Escalation rates applied to the capex forecast for the 2020-25 RCP

Escalation rates (real %)	2020/21	2021/22	2022/23	2023/24	2024/25
Labour	0.78	1.07	1.21	1.09	0.96
Contract labour	0.69	1.38	1.65	1.29	0.89

SA Power Networks' Cost Allocation Method (**CAM**) has been applied to the capex build-up process. This CAM was approved by the AER in January 2018.

Feedback from the customer and stakeholder engagement process has influenced the development of the scopes of our capex plans, and the review and refinement process, to ensure that we have developed plans that are consistent with customers' needs and requirements. We have a continuous engagement process and regularly revise plans based on customer input. This has resulted in support for some programs (such as customers on low reliability feeders), and has influenced the scope and focus of other programs (such as the bushfire risk mitigation and the low voltage (**LV**) management strategy).

In accordance with good governance, the SA Power Networks Executive Management Group (**EMG**) and Board (as the ultimate approvers) have reviewed and endorsed the capex plans at strategic stages in the capex development process. As required under the NER, the SA Power Networks' Board has certified the reasonableness of the key assumptions underlying the expenditure forecasts (refer Supporting Document 18.2 - Directors Certification).

5.11 Key assumptions

Our capex forecast is based on a number of key assumptions set out in Table 5-7.

Table 5-7: Key assumptions relevant to the capex forecast for the 2020-25 RCP

Key assumptions
Forecast capex incorporates customer and stakeholder engagement feedback
Past capex provide a reasonable indication of likely future capex, except where otherwise noted in the Proposal
Benchmarking confirms that we are acting as an efficient DNSP
Labour escalation as forecast
Contracted construction and labour services as forecast
Unit costs of work will remain consistent with historical costs, with the exception of labour and services cost escalation
Replacement and refurbishment asset management strategies and the scope of works selected for each asset category are appropriate to meet the capex objectives
Spatial peak demand growth is as forecast
Capacity asset management strategies and the scope of works selected for each asset category are appropriate to meet the capex objectives
Customer connections are as forecast

5.12 Summary of capex forecast for the 2020-25 RCP

Figure 5-10 shows our proposed capex forecast for the 2020-25 RCP as compared to our actual/forecast capex for the 2015-20 RCP, and our actual capex for the 2010-15 RCP. Our capex forecast for the 2020-25 RCP is $1,741.1 million and is substantially the same level of capex as the 2015-20 RCP ($12.9 million higher), and $108.9 million lower than the preliminary forecast we consulted on in 2018.

One key change contributing to this reduction has been a decision to treat repex relating to cable and conductor minor repairs as opex. This expenditure has historically been categorised as repex. However, we consider that the inter-generational equity concerns raised during the AER's review of the regulatory tax approach warrant re-categorising this type of expenditure as opex rather than capex. Cable and conductor minor repair work is more akin to repairs and maintenance rather than refurbishment and essentially only benefits current customers.

For these reasons, SA Power Networks is proposing to remove this type of expenditure from its repex forecast and include a capex/opex trade off step change in its opex forecast for this type of expenditure. This change has reduced our repex forecast by $69.9 million and increased our opex forecast (through a proposed capex/opex trade off step change) by $68.2 million[16]. We believe this change, along with the suite of other changes made as a result of the AER's tax review is efficient and in the long-term interests of customers and therefore better promotes the NEO.

Figure 5-10: SCS forecast gross capex trend for the 2010-2025 period (June 2020, $ million)

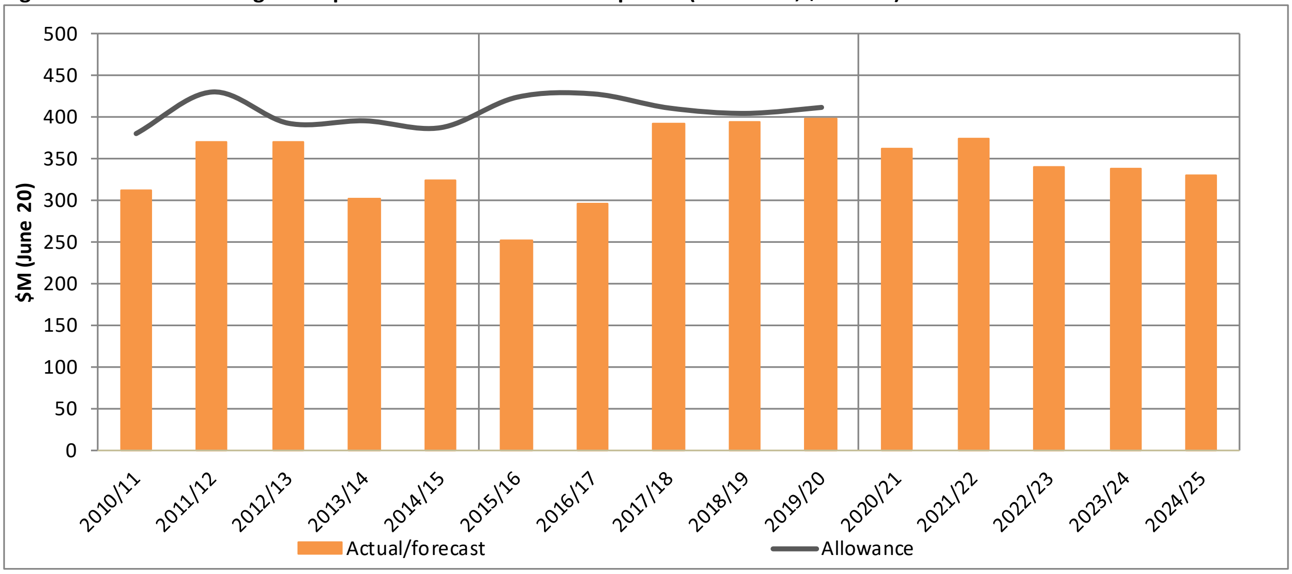


Table 5-8 shows SA Power Networks' forecast of the total net capex for SCS that we consider will be required during the 2020-25 RCP in order for us to achieve the capex objectives.

Table 5-8: SCS forecast net capex for the 2020-25 RCP (June 2020, $ million)

	2020/21	2021/22	2022/23	2023/24	2024/25	TOTAL
Replacement	129.0	135.8	137.9	135.1	131.7	**669.5**
Augmentation	84.9	83.0	73.4	74.2	75.4	**390.9**
Customer Connections						
Connections (gross)	111.3	113.2	114.4	114.0	110.2	**563.2**
Contributions	70.6	70.3	70.8	70.6	67.8	**350.1**
Connections (net)	40.7	43.0	43.6	43.4	42.5	**213.2**
Non-Network	106.4	112.7	83.9	84.7	79.7	**467.4**
Total SCS capital (net)	**361.0**	**374.6**	**338.9**	**337.3**	**329.2**	**1,741.1**

[16] The application of the escalators differs slightly between capex and opex, hence the variation of $1.7 million.

The following sections describe in detail our forecast capex programs for SCS for the 2020-25 RCP.

5.13 Repex forecast

Repex is non-demand driven capex for the replacement of:

- defective assets with their modern equivalent at the end of the assets life; or
- an asset at risk of failure, which could result in compromised safety or a failure to meet our service standard targets,

where it is economic to do so.

Repex also encompasses refurbishment expenditure aimed at efficiently extending the operating life of an asset (for example, pole plating as compared to pole replacement).

Replacement or refurbishment can occur either as a result of asset failure (ie unplanned asset replacement) or on the basis of age and condition of an asset and having regard to the levels of risk being managed (ie planned replacements).

We do not always replace assets 'like for like', we endeavour to install assets fit for current and future needs. For instance, if demand has reduced we will replace an aged power transformer with a new or refurbished lower capacity power transformer. Where feasible we consider non-network solutions, however, 80% of asset replacement is 'like for like' because we are only replacing individual components eg a pole or insulator, as opposed to an entire section of the network.

Repex comprises around 40% of our total capex forecast. This expenditure is necessary to enable SA Power Networks to:

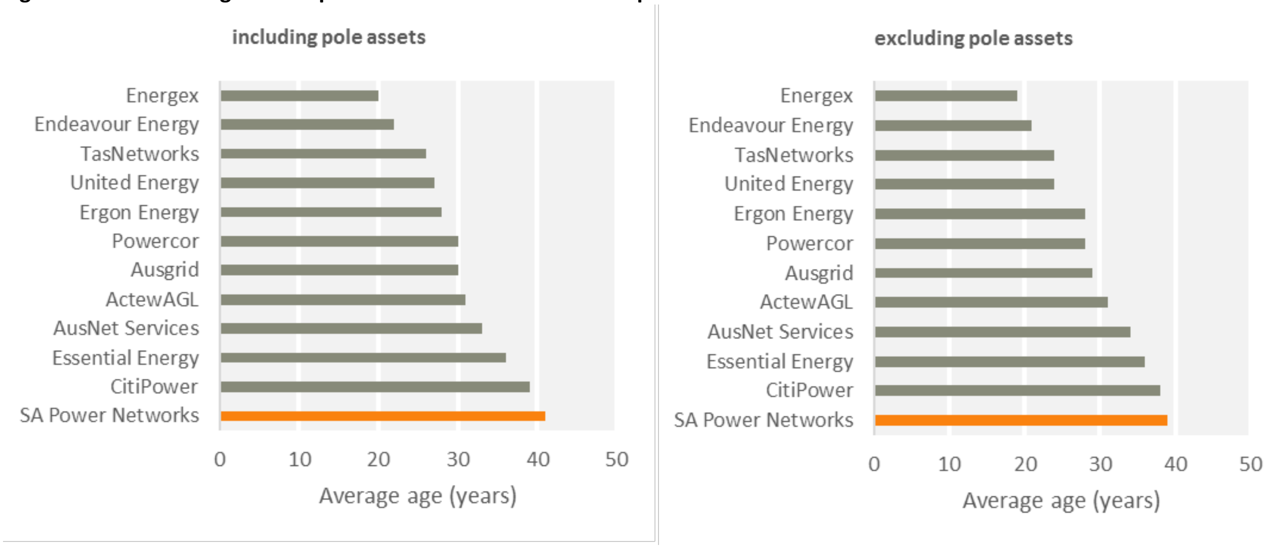
- maintain an acceptable level of distribution system safety and reliability by addressing identified defects in, and the degradation of, our ageing network assets; and
- to meet our jurisdictional service standards and to comply with our other regulatory obligations and requirements.

This level of repex reflects the increasing number of asset defects occurring within our network due to age, use and environmental conditions and is based on detailed modelling and methodologies as summarised in Section 5.13.3 and in greater detail, Supporting Document 5.8 – Powerline asset management plan and Supporting Document 5.9 – Repex overview.

We have ramped up repex during the 2015-20 RCP and the forecast repex for the 2020-25 RCP is maintaining repex at slightly below the current annual (2018/19) repex level.

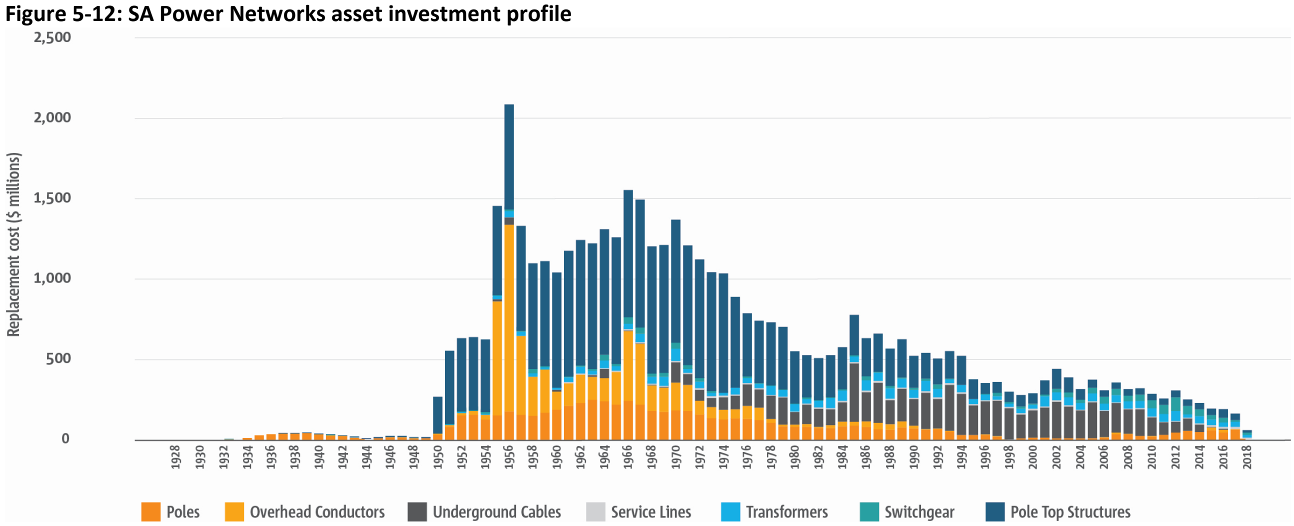
Figure 5-11 compares the average asset age of NEM DNSPs and shows we have the oldest electricity network in the NEM.

Figure 5-11: : DNSPs aged asset profile with and without Stobie poles[17] [18]



This age profile has developed over the last 60 years with many assets having been built in the 1950s, 1960s and early 1970s. This age profile reflects our asset management practice of repairing and refurbishing assets to extend their operating life where cost effective, rather than replacing them with new, more expensive assets. Figure 5-12 shows when the bulk of our assets were installed, and where we have invested in new assets in recent years.

Figure 5-12: SA Power Networks asset investment profile



In the 2015-20 RCP, we have significantly increased our repex, however even with this increase in repex we are only replacing 0.3% of our assets each year.

Other NEM DNSPs have made significant investments in new assets during the period from 2005 to 2012, while our investment has been low in comparison.

In order to continue to keep overall costs down whilst improving efficiency, we have actively sought to improve and refine our asset management practices.

Our understanding of network risk has evolved over the years. Twenty years ago, we would replace assets when they failed, with little to no proactive replacements. Fifteen years ago, we introduced a time-based

[17] One key difference between SA Power Networks' distribution network and the networks of other DNSPs is that our distribution poles are exclusively 'Stobie poles' which are constructed from steel and concrete. Although Stobie poles may be more subject to defects in high corrosion zones, they typically have longer lives than timber poles used by other DNSPs. Excluding Stobie poles, we still have the oldest network assets.

[18] *Data sourced from the AER, Electricity distribution network service provider performance data 2006-17, 5 November 2018.*

priority system with asset inspectors using their judgement to determine how quickly we needed to rectify defects. Ten years ago, we introduced a maintenance risk value score that considered additional factors such the bushfire risk area of an asset in assessing the priority of defects.

In 2012 we increased our inspection efforts and introduced inspection cycles based on asset criticality, bushfire risk and corrosion zones.

In 2014 we took our first step towards a condition based approach as we modelled network risk using CBRM. In 2017 we expanded the number of assets we modelled in CBRM and started operationalising our learnings from the CBRM methodology by capturing more condition data and additional environmental factors during inspections. These inputs are now being used to determine the value of addressing defects, considering more refined risk reductions and benefits such as improved customer experience.

Today we are focused on delivering the most value from our resources through improving how we make decisions throughout our end-to-end processes. This has allowed us to prudently manage our network risk and service.

Our next focus is on refining our understanding of how assets fail through further failure mode analysis and integration with robust statistical models.

We need to know more about our assets to maintain a view of our asset risk, by improving our data collection on high priority assets, why assets fail, and manufacturer and design details. We are extending our ability to efficiently capture asset condition using technology and investing in predictive analytics to ensure we focus expenditure on the highest value work.

Our asset management evolution is discussed more fully in Supporting Document:
- 5.7 – Strategic Asset Management Plan; and
- 5.9 – Repex overview.

We are also incentivised through the capital expenditure sharing scheme (**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, most asset replacement tends to involve like-for-like replacement of individual network components (e.g. poles, conductors, transformers, and switchgear). We have not yet identified any material non-network alternatives for this work although a number of opportunities are being considered for exploration over 2020-25 utilising the demand management incentive allowance mechanisim (**DMIAM**).

5.13.1 Repex regulatory obligations and requirements

Repex is required in order to achieve the capex objectives in relation to:
- complying with all applicable regulatory obligations or requirements associated with the provision of SCS[19]; and
- maintaining the safety of the distribution system through the supply of SCS[20].

Our regulatory obligations relating to the provision of SCS and the maintenance of the safety of our distribution system derive from a number of sources. These sources include:
- section 60 of the *Electricity Act* 1996 (SA) (**Electricity Act**) which requires us to take reasonable steps to ensure our infrastructure is compliant with the regulations and is safe and safely operated;
- the requirements of our distribution licence issued by the Essential Services Commission of South Australia (**ESCoSA**) (**Distribution Licence**);
- the OTR approved SRMTMP;

[19] *NER 6.5.7(a)(2).*
[20] *NER 6.5.7(a)(4).*

- the various requirements relating to the maintenance of network assets referred to in the Electricity (General) Regulations 2012 (SA) (**Electricity (General) Regulations**) (and section 12 of Schedules 1 – 4 in particular);
- the Electricity Distribution Code Version EDC/12.1 January 2018 (**EDC**);
- the ESCoSA Service Standards Framework for reliability; and
- Chapter 5 of the NER (and clauses 5.2.1 and 5.2.3 in particular which require us to maintain and operate our facilities in accordance with relevant laws and Australian Standards, the requirements of the NER and good electricity industry practice, and the power system performance and quality of supply standards set out in Schedule 5.1 of the NER).

These regulatory obligations are summarised below and described in further detail in Supporting Document 5.9 - Repex overview.

5.13.1.1 ESCoSA Service Standard Framework

The ESCoSA Service Standard Framework (**SSF**) prescribes the reliability and customer service levels that we must deliver to customers. The service levels that will apply for the 2020-25 RCP are based on the frequency and duration of unplanned interruptions in four broad feeder categories (CBD, Urban, Rural Short and Rural Long). On 7 January 2019, ESCoSA finalised the service standards and advised that targets will be finalised following consultation and once the 2018/19 reliability outcomes are known. The new targets will reflect the average historical performance levels over a five or 10 year period ending 30 June 2019, aimed at maintaining underlying average reliability to customers connected to those feeder categories.

The revised targets will exclude network performance during severe or abnormal weather events using the Institute of Electrical and Electronics Engineers (**IEEE**) MED exclusion methodology. ESCoSA will consult on the targets during 2019 with the actual targets incorporated into the EDC in early 2020, and will apply from 1 July 2020.

5.13.1.2 OTR approved SRMTMP

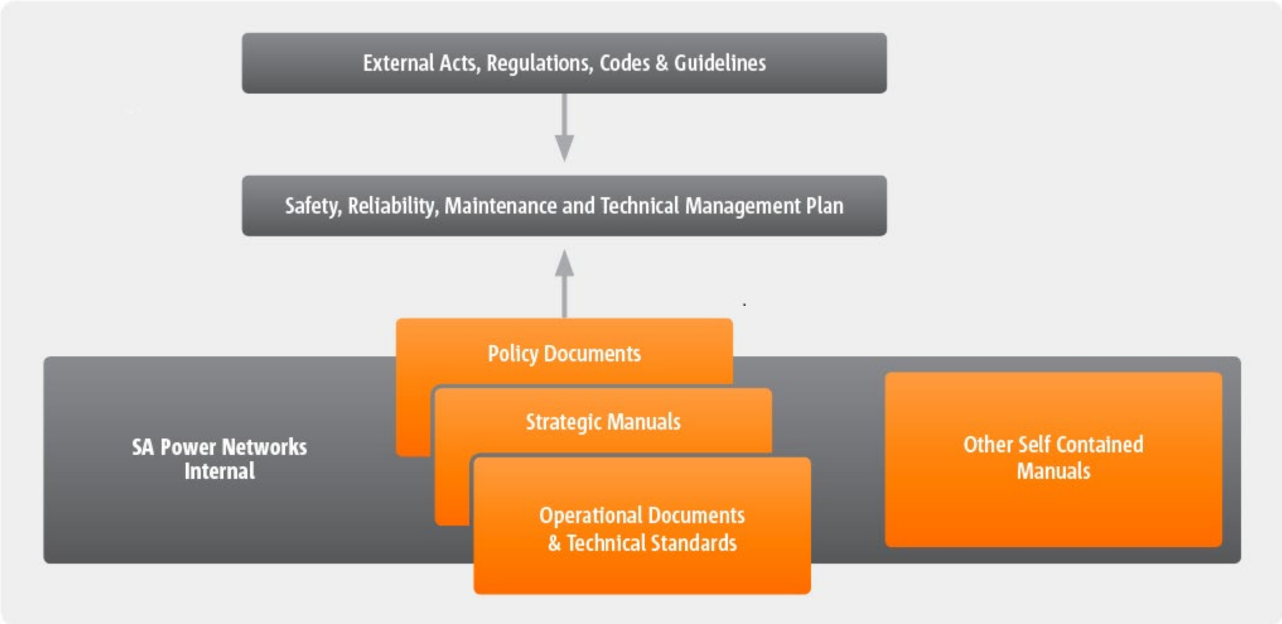
SA Power Networks is required under the conditions of its Distribution Licence and section 25 of the Electricity Act to comply with its OTR-approved SRMTMP.

The SRMTMP incorporates by reference a hierarchy of internal SA Power Network documents (refer to Figure 5-13 below). These internal documents are considered and updated during the annual SRMTMP review and approval process as they form an integral part of the plan. The SA Power Networks' internal documents include the Network Maintenance Manual (No. 12) and the Line Inspection Manual (No. 11) which outline the:

- system of maintenance;
- predetermined processes; and
- managed replacement programs,

instituted by SA Power Networks for the purposes of meeting (amongst other things) its obligations under Section 12 of Schedules 1 - 4 of the Electricity (General) Regulations.

Figure 5-13: SRMTMP referenced internal document structure



The internal SA Power Networks documents which form part of the SRMTMP include applicable standards and requirements that specify the rectification of network asset defects. The Network Maintenance Manual (No. 12), in particular, outlines the inspection cycles for all asset categories.

The SRMTMP and the internal documents which are incorporated by reference into the SRMTMP are required by the Electricity Act and our Distribution Licence and are approved by the OTR. As noted above, SA Power Networks is required to comply with the OTR approved SRMTMP under its Distribution Licence and the Electricity Act. The standard setting body for safety, reliability, maintenance and technical compliance is therefore the OTR.

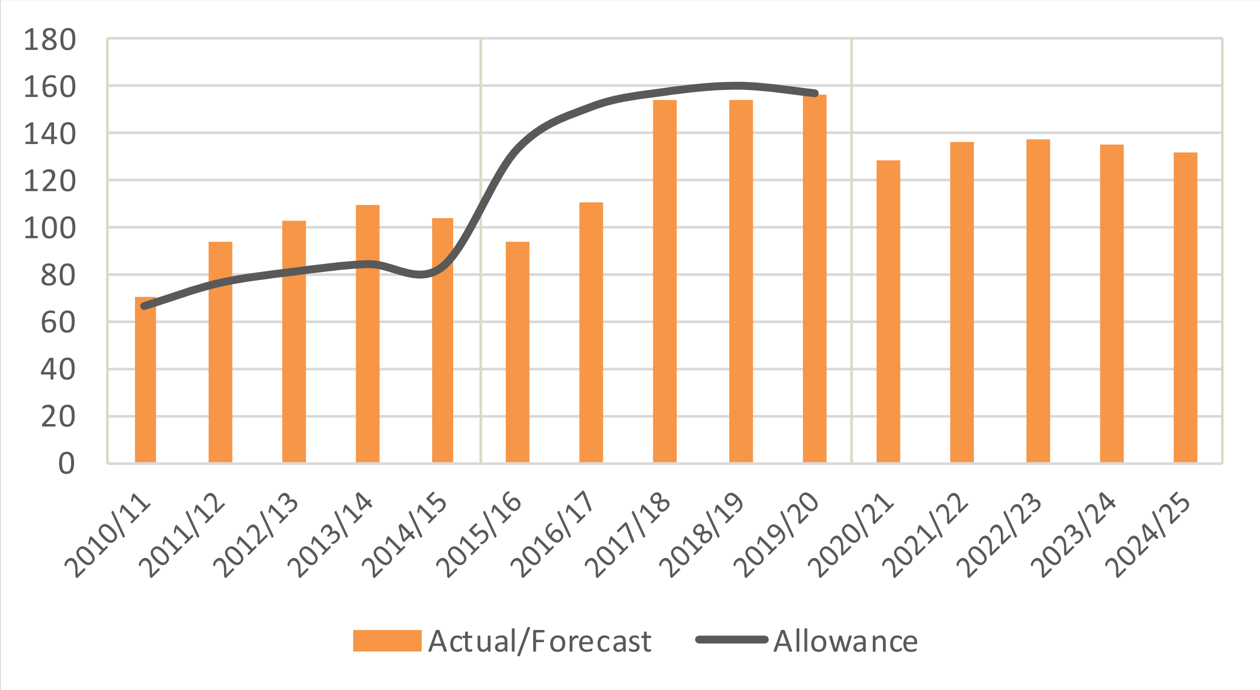
It follows that the OTR approved SRMTMP, together with clause 8 of our Distribution Licence and sections 25(1) and 60(1) of the Electricity Act impose a regulatory obligation on SA Power Networks to manage the integrity, safety and reliability of the network in accordance with the requirements of the SRMTMP (and the SA Power Networks internal documents which are incorporated by reference into the OTR approved SRMTMP). Refer to Supporting Document 5.3 for the most recent OTR-approved SRMTMP.

The SRMTMP sets the level of safety risk that must be maintained in order to achieve the capex objective set out in clause 6.5.7(a)(4) of the NER.

5.13.2 Repex outcomes for the 2010-15 RCP and 2015-20 RCP

For comparison purposes, Figure 5-14 shows our past, current and forecast[21] repex and spending profiles.

Figure 5-14: SA Power Networks repex allowance and actual spend (June 2020, $ million)



5.13.2.1 2010-15 RCP repex

As explained above, from 2010, we increased our inspection program across our entire asset base as a result of the changing safety environment and the consequential evolution of good electricity industry practice. A major part of that improvement was the continuation of the transition from a 'replace-on-fail' approach to a 'replace-before-fail' approach for our more critical assets, known as ‘priority’ assets. This approach required good asset condition data and the use of improved analysis techniques that allowed us to assess the risks of asset failure and better enable prudent replacement or refurbishment.

The change recognised that as the majority of SA Power Networks' assets were installed in the 1950s, 1960s and early 1970s, they were more likely to exhibit higher levels of defects as compared to newer assets. In addition, SA Power Networks had a historically low expenditure on asset replacement and refurbishment (pre 2010).

We have introduced more rigour in the way we inspect assets and collect asset condition data. This has allowed us, for the first time, to develop a comparatively near complete database on the condition of all network asset components, albeit data quality for some assets still needs significant improvement to enable more sophisticated asset management techniques and models to be utilised.

This improvement in our asset inspection process resulted in a significant increase in the volume of identified defects. Importantly, the volume of identified defects and consequential replacementand refurbishment activity is what we envisaged when we submitted our regulatory proposal for the 2010-15 RCP to the AER. It is also significantly above what the AER allowed for in its distribution determination for the 2010-15 RCP (**2010 Determination**).

[21] Note the forecast for the 2020-25 RCP excludes cable and conductor minor repairs now included as an opex step change.

As a result of this, we spent more than the AER allowance for repex in the 2010-15 RCP. We did this to ensure that we were able to prudently manage the unacceptable increase in risk that would have arisen as more assets failed — due to age related failures and during storms — and to address the increasing number of age-related defects identified during inspections.

In 2015, we agreed with the OTR to assess and rectify outstanding defects using a prudent long-term risk-based approach — with the objective of returning overall asset condition and risk to satisfactory historical levels consistent with the SRMTMP over a ten-year period (from 2015 to 2025).

5.13.2.2 2015-20 repex

In the 2015-20 RCP, our total repex will be $669.6 million, $89.8 million below the AER allowance of $759.4 million. Figure 5-15 and Table 5-9 below details our forecast repex compared to our allowance for the 2015-20 RCP.

Figure 5-15: SA Power Networks repex allowance and actual spend for 2015-20 RCP (June 2020, $ million)

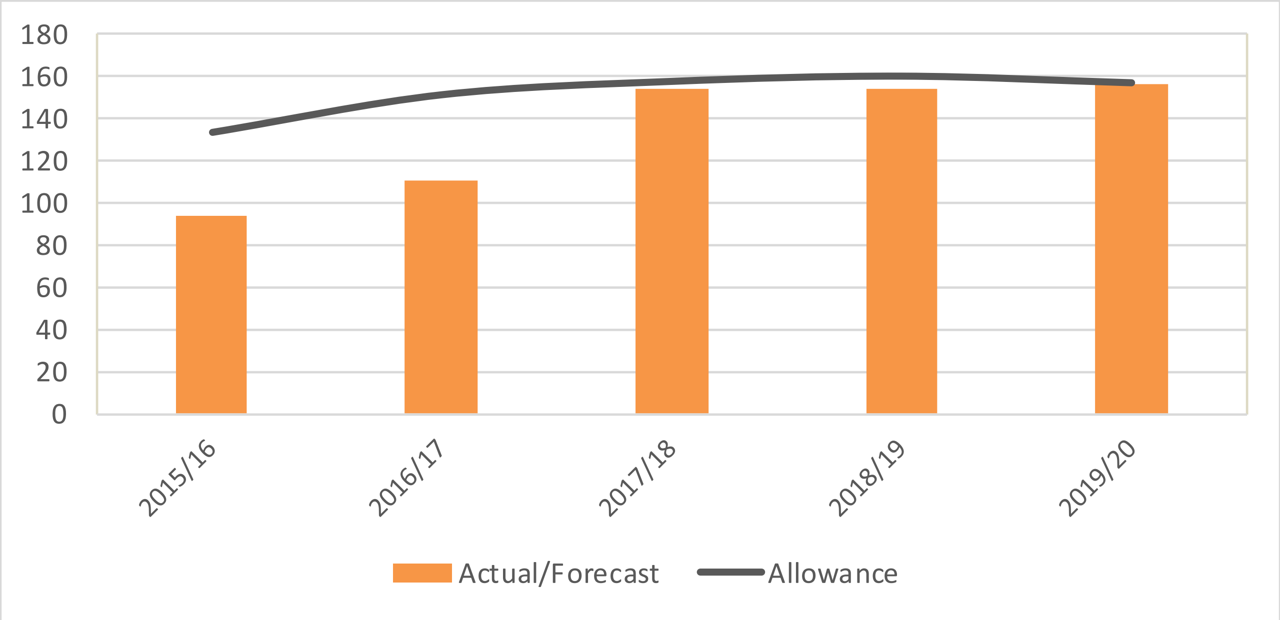


Table 5-9: Comparison of repex expenditure, AER allowance to actual/forecast (June 2020, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	TOTAL
Allowance	133.1	151.3	157.7	160.3	157.1	**759.4**
Actual and forecast	93.6	110.4	154.6	154.6	156.5	**669.6**

In developing our repex forecast for the 2015-20 RCP, we sought to prudently manage the return of our asset portfolio risk to the level that is required for compliance with our regulatory obligations and requirements under the SRMTMP, as approved by the OTR. The primary reason for returning our risk profile to historical levels was (and continues to be) our heightened concern that the structural failure of an asset would result in risk to people, property, the environment or our network. That is, limiting the potential for public safety risk (through direct impact or electric shock following structural failure, which risk is more significant in densely populated urban areas) and for bushfire risk (asset failure causing fires) particularly in bushfire risk areas.

For our powerline assets, we forecast a significant increase in repex to enable us to manage the forecast level of network asset defects while meeting our regulatory obligations and requirements and progressively moving our network risks back to levels acceptable to SA Power Networks, the OTR and our customers. We considered this approach was prudent, delivered an efficient outcome over the longer term, and was required to discharge our duty to take reasonable steps to ensure that our distribution system is safe and safely operated in accordance with section 60(1) of the Electricity Act.

For our substation assets, we forecast repex that was, overall, consistent with our average historic repex.

We also forecast repex for telecommunications and general safety programs required to maintain an acceptable level of safety and reliability (by addressing the degradation of our ageing assets), to meet our jurisdictional service standards and to comply with our regulatory obligations and requirements.

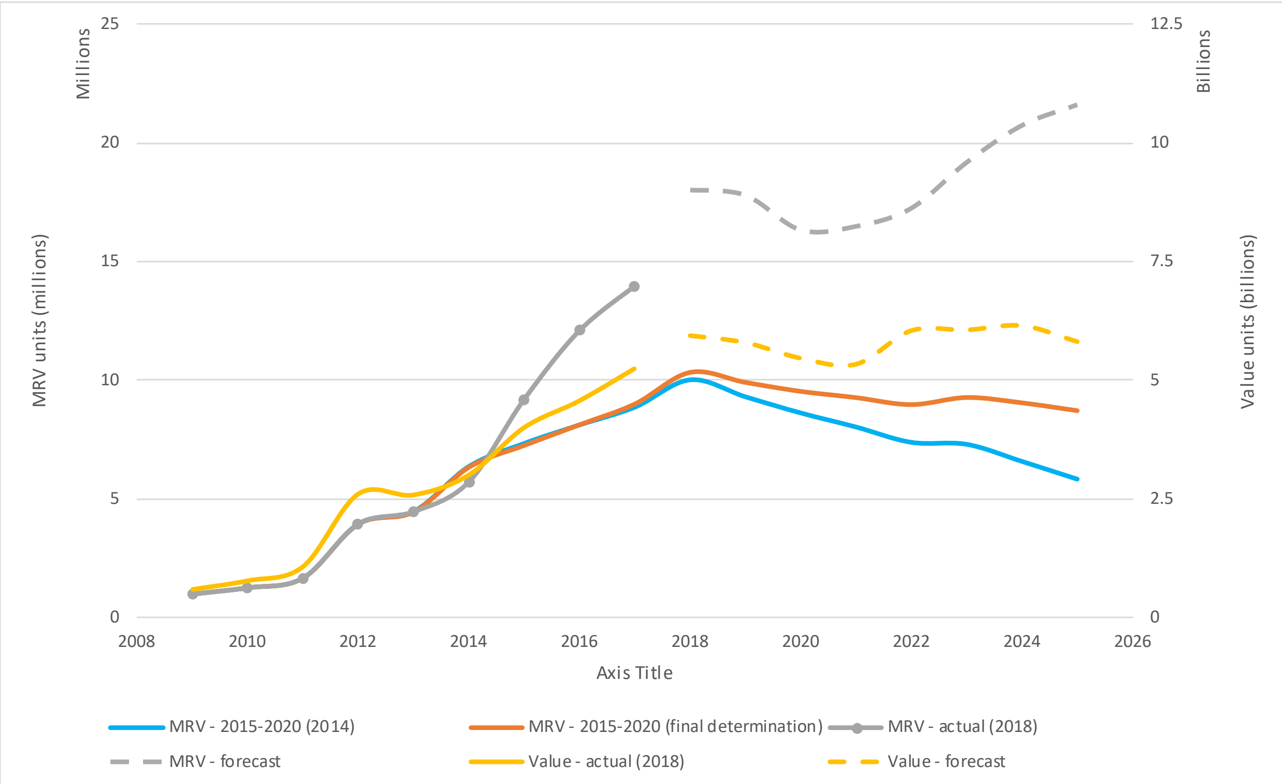
In its distribution determination for the 2015-20 RCP (**2015 Determination**), the AER applied a business as usual approach to our repex which recognised that our forecast increases in repex were required to manage the replacement of our assets and meet the capex objectives of maintaining safety, reliability and security of the distribution system[22].

In the 2015-20 RCP, our repex has been progressively increasing as we bring on additional resources to manage the larger volume of smaller defects identified during inspections. However, we have spent less than the AER repex allowance for the following reasons outlined below.

As outlined earier, in the first part of the 2015-17 period we delayed some repex where possible to allow us to change from our 'risk-based replacement' approach to a more efficient and prudent 'value-based replacement' approach using our Valuing and Visibility Tool for a number of asset categories (including poles, power transformers, circuit breakers and protection relays). The implementation of this new approach involved pilot trials at two metropolitan depots before being progressively rolled out to all depots during 2017.

Figure 5-16 shows how this approach has allowed us to use smarter risk assessment techniques to manage our repex costs within the constraint of customer affordability.

Figure 5-16: SA Power Networks maintenance risk value



The solid grey line shows the increasing level of risk (as measured in maintenance risk value (**MRV**) units) on our network as we have continued to identify defects through our inspection program. The dashed grey line

[22] *AER, SA Power Networks determination 2015-20: Final determination, Attachment 6 – Capital expenditure*, p 6-78.

shows how continuing to apply our 'risk-based replacement' approach (as applied in the 2016-17 regulatory year) would have resulted in unsustainable costs being incurred to reduce that increasing network risk[23].

Development of our 'value-based replacement' approach involved:

- creating a new risk assessment tool that considers the value of risk by considering factors such as consequence of failure (eg safety, customer impacts), and the likelihood of failure; and
- employing new work planning methodologies (using geographic information systems to make all work 'visible' to work planners) so that work planners can efficiently bundle work programs in similar geographic areas.

We call these two elements our 'Valuing and Visibility Tool'.

This Valuing and Visibility Tool has enabled us to reduce the level of increase in network risk more efficiently than would have otherwise been the case under our previous risk-based assessment approach, as shown by the solid and dashed yellow lines in Figure 5-16. Our 'value-based replacement' approach also results in less forecast repex for the 2020-25 RCP. Our value-based approach is discussed further in Section 5.13.2.

The IT expenditure element of our Value and Visibility Tools have the potential for further development and increased customer value and is part of our IT Asset and Works Program (documentation available on request by the AER).

The IT expenditure will extend the IT capabilities developed in 2015-2020 on asset identification, risk quantification and work selection capabilities by extending our asset identification, risk qualification and work management tools and integrating these tools to improve the timeliness of the process. In addition we will pilot new load forecasting, asset reliability, fault and restoration of service analytics to further inform our risk models and increase our preventative maintenance capability.

In the 2015-20 RCP, we have also developed other new technology-based tools to help us make better repex deployment decisions. We have developed a health index for many of our asset categories and can now model the level of repex required to achieve different levels of asset health (or condition) over time.

To minimise our repex costs further, 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 but are still sound at above and below ground-level. In these situations it is more cost effective to bridge the gap between the two sound portions by 'pole-plating'[24] and thereby extend the pole's life rather than replacing the whole pole.

During the 2015-20 RCP, we extended the pole plating program to re-plate poles that had been plated previously — resulting in further savings. We also commenced new refurbishment programs, such as refurbishing mechanical reclosers.

Customers and stakeholders supported these more efficient refurbishment approaches during our customer and stakeholder engagement program, Supporting Document 0.13 – AnnShawRungie Capex Deep Dive Workshop report

In 2018 we completed the full cycle of asset inspections as agreed with the OTR. This will provide us with the data we need to plan for the efficient replacement or refurbishment of assets in the future.

[23] Based on the forecast defect find rate.

[24] Pole plating involves partial excavation of the pole base and welding steel plates across the corroded sections.

5.13.3 Repex forecast methodology

The proposed repex program for the 2020–2025 RCP is a flattening off of the 2015-20 repex profile aiming to maintain network risk. Proposed repex for each regulatory year of the 2020-25 RCP is slightly lower than the current 2018/19 and forecast 2019/20 regulatory year levels[25]. A major factor in developing the repex forecasts has been the desire to keep the network cost component of customers' bills to an absolute minimum during the 2020-25 RCP. The 2020-25 repex forecasts are based on more accurate information and improved modelling techniques than previously available.

We have undertaken condition-based risk management (**CBRM**) modelling across four major asset classes (poles, circuit breakers, power transformers and protection relays) to optimise the volume of repex based on risk, and several other asset classes (conductors, cables, switching cubicles) have CBRM models under development.

Due to the unique nature of individual asset classes, five independent methods are used the determine the volumes of repex for each asset class:
1. CBRM
2. AER replacement model (or **repex model**)
3. Historical expenditure and future expenditure
4. Historical expenditure trend
5. Targeted

CBRM is an asset renewal forecasting methodology that utilises asset information, engineering knowledge, historical performance and practical experience to quantify the condition of an asset and the associated risk it poses. The CBRM methodology uses a bottom-up assessment of an asset population, determining the individual condition of each asset, the consequences of its failure and the resulting risk it creates. By aggregating this information, CBRM provides the ability to granularly analyse the impacts of numerous intervention strategies to determine the optimal choice of action that achieves a desired asset management outcome. However for the CBRM to work effectively it requires a significant level of information on the asset population.

The AER's **repex model** is a statistical based model that forecasts repex for various asset categories based on their condition (using mean life[26] as a proxy) and unit costs. The AER uses the repex model to only assess forecast repex that can be modelled. This typically includes high-volume, low-value asset categories and generally represents a significant component of total forecast repex. In the AER's previous determinations for SA Power Networks, it has modelled the following six asset classes in repex model: Poles, Underground Cables, Overhead Conductors, Service Lines, Transformers and Switchgear.

The **historical expenditure** method forecasts repex for the 2020-25 RCP for each asset class based on the actual repex for 2015/16 to 2017/18 and the SA Power Networks' forecast repex for the remaining two regulatory years of the 2015-20 RCP. Over the last few years our historical spend has been prioritised using an economic risk based system of management, using our Value and Visibility tool.

The **historical expenditure trend** method forecasts repex for the 2020-25 RCP for each asset class based on a projected trend for actual historical repex (2010/11 to 2017/2018) and projected spend for the last two regulatory years of the 2015-20 RCP.

The **targeted** forecasting method is used for specific assets that have known problems.

[25] Note some conductor and cable minor repair expenditure has been re-categorised as maintenance (opex) as discussed in section 5.11.

[26] Mean life is reverence to the average expected life of an asset population based on a normal distribution *(AER, Electricity network service providers replacement model handbook, December 2011).*

The forecasting methodology used for each asset class depends on the level of information we have on the asset class. Table 5-10 provides a comparison of each forecasting methodology.

Table 5-10: Forecasting methodology comparison

Category	CBRM	Repex Model	Current RCP Expenditure	Projected Trend
Asset information requirement				
Key input				
• Historical failure rate	✓	✓	✓	✓
• Asset age profile	✓	✓	✗	✗
• Asset condition	✓	✗	✗	✗
• Consequence	✓	✗	✗	✗
Risk quantification				
Model complexity				

For more detailed information on how the forecasting methodologies are applied, refer to Supporting Document 5.9 – Repex overview.

For each asset class the forecasting methodologies applied are shown in Table 5-11.

Table 5-11: Repex expenditure forecast models

	Historic expenditure	Historic trend	CBRM	Repex model	Targeted
Powerlines					
Poles	○	○	●	○	
Pole top structures	●	○			
Reclosers	●	○			
Conductors	●	○	∆	○	
Distribution transformers	●	○		○	
Service lines	●	○		○	●
Switchgear	●	○	∆		
Cables	●	○	∆	○	●
Other	○	○			●
Substations					
Protection relays	○	○	●		
Circuit breakers	○	○	●		
Power transformers	○	○	●	○	
Other	●	○			
Telecommunications	○	●			●
Safety	○	●			●

○ = other forecast models considered
● = proposed forecast method(s)
∆ = under development

In establishing our repex forecasts, we have considered the potential for overlap between our augmentation expenditure and repex expenditure where replacement of assets under an augex program provides a risk reduction (replacing a poor condition asset with new). We have implemented various processes such as a detailed 'top-down' review of all programs to ensure that we are not double-counting asset replacements/upgrades between programs and are allowing for the effects that risk reduction in one program will have on other programs. For a more detailed discussion on the interrelationship between repex and augex refer to Supporting Document 5.9 – Repex overview, Section 3.

5.13.4 Repex forecast for the 2020-25 RCP

Table 5-12 sets out the forecast repex that we consider will be required during the 2020-25 RCP in order to achieve the capex objectives described in Section 5.5 of this Attachment.

Table 5-12: Repex for the 2020-25 RCP (June 2020, $ million)

	2020/21	2021/22	2022/23	2023/24	2024/25	TOTAL
Replacement	129.0	135.8	137.9	135.1	131.7	**669.5**

Our total forecast repex for the 2020-25 RCP is consistent with our forecast repex for the 2015-20 RCP, however, as explained in Section 5.11, $69.8 million of capex associated with conductor and cable minor repair work has been re-categorised as maintenance (opex) as discussed in section 5.11.

As discussed above, our repex program for the 2020-25 RCP is based on more up to date and comprehensive asset condition information and improved modelling techniques. We have also established new systems and trained additional field staff to ensure the program is delivered more efficiently.

As noted earlier, before we replace assets, we consider:
- whether we can refurbish, rather than replace, assets where it is prudent and efficient to do so;
- customers' future electricity needs and install appropriate assets to fit into longer term plans where possible; and
- consider all viable demand management and non-network alternative options.

Our ageing asset base means that ongoing investment is essential to comply with our regulatory obligations in relation to safety and service levels and maintain current standards. Failure to invest sufficiently in our network will ultimately lead to non-compliance, unacceptable safety and service level outcomes and higher expenditure to be borne by future customers.

5.13.4.1 Customer and stakeholder engagement outcomes

Through two dedicated full-day capex deep dive workshops, we explored with customers and stakeholders the evolution of our value-based replacement approach. Customers and stakeholders were broadly supportive of the logic of our approach and our desire to more efficiently reduce risk on the network through more innovative asset management practices.

Our customers and stakeholders also told us:
- Regular asset inspection, maintenance and repair or replacement, is important.
- Our job is to balance safety, risk and affordability when managing the network.
- It is important to keep prices down, but it is equally important that we do not leave a cost burden for future generations.

We agree. We consider our repex program for the 2020-25 RCP, which continues to apply the 'value-based replacement' approach implemented in the 2015-20 RCP, appropriately balances these aims.

The following sections provide further detail on the forecasting methodologies used to develop our repex forecast for the powerlines, substations, telecommunications and safety categories.

5.13.4.2 Repex forecast for 2020-25 RCP by asset category

Our repex forecast for the 2020-25 RCP by asset category is set out in Table 5-13 along with a detailed summary for each asset category below.

Table 5-13: Repex programs for the 2020-25 RCP (June 2020, $ million)

Reference	Asset class	$M	Asset Plan[27]
A	**Powerlines**	**434.7**	
(i)	Poles	146.4	3.1.05
(ii)	Pole top structures	94.7	3.1.06
(iii)	Underground cable	9.5	3.1.09
(iv)	Conductor	13.9	3.1.10
(v)	Switchgear	32.4	3.1.03 and 3.1.07
(vi)	Distribution transformers	40.0	3.1.01
(vii)	Reclosers	19.2	3.1.13
(viii)	Service lines	25.0	3.1.08
(ix)	CBD	28.3	2.1.07
(x)	Other	25.3	Refer Attachment 18
B	**Substations**	**140.9**	
(i)	Power transformers	26.8	3.2.01
(ii)	Circuit breakers	72.4	3.2.05
(iii)	Protection	16.4	3.2.14
(iv)	Other	25.4	Refer Attachment 18
C	**Telecommunications**	**24.5**	Refer Attachment 18
D	**Safety (repex related)**	**69.3**	Refer Attachment 18

Supporting Document 5.7 – Strategic Asset Mangement Plan, Supporting Document 5.8 – Powerline Asset Management Plan and Supporting Document 5.9 – Repex overview, provide detailed information on our asset management practices, forecasting approach and modelling outputs for each asset class. Further information can be provided through the provision of individual asset plans which are available on request by the AER.

5.13.4.3 Powerlines

Powerlines consist of poles, pole top structures, cables, conductors and all associated distribution transformers, powerline protection and switching devices.

5.13.4.4 Poles

Stobie poles are unique to South Australia and have been used to support overhead distribution lines for 95 years. They were introduced due to a lack of suitable timber within the state and other than metrification, Stobie poles are a proven product that have remained largely unchanged.

Stobie poles consist of a concrete core with two outer steel beams connected by bolts to ensure strength. The poles are symmetrically tapered at both ends to ensure that maximum width and bending strength requirements occur just below ground level. Footings incorporating reinforced concrete are used to ensure that poles are securely anchored in the ground. Sizes of Stobie poles may vary from 9m in length for LV applications to greater than 15m for sub-transmission applications.

[27] Available on request.

Whilst the initial cost of installing a stobie pole is greater than its timber equivalent, they significantly exceed the life of timber poles. The service life of Stobie poles has been assessed as between 30 and 90 years depending upon the corrosive conditions of the installed location.

The expected life of poles varies but is typically 66-71 years. The main factors that influence expected operating life are corrosion zone, load capacity and atmospheric pollution. Based on the existing age profile, there are currently 5% of poles greater than 70 years in our asset base, increasing to 13% by 2025.

SA Power Networks' OTR approved SRMTMP includes an inspection regime with associated defect rectification standards. The period between inspections, known as the inspection cycle, is set to reflect the risks associated with pole failure. That is, poles in a higher risk environment have a shorter inspection cycle than those in a lower risk environment.

For the purpose of defining the appropriate inspection cycle, we classify our poles based upon two parameters that reflect the location of the poles:

- The corrosion zone (**CZ**), which reflects the rate of corrosion we may expect given the environmental conditions. This is graded as either low (CZ1), severe (CZ2) or very severe (CZ3).
- The bushfire risk zone, which is graded as a high bushfire risk, medium bushfire risk, or no fire risk.

As explained above, we have undertaken a comprehensive inspection program, inspecting all of our assets. The more detailed and frequent asset inspection program has collected more asset condition data than was previously available and has resulted in the identification of a large volume of pole defects requiring rectification. The increased number of defects has contributed to an escalation of the known risk on our network.

5.13.4.4.1 Poles failure modes

Ground level corrosion is the main failure mode for Stobie poles. The rate of ground level corrosion varies depending on the pole corrosion zone. In the low corrosion zone, the above ground corrosion tends to be lower which results in a higher proportion of poles being suitable for refurbishment than replacement. Refurbishment can be achieved by welding steel plates across the corroded section (pole plating). We consider refurbishment the most prudent and efficient option as the cost is approximately 15% of replacing the pole and can extend pole life up to 50%.

In the moderate and high corrosion zones the proportion of poles refurbished in favour of replacement is likely to be less because above ground corrosion of steel elements becomes more prevalent. In addition, corrosion and distortion of concrete-embedded anchor bolts leads to losses/spalling of the concrete. We replace poles in those cases where pole plating is not an option, for example, where there is severe corrosion along the length of outer steel beams.

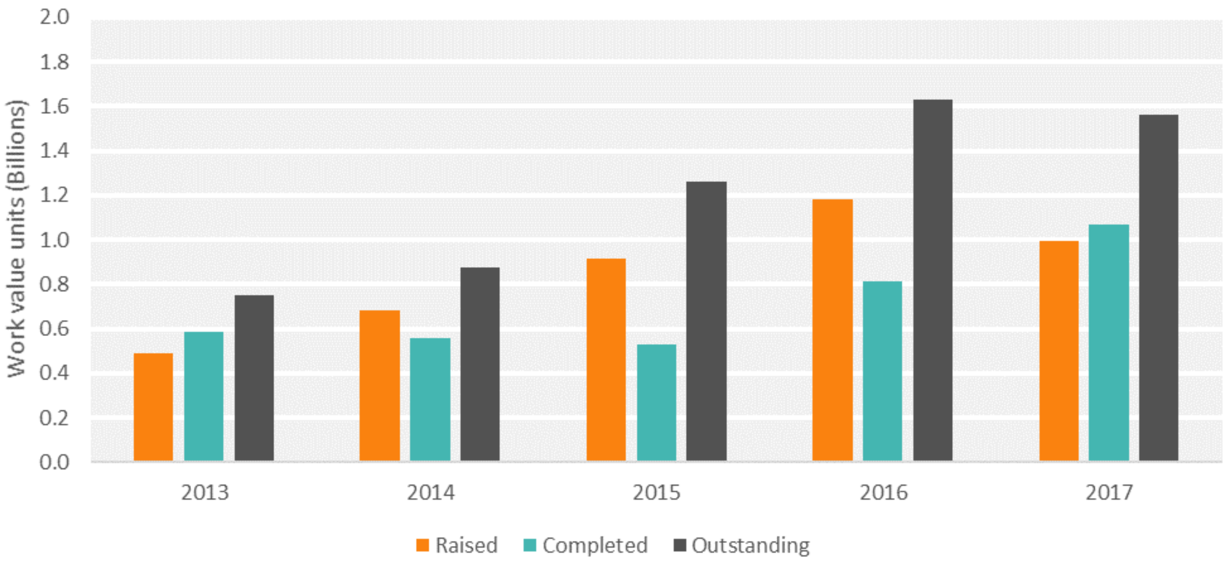
The end of life of a pole is determined by the extent of corrosion, both above ground and at ground level. Reaching this end of life standard, as defined in the Line Inspection Manual, does not mean that the pole will fall over, rather that the strength is diminished and there is a high probability that the pole strength will be insufficient under expected high mechanical load conditions. That is, the remaining strength of the corroded pole is such that it can no longer safely operate in its physical environment as required by the Electricity (General) Regulations.

5.13.4.4.2 Poles forecasting methodology

We have undertaken an assessment to determine the volume of pole replacement and refurbishment work for the 2020-25 RCP using multiple methodologies, including CBRM, repex model, historical and historical projected trend.

Figure 5-17 shows the trend of known pole defects (in work value units). The outstanding pole defects have high value with the total value of outstanding defects increasing over the last five years.

Figure 5-17: Repex forecast models for poles



Due to the increasing risk of our pole population, our preferred forecasting methodology for poles is the risk based CBRM approach.

For a more detailed explanation of the forecasting methodologies, analysis and model calibration for our poles program, refer to Supporting Document 5.9 – Repex overview.

5.13.4.4.3 Poles expenditure forecast

SA Power Networks' forecast repex for pole replacement for the 2020-25 RCP is $111.3 million and pole refurbishment is $35.1 million (June 2020).

5.13.4.5 Pole top structures

The overhead line component category covers a variety of assets that enable overhead conductors to be securely attached to their support structures, support other pole mounted equipment and connect the overhead conductors to other equipment. Overhead line components include cross arms, insulators, overhead switchgear, joints and taps, and other minor components.

The expected operating life of pole top structures varies but is typically 40–50 years. The expected operating life of pole top structures is highly variable because they themselves are varied as is the environment in which they operate. The main factors that influence expected operating life are the materials used, corrosion zone, load capacity, atmospheric pollution and fatigue.

The number of in-service failures of pole top structures has trended upward since 2011. The management of pole top structures is largely based on replacing any that have failed and identifying defects and subsequently valuing and prioritising proactive replacements.

We are experiencing several emerging issues relating to our pole top structures which is further exacerbating our failure rates. These emerging issues are listed in detail in our SAMP (Supporting Document 5.7).

Pole top structures have not been modelled using CBRM to assess risk or asset health nor in AER’s repex model because they are numerous and varied, and data is limited. The pole top structures forecast is based on the historical performance and expenditure.

SA Power Networks' forecast repex for pole top structures for the 2020-25 RCP is $94.7 million (June 2020).

5.13.4.6 Underground cables (excludes CBD cables)

The underground cable network, which transmits electricity between substations and from substations to customers, extends for 18,000 km. A small proportion (~1%) of these cables are more than 50 years of age, these are mostly located in the CBD.

The number of cable failures has remained relatively stable since 2011, but was higher in 2016 and 2017 mainly due to an increase in LV cable failure. The management of HV cable assets is transitioning from a reactive 'fix on fail' approach to one of proactively managing the assets in response to outcomes from a proactive cable condition assessment program. The LV cables will continue to be fixed on failure due to the relatively low consequence of fault events.

The underground cables have not been reliably modelled within CBRM to assess risk or asset health; data quality improvements are required. The historical performance and expenditure of this asset class informs the required forward investment to 2030.

The current average age of cables is 45 years of age. The expected life of cables varies but is typically between 75 and 83 years. Although manufacturers' design life for cables can be significantly lower, the actual rate of replacement of cables in the network suggests that the life of many cables is being extended beyond that previously expected. The main factors that influence expected life are cable type, size, age and location.

The management of risks associated with the cable network has historically been reactive with cable assets fixed on failure. For HV cables we are transitioning to a proactive condition assessment program as outlined above.

5.13.4.6.1 Cable failure modes

Cable failure modes include corrosion, third party property damage and insulation breakdown.

Cable forecasting methodologies
We have utilised a range of forecasting methodologies for cables, however primarily the cables forecast is based on historic expenditure and targeted expenditure for cables with known problems.

Our network strategy is to transition cables to condition-based risk management but the CBRM model requires significant asset information which is not easy to economically obtain because of the difficulty in accessing underground cables. As such we have limited asset data information for cables and therefore further development is required for us to gain confidence in our CBRM modelling.

Cable expenditure forecast
Historically most cable repair works have been reactive minor repairs (inserting a short section of new cable to replace the damaged section) after a fault has occurred. Over the 2020-25 RCP we plan to continue this practice however as explained previously, we plan to now re-categorise these costs to maintenance (opex). For further information refer to Section 5.12 of this Attachment above and Attachment 6 – Operating expenditure.

The cable repex forecast of $9.5 million (June 2020) for the 2020-25 RCP (excludes CBD cables) is based on historical expenditure and targeted (adjusted to remove costs associated with conductor minor repair works).

5.13.4.6.2 Conductor

The route length of overhead powerlines is commonly used to measure the size of our overhead network. The route length of a powerline is based on the distance between the first and last tensioned structures supporting the overhead line. Figure 5-2 above details our overhead line coverage in South Australia.

The age profile of SA Power Networks' overhead network is varied. There was a significant increase in the route length of overhead powerlines during the period from 1955 to 1977. The average age of SA Power Networks' overhead powerlines network is 49 years, with many of the overhead powerlines installed in the years 1955, 1956, 1958 and 1966. Approximately 54% of the overhead powerlines are greater than 50 years old, conversely 7% of overhead powerlines are less than 20 years old.

SA Power Networks' overhead powerline network consists of both sub-transmission and distribution assets operating at voltages that range from 66kV down to 240V.

The majority of powerlines installed during 1930 to 1949 are 33kV powerlines, while the majority of powerlines installed in 1955, 1956, 1958 and 1966 are SWER and 11kV powerlines. To a lesser degree, LV, 33kV and 66kV powerlines were installed throughout 1950 to 1979. In the past 20 years, SWER lines were the most predominantly installed, followed by 11kV and 33kV powerlines.

Conductor failure modes

There are several conductor failure modes. Two of the most common failure modes of overhead conductor are corrosion and fatigue. Overhead powerlines in various corrosion zones are prone to different rates of conductor degradation.

The identification of one failure mode can also signal other impending or active failure modes. For example, the pitting in conductor strands due to corrosion may increase stress; this in turn magnifies the effect of wind induced vibrations in the remaining conductor strands. Consequently, a conductor exposed to a corrosive environment is prone to fatigue at a higher rate than one that is not in a corrosive zone.

Conductor condition assessment

Of the 64,000 km of overhead powerlines registered in SA Power Networks' Asset Management Database, 53% of overhead powerlines are in the low corrosion zone, 35% of powerlines are in the severe corrosion zone, and the remaining 12% are in the very severe corrosion zone. It is important to highlight that whilst the majority of the overhead powerlines in low and severe corrosion zones reside in MBRAs, the majority of the overhead powerlines in the very severe corrosion zones are located in HBRAs, representing a significant risk.

It is often difficult to assess the condition of conductors and produce a reliable estimate of the likelihood of failure. However, it is known that all the failure modes can be induced through the effect of ageing. Therefore, in addition to the indicators stated above, the age of a conductor is also considered when assessing the potential for conductor failure.

Conductor forecasting methodologies

We have utilised three methods to assess the required repex for conductors, being repex modelling, historical and forecast expenditure and historical expenditure trend.

Like our cable assets, our network strategy is to transition conductors to condition-based risk management but the CBRM model requires significant asset information which is not easy to economically obtain owing to the difficulty in accessing overhead conductors. As such we have limited asset data information for conductors and therefore further development is required for us to gain confidence in our CBRM modelling.

Conductor expenditure forecast

While we have several major conductor replacement projects scheduled for the 2018/19 and 2019/20 regulatory years, historically most conductor repair works have been reactive minor repairs (ie inserting a short section of new conductor to replace the damaged section) after a fault has occurred. Over the 2020-25

RCP we plan to continue this practice however as explained previously, we plan to now re-categorise these costs to maintenance (opex). For further information refer to Section 5.12 of this Attachment above and Attachment 6 – Operating expenditure.

The conductor repex forecast of $13.9 million (June 2020) for the 2020-25 RCP is based on historical expenditure and historical expenditure trend (adjusted to remove costs associated with conductor minor repair works).

5.13.4.7 Switchgear

Switchgear consists of overhead switches on powerlines and switching cubicles. We have utilised two methods to assess the required expenditure for switchgear, being historical expenditure and historical expenditure trend.

We have historically undertaken very minimal switchgear replacements. However we have had a significant increase in expenditure across 2016 to 2018 for switching cubicles due to the replacement of a large proportion of out of service units across the network that cannot be safely operated while energised. Over the 2020-25 RCP we plan to continue the average rate of replacement being undertaken in the 2015-20 RCP.

The switchgear repex forecast of $32.4 million (June 2020) for the 2020-25 RCP is based on historic expenditure and historical expenditure trend.

5.13.4.8 Distribution transformers

Distribution transformers change the voltage of electricity. Electricity is transported across the network at higher voltages to minimise losses and the 75,945 distribution transformers installed across the network progressively reduce voltage to a level that it can be used by customers. They are installed overhead and mounted on poles (pole top), or installed at ground level inside a cabinet/cubicle (padmount) or in enclosed chambers (ground level station). A significant proportion (~47%) of distribution transformers are 30–60 years old.

The number of failures on distribution transformers has remained relatively stable since 2011. Their management is largely based on refurbishment or replacement on failure due to the relatively low consequence of such events. Replacements include both new and refurbished units.

The historical performance and expenditure of this asset class informs the required forward investment to 2030.

The distribution transformer repex forecast is $40.0 million (June 2020) for the 2020-25 RCP.

5.13.4.9 Reclosers

Reclosers and sectionalisers are specialised switchgear located on the overhead network. A recloser is similar to a circuit breaker connected to adjacent sections of overhead conductors in an electrical circuit. A sectionaliser is a switch always used in conjunction with an associated recloser. They are positioned within the network to reduce the risk of damage from electrical faults and to improve the reliability of supply to customers. Of the 1,394 reclosers installed across the network, 92% have been refurbished or replaced in the last 10 years. The age profile of 676 sectionalisers installed across the network is relatively evenly distributed over the last 50 years.

The failure rate has trended downward for reclosers and remained stable for sectionalisers since 2010/11. Management of reclosers is based on the cyclic inspection program to identify defects where the frequency of recloser operation informs the refurbishment program. Any reclosers or sectionalisers that have failed to operate during an outage event are repaired, refurbished or replaced.

The historical performance and expenditure of this asset class is used to inform the required forward investment to 2030.

The recloser and sectionaliser repex forecast is $19.2 million (June 2020) for the 2020-25 RCP.

5.13.4.10 Service lines

Service lines connect the LV network to electricity meters which measure the electricity supplied to customers. The service lines provide electricity to the connection point between SA Power Networks infrastructure and the customer owned electrical instalation.

In rural areas, the electricity meter may be mounted on a readily accessible stobie pole to facilitate ease of meter reading with customers supplied through an extension of the network (usually comprising stobie poles and overhead conductors to customer properties) with these types of supply referred to as metered mains. Metered mains have an interface point marked to clearly identify the extent of SA Power Networks' and customer asset ownership.

Service line program is grouped into sub-classes based on the similarity in service types, lifecycle, failure modes and mainten ance strategy. Each sub-class is further detailed in terms of the asset condition, known problems or failures and strategy. The most common failure mode is corroded conductor. The proposed management strategy for service lines is to 'fix on failure' except for high risk categories such as metered mains in BFRAs.

The service lines repex forecast of $25.0 million (June 2020) for the 2020-25 RCP is based on historic expenditure.

5.13.4.11 CBD

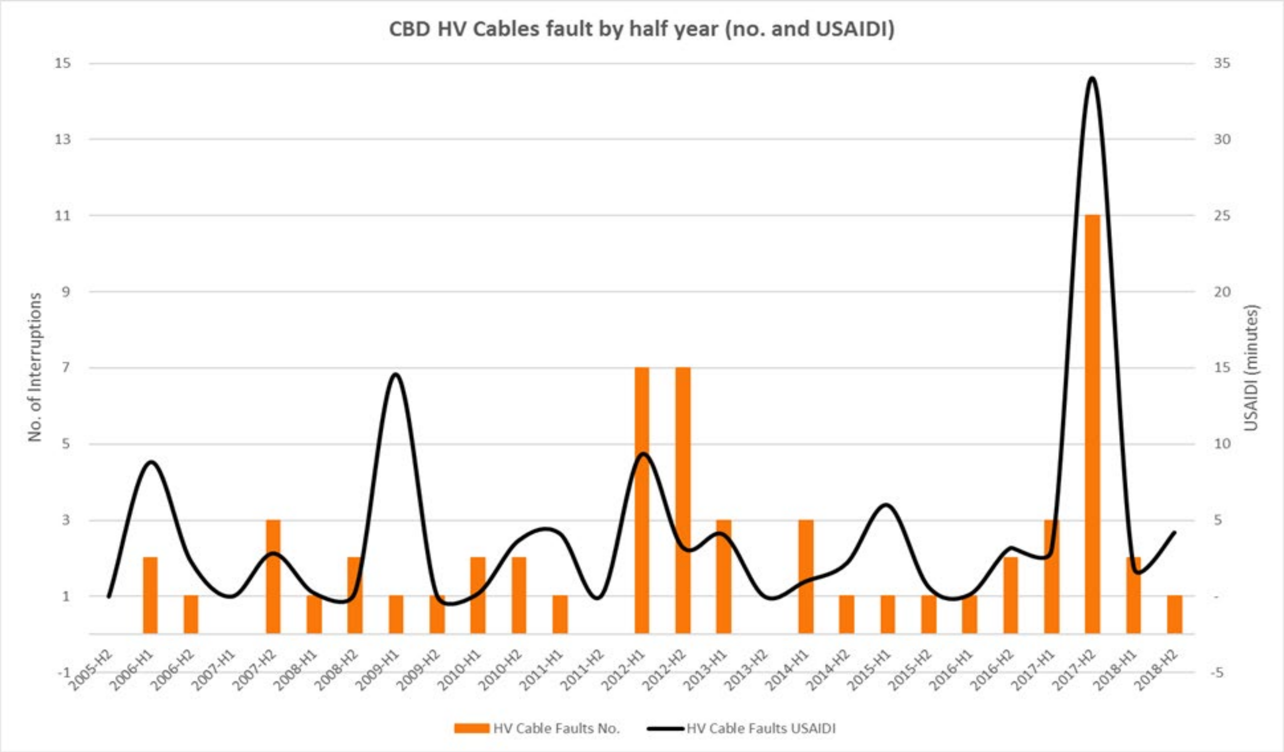
Most of the SA Power Networks' distribution network within the Adelaide CBD comprises high voltage (**HV**) and LV underground cables.

Cable failures generally occur due to thermal cycling, corrosion, degradation of external insulation and broken cable supports which leads to mechanical stress on the cable ultimately resulting in failure. The bare (non-HDPE sheatherd) lead cable joints are particularly prone to failure (due to the jointing technique). Within the CBD, factors such as stray direct current (**DC**) (from light rail systems eg trams) and ducts filled by chemical contaminated ground water can contribute to accelerated corrosion of the lead external protective sheath of certain cable types.

Around 40% of the HV distribution network consists of bare paper insulated lead covered (**PILC**) cables and of those, almost 85% of the bare HV cables are within the 11kV network. These cables are subject to accelerated corrosion of the lead sheath as explained above.

CBD cable investment in the medium term is proposed to be increasingly focused on the bare 11kV PILC distribution cables within the CBD due to their overall poor condition and the impact on reliability service standards observed across the 2016/17 and 2017/18 regulatory years that significantly exceed the ESCoSA Service Standards, as shown in Figure 5-18.

Figure 5-18: CBD HV cable failures



We have utilised three methods to assess the required expenditure for underground cables, being repex modelling, historical and forecast and historical expenditure trend.

Although our overall network strategy is to transition all assets to condition-based risk management, the CBRM model requires significant asset information which is not easy to economically obtain for cables. We have limited asset data information for underground cables and therefore further development is required for us to gain confidence in our CBRM modelling.

Historically most cable minor repair works have been on reactive minor repairs after a fault has occurred. Over the 2020-25 RCP we plan to continue this practice however as explained previously, we plan to now re-categorise these costs as maintenance (opex). For further information refer to Section 5.12 of this Attachment above and Attachment 6 – Operating expenditure.

The CBD cable repex forecast of $28.3 million (June 2020) for the 2020-25 RCP is based on a combination of historic expenditure (adjusted to remove costs associated with cable minor repair works) and targeted expenditure for the whole replacement of some PILC cables on a project by project basis, with prioratisation based on asset condition.

5.13.4.12 Powerline other

The powerline ‘other’ assets are earthing systems, regulators and capacitors, and ancillary assets:

- **Earthing** – ensure current is directed to earth rather than through the asset to minimise risks to staff, contractors and the public.
- **Regulators and capacitors** – ensure the line voltage is maintained within acceptable limits — of increasing importance as voltage fluctuations across the network increase with the two-way grid.
- **Ancillary assets** – prevent unauthorised access, enable staff and contractors access to our assets, and assist network operations staff with locating faults.

These assets are typically replaced on failure. They have not been modelled using CBRM. The historical performance and expenditure of this asset class informs the required forward investment to 2030.

The powerline 'other' repex forecast is $25.3 million (June 2020) for the 2020-25 RCP.

5.13.4.13 Substations

Substations consist of transformers, circuit breakers, disconnectors, supporting structures and connecting buses, protection devices and control rooms, among other items. The priority assets expenditure items in the substation category are transformers and circuit breakers.

5.13.4.13.1 Power transformers

Substation power transformers provide transformation of electricity from sub-transmission voltages to distribution voltage levels and are located at the zone electricity supply substations. There are approximately 696 substation power transformers in service with unit replacement values ranging typically from $260,000 to $1,640,000.

Each transformer must be suitably rated to carry the load of the circuit it is placed in and be able to withstand periods of cyclic overloading to meet peak energy and emergency demands. In general, the substation transformers are moderately loaded for the majority of the time and called upon to operate at full rating or greater during peak periods of seasonal load cycles. Each transformer must also be able to withstand abnormal voltages, resulting from lightning strikes and switching surges, as well as transient currents due to network faults.

As the substation power transformers age and deteriorate, they become more prone to failure. A failure of a transformer may result in unplanned supply interruptions to a very large number of customers. As substation transformers contain insulating oil and faults can result in significant energy being released within the transformer, there is also a risk of explosive failures which can result in subsequent oil fires, damage to co-located or adjacent assets, and potential environmental pollution from release of oil.

SA Power Networks undertakes prudent asset management of power transformers due to the high cost of the asset and the consequence of failure, through condition and performance monitoring with routine inspections and maintenance, overhaul maintenance and refurbishment to extend the asset service life and a long-term replacement program, consistent with sound asset and risk management principles.

5.13.4.13.2 Power transformers failure modes

Substation transformers are generally reliable with historically low failure rates until they approach the end of their service life. The consequences of in-service failures include supply interruption to large numbers of customers (up to 20,000) and catastrophic failures.

Typical causes of transformer faults are:

- **mechanical failure** – usually due to age, condition and in-service cycles;
- **insulation failure** – due to lightning, over-voltages during switching, internal short circuit and water ingress; and
- **thermal failure** – due to high resistance connections, or overloading or cooling equipment failure.

The consequence of a transformer fault can include the following:

- external flashover and damage to HV bushings;
- oil fire;
- distortion of tank, winding, lead supports;
- short circuit between winding turns; and
- winding collapse.

The response time to replace a large transformer is from five to 20 days provided adequate spares are readily available. Failed transformers are replaced utilising strategic spares. Based on our experience, a lead time of up to 12 months is the typical duration for the new power transformer to be purchased, manufactured and delivered. Over the last five years there has been a rising trend in the number of failures.

Power transformers condition assessment

The ages of substation transformers in SA Power Networks' network range up to 72 years, averaging 35 years. Manufacturers generally design transformer insulation to an international standard that aims to achieve a nominal insulation life of approximately 20 years for continuous full load applications. This design criterion is typically well away from the normal operating conditions of a substation transformer and thus transformers are able to attain operating lives ranging approximately 40-60 years in practice.

A comprehensive condition monitoring and maintenance regime can substantially reduce the incidence of failures through the early detection of incipient degradation and damage to transformers and thus allow for a strategic response to developing issues.

Inspection and condition monitoring tasks are normally scheduled at standard intervals as detailed in our Maintenance Plan (Manual 12). Monitoring condition trends over time is a primary strategic asset management tool which tracks deterioration over time. As areas of concern are identified, condition monitoring frequencies may need to be shortened as the risk of an impending failure becomes apparent. For further explanation of transformer failure modes and our condition monitoring regime, refer to the Substation Transformers AP 3.2.01, which is available on request.

Power transformers forecasting methodology

Three approaches have been considered to forecast the expenditure requirements for substation transformers. These are CBRM modelling, repex modelling, historical expenditure over the 2015-20 RCP and a trended forecast using historical expenditure over multiple RCPs.

Our preferred forecast method for repex on the power transformer is the risk based CBRM approach.

Our repex in the 2020-25 RCP is based on our CBRM modelling. The total power transformer repex forecast for the 2020-25 RCP also incorporates targeted refurbishment and replacement programs to address asset specific risks (as outliers to the general population) that would otherwise make them prone to early failure. This is accounted for in the CBRM model.

Power transformers expenditure forecast

SA Power Networks' forecast repex for substation power transformers for the 2020-25 RCP is $26.8 million (June 2020).

(i) Circuit breakers

Circuit breakers are power switching devices installed within substations to selectively control the energization/de-energisation of electricity distribution equipment and provide protection for the public, personnel and equipment by selectively isolating network faults.

Circuit breakers failure modes

Circuit breaker failures can be classified into a number of common types based on the nature of failure and the consequential effect on circuit breaker performance. The root cause for the failure mode will usually be specific to a particular construction, but typical failures include:

- failure to trip, resulting in slow clearing of network damage (or network instability);
- failure to reclose, resulting in an extended interruption of supply for transient faults; and
- failure to interrupt, resulting in a catastrophic explosive damage and therefore public and personnel safety risk, environmental impacts and widespread network outages.

Generally, the design of the network is such that faulty circuit breakers can be bypassed by switching or with mobile plant to allow restoration of supply. This allows for individual circuit breakers to be safely isolated to enable replacement, inspection and maintenance.

In the event of circuit breaker failure, operation can typically be restored within a few hours, subject to the location, circuit breaker function and nature of the failure. However, where a simple bypass arrangement is not possible, supply interruption may exceed 12 hours. Bypassing a failed circuit breaker will put further network load at risk as the network will be operating under abnormal conditions. This means there is an increased risk of subsequent faults occurring in other parts of the network causing extensive outages.

Circuit breakers condition assessment
SA Power Networks' circuit breaker assets vary greatly in age and construction, from oil insulated circuit breakers to modern vacuum and SF6 insulated units. SA Power Networks' HV circuit breaker assets operate across a range of network voltages including 66kV, 33kV, 11kV, 7.6kV and 6.6kV, with operating lives extending to 78 years.

As of 30 June 2019, there are approximately 1,920 circuit breakers in service on the network with unit replacement values ranging from $250,000 to in excess of $500,000.

Circuit breakers forecasting methodologies
Three approaches have been considered to forecast the repex requirements for substation transformers for the 2020-25 RCP. These are CBRM modelling, repex modelling, historical expenditure over the 2015-20 RCP and a trended forecast using historical expenditure over multiple RCPs.

Our proposed repex is based on CBRM risk analysis to maintain risk along with additional targeted expenditure to remove risks related to specific design flaws or performance issues with certain types of circuit breakers that are not captured by the CBRM modelling.

Without undertaking any expenditure on the replacement or refurbishment of substation circuit breakers our risk levels for our circuit breaker population are forecast to increase by 20% on average by 2025 and 30% by 2030.

Implementing a maintain risk strategy, efficiently maintains the long-term performance of the circuit breaker population through targeted interventions in areas of risk that provide the greatest return on investment, prioritising poor condition, critical assets that are approaching the end of their operating life. The combined effect of all planned replacement and refurbishment plans is to maintain levels of safety, reliability and network performance for the asset class to 2030.

Circuit breakers expenditure forecast
SA Power Networks' forecast repex for substation circuit breakers for the 2020-25 RCP is $72.4 million (June 2020).

(ii) Protection
Protection relays and control assets in the HV network automatically protect personnel and the network in the event of fault conditions. Of the 5,904 protection relays installed in substations, a significant proportion (~63%) are over 25 years of age.

Due to the age of the protection population, protection relay failures have an increasing trend in recent years. Their management is based on the outcomes of the visual inspections and diagnostic tests, in addition to responding to any identified faults reported through Supervisory control and data acquisition (**SCADA**) or network outages where protection relays failed to operate.

Protection relay assets have been modelled within CBRM to assess their current health and projected deterioration, and failure risk based on current asset and condition data. Ccondition data indicates 75% of the protection relay population are in good condition, with 25% having observable to serious deterioration and no reprotection relays with advanced deterioration. The model outputs inform the required forward investment to 2030 to maintain the risk across the protection relay asset base.

The protection repex forecast is $16.4 million for the 2020-25 RCP.

(iii) Substation other

The forecast repex for our priority substation assets (transformers and circuit breakers) has been outlined above. This section summarises the forecast repex for the remainder of our substation asset classes consisting of assets such as auxiliary supplies, substation civil infrastructure, SCADA devices and other items.

These programs are the continuation of long term programs necessary for SA Power Networks to maintain an acceptable level of safety and reliability by addressing degradation of our ageing assets to meet our jurisdictional services standards and to comply with our regulatory obligations and requirements.

The substation 'other' repex forecast of $25.4 million for the 2020-25 RCP is based on historic expenditure.

C Telecommunications

This section summarises the forecast repex for our telecommunications assets which consists of assets such as 48V DC systems, data network, microwave radio, optical fibre network and pilot cable network. This forecast excludes capex associated with non-network operational telecommunications, as this expenditure is located in the non-network category of capex, refer Section 5.16.2 of this Attachment below.

These programs are the continuation of long term programs necessary for SA Power Networks to maintain an acceptable level of safety and reliability by addressing degradation of our ageing assets to meet our jurisdictional services standards and to comply with our regulatory obligations and requirements.

SA Power Networks' forecast repex for telecommunications for the 2020–25 RCP is $24.5 million and is based on historic trend and some targeted expenditure.

D Safety related repex

Safety repex is specifically required to comply with applicable regulatory obligations or requirements associated with safety and the provision of SCS and to ensure prudent and efficient management of safety risks in order to maintain the safety of the distribution system through the supply of SCS[28].

This expenditure is for replacement of 'like for like' assets and differs from augmentation related safety expenditure which involves upgrading the network with the installation of new assets or the replacement of existing assets with improved technology. Safety augex expenditure has been included in the forecast augex discussed in Section 5.14 of this Attachment.

The safety repex forecast in the 2015-20 RCP is $41.1 million. Note the AER did not specifically specify an allowance for the 2015-20 RCP, rather an amout was included within the total repex allowance.

Safety expenditure for the 2020-25 RCP is focused on activities that will maintain the appropriate safety of our network for our workforce and the general public (ie the second and fourth objectives in clause 6.5.7(a) of the NER).

The safety program is a continuation of the existing programs. Refer to Table 5-14 below for details of our proposed safety program for the 2020-25 RCP.

SA Power Networks' forecast repex for safety is $69.3 million (June 2020) and is based on historic trend and some targeted works.

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[28] *NER 6.5.7(a)(2) and (4).*

Table 5-14: Safety program for the 2020-25 RCP, forecast expenditure (June 2020, $million)

Safety program	$M	Supporting Document
Switchgear ground level	19.4	5.8
Line clearance rectification	18.5	5.8
Pipework substation rebuild	13.9	5.8
Emergency switching communication	3.8	5.8
Elizabeth transformer stations	2.7	5.8
CBD safety	2.0	5.8
Distribution earthing	0.5	5.8
Telco structures	2.1	5.8
Instrument transformers	3.1	5.8
Disconnector replacement	2.1	5.8
CBD pilot cables	0.7	5.8
Distribution earthing	0.5	5.8

5.13.5 Consistency with NER requirements

Our forecast repex meets the requirements of the capex objectives and criteria in clauses 6.5.7(a) and (c) of the NER. In particular:

- the forecast activity volumes are a reasonable estimate of the volumes required to both:
  - comply with our regulatory obligations and requirements associated with the provision of SCS (in particular our regulatory obligation to comply with the OTR approved SRMTMP and take reasonable steps to ensure that the distribution system is safe and safely operated); and
  - maintain the safety of the distribution system;
- we have used reasonable approaches to forecast the volume of activity to achieve these capex objectives. The CBRM model has been widely accepted across the industry as suitable for regulatory purposes. The CBRM models used rely upon our detailed asset data and have been calibrated to reflect our circumstances, or are based on historic trend;
- the forecast volumes and expenditure are broadly supported by other assessment techniques the AER could apply:
  - analysis of RIN data indicates that we have the oldest distribution network in the NEM and have been replacing assets at one of the lowest levels, consistent with the proposition that replacement volumes need to increase; and
  - we have used the AER's repex model to review the reasonableness of our forecast repex and for a number of our asset classes, our forecast is lower than the repex model forecast;
- it is prudent to manage identified defects in the manner we have proposed. Our forecast allows for the high value, high risk defects to be addressed as a priority. However, our forecast is predicated on balancing cost impacts with lower risk defects and adopting a value based approach that supports a 10 year strategy to remediate those defects;
- we have allowed for prudent and efficient solutions to address forecast needs. As noted above, we have allowed for the much lower cost life extension options in our forecast, when the options are available to us (eg pole plating instead of pole replacement). We have used recent history to estimate the proportion of poles and other equipment eg reclosers, where the use of this lower cost solution should be possible;
- we have allowed for the efficient unit cost for the assumed solutions. Our unit costs are based upon our historical costs; and
- customers and stakeholders have supported our ‘risk value’ approach to asset management.

Further details in relation to how our forecast repex meets the requirements of the capex objectives and criteria is set out in Supporting Document 5.9 – Repex overview.

Finally, if the AER does not permit the capex/opex trade off step change included in our proposed forecast opex in respect of the cable and conductor minor repair work then our repex forecast for the 2020-25 RCP will need to be increased by $69.9 million. Further details in relation to this step changes are set out in Section 5.12 of this Attachment above and in Attachment 6 – Operating expenditure.

5.14 Augex forecast

Augex relates to expenditure required to expand or upgrade network assets to address changes in demand for SCS or to maintain quality, reliability and security of supply in accordance with regulatory requirements.

Our augex forecast does not include forecast capex for connections and other customer related works. For details on connections capex refer to Section 5.15.

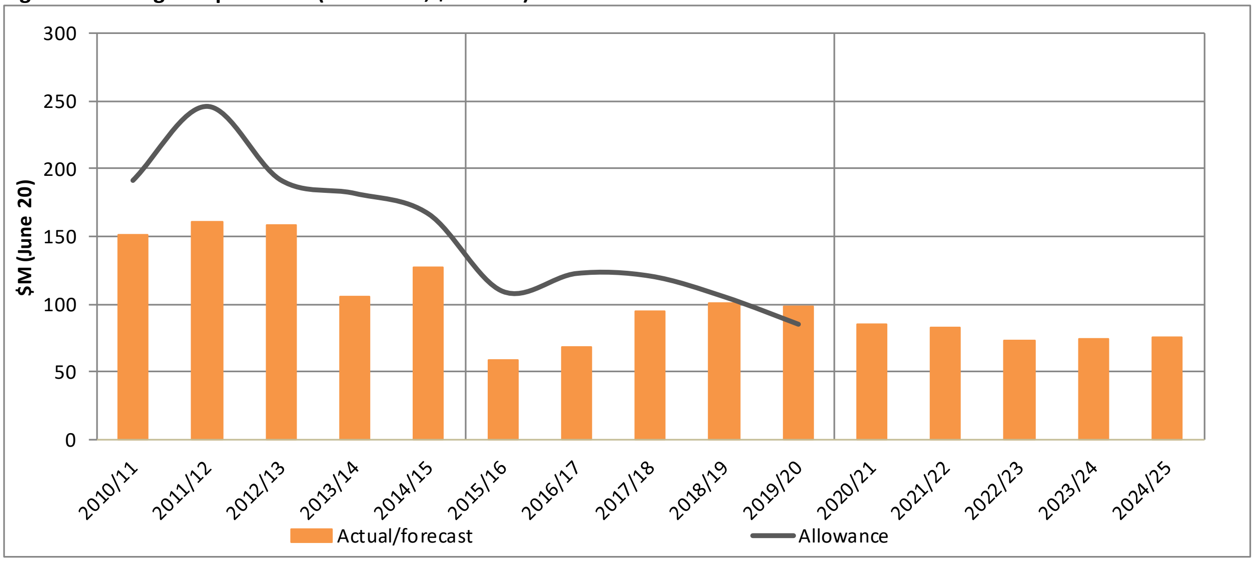
Augex comprises the following key components:

- **Capacity driven augmentation** – works required to meet forecast demand that necessitate the extension or upgrade of our sub-transmission, distribution and LV networks;
- **Reliability** – installation of assets required to maintain the reliability of the network to ensure compliance with ESCoSA's defined reliability service standards;
- **Strategic** – specific one-off programs to manage key network risks and compliance issues and/or optimise long term expenditure;
- **Environmental** – works necessary to address environmental risks within the network to comply with Environmental Protection Authority (**EPA**) requirements;
- **Safety** – expenditure necessary to maintain the safety of our network (excluding repex) for SA Power Networks' workforce and the general public and include a number of initiatives arising from our customer engagement program; and
- **Power Line Environmental Committee (PLEC)** – expenditure to underground parts of the network in accordance with State Government legislation.

5.14.1 Augmentation outcomes for the 2010-15 and 2015-20 RCPs

Figure 5-19 shows SA Power Networks' total augex for the 2010-15 and 2015-20 RCPs, along with the total forecast augex that we consider will be required during the 2020-25 RCP in order for us to achieve the capex objectives described in Section 5.5 of this Attachment.

Figure 5-19: Augex capex trend (June 2020, $ million)



Various factors contributed to the variation between the allowance and the forecast/actual augex for the 2015-20 RCP. These factors are documented in this section.

5.14.2 Augex for the 2015-20 RCP

Table 5-15 summarises our forecast augex by expenditure category for the 2015-20 RCP.

Table 5-15: Augex total net capex for the 2015-20 RCP (June 2020, $ million)

Augmentation	2015/16	2016/17	2017/18	2018/19	2019/20	TOTAL
Capacity	32.0	38.3	50.5	36.9	40.8	**198.6**
Reliability	4.2	6.2	12.1	15.2	15.6	**53.2**
Safety (augex)	5.4	9.0	19.0	19.3	17.3	**70.1**
Environment	1.4	2.5	1.0	2.7	2.7	**10.3**
Strategic	7.2	2.3	2.6	13.9	12.1	**38.1**
PLEC	8.8	10.1	9.5	13.0	9.6	**51.1**
Total	**59.0**	**68.5**	**94.7**	**101.1**	**98.0**	**421.3**

For capacity related augex, we discuss key areas of expenditure according to their drivers and make reference to the material projects for the 2020-25 RCP – see section 5.14.1 below.

For the remaining components of augex (ie reliability, strategic, environmental, safety and PLEC), we provide detailed discussion of the key capex categories according to our assessment of materiality of expenditure levels or risk – see section 5.14.2 to 5.14.6 below.

5.14.3 Capacity

The capacity related augex program consists of works required to meet or manage the expected demand for SCS over the 2020-25 RCP[29].

5.14.3.1 Capacity outcomes from the 2015-20 RCP

The capacity related augex for the 2015-20 RCP is $198.6 million, $155.7 million (44%) below the AER allowance of $354.3 million, refer Table 5-16.

Table 5-16: Comparison of capacity augex, AER allowance to actual/forecast augex for the 2015-20 RCP (June 2020, $ million)

Capacity	2015/16	2016/17	2017/18	2018/19	2019/20	TOTAL
Allowance	80.0	79.0	72.1	67.1	56.0	**354.3**
Actual and forecast	32.0	38.3	50.5	36.9	40.8	**198.6**

Within the 2015-20 RCP, we forecast to spend (on average) $40 million per annum on capacity related augmentations of the network.

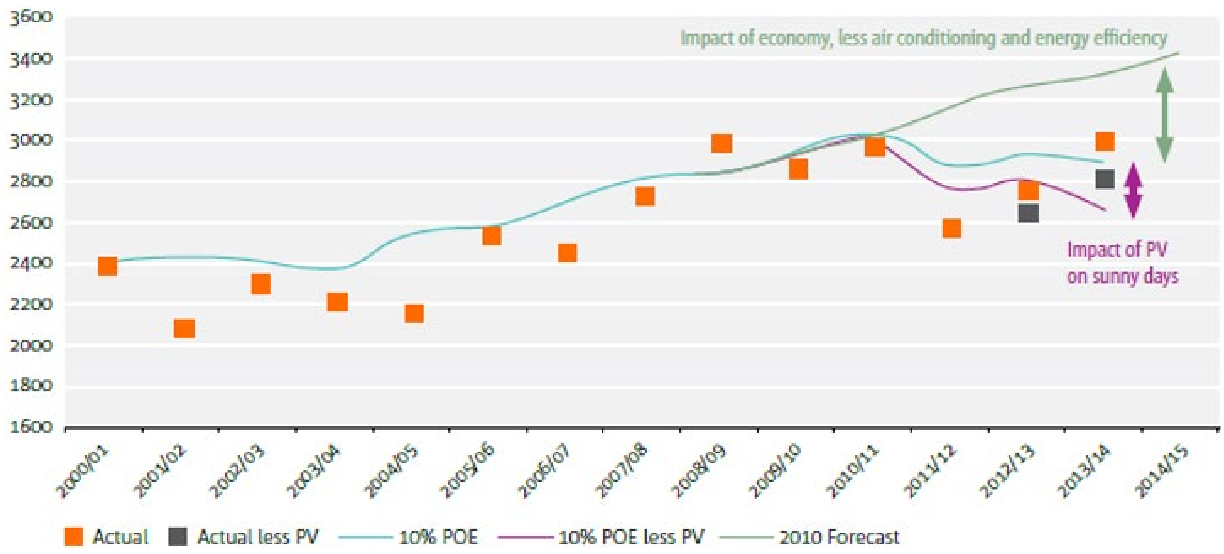
The lower than forecast growth in global demand resulted in us prudently deferring some augmentation projects. This lower than forecast demand was due to external factors beyond our control, including continued general economic downturn that resulted in the closure of some major commercial and industrial businesses in South Australia (eg the Holden manufacturing plant), and a slowdown in the new housing industry and agricultural industry. In addition, the continued significant uptake of solar (which exceeded the forecasts in our 2015-20 RCP) has reduced the peak demand on our network.

Improvement in customer energy efficiency from building design practices (eg green star ratings) and appliance efficiency standards have also added to the global demand growth curtailment.

[29] *NER 6.5.6(a)(1).*

Consistent with the 2015 Determination, the estimated future growth of solar generation is based on the Australian Energy Market Operator's (**AEMO's**) latest forecast[30] and has been included in the 2020-25 RCP forecasts, but its impact in reducing peak demand will be much lower for many regions as solar output is very low after 7:00pm and our peak demand has shifted to later in the evening, beyond this period. Measured growth in demand at 8:00pm still occurred in several regions because solar ceased to have an impact from this time. Refer to Figure 5-20.

Figure 5-20: Global 10% probability of exceedance (PoE) demands (MW) at 1630 EST (5pm local time) excluding major business



Major augmentation projects (ie projects exceeding $6 million) must pass a rigorous planning criteria test before they are committed, and consequently several projects have been deferred to the 2020-25 RCP or later due to the lower than forecast demand growth. For example, projects designed to manage network contingencies[31] are not considered until the measured demand (temperature adjusted) exceeds the network contingency capacity. For the transmission network, this is with a 10% probability of exceedance (**PoE**) temperature adjustment and for the zone substation network, a 50% PoE temperature adjustment. All major projects exceeding $6 million in value are also subject to the AER's Regulatory Investment Test – Distribution (**RIT-D**).

In the 2015-20 RCP, we only had one major project exceeding $6 million, the Kangaroo Island cable project, which was largely completed in 2018.

Within our regulatory proposal for the 2015-20 RCP, we included 34 large projects with forecast augex in excess of $2 million. Of these 34 projects, eight are no longer forecast to be required until post 2025 and one has been deferred to the 2020-25 RCP, with the remaining projects complete or in progress. The eight deferrals are due to a reduction in demand forecast which has resulted in changes to the timing of the constraint the project was proposed to resolve.

For a detailed summary of the projects approved by the AER in the 2015 Determination and an indication of those completed, in progress or deferred, refer to our Distribution System Planning Report (**DSPR**), Supporting Document 5.10.

As explained above, several factors have combined to reduce the forecast demand growth at peak times. This includes the connection of over 1000 MW of embedded solar generation at the distribution level, closure of large commercial and industrial businesses, self-generation of some larger commercial businesses and the

[30] *AEMO, 2018 Electricity Statements of Opportunity, August 2018.*
[31] *With respect to a zone substation, will be taken to mean the N-1 or firm delivery capacity of the zone substation plus any load which can be transferred to adjacent zone substations via feeder transfers (excluding those zone substations where feeder transfers are not to be considered according to SA Power Networks' planning criteria – eg the Adelaide Central Region).*

general economic slowdown. As a consequence, the capacity program has followed a downward trend to reflect these changes.

These changes in customer demand have been factored into the demand forecast for the 2020-25 RCP including the increase in embedded solar generation. While the growth in maximum demand has been reduced, the significant growth in number and scale of embedded generation does pose challenges to our network with the increasing reverse power flows and rising network voltages.

The continuing uptake of residential DER, particularly residential solar generation, is resulting in increasing high voltage issues on the LV distribution network during periods of high residential solar generation and low customer loads. As a result, we have experienced a significant increase in QoS enquiries in the 2015-20 RCP.

In order to effectively manage these increasing QoS enquiries more prudently, we commenced a LV transformer monitoring program in 2017, installing power quality monitors on feeders with a high solar penetration.

This program is proposed to continue over the 2020-25 RCP, bringing our level of LV monitoring up to levels more comparable with other DNSPs.

In summary, the variation in capacity augex compared to the allowance for the 2015-20 RCP was due to uncontrollable external factors such as the economic downturn and the rapid take up of embedded solar generation resulting in deferral of projects.

In the 2015-20 RCP, our capacity program was prudent as we undertook the most appropriate course of action at the time, only spending capital when necessary and where projects did proceed, our expenditure was efficient. We only implemented programs that resulted in the lowest long-term costs to our customers. For example, projects were only undertaken when the constraint necessitated action (constraints were adjusted annually based on the latest spatial demand forecasts).

The changes in customer demand have been factored into the demand forecast for the 2020-25 RCP, including allowances for the increase in embedded solar generation.

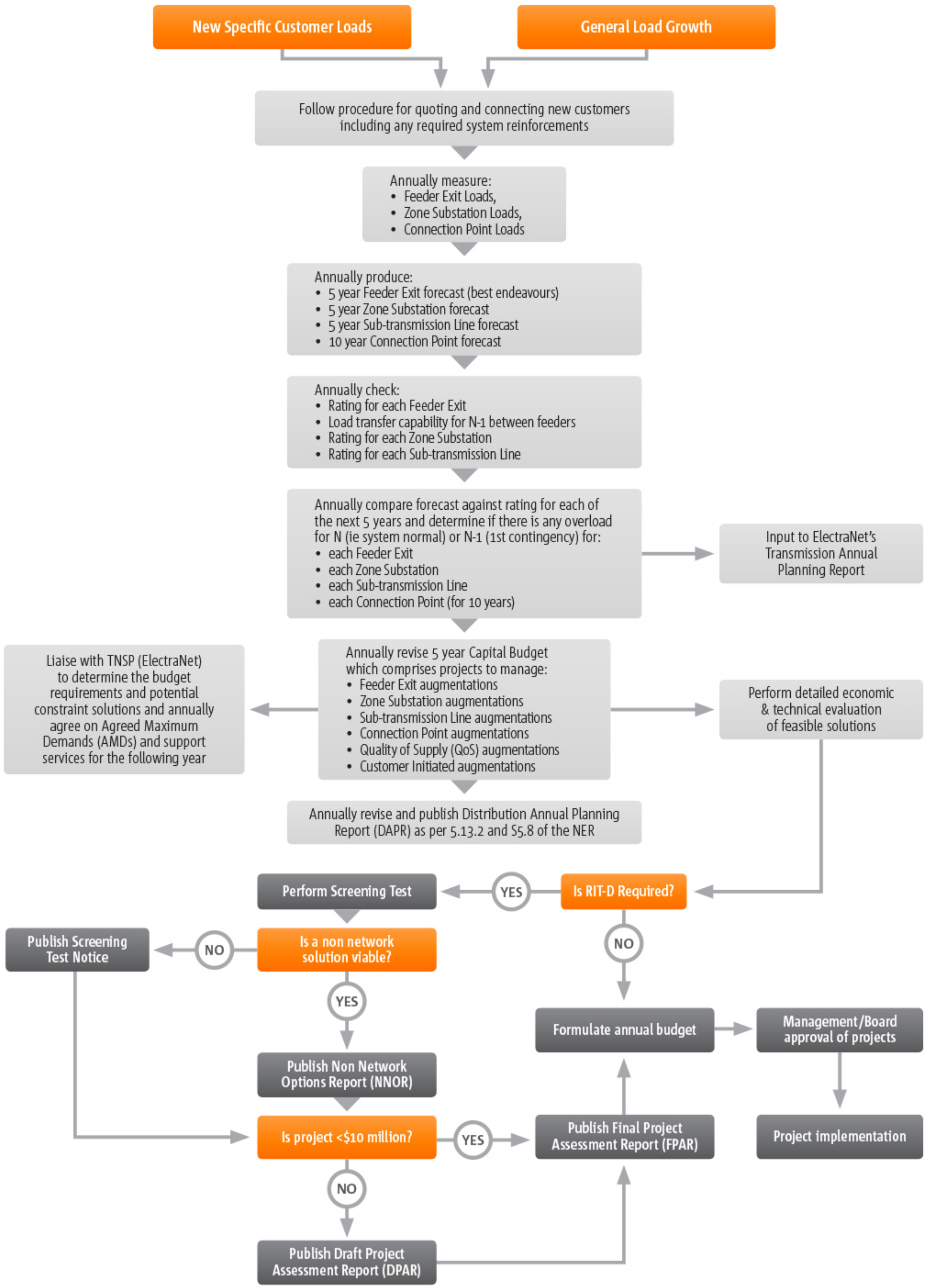
Our forecasts incorporate global changes in economic factors such as State population and GDP growth, and improved energy efficiency initiatives and have also been reconciled with AEMO's latest forecast.

For further detail on capacity augex incurred during the 2015-20 RCP, refer to the DSPR AP 1.1.01.

5.14.3.2 Capacity forecasting methodology

SA Power Networks' sub-transmission and distribution network augmentation is generated either from requirements to upgrade our infrastructure resulting from changes to the Electricity Transmission Code (**ETC**), or as an output of our planning process to ensure we are able to achieve the capex objectives in clauses 6.5.7(a)(1) and (2) of the NER. The network planning process considers when network and/or specific customer load growth breaches the network planning criteria. This triggers a network constraint that must be addressed by either a network or non-network solution. The process followed in planning and augmenting the distribution network is shown in Figure 5-21.

Figure 5-21: Overview of the distribution system planning process



Key inputs that underpin our capacity driven augex forecasts include:

- **Network planning criteria** – defining the level of redundancy required (at SA Power Networks' connection points, zone substations and transmission lines) to meet the EDC and ETC standards, reliability standards and standards related to the maintenance of security of supply; and
- **Spatial peak demand growth**.

5.14.3.3 Network planning criteria

SA Power Networks' network planning criteria are a key driver of future capacity related augex because they define when a network 'constraint' exists that must be addressed by means of a prudent network or non-network solution. Constraints occur when forecast load demand exceeds the capacity of a particular element of the distribution system. The network planning criteria also define the level of redundancy required in particular parts of the distribution network.

SA Power Networks' planning criteria incorporate the objectives of establishing and maintaining compliance with all regulatory obligations including, National and International Standards, Codes of Practice, the Electricity Act, and satisfying the obligations specified within the EDC and the NER. In particular, the criteria embody obligations imposed by legislation including the requirement to adhere to standards and practices generally accepted as appropriate either internationally or throughout Australia by the electricity supply industry and to ensure the security and reliability of electricity supply to customers.

The criteria must ensure that the requirements relating to power quality, short circuit capability, system stability clearing times, reliability and system security contained in Schedule 5.1 of the NER are met. We are also obliged to comply with the mandatory ETC requirements.

The forecast load for future regulatory years contained within the 10% and 50% PoE load forecasts is compared with the capacity rating of the relevant network segments to produce a list of overloaded or constrained assets. This is undertaken for both system normal (N) and single contingency conditions (N-1).

SA Power Networks implements solutions for those assets forecast to be overloaded under normal conditions, prior to the overload occurring. However, SA Power Networks also implements solutions to ensure those assets are not overloaded under contingency conditions after a potential overload is measured. The criticality of the asset is taken into account by the PoE used (10% or 50%) and the allowed maximum load at risk (load that cannot be supplied). By way of example, transmission connection points and CBD zone substations use 10% PoE and other zone substations use 50% PoE. For more details refer to the DSPR.

The network planning criteria are also published in the Distribution Annual Planning Report (**DAPR**) on our website[32].

5.14.3.4 Spatial peak demand forecasting

For the spatial peak demand forecasts, we apply a 10% and 50% PoE forecasting methodology, consistent with most other DNSPs. We utilise an independent and transparent spatial forecasting tool which reconciles with AEMO's State-wide forecast.

The forecasting tool performs regression analysis to weather correct recorded load readings with respect to historic temperatures dating back to 1978. To account for econometric factors, the temperature corrected PoE spatial forecasts are able to be reconciled to the next level of the network (ie zone substations reconciled to connection point, connection points reconciled to total State). The tool considers the impact of past and future embedded generation (including solar and batteries), spot loads, load transfers and the behaviour of major customers in arriving at its final forecast values for the nominated PoE level.

[32] *https://www.sapowernetworks.com.au/industry/annual-network-plans/.*

When reconciling the aggregated transmission connection points forecast trend to the AEMO South Australian forecast trend, major customer variations are eliminated by removing the four transmission connection points dominated by a single major customer (ie Whyalla, Port Pirie, Snuggery Industrial and North West Bend), prior to the reconciliation. The reconciliation process then modifies the transmission connection point forecast to include the global impact of energy efficiency, solar and economic factors as forecast by AEMO for South Australia. The major customers connection points are separately forecast based on their agreed maximum demand and the customers' advice of future plans.

Each transmission connection point forecast trend is then reconciled with the forecast trend of the zone substations that are supplied from the transmission connection point, similarly modifying the zone substation forecast to include the global factors forecast by AEMO.

Our capacity driven augex program for the 2020-25 RCP is based on AEMO's 2018 spatial demand forecast. All identified constraints and their timings are described in the Distribution System Planning Report and are either based on measured load (where it exceeded the network planning criteria) or the forecasts produced by our forecasting tool at 10% and 50% PoE level (as applicable).

5.14.3.5 Capacity ratings

Major network assets are generally assigned a normal and emergency cyclic rating calculated in accordance with the relevant Australian Standard or Guideline. Normal ratings are applied when all network components are in service while emergency ratings are applied when one or more network components are out of service.

The normal rating is used for preservation of the asset's operating life, while the emergency rating is used for short term network contingencies when another portion of the network has failed. Operating at the emergency rating will significantly shorten an asset's operating life and cannot be sustained.

The cyclic rating takes into consideration the normal load profile seen by the asset and normally allows an increase in the asset's rating compared to its nameplate rating. For substation transformers, the normal and emergency ratings include the change in load profile due to the connection of solar generation on the network. The reduction in net demand during the middle of the day when solar is generating typically increases the allowable cyclic rating by a small margin.

For further details on the forecasting methodology used for capacity related augex, refer to the DSPR. Additionally, SA Power Networks is required under clauses 5.13.2 and S5.8 of the NER, to publish a DAPR that provides information about actual and forecast constraints on our network, details of these constraints and where they are expected to arise within the forward planning period. The DAPR is produced annually and must be published by the 31 December each year[33].

5.14.3.6 Costing methodology

In developing our capacity augmentation driven capital program, we have assigned each project to a works category relating to the component of the network requiring augmentation, reinforcement or construction (eg sub-transmission network — connection point, zone substation, feeder, LV and distribution transformers, land).

The costs assigned to each project are determined using a set of standard component or unit costs expressed in nominal dollars. In our DSPR AP 1.1.01, all values are expressed in 2017 dollars terms. As mentioned previously, in this Attachment, all values have been expressed in June 2020 dollars.

[33] NER 5.13.2(b).

Each project's total cost is derived using these standard construction components in order to ensure each project's costs are directly comparable to one another. These unit costs are revised annually and have been determined based on estimates for each unit using SA Power Networks' RealEst estimating tool. The costs developed within RealEst have been compared to the historic costs of actual projects (escalated to 2017 dollars) within the 2015-20 RCP.

These unit costs represent all possible costs likely to be incurred by SA Power Networks in undertaking a specific project. They include expenditure on non-field based activities such as design and third party approvals services.

5.14.3.7 Consideration of non-network solutions

When considering how best to address a network constraint, SA Power Networks must undertake a rigorous process to consider whether a non-network solution is applicable.

As required, we consider various non-network solutions when determining our preferred solution to address an identified constraint on our network. Examples of demand management solutions considered by us include:

- power factor correction;
- peak lopping embedded generation;
- load transfers/balancing;
- amendment or creation of, Network System Support Agreements (**NSSA**) with customers to generate or curtail load on demand; and
- leverage of DER, particulary residential or commercial batteries.

In addition, all projects estimated to cost in excess of $6 million are subject to the RIT-D in accordance with clause 5.17 of the NER. Where it is determined as a result of the screening test that publication of a non-network options report (**NNOR**) is warranted, a NNOR is created and issued for public consultation seeking alternative solutions to remedy the identified network constraint[34].

In the 2020-25 RCP, we will also seek to procure non-network alternatives for lower value projects that fall below the RIT-D threshold, building on work undertaken over the 2015-20 RCP utilising the DMIAM. Our customers and stakeholders support this approach.

5.14.3.8 Capacity forecast expenditure for the 2020-25 RCP

AEMO's 2018 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 the 2020-25 RCP, as traditional drivers of peak demand growth (summer air-conditioning load) continue to be offset by solar, the use of increasingly efficient appliances and housing stock, and slow economic growth. Correspondingly, we forecast a continued reduction in our capacity-driven augex for the 2020-25 RCP.

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 and Mt Barker West as well as in higher density developments of older areas like St Clair and Bowden.

SA Power Networks sub-transmission, distribution and LV networks capacity program has been generated from requirements to upgrade our infrastructure resulting from changes to the ETC or as an output of SA Power Networks' planning process as detailed in our DSPR.

SA Power Networks' forecast capacity augex for the 2020-25 RCP is $154.6 million and is summarised in Table 5-17. The forecast augex is a reduction of $44.0 million (22%) compared to actual/forecast augex for the 2015-20 RCP, and $199.7 million lower than the allowance for the 2015-20 RCP.

[34] Clause 5.17.4(b) to (d).

Table 5-17: Forecast capacity expenditure for the 2020-25 RCP (June 2020, $ million)

	2020/21	2021/22	2022/23	2023/24	2024/25	TOTAL
Capacity	38.0	32.5	26.3	27.4	30.4	**154.6**

As discussed above, our DSPR is our assessment of our distribution system's capacity to meet forecasted demand over the ten years from 2020/21 to 2030/31. The DSPR includes SA Power Networks' proposed plans for augmentation of the distribution network based on the information and estimates available at the time of publication. The project implementation timeframes have been based on the actual 2018 peak, 10% and 50% PoE load forecasts (as applicable).

The DSPR includes an overview of SA Power Networks' system planning methodology, 15 regional development plans covering SA Power Networks' connection points, sub-transmission lines, zone substations, distribution feeder exits and the low voltage network. Where relevant, details of system constraints and the proposed corresponding projects are included within these development plans.

Only those projects that have the most significant customer impact have been specified in detail. This generally includes those connection points, zone substations and sub-transmission line projects with an estimated value in excess of $6 million, whilst for all other expenditure categories (eg voltage support, power factor correction, feeders etc), these have been specified in detail where the estimated value is in excess of $0.5 million.

Future (non-committed) large customer connections, where the customer's maximum demand increase exceeds the forecasted annual load growth of the relevant network asset, are not included within the demand driven augex forecast. Network augmentations required for such projects will be managed in accordance with the EDC and SA Power Networks' customer connection processes in accordance with the National Energy Customer Framework (**NECF**) and SA Power Networks' Connection Policy (refer to Section 5.15 of this Attachment) and Attachment 16 – Connection Policy.

Whilst the majority of projects included in the capacity driven augex forecast for the 2020-25 RCP are driven by capacity constraints, many are driven by constraints unrelated to future load growth for the asset(s) concerned. The drivers of the projects contained within our DSPR can be classified as either independent or dependent of the future load growth.

Those projects which may be categorised as being independent of future demand growth include:

- ETC or ElectraNet augmentations;
- regulatory compliance (eg NER or EDC driven and QoS);
- existing committed augmentations or those constraints where the planning criteria has already been breached;
- security driven augmentations; and
- strategic projects (eg land and easements).

Those projects which may be categorised as future demand growth dependent include:

- continued real estate developments; and
- general demand growth.

Table 5-18 Sets out our capacity related augex programs.

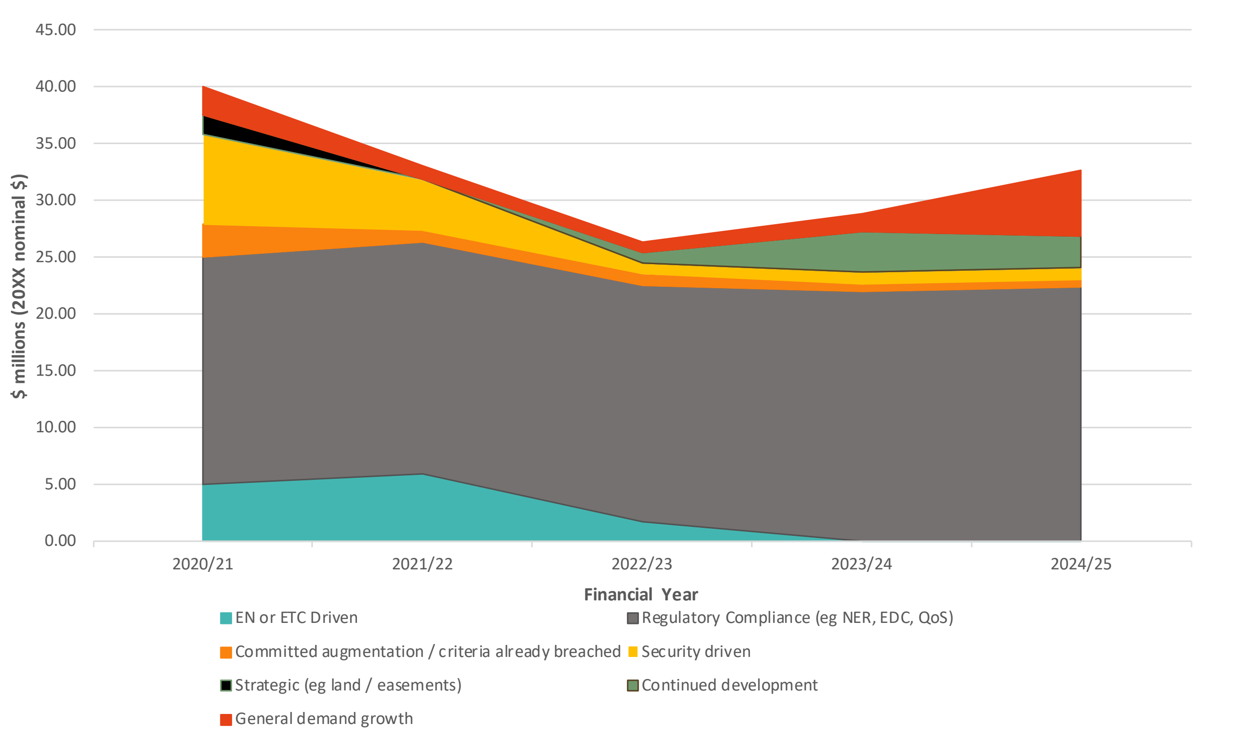
Table 5-18: Capacity augex for the 2020-25 RCP (June 2020, $ million)

Reference	Capacity	Description	$M	Supporting Document
A	**Committed**	Committed projects independent from future demand growth		
(i)	ETC or ElectraNet	Connection point augmentation mandated through the alteration of existing connection points categorisation within the ETC or as approved by the AER	12.3	5.10
(ii)	Regulatory compliance	Programs necessary to maintain regulatory compliance. Including QoS, LV monitoring and voltage regulation (transformer tap changer replacement) and other minor programs	101.2	5.10
(iii)	Existing committed	Constraint projects where the planning criteria has already been exceeded	6.1	5.10
(iv)	Security driven	Projects to improve the security of the network where a positive market benefit exists	14.8	5.10
(v)	Strategic projects	Land and easements acquisition, prior to ensure that both suitably located and sized areas exist for future network augmentation	1.6	5.10
B	**Future demand growth**	Projects dependant on the forecast future demand growth		
(i)	Continued real estate developments	Augmentation necessary to support forecast housing development	7.1	5.10
(ii)	General demand growth	Constraint projects where the planning criteria is forecast to be exceeded	11.5	5.10

Of the project expenditure contained within the 2020-25 RCP, on average, 93% are independent of the load forecast. Figure 5-22 details the expenditure breakdown by forecast dependent and forecast independent project categories.

The key investments in the capacity driven augex categories are summarised in Figure 5-22 below by driver. A consolidated list of all projects in the 2020-25 RCP and their driver is contained in the DSPR.

Figure 5-22: Expenditure breakdown by forecast dependent and forecast independent project categories (June 2020, $ million)



5.14.3.9 Committed projects

The following programs consist of committed projects categorised as being independent from future demand growth.

5.14.3.10 ETC compliance

Transmission connection points are categorised according to the different levels of reliability and security of supply, as specified by ESCoSA within the ETC.

ElectraNet augments its connection point capacity based on joint planning with SA Power Networks and the connection point forecast annually produced by SA Power Networks in conjunction with ElectraNet. ElectraNet and SA Power Networks jointly maintain a Connection Point Management Plan (**CPMP**) which outlines the predicted timing and high-level scope of new connection points, connection point upgrades and deferral solutions to connection point constraints via our distribution network.

The augex forecast for the 2020-25 RCP only includes SA Power Networks' component of these connection point upgrades. These upgrade works are mandated through the alteration of existing connection points categorisation within the ETC or due to the timing of asset replacement works by ElectraNet approved by the AER as part ElectraNet's most recent Determination in 2018, as such, these works are required irrespective of the forecast demand at these sites.

The forecast augex for ETC projects in the 2020-25 RCP is $12.3 million and represents 8% of our forecast capacity driven augex.

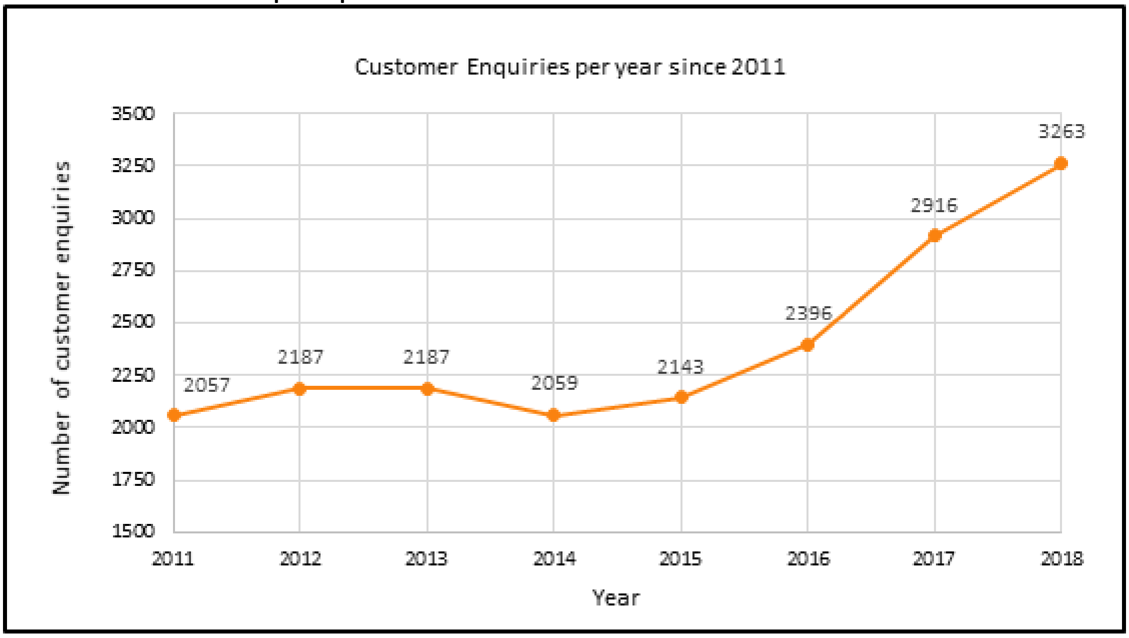
5.14.3.11 Regulatory compliance (LV monitoring and quality of supply)

Augmentation projects in this category require an upgrade of the LV and distribution transformer network. This is a large number of relatively small projects, which are triggered by customer enquiries (low or high voltage). These reactive projects are only committed after measurement at the customer's service point confirms the constraint.

SA Power Networks must maintain supply voltage at customer premises within the range specified in Australian Standard AS60038[35]. The continuing uptake of residential DER, particularly residential solar generation, is resulting in increasing voltage issues on the LV distribution network during periods of high residential solar generation and low customer loads.

With increasing levels of DER significantly impacting the voltages on the LV network, voltage excursions outside of mandated limits are becoming more prevalent, significantly increasing the number of QoS enquiries as can be seen in Figure 5-23.

Figure 5-23: Residential customer enquiries per annum



Customers' increasing expectations are that their solar inverters can export at full power throughout the day and that no loss of export levels will occur during high residential solar generation periods.

The clear feedback from customers through our customer and stakeholder engagement activities is that they expect us to prudently plan for the future to ensure that the distribution network can continue to support the transition to a low-carbon, decentralised energy system.

Given our limited visibility of the LV network, we propose to continue installing power quality monitors on a representative range of metropolitan residential LV transformers to better manage residential solar issues and daily business operations via modelling and analysis of the LV network.

This new visibility will improve LV network knowledge and decision making capability and will also provide opportunities to explore non-network solutions which can't be implemented effectively in the current process.

The LV monitors will allow us to proactively monitor our LV network in areas with high solar penetration, and to collect better information on how the network is performing. This will improve network planning and operation and defer large augmentation remediation works.

Note the LV monitoring program provides the foundation for our strategic LV management program (refer Section 5.14.3) that will develop the new operational capabilities we require to transition to more active management of the LV network by 2025.

Capacity related augex is also required to correct QoS issues. Some customers are

[35] *Clause 5.2.1(a) of the NER requires SA Power Networks to maintain and operate all equipment that is part of its facilities in accordance with relevant Australian Standards, which includes Australian Standard AS60038.*

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 also have a program of work to rectify voltage regulation where a number (one per annum) of tap changers beed to be replace on power transformers as they have insufficient tap range during light demand periods and high solar generation.

The forecast augex for these LV and QoS projects in the 2020-25 RCP is $101.2 million (2020 $) as shown in Table 5.19. This represents 65% of our forecast capacity driven augex. For further information refer to Supporting Document 5.13 – Distribution System Planning Report.

Table 5-19: Forecast compliance related capacity capex for the 2020-25 RCP (June 2020, $ million)

Program	$M
Quality of Supply	46.3
LV monitoring	18.9
Voltage regulation	15.0
Other compliance	21.0

5.14.3.12 Committed augmentation (Planning criteria exceeded)

This program consists of constraint projects identified from where the network planning criteria were exceeded. Demonstrated demand has exceeded the network planning criteria and customer load is now at risk until the augmentation projects (or non-network solutions) are implemented to resolve the network constraint. Many of these projects are in progress and are expected to be completed in the 2020/21 regulatory year.

The forecast augex for planning criteria exceeded projects in the 2020-25 RCP is $6.1 million (June 2020 $), and represents 4% of of our capacity driven augex.

5.14.3.13 Security

Projects within this category are not growth driven, but rather relate to improving the security of the network where a positive market benefit based on RIT-D can be demonstrated.

A preliminary RIT-D assessment has been performed on these projects and demonstrates a positive market benefit.

These network augmentations are intended to either minimise the duration of network outages or prevent cascade outages within the network.

We have one material security project proposed to improve the security of supply to 28,900 customers on the Fleurieu Peninsula network by the construction of a new 66kV sub-transmission powerline between the Myponga and Square Waterhole substations. A non-network solution is also being considered to resolve this constraint, for further information refer to Supporting Document 5.13 – Distribution System Planning Report.

The forecast augex for the identified capacity related security projects in the 2020-25 RCP is $14.8 million (June 2020 $), and represents 10% of our forecast capacity driven augex.

5.14.3.14 Strategic (Land, easements, other)

In order for us to adequately plan for the future, we may need to make strategic land and easements acquisition, prior to their actual need. This requirement is to ensure that both suitably located and sized areas exist for future network augmentation requirements and to ensure new regions can be planned by the responsible jurisdiction (eg SA Government and/or local council) in a prudent and efficient manner.

While overall system demand is not forecast to increase over the 2020-25 RCP, a number of locations in the State are still experiencing demand growth due to greenfield developments. Where greenfield development is occurring at the fringes of the metropolitan network, new substation sites may be required as existing substations are unable to cater to the new load.

We have only identified one required land acquisition at Mount Barker East. The forecast augex for land, easements and other in the 2020–25 RCP is $1.6 million (June 2020 $), and represents 1% of our forecast capacity driven augex.

5.14.3.15 Future demand growth

The following programs consist of projects which may be categorised as future demand growth dependent.

(i) Continued real estate development

Augmentation necessary to support forecast housing development. Typicaly based on approved property development plans.

The forecast augex for the identified capacity related continued development projects in the 2020-25 RCP is $7.1 million (June 2020 $), and represents 5% of our capacity driven augex.

(ii) General demand growth

This program consists of projects where it has been forecast that the load will exceed the network planning criteria in the 2020-25 RCP. This portion of the capacity driven augex is dependent on the spatial demand forecast.

The capacity driven (general demand growth) augex is forecast to be similar to the 2015-20 RCP as the global SA demand forecast has also been forecast to remain relatively flat. It is important to note that whilst we forecast minimal global demand increases across our network, there are localised areas of growth requiring network augmentation to be undertaken in order to achieve the capex objective in clause 6.5.7(a)(1) of the NER.

We are forecasting regional growth in the northern and southern suburbs (new housing developments) where time of peak has already reached 7:00pm (and any future solar will have minimal impact) and a number of localised zone substations, such as Campbelltown, Clare and Aldinga (new housing developments or infill housing). The full details of our forecast capacity driven augex are in our DSPR.

The forecast augex for 'planning criteria forecast to be exceeded' projects in the 2020-25 RCP is $11.5 million.

5.14.4 Reliability

Reliability augex is required to maintain our reliability performance so that we achieve the ESCoSA service standards for reliability as detailed in the EDC and in accordance with the requirements of our Distribution Licence and the capex objective in clause 6.5.7(a)(2) of the NER.

Reliability augex is limited to the installation of new assets or alteration of existing assets which upgrade the network. Where assets are replaced on a like for like basis, or refurbished, that expenditure has been included in our repex forecast discussed in Section 5.13 of this Attachment.

Although SA Power Networks' average underlying performance remains relatively stable, augex targeted for reliability performance management is essential to maintain the underlying reliability performance at this present level given the continued ageing of underlying assets and the impact of new issues such as the increasing flying fox populations in South Australia. Without this investment, average reliability experienced by customers would decline.

5.14.4.1 Reliability outcomes for the 2015-20 RCP

In the 2015-20 RCP, the overall reliability performance that customers have experienced, including days classified as MEDs, demonstrates customers have and are being adversely impacted by increasing outages and longer outage durations. We have also observed an increase in storm related interruptions through vegetation from outside the clearance zone.

However, when excluding MEDs, the underlying reliability performance of the network is being managed in accordance with ESCoSA's service standards, with the exception of the CBD region in recent years. Our underlying CBD feeder performance has recently deteriorated due to an unprecedented number of random CBD cable faults in PILC cables. Short term solutions to efficiently rectify this have been implemented and long term solutions are currently being evaluated. The proposed expenditure for the CBD cable replacement has been included in our repex forecast as discussed in Section 5.13.4 A(ix) of this Attachment.

In the 2015-20 RCP, we commenced a program to harden the network against the impact caused by escalating storm activity, which was necessary to address the decline of our overall reliability performance during MEDs.

We have also observed that there are a number of low reliability feeders whose performance has consistently exceeded ESCoSA's performance targets by a factor of two or more and their adverse reliability impact is increasing. Through our customer and stakeholder engagement program, particularly when speaking with our regional customers, it became apparent that there is an expectation that we will improve the performance of these feeders, where there is a positive net benefit and this augex has been included in our forecast.

The actual/forecast reliability augex for the 2015-20 RCP is $53.2 million, $4.2 million (9%) above the AER allowance of $49.0 million, refer Table 5-20.

Table 5-20: Comparison of reliability expenditure, AER allowance to actual/forecast for the 2015-20 RCP (June 2020, $ million,)

Reliability	2015/16	2016/17	2017/18	2018/19	2019/20	TOTAL
Allowance	7.5	9.2	10.1	11.0	11.2	**49.0**
Actual and forecast	4.2	6.2	12.1	15.2	15.6	**53.2**

Reliability augex in the early part of the 2015-20 RCP was lower than forecast due to an unprecedented number of significant storms, requiring resources to be diverted to return the network to normal operation. During the 2017/18 regulatory year we increased reliability augex and this is forecast to continue as we progress our maintaining reliability and hardening the network programs.

Reliability augex is also targeted at areas of the network where customers are experiencing poor performance of which many are regionally based. There are small remote communities whose reliability levels significantly exceed ESCoSA's service standards. As only a small number of customers are affected in these areas, the lower service levels they receive do not contribute materially to the overall average reliability performance outcomes of the region. We are required to annually report to ESCoSA on actions taken to improve the reliability of these areas.[36] In the 2015-20 RCP, we commenced a small program to improve supply reliability to some of our long-term low reliability feeders and 'poorly served' customers where there is a positive net benefit to do so. This is explained in greater detail below.

In the 2020-25 RCP, we propose to continue these programs of works at similar expenditure levels to the 2015-20 RCP, except for the low reliability feeder program where we have forecast an increase in augex owing to the increasing reliability impact of these long-term low reliability feeders and based on feedback from our

[36] *EDC, clause 2.6.1; ESCoSA, Electricity Industry Guideline No.1 (G1/12), clause 4.6 and 5.*

customers and stakeholders. There is a customer and stakeholder expectation that we will improve the performance of these feeders, where there is a positive net benefit to do so.

5.14.4.2 Reliability forecast capex for the 2020-25 RCP

SA Power Networks' forecast reliability augex for the 2020-25 RCP is summarised in Table 5-21.

Table 5-21: Forecast reliability augex for the 2020-25 RCP (June 2020, $ million)

	2020/21	2021/22	2022/23	2023/24	2024/25	TOTAL
Reliability	12.7	12.9	13.0	13.1	13.2	**64.9**

Our forecast reliability augex consists of the programs set out in Table 5-22.

Table 5-22: Reliability programs for the 2020-25 RCP (June 2020, $ million)

Reference	Reliability	Description	$M	Supporting Document
A	Maintain underlying reliability	Remedial works undertaken to maintain the overall reliability of the network to achieve the ESCoSA service standards for reliability as detailed in the EDC	34.6	5.25
B	Hardening the network	Remedial works to mitigate extended duration interruptions due to the impact of MEDs (eg due to the impact of increasing number and severity of severe weather events)	15.4	5.26 and 5.29
C	Low reliability feeders	Remediation of the consistently (long term) worst performing power lines	14.9	5.27 and 5.28

5.14.4.3 Maintaining underlying reliability

As explained above, reliability augex is required to maintain our reliability performance so that we achieve the ESCoSA service standards for reliability as detailed in the EDC and in accordance with the requirements of our Distribution Licence and the capex objective in clause 6.5.7(a)(2) of the NER.

The 'maintain underlying reliability' program targets operational flexibility and protection of the network to minimise the impact of supply outages. It is mainly required to address emerging issues (through implementing reliability enhancements) that arise such as to address escalating customer issues and complaints, a deterioration of 'localised' feeder performance and/or the escalation of causes such as the migration of bats/corellas, non-MED vegetation related interruptions and CBD interruptions.

Through our customer and stakeholder engagement program we have learned that customers expect (as a minimum) SA Power Networks to deliver the current levels of reliability and there is no appetite to lower the reliability standards. This was supported by ESCoSA's recent review of the reliability standards framework that will apply to SA Power Networks for the 2020-25 RCP (which confirmed that standards set to maintain reliability at current levels rather than improve or reduce reliability).[37]

We propose to continue our maintaining underlying reliability consistent with historic levels of expenditure, with forecast augex of $34.6 million for the 2020-25 RCP. For further information on our maintaining underlying reliability program refer to the Supporting Document 5.25 – Reliability and Resilience Performance Management Strategy.

[37] *ESCoSA, SA Power Networks reliability standards review – Final decision, January 2019, page i.*

5.14.4.4 Hardening the network

To mitigate the deterioration in our overall reliability performance (including MEDs), we need to harden our network in locations that are consistently affected by MEDs (primarily major lightning and wind storms).

Regulatory targets and reported performance typically excludes MEDs and therefore there is significant variability in the annual reliability of supply experienced by customers due to MEDs. Because MED reliability contribution is excluded from STPIS, there is no financial incentive for SA Power Networks to mitigate the MED impacts.

Customers who are mostly impacted during MEDs are predominantly supplied via overhead bare-wire conductor construction in heavily vegetated areas or in lightning prone zones, therefore they are more likely to be affected by storm activity.

The need for the hardening the network program to continue through the 2020-25 RCP has been identified through:

- customer and stakeholder feedback supporting this program;
- a review of network performance that has impacted our customers since 2010/11; and
- a prediction and extrapolation of weather-related performance trends in line with the risk identified by the Bureau of Meteorology report titled 'Climate extremes analysis update for South Australian Power Network operations' (which is available on request) and the CSIRO who also predict ongoing, long-term climate change particularly in weather and climate extremes, as detailed in their report titled 'The State of the Climate 2018'.

Extreme weather in the 2016/17 regulatory year (and previously in 2010/11 and 2013/14) resulted in significant network outages and loss of electricity supply to customers for extended durations. The scale and impact of extreme weather, in terms of network damage and customer impact, exceeded anything previously experienced in South Australia. The South Australian Emergency Services Minister stated that, *"2016 has been the busiest year on record for our State Emergency Services. We've had double the number of calls this calendar year''*.

5.14.4.5 Customer and stakeholder engagement outcomes

Throughout our extensive engagement, particularly in rural areas, customers reinforced the importance of reliability for regional business, industry and economies. While electricity prices were important, in regional areas we saw that reliability and resilience of the network consistently ranked as the highest priority for these customers[38].

Customers and stakeholders largely support expenditure to harden the network providing it is economically viable to do so, and is justified by cost/benefit analysis. Regional customers and many regional councils, as well as business representatives such as Business SA and the SA Wine Industry Association, have advocated for improved reliability in regional areas, and have indicated their support for targeted programs to improve reliability[39]. However, groups representing vulnerable customers, while appreciating the need for this work, expressed some concern over the additional cost of such programs. In response to this feedback, we have refined the scope of the program, reducing its cost and making it a modest continuation of expenditure in the 2015-20 RCP. We consider this a balanced response to meet the competing customer and stakeholder objectives.

[38] *Refer Supporting Document 0.7 - MDC Planning and Directions Workshop Report*
[39] *2020-25 Draft Plan feedback listed on Talking Power website: talkingpower.com.au*

The forecast augex for the hardening the network program for the 2020-25 RCP is $15.4 million. The program aims to mitigate the extended duration interruptions experienced by customers who are significantly impacted by MEDs, improving the reliability of supply to 53,795 customers.

173 feeders repeatedly damaged by storms were analysed by identifying the historical interruptions that could have been mitigated if hardening augmentation was in place. 37 projects have been selected on 35 of these feeders for the hardening the network program for the 2020-25 RCP, where the value of customer reliability (**VCR**) benefit of the project most exceeded the cost of the recommended augmentation and where the net present value (**NPV**) of any STPIS benefit was negative.

The targeted 35 feeders identified for hardening supply affect approximately 53,795 customers, representing approximately 7% of SA Power Networks customers.

Providing that all of the proposed solutions are implemented, the total net economic (VCR) benefit of the program is $5.2 million per annum. The net economic (VCR) benefits for individual hardening projects range between $9,500 and $365,000 per annum.

This program will include a combination of strategies aimed at addressing the specific causes of extended duration interruptions to our customers during MEDs, including:

- re-insulating vulnerable sections of overhead lines to minimise insulator failures due to lightning;
- alternative network asset configuration / standards to reduce vegetation outages and damage from outside the prescribed clearance zone; and/or
- installing mid line switches to reduce the number of customers interrupted during MEDs.

For more information on the proposed hardening the network program, refer to Supporting Documents:

- 5.26 – 2020-2025 Reliability and resilience programs - hardening the network; and
- 5.29 - Hardening the network regulatory model.

5.14.5 Low reliability feeders

We have developed a $14.9 million program to improve the reliability of supply to 16,600 customers supplied by low reliability feeders. This program is proposed to be implemented over the 2020-25 RCP.

The low reliability feeder program only includes work elements that we have found to be economically viable (ie the benefits exceed the costs in NPV terms). We estimate the total economic benefit (VCR) due to the implementation of this program is $2.2 million per annum and the net benefit is $0.9 million per annum.

As we noted earlier, we are required under the EDC administered by ESCoSA to manage our worst performing feeders.[40] This scheme defines 'Low Reliability Distribution Feeders' as feeders within a particular region, which have exceeded two times the System Average Interruption Duration Index (**SAIDI**) service standard (excluding MEDs) for two consecutive regulatory years.

These requirements are focused on identifying and monitoring our low reliability feeders. Currently, we have no direct obligation to improve the supply from these feeders. Nonetheless, there is still an expectation through these requirements that we will improve the performance of those feeders, where it is economically viable to do so.

Our low reliability feeder program will improve the supply from 96 of our worst performing feeders through a combination of works, covering:

- re-insulation of poor performing line sections;
- installation of reclosers and sectionalisers;

[40] *EDC, clause 2.6.1; Electricity Industry Guideline No.1 (G1/12), clause 4.6 and 5.*

- undergrounding of critical line sections; and
- upgrading critical bare wire line sections with covered conductor.

We estimate that this program will provide, on average, 169 minutes improvement in the SAIDI for customers supplied by these feeders, representing a 39% improvement in their supply reliability (including on MEDs).

The greatest improvement will be to 13,269 of our customers served by 84 Rural Long feeders addressed by this program, who will on average receive 172 minutes improvement in SAIDI (including on MEDs). 1,343 customers served by 9 Rural Short feeders will receive, on average, a 123 minute improvement in SAIDI (including on MEDs) and 2,652 customers served by 6 Urban feeders addressed by this program will receive, on average, a 150 minute improvement in SAIDI (including MEDs).

Our customers served by low reliability feeders in the Upper North region will receive the greatest improvement, with a 254 SAIDI minute improvement (including MEDs). Customers served by low reliability feeders in the Riverlands and Murraylands; Barossa, Mid-North, Yorke Peninsula; and Eyre Peninsula regions will also receive significant improvements, with an average SAIDI improvement (including MEDs) of 187 minutes. Other regions, other than the Rural Metropolitan Centres[41], will still receive significant improvements, ranging between 64 minutes for the Eastern Hills to 103 minutes for Adelaide Metropolitan Area (including MEDs).

5.14.5.1 Customer and stakeholder engagement outcomes

Throughout our extensive engagement, particularly in rural areas, customers reinforced the importance of reliability for regional business, industry and economies. While electricity prices are important, in regional areas we saw that reliability and resilience of the network consistently ranked as the highest priority for these customers[42].

Similar to hardening the network, customers and stakeholders largely support expenditure to improve supply to low reliability feeders, providing it is economically viable to do so, and is justified by cost/benefit analysis. Regional customers and many regional councils, as well as business representatives such as Business SA and the SA Wine Industry Association, have advocated for improved reliability in regional areas, and have indicated their support for such programs[43]. However, groups representing vulnerable customers, while appreciating the need for this work, expressed some concern over the additional cost of such a program. In response to this feedback, we have refined the scope of the program and reduced its cost. We consider this a balanced response to meeting the competing customer and stakeholder objectives.

The low reliability feeder program is a reliability improvement program and so the reliability benefits can *notionally* affect STPIS outcomes. However, the benefit-cost ratios for these types of improvement are typically much lower than our more usual reliability improvement projects, which are aimed at addressing underlying reliability. The consequence of this is that the existing STPIS mechanism does not provide the appropriate incentives to fund the types of work identified for feeders under this program. For further details in relation to adjustments to STPIS targets are discussed in Attachment 10 – Service Target Performance Management Scheme.

For more information on our low reliability feeders program, refer to the Supporting Document 5.27 – 2020-25 Reliability and Resilience Programs - Low Reliability Feeders and Supporting Document 5.28 – Low reliability feeders regulatory model.

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[41] *We have found no viable solutions for the Rural Metropolitan Centres. However, it is worth noting that there are only 3 feeders identified as long term low reliability in this regional category, all of which are Urban.*

[42] *Refer Supporting Document 0.7 - MDC Planning and Directions Workshop Report.*

[43] *2020-25 Draft Plan feedback listed on Talking Power website: talkingpower.com.au*

5.14.6 Strategic

The strategic expenditure category primarily includes a number of one-off strategic projects aimed at ensuring the security of supply of the network.

5.14.6.1 Strategic outcomes for the 2015-20 RCP

The strategic augex actual/forecast in the 2015-20 RCP is $38.1 million, $13.0 million (25%) below the AER allowance of $51.1 million, refer Table 5-23.

Table 5-23: Comparison of strategic expenditure, AER allowance to actual/forecast (June 2020, $ million)

Strategic	2015/16	2016/17	2017/18	2018/19	2019/20	TOTAL
Allowance	3.4	15.6	22.1	9.9	0.0	**51.1**
Actual and forecast	7.2	2.3	2.6	13.9	12.1	**38.1**

The primary reason that forecast strategic augex for the 2015-20 RCP was lower than the allowance was due to an efficient installation of the new Kangaroo Island cable. The initial capital forecast for this project in the 2015-20 RCP was based on budget estimates from cable suppliers. A competitive tender process combined with the modification of the technical specification of the submarine cable to reflect the future forecast growth requirements on Kangaroo Island resulted in a lower project cost.

In accordance with the RIT-D process, we implemented the best economic solution for our customers to meet the minimum planning criteria relating to network security, customer reliability, and the ability to manage future customer demand increases and generation connections.

5.14.6.2 Strategic forecast capex for the 2020-25 RCP

The strategic program for the 2020-25 RCP is a continuation of existing programs totalling $17.2 million, as well as a new LV management program to enable customers continued uptake of DER. The total forecast is $49.0 million which is $2.1 million less that the forecast strategic augex for the 2015-20 RCP, refer to Tables 5-24 and 5-25 for details of our forecast strategic augex and proposed strategic program for the 2020-25 RCP.

Table 5-24: Forecast strategic augex for the 2020-25 RCP (June 2020, $ million)

	2020/21	2021/22	2022/23	2023/24	2024/25	TOTAL
Strategic	9.3	12.6	10.2	9.5	7.4	**49.0**

Table 5-25: Strategic programs for the 2020-25 RCP (June 2020, $ million)

Reference	Strategic	Description	$M	Supporting Document
A	**Network control**			
(i)	SCADA to substations	Installation of SCADA to country substations for operational and reporting	8.2	5.23
(ii)	SCADA (RTU) upgrade	Upgrade of aged SCADA RTUs	4.7	5.23
(iii)	Network data capture	Data collection on the Adelaide CBD, Adelaide and North Adelaide area to support OMS, GIS and ADMS operations.	2.9	5.23
B	**Condition monitoring**	Testing and on-line monitoring of priority assets	1.4	On request
C	**Low voltage management**	Installation of the systems required to enable us to manage the impact of DER	31.8	5.17 anc 5.18

5.14.6.3 Network Control

SCADA is a key tool used by SA Power Networks' network operations centre (**NOC**) to manage and control the distribution network. SCADA control and monitoring of the distribution network is an industry standard across the Australian electricity industry. The SCADA system is used to gather, process, and display information about the status of the network as well as change the operating state of devices remotely. The system comprises a central master station and numerous field installed remote terminal units (**RTUs**) and data concentrators which aid in transferring data from field based intelligent digital devices (**IDDs**), such as substation relays and midline protection reclosers, back to the master station.

With SA Power Networks' evolving distribution network, there is a requirement to further develop SCADA network control and monitoring to optimise network and asset performance, maintain service levels to customers and meet regulatory obligations and requirements.

SA Power Networks' SCADA augmentation priorities over the 2020-25 RCP are as follows:

- continue the rollout of supervisory control and monitoring on key network assets in the distribution system to provide adequate tools for network management and providing actual data for RIN reporting and DAPR preparation;
- continue the replacement of outmoded RTUs; and
- continue the migration of data into the advanced distribution management system (**ADMS**).

Note, the upgrade of the ADMS is now included in our non-network – network operations IT capex forecast.

For further information on the network control programs below, refer to Supporting Document 5.23 – DGA Consulting – Network Control – projects review 2020-25.

5.14.6.4 SCADA to remaining substations

In the absence of SCADA control and monitoring, there are reduced levels of network management and control. In particular, without SCADA there is a dependency on customer outage reports to identify substation interruptions, and a reliance on line crews to travel to site in order to undertake local operations during restoration work.

Given the ageing population of our assets, installing SCADA in country substations is essential in order to maintain the current levels of reliability and customer service. As assets age there is a greater probability of failure and SCADA is essential to identifying these failures through remote alarm indication. Furthermore, the metering information from these substations is essential to ensure that there is sufficient distribution capacity to supply increases in demand in the long term and to support reporting requirements.

Our proposed SCADA to remaining substation augex forecast of $8.2 million (June 2020 $) is consistent with the activities in the 2015-20 RCP and this program is scheduled to be completed by 2025.

5.14.6.5 SCADA RTU upgrade

RTUs form a large overall component of our SCADA system. RTUs are typically located within the relay room of a substation and provide control outputs, process alarms and status indications, and collect metering data from the corresponding substation via hard-wired or serial communications channels.

Information from substation RTUs is typically transmitted over dedicated telecommunications channels to one of nine data concentrating RTUs. The data concentrators serve two purposes – to act as a protocol converter between the substation RTUs and the NOC, and to concentrate data onto limited communications channels into the NOC.

Historically our large fleet of older GE RTUs have proven to be very reliable, however, over the last five years the failure rate of the RTUs has averaged 18 failures per year, with the bulk of the failures due to RTU module processor failure. We have had great difficulty in sourcing spare parts for these RTUs as they have been phased out and are no longer supported.

Given the recent failure rates of these assets an upgrade strategy has been implemented in the 2015-20 RCP (and will be continued in the 2020-25 RCP) to gradually replace and upgrade all RTUs that will be significantly over 20 years old by the end of the 2020-25 RCP. This will ensure that we are able to maintain current service levels.

Our proposed SCADA RTU upgrade augex forecast for the 2020-25 RCP is $4.7 million (June 2020 $).

5.14.6.6 Network data capture

The network data capture program captures network upgrades and modifications within the Adelaide CBD, Adelaide and North Adelaide areas. Due to the volume of work and complexity of the network within these areas, this program includes the update of all drawings and data sets to enable high accuracy network models, customer connectivity details and network equipment details to support outage management system (**OMS**), GIS and ADMS operations.

The network data capture program is the continuation of an existing program. The augex forecast for this program is $2.9 million (June 2020 $) and is consistent with the expenditure in the 2015-20 RCP.

5.14.6.7 Condition monitoring

The internal condition of power transformers cannot easily be observed directly, however insulating oil tests such as dissolved gas analysis (**DGA**) and consequential estimation of paper degree of polymerisation (**DP**)) and oil quality (**OQ**) along with on-line monitoring can be used to assess the internal condition of these assets and assist in the diagnosis and quantification of failure risk.

This is the continuation of the condition monitoring program in line with historic expenditure. The forecast augex for the 2020-25 RCP is $1.4 million (June 2020 $).

5.14.6.8 Strategic LV management

As noted earlier, South Australia has the highest ratio of solar generation to operational consumption of all the NEM regions, and this is forecast to remain the case for the next ten years[44]. South Australia also leads the nation in the adoption of battery storage and Virtual Power Plants (**VPPs**), driven in part by Government programs that combined could see up to 90,000 new batteries with 400MW of controllable storage connected to the distribution network in the next five years.

There are technical limits to the amount of embedded generation that can operate on the network before customer issues arise such as HV issues in the middle of the day. If we continue to apply our current small-embedded generator connection rules, in which all embedded generators of 5kW export capacity or less are approved for connection, many areas of our network will exceed these technical limits in the 2020-25 RCP as solar and battery storage uptake continues to grow. This is the case even after taking into account the impact of measures such as inverter settings and tariffs, and allowing for a wide range of possible solar and battery growth scenarios[45]. If we do not manage this effectively, the distribution network may become a bottleneck that severely curtails the ability for customers and new energy services providers to participate in the market and contribute effectively to the energy system in South Australia.

While we will continue to employ established approaches to managing these issues in the 2020-25 RCP, and improve these processes through initiatives such as targeted sample LV transformer monitoring, our modelling shows these approaches are not sustainable. To manage forecast levels of DER in the longer term we will need

[44] *AEMO, South Australian Electricity Report, 2018*

[45] *Refer supporting document 5.18 - LV Management business case*

to take a more active and dynamic approach to managing the integration of solar, battery storage and VPPs into the distribution network, and this requires the development of new operational systems and business processes.

Our proposal includes augex of $31.8 million for the 2020-25 RCP to develop these new capabilities. Specifically, this involves expenditure to:

- improve visibility of the LV network through targeted mid-line and end-line monitoring, primarily through the procurement of data from smart meter providers and other third parties;
- develop an LV network model to understand the 'hosting capacity' of our network[46];
- put in place a register of DER; and
- implement open interfaces (eg Application Programming Interfaces, (**APIs**) to publish dynamic export limits to customers and DER aggregators.

This expenditure is in addition to the ongoing 'business as usual' capacity related expenditure on QoS and the associated LV transformer monitoring described earlier in Section 5.14.1.

The AEMC considered efficient long-term approaches to integrating DER into Australia's distribution networks in its 2018 Economic Regulatory Framework Review and recommended that networks move to implement a more dynamic approach to DER management[47]. Our proposal aligns with this recommendation, and our own economic modelling, set out in detail in the supporting business case[48], supports the AEMC's findings that this approach delivers the best long-term outcome for all customers. We have also consulted extensively on our proposed approach in 2018 through our customer and stakeholder engagement program, and found that customers, industry and other stakeholders are supportive of this proposed expenditure[49].

Further details in relation to this proposed expenditure are set out in Attachment 6 – Operating expenditure and Supporting Document 5.18 – LV Management business case.

5.14.7 Safety

Augmentation safety expenditure is required to prudently maintain the safety of the distribution system through the supply of SCS[50]. This expenditure requires the installation of new assets or the replacement of existing assets with improved technology and differs from safety repex which is for the replacement of 'like for like' assets and has been included in our repex forecast discussed earlier.

The safety augex forecast in the 2015-20 RCP is $70.1 million, $46.2 million above the AER allowance of $23.9 million, refer Table 5-26.

[46] *That is, how much energy can be fed into the network by embedded generators like solar and batteries at any given point in time before voltage issues or other problems arise. This varies from one local LV area to the next according to a range of factors including the type of network construction, the nature of the loads connected to the local network and so on.*
[47] *AEMC, 2018 Final report, Economic regulatory framework review, 26 July 2018.*
[48] *Refer supporting document 5.18 - LV Management business case and supporting document 0.16 – Newgate research community attitudes towards solar.*
[49] *Refer to our Customer and stakeholder engagement report.*
[50] *NER 6.5.7(a)(4).*

Table 5-26: Comparison of safety augex, AER allowance to actual/forecast (June 2020, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	TOTAL
Allowance	4.6	4.7	4.1	5.1	5.5	**23.9**
Actual and forecast	5.4	9.0	19.0	19.3	17.3	**70.1**

The forecast variance in safety augex in the 2015-20 RCP has arisen due to the implementation of a new bushfire mitigation program to ensure SA Power Networks continues to operate in accordance with good electricity industry practice. We have also commenced our protection compliance program and the migration of our CBD 33kV network to the 11kV network in the 2015-20 RCP.

SA Power Networks' forecast safety augex for the 2020-25 RCP is summarised in Table 5-28. In the 2020-25 RCP, safety augex will be focused on activities that maintain the appropriate safety of our network for our workforce and the general public.

The proposed safety program is a continuation of the existing program, totalling $57.5 million (June 2020, $ million). Refer to Table 5-27 for details of our proposed safety program for the 2020-25 RCP.

Table 5-27: Forecast safety augex for the 2020-25 RCP (June 2020, $ million)

	2020/21	2021/22	2022/23	2023/24	2024/25	TOTAL
Safety	12.2	12.3	11.0	11.0	11.1	**57.5**

Table 5-28: Safety programs for the 2020-25 RCP (June 2020, $ million)

Reference	Program	Description	$M	Asset Plan[51]
A	**Substation lighting**	Long term program to remediate substation lighting to ensure safe substation access for our workforce	0.5	5.1.05
B	**Substation security and fencing**	Long term program to remediate inadequate substation security fencing and security systems	12.5	5.1.03
C	**Substation earth grids**	Long term program to remediate unsafe substation earthing system	5.9	5.2.10
D	**Protection compliance**	Program to upgrade protection systems for compliance and system stability	14.8	3.2.14
E	**CBD 33kV to 11kV migration**	Program to migrate our ageing 33kV high risk network to the 11kV network	12.4	2.1.0.7
F	**Bushfire mitigation**	Targeted program to manage the risk of bushfires starting from our infrastructure in the HBRAs	11.4	Supporting Documents 5.13, 5.14, 5.15 and 5.16

Supporting Document 5.7 – Strategic Asset Mangement Plan and Supporting Document 5.8 – Powerline Asset Management Plan, provide detailed information on our asset management practices, forecasting approach and modelling outputs for each asset class. Further information can be provided through the provision of individual asset plans on request.

5.14.7.1 Substation lighting

Substation lighting is critical to the safe entry and egress to substations. Following an incident at Coromandel Place Substation in the Adelaide CBD, in early 2001 we commenced a program to upgrade the indoor

[51] *Available on request*

emergency lighting in indoor substations and substation control buildings. This program was also extended to outdoor lighting to address safety concerns raised after an increase in copper theft and vandalism in substations in the mid-2000s.

Our augex forecast for substation lighting for the 2020-25 RCP is $0.5 million, consistent with our historical expenditure. Further information is contained in our Asset Plan 5.1.05 – Substation lighting, which is available on request.

5.14.7.2 Substation security and fencing

Substation security, specifically the potential for intruders or unauthorised parties to enter an SA Power Networks' substation and harm themselves is ranked as a strategic high risk under our corporate risk management framework.

Any unauthorised person entering a substation has a real risk of serious injury or death. These people have typically little or no understanding of the dangers of HV electricity, for example, that it is not necessary to touch a live conductor to be electrocuted but only necessary to breach the minimum flashover distance.

Unauthorised persons entering substations fall into two broad categories, the 'determined' and the 'non-determined' persons. The impracticality of preventing access to determined unauthorised persons (persons carrying tools or persons with criminal intent) is recognised in legal advice and national guidelines. Our highest liability is related to entry by the 'non-determined' intruder, in particular children who may enter out of curiosity.

The number of unauthorised entries into substations tends to fluctuate significantly. On average we experience one break-in per month, generally for the purpose of removing copper earthing leads from substation structures for scrap metal value.

The Electricity (General) Regulations state that all substations must be designed, installed, operated and maintained to be safe for the electrical service conditions and the physical environment in which they will operate[52]. Additionally, SA Power Networks owes a duty of care to entrants (which include trespassers) into its substations.

In 2006, the Energy Networks Australia (**ENA**) released the 'National Guidelines for Prevention of Unauthorised Access to Electricity Infrastructure', ENA DOC 015-2006. This document details some examples of intruder resistant fences and these types of fences are recommended to prevent opportunistic intruders from gaining unauthorised access to a substation. The document also recognises the impracticality of preventing access to determined unauthorised persons, being persons carrying tools or persons with criminal intent.

Based on these ENA guidelines, our strategy to address substation security risk due to unauthorised access is to progressively install high security fencing and surveillance systems at all sites with exposed conductors less than 4.6m above ground level. Sites with fully insulated conductors may also require high security fencing, depending on the specific risk of damage to equipment (for example, risk of vandalism).

Our augex forecast for substation security and fencing for the 2020-25 RCP is $12.5 million, consistent with our historical expenditure. Further information is contained in our Asset Plan 5.1.03 – Substation fences and security, which is available on request.

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[52] *Electricity (General) Regulations, regulation 51.*

5.14.7.3 Substation earth grids

SA Power Networks currently has 408 substations, each containing a set of conductors, and connections that form the substation earth grid. Our earth grids are an ageing asset with the majority installed more than 40 years ago.

Lack of an effective substation earth grid can pose a significant threat to human safety and protection equipment integrity during network earth fault conditions. The dangers of earth potential rise and associated step and touch potentials are not only a risk within substation fences, but also in nearby publicly accessible areas and adjacent telecommunication infrastructure.

We have established an earth grid test program and in consultation with Sinclair Knight Merz (now Jacobs), developed a methodology to rank substations according to the safety risk imposed by earth grid condition. A testing frequency of 30 sites per year allows all substations to be tested every 15 years. Sites identified as high and medium risk are prioritised for remediation or upgrade. This strategy is in line with good industry practice and published Australian standards and guidelines.

The earth grid testing and remediation strategy was implemented in 2009. Since this time 224 substations have been tested and 36 high priority sites have been remediated. A further 11 high priority sites have remediation work either planned or in progress and 102 sites identified as medium risk require minor upgrade work over the 2020-25 and future RCPs.

Our augex forecast for substation earth grids for the 2020-25 RCP is $5.9 million, consistent with our historical expenditure. Further information is contained in our Asset Plan 5.2.10 – Substation earth grids, which is available on request.

5.14.7.4 Protection compliance

We have more than 12,500 substation protection and control assets with a variety of types and associated maintenance requirements, failure mode characteristics and resultant life cycles. This includes more than 6,500 complex relays that consist of many components and have multiple functions. The protection and control relay assets form an integral part of the HV network and automatically protect the network, personnel and public in the event of fault conditions.

The protection assets on our distribution network vary in age and technology from the earliest basic fuse protection and the electro-mechanical relays installed between the 1930s to the 1980s, through the transition to solid state relays and then to the latest digital microprocessor based protection relays being installed since the 1990s. Most of the protection relays presently installed are of the electro-mechanical type, which are either approaching or have exceeded their design life.

The protection compliance program addresses existing network protection issues that do not comply with SA Power Networks' Network Directives and/or the NER requirements. The compliance program commenced in 2013 following identification by SA Power Networks of a large part of its network as having inadequate back-up protection, with Country HV Compliance and Metropolitan HV Compliance in 2017.

If a protection device fails to operate and fault remains, it presents a significant public safety and fire risk and damage to network assets can result. Accordingly, both primary and backup clearing times are required to be compliant to reduce fault energy and minimise plant damage and risk of harm to personnel and the public.

Country HV Compliance is an existing and on-going program addressing the backup protection issues applicable to rural areas where backup clearing times are not acceptable when the primary protection fails.

This is required for compliance with clause S5.1.9 of the NER[53] and the SA Power Networks' distribution network directive ND J1[54]. The program aims to adequately manage the protection of our HV network from the impacts of electrical faults and minimise dangerous exposure to works and the public.

Metropolitan HV Compliance is a program addressing vulnerabilities in the HV protection schemes that largely protect the Adelaide metropolitan meshed 66kV network. This is required for compliance with clause S5.1.9 of the NER and Australian Standard AS60038[55].

Existing old technology and protection schemes are not capable of meeting the current demands on the distribution network. Substation switchboards, transformers, and 66 kV lines that are protected using old 1960s to 1980s single set protection schemes have no ability to detect if an old relay has failed and have slow backup protection from adjacent substations.

Furthermore, high wind and solar generation sources have resulted in lower system strength and lower fault levels resulting in higher instability of the electricity network.

Substations now have power flowing 'backwards' through them at certain times due to high DER. Our older substation transformers have insufficient tap ranges to manage this new phenomenon and in some cases they have failed to operate. We have experienced two substation switchboard failures in 2012 and 2013, and four transformer asset failures in 2017 and 2018 as a result of outdated protection systems. This has highlighted the consequences of the existing inadequate protection.

Our augex forecast for protection compliance for the 2020-25 RCP is $14.8 million, consistent with our expenditure for the 2015-20 RCP. Further information is contained in our Asset Plan 3.2.14 Protection and control, which is available on request.

5.14.7.5 CBD 33kV to 11kV migration

The Adelaide Central Region (**ACR**) is meshed within the Eastern Suburbs sub-transmission network system, supplied via East Terrace and City West transmission connection points, with other sub-transmission lines supplying the ACR from the Magill and Northfield transmission connection points.

Electricity is supplied throughout the ACR via Zone Substations. These Zone Substations are operated at either 66,000 volts stepped down to 11,000 volts or 33,000 volts or 33,000 volts stepped down to 11,000 volts.

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[53] *SA Power Networks is required under clauses S5.1.9(c) and (f) to provide such back-up protection systems as are reasonably required to ensure that a fault of any fault type anywhere on its distribution system is automatically disconnected within the fault clearance time required under clause S5.1.9(f) in the particular circumstances. The only circumstance where a back-up system is not required to be provided under clause S5.1.9(c) and (f) is if the occurrence of a short circuit fault of any type that remains un-cleared would not cause damage to any part of the power system (other than the faulted element) while the fault current is flowing or being interrupted.*
SA Power Networks is not required to establish that the lack of a back-up protection system could cause power system instability in order to justify the installation of a back-up protection system. SA Power Networks must comply with clauses S5.1.9(c) and (f) even if the lack of a back-up system will not cause power system instability.

[54] *SA Power Networks is required, under the conditions of its Distribution Licence and section 25 of the Electricity Act, to comply with its OTR approved SRMTMP. Section 2.3.3 of the SRMTMP provides that SA Power Networks must comply with ND J1 which addresses certain safety and technical matters. Section 6.1 of the ND J1 explicitly states that electrical protection and earthing systems must be designed, installed and operated and maintained to safely manage abnormal electricity network conditions likely to significantly increase the risk of personal injury or significant property damage. Section 6.2 of ND J1 states that SA Power Networks must provide backup protection to the adjacent portion of the HV network, where duplicated or 2 sets of protection are not currently used. Further section 6.3 states that the protection system must comply with the requirements of the Electricity Technical Regulations and the NER.*

[55] *Clause 5.2.1(a) of the NER requires SA Power Networks to maintain and operate all equipment that is part of its facilities in accordance with relevant Australian Standards, which includes Australian Standard AS60038.*

CBD customers are supplied from our distribution system via 33kV and 11kV feeders. The ACR feeder system supplying the CBD is characterised by cables installed within an extensive duct and manhole system.

Many of the CBDs distribution substations supply either a single or a specific set of customers within a prescribed precinct of the CBD, with requests for capacity increases requiring the upgrade or these sites being infrequent. Hence, equipment replacement is typically driven by asset condition or safety concerns as opposed to increases in load demand.

Most of our 33kV CBD network (transformers, switchgear and cables) were installed in the 1950's, 60's, 70's and 80's and are in need of replacement or refurbishment. Owing to the poor condition of the 33kV CBD network and the corresponding increase in cable failures and network risk, worker safety and public safety, we have implemented a strategy to rationalise the number of 33kV assets within the CBD.

Our CBD strategy for the 33kV distribution network is to:

- upgrade the unsafe 33kV substations or migrate to the 11kV network where retention is not feasible; and
- rationalise the number of 33kV feeders to maintain supply to high density high security customers only.

Our forecast safety augex relates to the migration of unsafe 33kV low customer density feeders to the 11kV network. Expenditure related to the replacement or refurbishment of the 33kV CBD network is included in our repex forecast.

Our safety augex forecast for the CBD 33kV to 11kV migration for the 2020-25 RCP is $12.4 million, consistent with our expenditure for the 2015-20 RCP. Further information is contained in our CBD asset plan which is available on request.

5.14.7.6 Bushfire mitigation

Faults on our network can start fires. The effect of fires in HBFRAs can be catastrophic for our customers and the wider South Australian community. With extreme weather events increasing, we need to manage this risk and adapt to new circumstances.

We have a comprehensive Bushfire Risk Management System, and each year we undertake numerous activities (eg line patrols, asset inspections and vegetation management) to reduce the likelihood that our network will start a major bushfire. To enhance these existing operational practices and address increasing bushfire risks arising in relation to our network, in the 2015-20 RCP we commenced a bushfire mitigation capex program that is aimed at reducing this likelihood further. This bushfire mitigation program includes two elements:

- installing fast operating switches with remote control facilities – this allows us to clear network faults much quicker, so the faults are less likely to start fires; and
- replacing some outdated surge arrestor technologies, of which their exposed terminal design made them prone to starting fires due to contact from birds and air-borne debris.

We are investing $16 million of capex in these programs in the 2015–20 RCP. We propose to continue this program over the 2020-25 RCP and have forecast slightly less capex of $11.4 million (June 2020) to continue to reduce increasing bushfire risks in the HBFRA.

Importantly, over the 2015-20 RCP we have made two significant developments that we believe will further improve the efficient implementation of our bushfire mitigation program in the 2020-25 RCP:

- **Ultra-fast fault clearance protection strategy** – We have developed a new protection strategy that will allow us to achieve very fast clearance of faults during extreme bushfire conditions. Our analysis suggests that this strategy will significantly reduce the probability that a network fault will result in a fire starting[56].

- **Bushfire risk and cost/benefit analysis environment** – We have undertaken extensive analysis, using experts such as the CSIRO, and developed a model that allows us to quantify the bushfire risks arising due to our network. This model also allows us to perform formal cost/benefit analysis on proposed program elements. We have used this model to assess the economic benefits (in terms of the bushfire risk reduction) of possible program elements, and importantly, ensure that the proposed program for the 2020-25 RCP will provide a positive net benefit to the South Australian community.

We estimate that the total net benefit of the program will be $3.4 million per annum. This net benefit is equivalent to approximately $66 million over the average 25-year life of the assets[57]. Approximately half of the life-time net benefit will be achieved by the program elements planned for the remaining two years of the 2015-20 RCP, and the other half of these net benefits will be achieved through the program elements planned for the 2020-25 RCP.

5.14.7.7 Our new bushfire risk and cost/benefit analysis (CBA) model

In its 2015 Determination, the AER questioned our analysis of our bushfire mitigation program and concluded that we had not sufficiently quantified the bushfire risk and undertaken cost/benefit analysis to justify the forecast capex associated with our bushfire mitigation program. We now have developed a model to assess bushfire risk and undertake cost/benefit analysis. This model places us at the frontier of Australian DNSPs in assessing the prudency and efficiency of expenditure relating to bushfire mitigation.

In this model, bushfire risk is calculated based on the quantification of:

- **Likelihood** – both in terms of our network starting a fire and this fire becoming a major bushfire; and
- **Consequence** – both in terms of the physical fire footprint and the economic cost of the land and property damage and public harm.

Furthermore, to ensure we have a detailed understanding and accurate estimate of risk, we calculate these terms across a range of bushfire conditions (36 in total) and a large number of fire start locations along our HV feeders (29,855 locations in total representing 500m increments along the feeders in the HBFRA covered by this program).

Key features of the development of the model that demonstrate its robustness are that we have:

- engaged expert advice on modelling – the CSIRO has undertaken extensive bushfire simulation, weather analysis, and fire suppression analysis to form inputs to our model;
- consulted with stakeholders that have South Australian bushfire expertise during the development of the modelling – we have held a number of workshops with the South Australian Government's Department of Environment and Water (**DEW**) and the South Australian Country Fire Service (**CFS**); and
- calibrated many aspects of the model with our historical data and South Australian bushfire events – we have used our own recent fire start history to develop fire start rates associated with our powerlines.

At this stage, we have developed the model to cover the HBFRAs that our networks traverse. This covers the Mount Lofty Ranges, the South East, and high-risk regions of the Mid North, Flinders Ranges, Lower Eyre Peninsula and Kangaroo Island. In total, 415 of our HV feeders are covered by our model, representing approximately 13,900 route km of overhead line.

[56] *Note, the probability of a fire starting increases with the time that the electrical current caused by the fault flows through combustible material.*

[57] *Note, we have used a lower life here than we may achieve from the assets to ensure we are not overstating the likely net benefit.*

5.14.7.8 Developing the scope of our bushfire mitigation program

We used our new bushfire CBA model to assess a range of investment options and confirm the extent that they will produce a net benefit in terms of bushfire risk reduction. The options considered include replacing old surge arrestor equipment and installing ultra-fast clearance protection. We also considered the replacement of bare conductors with covered conductors or underground cables however the costs to implement these solutions far exceeded the benefits.

5.14.7.9 Our bushfire risk and the benefits of the proposed program

On average, over the last 10 years[58], faults on our network have started 19 fires per bushfire season in HBRFAs. While none of these fires have resulted in catastrophic bushfires, a small number have resulted in some significant fires with material levels of land and property damage.

Although our analysis indicates that most of our fire starts will be suppressed or self-extinguish without any significant damage or harm, any of these fires has the possibility of becoming more significant. Our bushfire CBA model estimates that the expected annual bushfire risk in 2018 over the modeled region was $18.6 million[59]. Our model also provides information on the distribution of possible bushfire outcomes in any regulatory year. For example, over the region covered by our model:

- a major bushfire (ie $10-50 million fire or greater) will start around every 10 to 15 years – on average; and
- a catastrophic bushfire (ie $250 million fire or greater - Ash Wednesday scale fire) will start around every 40 to 50 years – on average.

Using our bushfire CBA model, we estimate that our bushfire mitigation program will reduce the expected annual bushfire risk by 26%, or $4.7 million. A reduction in bushfire risk of $2.2 million per annum will be achieved by the program planned for the remaining two years of the 2015-20 RCP, and a further $2.6 million per annum reduction in risk will be achieved in the 2020-25 RCP.

We estimate that the total *net* benefit due to the program will be $2.9 million per annum. This net benefit is equivalent to approximately $60 million over the average 25 year life of the assets[60].

5.14.7.10 Customer and stakeholder engagement outcomes

We have customer and stakeholder support for this program. We began our bushfire mitigation program in the 2015-20 RCP and have spoken to our customers and stakeholders through the recent engagement process about continuing the program. Our customers and stakeholders supported the program provided that the benefits to the community exceed the costs. We have demonstrated that this is the case though our bushfire CBA model.

Throughout our customer and stakeholder engagement program, customers and stakeholders told us that it was important that we proactively manage the general safety of the network, including mitigating the risk of bushfire start. In our capex deep dive workshops we explored our approach to mitigating bushfire start risk, which received support from workshop participants[61] In consideration of more detailed customer stakeholder feedback about the assumptions in our modelling, we have subsequently refined our approach and reduced our augex forecast from $19.0 million to $11.4 million (40%).

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[58] *From summer 2007/08 to summer 2016/17 inclusive.*
[59] *Note, this is the expected bushfire risk, which can be considered the long-term average, allowing for the probability distribution of outcomes ie some years will a have a lower outcome and some with a higher outcome.*
[60] *Note, we have used a lower life here than we may achieve from the assets to ensure we are not overstating the likely net benefit.*
[61] *Refer Supporting Document 0.7 MDC Planning and Directions Workshop*

5.14.7.11 Bushfire mitigation forecast capex for the 2020-25 RCP

Our augex forecast for the bushfire mitigation program for the 2020-25 RCP is $11.4 million, consistent with our expenditure for the 2015-20 RCP.

We consider that this proposed augex is required in order to achieve the capex objectives as it is required to continue to comply with our regulatory obligations and requirements, and maintain the safety of our distribution system. In particular:

- We have a duty to take 'reasonable steps' to ensure that the distribution system is safe and safely operated in accordance with section 60(1) of the Electricity Act, and to maintain and operate the distribution system in accordance with good electricity industry practice and clause 5.2.1(a) of the NER. These duties require us to have regard to objectively determined standards of safety.
- The thorough analysis, including cost/benefit analysis, we have applied to determine the prudent actions to reduce our bushfire risk demonstrates that the proposed program reflects the 'reasonable steps' we will need to take to continue to comply with our regulatory obligations and maintain the safety of our distribution system into the future.
- The need for us to continue to look for cost-effective and efficient methods to reduce bushfire risk is important in light of reports released by independent bodies such as the Bureau of Meteorology, which indicate that extreme bushfire conditions will be more likely in the future[62].

In addition, this proposed augex is required in order to satisfy the capex criteria as it reflects the efficient costs that a prudent operator would require to achieve the capex objectives, most notably:

- we have applied a robust approach to develop our bushfire CBA model and its input parameters (eg we have used independent experts, such as the CSIRO, to develop key bushfire risk inputs), and we have used our historical fire start data and South Australian historical bushfire data to calibrate and verify various model inputs;
- we have applied formal cost/benefit analysis to the program, which demonstrates that it only includes elements that provide a positive net benefit to our customers; and
- we have used recent historical unit costs to develop the program cost estimate, which we consider can be assumed to reflect efficient costs for our circumstances given our good benchmark performance compared to other DNSPs.

For further information and detailed analysis refer to the following Supporting Documents:

- Bushfire mitigation program;
- Bushfire CBA methodology;
- Bushfire CBA model; and
- CSIRO Electricity initiated bushfire suppression model analysis.

5.14.8 Environmental

Environmental expenditure is required to ensure prudent management of environmental risks to comply with EPA legislation, regulations, policies and standards and achieve the capex objectives set out in clause 6.5.7(a)(2) of the NER.

Our environmental management program is an ongoing program that consists of environmental related capex and opex resulting from periodic asset inspections, as specified in our Distribution Environmental Asset Plan, which is available on request.

[62] *BOM, climate extremes analysis update for South Australian Power Networks Operations; BOM (available on request), CSIRO/BOM, State of the climate 2018.*

Our environmental actual/forecast augex for the 2015-20 RCP is $10.3 million, $6.5 million (39%) below the AER allowance of $16.8 million, refer Table 5-29.

Table 5-29: Comparison of environmental augex, AER allowance to actual/forecast for the 2015-20 RCP (June 2020, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	TOTAL
Allowance	4.6	4.5	2.5	2.5	2.6	**16.8**
Actual and forecast	1.4	2.5	1.0	2.7	2.7	**10.3**

Through combining some distribution powerline and substation environmental remediation works such as transformer oil containment with other larger asset replacement projects, we have been able to implement the environmental program below allowance in the first three years of the 2015-20 RCP. However, we experienced a catastrophic transformer failure at Thebarton substation (late 2017) that resulted in the release of oil into the Torrens River in part due to a concealed storm water drainage system within the substation. A subsequent review in 2018 revealed four metropolitan sites with similar drainage arrangements, these are scheduled for remediation in 2018/19 and 2019/20 and will result in allowances being slightly exceeded in the final two years of the 2015-20 RCP.

When developing our environmental augex forecast for the 2020-25 RCP, we have taken into consideration our expenditure for the 2015-20 RCP, along with our customer and stakeholder views on keeping prices down.

SA Power Networks' forecast augex for the 2020-25 RCP is $9.8 million consistent with actual/forecast expenditure in the 2015-20 RCP and is set out in Table 5-30. Table 5-31 provides a summary of our proposed environmental program for the 2020-25 RCP.

Table 5-30: Forecast environmental expenditure for the 2020-25 RCP (June 2020, $ million)

	2020/21	2021/22	2022/23	2023/24	2024/25	TOTAL
Environmental	1.9	1.9	2.0	2.0	2.0	**9.8**

Table 5-31: Environmental programs for the 2020-25 RCP (June 2020, $ million)

Reference	Environmental	Description	$M	Asset Plan[63]
A	**Environmental management**	Long term program to replace aged or corroded oil filled distribution equipment, adjacent 'sensitive receptors' (areas representing a high risk of potential or actual environmental harm through a pollution event, eg in lakes and rivers)	1.0	4.1.01
B	**Substation oil containment**	Long term program to install oil containment systems in substation to comply with EPA requirements	8.0	4.1.01
C	**Substation noise abatement**	Long term program to install noise abatement measures to rectify targeted substation transformers that exceed EPA noise limits	0.8	4.1.05

The *Environment Protection Act 1993* (SA) (**Environment and Protection Act**) and the Environment Protection (Water Quality) Policy 2015 (SA)[64] places a legal responsibility on us to not undertake any activity that pollutes, or has the potential to pollute, the environment unless we take all reasonable and practicable measures to prevent or minimise any resulting harm.[65] New regulations established under the policy place a greater onus on industry and business to take steps to avoid potential environmental harm[66], emphasising the need for SA

[63] *Available on request.*

[64] *The Environment Protection (Water Quality) Policy 2003 was revoked by the Environment Protection (Water Quality) Policy 2015 which came into effect 1 January 2016.*

[65] *Environment and Protection Act, section 25.*

[66] *EPA, Information sheet titled 'The Environment Protection (Water Quality) Policy 2015: 'What's new in the policy'.*

Power Networks to continue its environmental management and substation oil containment programs in a prudent manner.

5.14.8.1 Environmental management

The capital portion of the distribution environmental management program is $1.0 million (June 2020 $) and is primarily to address smaller oil filled assets that have been classified as medium or high risk through formalised assessment criteria. This process is in alignment with our regulatory obligations and includes (but is not limited to) proximity to a sensitive receptor (eg a watercourse/body, shallow groundwater), land use (horticulture /agriculture, residential properties, grazing land) and areas considered to be of high environmental benefit.

An important element of the environmental program is the identification and rectification of those oil filled assets that display visual signs of failure (eg severe corrosion or leakage). SA Power Networks has determined that this prudent and precautionary approach is reflective of our obligations under the Environment Protection Act as it seeks to reduce the risk of failing equipment causing significant environmental impact. Proactive avoidance/minimisation of the costs associated with a 'reactionary' approach to oil filled asset ruptures, including emergency response, clean up and possible EPA penalties provides better longer-term outcomes for our customers and the South Australian community.

5.14.8.2 Substation oil containment

Our Substation Oil Containment Asset Plan has been developed to address specific environmental risk by auditing, monitoring, remediating and retrofitting substations, in line with the EPA requirements. SA Power Networks currently has 408 substations with oil filled equipment. Presently, only 55% of the 408 sites are equipped with adequate oil containment systems, presenting an environmental risk at those sites without oil containment. Forecast augex of $8.0 million has been included for oil containment in the 2020-25 RCP.

The Environment Protection Act along with the *National Environment Protection (Assessment of Site Contamination) Measure 1999* (Cth) made under the *National Environment Protection Council (South Australia Act 1995* (SA) provides a framework for investigating and determining the risks associated with contamination on a site. SA Power Networks is also required by the EPA to bund transformers containing oil that may pose a risk of pollution to the surrounding environment. The EPA 'Bunding and spill management Guideline' was revised in 2012 and now includes more stringent requirements for bunds and spill containment systems. Beyond 2020 we intend to remediate the remaining medium risk sites. We propose to continue with our current level of annual expenditure to prudently remediate all sites by 2035.

5.14.8.3 Substation noise abatement

The Environmental Protection (Noise) Policy 2007 (SA) specifies the maximum allowable continuous noise levels dependent on land use and the time of day. The limits take into account the low frequency emissions that are characteristic of substation transformer noise. Our Substation Noise Control Asset Plan has been developed to address noise related emissions from our substations, in line with our EPA obligations and this policy.

Forecast augex of $9.8 million for our environmental program in the 2020-25 RCP has been based on historic costs.

5.14.9 Power Line Environmental Committee (PLEC)

The Power Line Environment Committee (**PLEC**) program provides for the undergrounding of selected parts of the network in accordance with State Government legislation and the PLEC Charter.

The PLEC program is an undergrounding program to improve the aesthetics of electricity infrastructure to benefit the community, having regard to road safety and electrical safety. SA Power Networks is obliged to implement the PLEC program under the section 58A of the Electricity Act. The PLEC program is further defined in Part 3A of the Electricity (General) Regulations. Expenditure is required in order for comply with these applicable regulatory obligation as contemplated by clause 6.5.7(a)(2) of the NER.

The PLEC program is an 'un-scoped allowance' in accordance with the Electricity (General) Regulations. PLEC projects are approved by an independent committee convened by ESCoSA. Typically projects are funded two-thirds by SA Power Networks and one third by councils, and construction is generally completed via a competitive tender process.

The PLEC forecast augex in the 2015-20 RCP is $51.1 million, $1.3 million (3%) above the AER allowance of $49.8 million, refer Table 5-32, which is largely consistent with the AER allowance.

Table 5-32: Comparison of PLEC expenditure, AER allowance to actual/forecast for the 2015-20 RCP (June 2020, $ million)

PLEC	2015/16	2016/17	2017/18	2018/19	2019/20	TOTAL
Allowance	9.7	9.8	9.9	10.1	10.3	**49.8**
Actual and forecast	8.8	10.1	9.5	13.0	9.6	**51.1**

SA Power Networks' forecast augex for the PLEC program for the 2020-25 RCP is determined in accordance with the Electricity (General) Regulations and is summarised in Table 5-33. The increase in augex represents a CPI increase in accordance with the formula outlined in the Electricity Act.

Table 5-33: Forecast PLEC augex for the 2020-25 RCP (June 2020, $ million)

	2020/21	2021/22	2022/23	2023/24	2024/25	TOTAL
PLEC	10.8	10.9	11.1	11.2	11.3	**55.2**

5.15 Customer connections expenditure forecast

Customer connection expenditure is associated with new connections, connection upgrades or alterations resulting from the requirements of specific customers supply requirements. This expenditure is divided into four categories, being:

- **Minor Customer Connections** (less than $30,000) – connection services generally associated with residential houses or small business, where little or no augmentation of the network is required;
- **Medium Customer Connections** (between $30,000 and $100,000) – connection services which are typically associated with non-residential developments, where augmentation of the network may be required;
- **Major Customer Connections** (more than $100,000) – connection services which are typically more complex and large, such as large business investment, mining, major non-residential buildings, services, shopping centres and intensive agriculture, and government and private infrastructure investment, ie defence, schools, railways and water supply; and
- **Real Estate Developments** – the establishment of new real estate development (**RD**) connections to the existing distribution network for new housing developments including suburban infill where one dwelling is replaced by more than three dwellings.

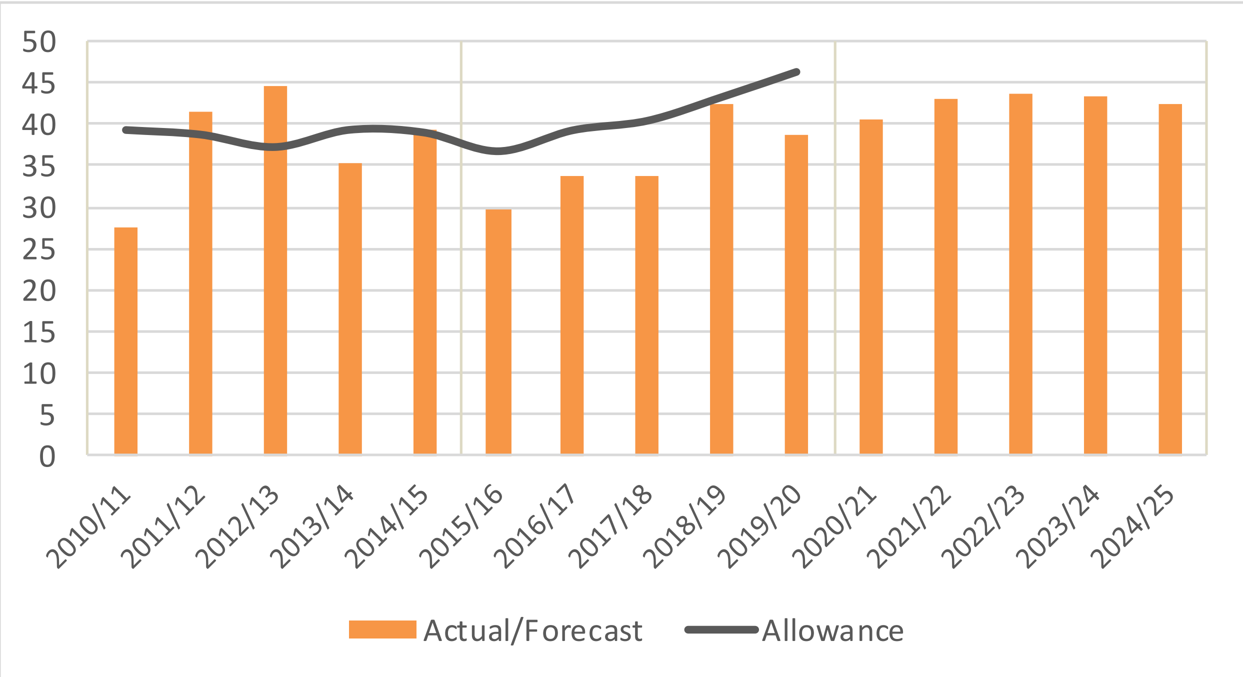
SA Power Networks operates under the NECF arrangements and in particular Chapter 5A of the NER. The NECF arrangements applies to all SA Power Networks customers who apply for a connection service. It provides provisions for:

- the retailer-customer relationship and associated rights, obligations and consumer protection measures;
- distributor interactions with customers and retailers, and associated rights, obligations and consumer protection measures;
- retailer authorisations; and
- compliance monitoring and reporting, enforcement and performance reporting.

Within this section we have specified both the gross expenditures on customer connections and the contributions made by customers in accordance with our proposed Connections Policy. The net expenditure is included in our forecast capex allowances.

Figure 5-24 shows SA Power Networks' total net customer connections actual/forecast capex for the 2010-15 and 2015-20 RCPs, along with the total forecast net customer contributions capex that we consider will be required during the 2020-25 RCP.

Figure 5-24: Customer connections capex trend (June 2020, $ million)



5.15.1 Connections Policy

Pursuant to Chapter 6 of the NER, SA Power Networks must prepare a Connection Policy, 'setting out the circumstances in which it may require a retail customer or real estate developer to pay a connection charge, for the provision of a connection service under Chapter 5A of the NER. The Connection Policy must specify a range of matters, covering:

- the categories of customers that may be required to pay a connection charge;
- the circumstances in which such a requirement may be imposed;
- the aspects of a connection service for which a connection charge may be made;
- the basis on which connection charges are determined;
- the manner in which connection charges are to be paid (or equivalent consideration is to be given); and

- a threshold below which a customer will not be liable for a connection charge for an augmentation other than an extension.

SA Power Networks has prepared a proposed Connection Policy to cover connection services we expect to provide over the 2020-25 RCP, refer to Attachment 16 – Connection Policy.

The approval of this Policy by the AER is a constituent decision of the AER's distribution determination for the 2020-25 RCP, and consequently, remains in force for the entirety of the 2020-25 RCP.

When our Connections Policy was discussed with customers and stakeholders, they felt comfortable with its 'causer pays' approach.

5.15.2 Connections outcomes for the 2020-25 RCP

The actual and forecast customer connections capex compared to the AER allowance for the 2015-20 RCP is shown in Table 5-34. The gross connections forecast capex for the 2015-20 RCP is forecast to be $475.7 million, $137.8 million (22%) below the AER allowance of $613.5 million.

The forecast connections contributions capex for the 2015-20 RCP is $297.5 million, $109.6 million (27%) below the AER allowance of $407.1 million, refer to Table 5-35.

The total net difference between the customer connections allowance and forecast for the 2015-20 RCP is $178.2 million, $28.2 million (14%) below the allowance of $206.4 million, refer to Table 5-36.

Table 5-34: Comparison of gross connections expenditure, AER allowance to actual/forecast (June 2020, $ million)

Connections	2015/16	2016/17	2017/18	2018/19	2019/20	TOTAL
Allowance	113.7	116.6	119.6	127.5	136.1	**613.5**
Actual and forecast	94.5	90.6	90.0	104.8	95.7	**475.7**

Table 5-35: Comparison of connections contributions expenditure, AER allowance to actual/forecast (June 2020, $ million)

Contributions	2015/16	2016/17	2017/18	2018/19	2019/20	TOTAL
Allowance	76.9	77.2	79.1	84.2	89.8	**407.1**
Actual and forecast	64.9	56.9	56.3	62.4	57.0	**297.5**

Table 5-36: Comparison of connections net expenditure, AER allowance to actual/forecast (June 2020, $ million)

Connections Net	2015/16	2016/17	2017/18	2018/19	2019/20	TOTAL
Allowance	36.9	39.4	40.5	43.3	46.3	**206.4**
Actual and forecast	29.7	33.6	33.8	42.4	38.7	**178.2**

The general downturn in customer connections as a result of a slowing South Australian economy experienced towards the end of the 2010-15 RCP, which continued into the early period of the 2015-20 RCP but is expected to pick-up in the remaining two regulatory years. This impacted many sectors of customer connections including real estate developments, residential housing construction, manufacturing and mining. The downturn was slightly off-set by other sectors including government projects, support services (eg HR, IT, Finance), food production, and retail sales industries which remained steady and by the Government incentivised solar panel installations which drove a significant rise in associated residential alteration activity during the period.

The connections forecast for the 2015-20 RCP was based on the BISOE economic outlook for South Australia[67] which was accepted by the AER in the 2015 Determination.

[67] *BIS Oxford Economics - Gross customer connections expenditure forecasts to 2025/26, final report November 2018.*

5.15.3 Connections forecasting methodology

SA Power Networks engaged BISOE again to prepare forecasts of its customer connection capex from 2018/19 to 2025/26. This report is included as a Supporting Document 5.12. These forecasts relied on source data from the Australian Bureau of Statistics (**ABS**), in particular ABS catalogue numbers 8752.0 (building activity), 8731.3 (building approvals), 8762 (engineering and construction), and our historical and forecast data.

For each of the four categories of connections (discussed above), SA Power Networks has calculated the proportion of the customer contribution to the connection costs on the basis of the proposed Connection Policy (2020/21 to 2024/25), having regard to recent historical contribution levels (including the recent impact of AEMC's Metering Contestability, and the impact of the (lower) proposed pre-tax weighted average cost of capital (**WACC**) used for calculating contribution (ie Incremental Revenue).

The unit costs for each category are applied as constant by virtue of the methodology utilised by BISOE in their forecast. It should be noted that the vast majority of greenfield connection works are contestable (ie work that can be built in isolation to the existing distribution network and is performed by appropriately accredited design and construction resources) up to the connection point under SA Power Networks' Connection Policy. Competitive pressures can therefore be relied upon to drive efficient costs.

BISOE developed the customer connections capex forecast for the 2020-25 RCP using the forecasting methodologies described below. SA Power Networks developed the forecast contributions in accordance with our Connections Management Plan – Supporting Doument 5.11.

5.15.3.1 Minor (<$30,000)

The minor connections expenditure model uses various economic drivers and historical data from ABS as follows:

- total residential connection capex is assumed to be driven primarily by forecasts of residential building alterations and additions approval activity for South Australia;
- small commercial connection activity is assumed to be driven by the real value of non-residential commencements for buildings with an individual value below $1 million; and
- RD connections capex model is assumed to be driven by total house commencements.

Underpinning the forecasts of residential building and non-residential building activity is BISOE forecasts of South Australian population growth. SA Power Networks developed the contributions for minor connections based on adjusted historical contribution levels of 33% of expenditure.

5.15.3.2 Medium Customer Connections (Projects $30,000 to $100,000)

The medium connections capex model is based on historical data from SA Power Networks, the ABS and on forecasts of the following drivers:

- the real value of non-residential building commencements for projects below $20 million; and
- the number of 'other' dwelling commencements, in particular, flats (ABS Building Activity Catalogue No. 8752.0).

These two drivers are weighted because it was found that changes in the value of non-residential building commencements had a greater impact on medium customer connections expenditure than changes in the commencement of flats.

SA Power Networks developed the contributions for medium connections based on historical contribution levels of 29% of expenditure.

5.15.3.3 Major Customer Connections (Projects >$100,000)

The forecasts for major connections capex were developed from a bottom-up process, as follows:

- SA Power Networks' forecasts of major project developments were reconciled with BISOE list of major projects in the infrastructure (engineering construction) and non-residential building sectors. This was used to produce a list of plausible major connection projects, covering their starting dates, load (ie kVA), estimated connection cost, and likelihood of proceeding;
- any project below a 50% likelihood of proceeding was removed, but the timing, probability and value of removed projects were noted and taken into consideration; and
- the estimated connection cost of each included major project was summed to arrive at a grand total.

A residual for unknown and possible customer driven projects has been included in the forecasts. This residual was derived from the forecasts for non-dwelling building commencements (projects above $20 million) and engineering construction activity (excluding sectors not deemed relevant) and review of historical actual expenditure for this category.

SA Power Networks developed the contributions for major connections based on adjusted historical contribution levels of 53% of expenditure.

5.15.3.4 Real Estate Developments (RDs)

The RD forecast is based on the residential forecast as per Minor Connections, as RD's lead new housing commencements. Additionally, SA Power Networks reviews its forecasts of known RD's and allowances for residual projects where reconciled with the BISOE forecast.

SA Power Networks developed the contributions for RDs based on adjusted historical contribution levels.

5.15.4 Connections capex forecast for the 2020-25 RCP

The forecast gross customer connection capex, contributions and net connections for the 2020–25 RCP are shown in Table 5.37 below.

The BISOE outlook for customer connections for the 2020–25 RCP is outlined below.

5.15.4.1 Minor (<$30,000)

Minor customer connections are made up of alterations to existing supplies and connection of new supplies for predominantly residential customers. Minor customer projects are split between alterations and new connections.

Minor customer connections capex has decreased owing to the introduction of 'metering contestability' and therefore the removal of metering from these costs. The decline has been partially offset by an increase in both house commencements and alterations and additions activity. It is expected minor customer connections capex over the 2020-25 RCP will track house commencements and on average will remain relatively flat.

Underground residential development (**URD**) customer connection capex tends to be erratic. BISOE forecast URD expenditure will bound back in in the latter part of the 2020-25 RCP and the early part of the 2020-25 RCP increasing 6.7% in 2019/20, 4.0% in 2020/21 and 5.8% in 2021/22. Thereafter, BISOE expect the weakening in housing approvals and commencement to cause declines in URDs. BISOE forecast the level of URD expenditure to be slightly higher over the next 8 years on average, compared to the past 5 years.

5.15.4.2 Medium Customer Connections (Projects $30,000 to $100,000)

Medium customer connections are made up of small to medium commercial and residential connection works. The major trends and drivers associated with medium customer projects include:

- non-dwelling building commencements in the small to medium range; and
- flats commencements.

BISOE are forecasting declines of -5.2% and -2.1% in 2019/20 and 2020/21 respectively, as the effect of substantial falls in other dwelling commencements outweighs modest growth in non-dwelling building commencements below $20 million.

Medium connections capex are forecast to rise in 2021/22 (+2.5%) and 2022/23 (+0.6%), supported by increased non-residential building and other dwelling commencements. Medium connections are then expected to decline in 2023/24 (5.6%), before increasing in 2024/25 and 2025/26 (+1.3% and 5.1% respectively), cycling with non-residential building (<$20 million) and other dwelling commencements.

5.15.4.3 Major Customer Connections (Projects >$100,000)

Major customer connections are made up of connection works for major non-residential buildings, commercial, industrial projects, government and private sector infrastructure projects, large residential land developments and the occasional multi-unit residential or retirement village project. In South Australia, the value of major projects tends to be the key driver of activity, rather than changes in project volumes. The major trends and drivers associated with major customer projects include:

- major non-dwelling building commencements (projects above $20 million); and
- major engineering construction commencements, including infrastructure such as roads, bridges, railways, harbours, water supply, sewerage works, electricity generation and supply works, and heavy industry construction.

Major customer connections capex is forecast to increase 2.4% in 2020/21, supported by known projects and particularly strong growth (+35%) in non-residential building commencements above $20 million. Expenditure is then forecasted to weaken (-5.6%) in 2021/22, due to declines in non-residential building commencements above $20 million and a further decline in engineering construction commencements - which are expected to decline by a cumulative 28% from 2018/19 levels. Growth is then expected to rebound 5.7% in 2022/23, due to strong growth in relevant engineering construction commencements. Major connections capex is subsequently expected to ease slightly over 2023/24 and 2024/25, and then rise 0.6% in 2025/26.

5.15.4.4 Real Estate Developments (RDs)

RDs include new residential subdivisions and urban infill where one allotment is divided into more than two allotments.

RD customer connection capex tends to be erratic. BISOE forecast RD expenditure will increase in the latter part of the current RCP and the early part of the next RCP increasing 6.7% in 2019/20, 4.0% in 2020/21 and 5.8% in 2021/22. Thereafter, BISOE expect the weakening in housing approvals and commencement to cause declines in RDs. BISOE forecast the level of RD expenditure to be slightly higher over the next 8 years on average, compared to the past 5 years.

5.15.4.5 Connections capex forecast for the 2020-25 RCP

Our proposed connections capex for the 2020-25 RCP is based on these independent forecasts and is slightly higher than current levels due to slightly higher activity forecasts and customer contribution levels being slightly lower[68] than the 2015-20 RCP. SA Power Networks' connections capex forecast for the 2020-25 RCP is summarised in Table 5-37 below.

[68] *A lower WACC results in lower customer contributions and a higher net capex.*

Table 5-37: Forecast customer connections expenditure for the 2020-25 RCP (June 2020, $ million)

	2020/21	2021/22	2022/23	2023/24	2024/25	TOTAL
Connections (gross)	111.3	113.2	114.4	114.0	110.2	**563.2**
Contributions	70.6	70.3	70.8	70.6	67.8	**350.1**
Net expenditure	40.7	43.0	43.6	43.4	42.5	**213.2**

5.16 Non-network expenditure forecast

SA Power Networks will continue to maintain our capabilities to ensure we can deliver on all our regulatory obligations and meet our customers' expectations.

The 2020-25 RCP will be a period that will see the most significant and transformative change in the distribution sector since the establishment of the NEM. These changes include:

- **Technology** — digital technologies continue to proliferate in all areas of our industry and society, data volumes are rising exponentially, convergence and integration of technologies, systems and processes are accelerating, legacy systems that are unable to provide required flexibility;
- **Customer** — everyday usage of mobile technologies is changing expectations of DNSPs, information access is now regarded as essential, interest in and adoption of new DER is now mainstream, choice in energy options to help manage costs and convenience is increasingly expected;
- **Market** — new sectors have emerged around microgeneration, energy usage and demand patterns have transformed, new markets for electrical products like electric vehicles and storage are emerging, new competitive sectors are emerging (eg metering, home energy systems and energy services); and
- **Regulatory** — governments are highly active in energy policy and incentive systems, regulators are pursuing competition outcomes in previous monopoly sectors, and are demanding new data requirements of monopoly sectors for oversight and benchmarking purposes.

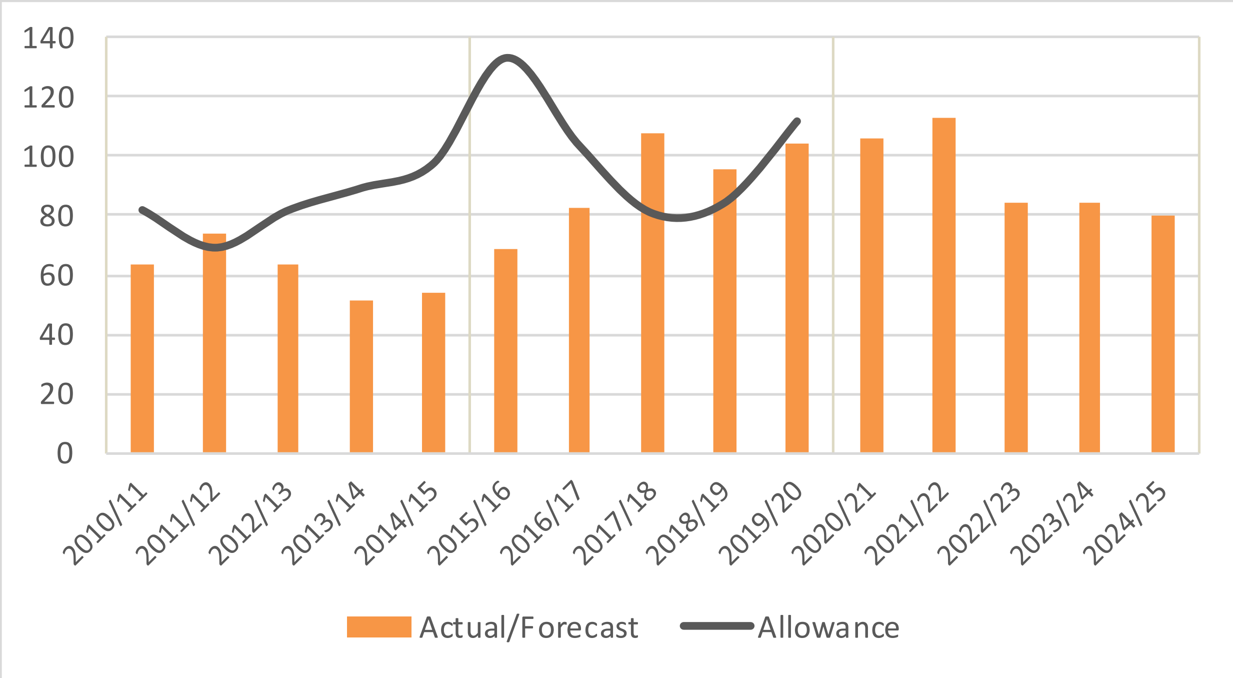
In this context, our areas of focus on maintaining our business capabilities to enable delivery of services over the 2020-25 RCP include:

- a continuing focus on providing the right services;
- optimal integration of technologies and systems; and
- fit-for-purpose facilities and equipment.

Our non-network capex is separated into five categories – IT, Network operations IT, Property, Fleet, and Other as detailed in this section.

Figure 5-25 shows SA Power Networks' total non-network capex for the 2010-15 and 2015-20 RCPs, along with the total forecast non-network capex that we consider will be required during the 2020-25 RCP.

Figure 5-25: Non-network capex trend (June 2020, $ million)



For each category, we examine capex outcomes for the 2015-20 RCP, the capex forecasting approach for the 2020-25 RCP, the capex forecast for the 2015-20 RCP and reasoning underpinning the capex forecast for the 2020-25 RCP.

5.16.1 Information technology

IT expenditure is associated with maintaining IT systems and delivering the capabilities required to enable SA Power Networks' operations and business. IT expenditure does not include strategic electricity network operating and communication technology costs which are categorised as network repex or augex and detailed in Sections 5.12 and 5.13 above and 5.16.2 below.

This section summarises our IT proposal for the 2020-25 RCP, for more detailed information refer to the following Supporting Documents:

- 5.32 - IT Investment Plan;
- 5.33 – External related party transactions report; and
- 5.34 – IT asset management plan.

IT is fundamental to enabling the effective and efficient delivery of low cost electricity distribution services to our customers. During the 2020-25 RCP the role of IT will increase as more elements of our services to the customer and the resilience of the network are enabled by, and rely on, IT systems. Efficiently managing our distribution asset risk and maintaining reliability on our ageing network, in a very dynamic environment, requires investment in our IT systems and in the quality of our data. These IT capabilities also provide the foundation for the delivery of the Future Network Strategy

We are already successfully delivering cost-efficient, reliable and secure distribution services to our customers with one of the lowest IT operating costs per customer of any of the NEM DNSPs.[69]

[69] *KPMG Utilities IT Benchmarking: Technology Regulatory Benchmarks, January 2019. Based on bi-yearly IT benchmarking studies conducted by KPMG using publicly available yearly RIN reported data*

The overall aim for our IT investment is to enable the delivery of required business and customer outcomes at a lower price through secure and efficient IT capabilities and in particular to:

- **Maintain compliance with existing and meet new regulatory obligations**, as they emerge in a dynamic market environment**.**
- **Maintain current levels of service and manage IT operational technology risks** through efficient, secure technology management services, and IT asset refresh/replacement cycles that maximise the useful life of our assets and optimise the outcomes for our customers .
- **Manage business and network costs through the efficient use of data and digital technology**. We will build on the initial phases of our program to improve how we manage our assets (**Assets and Work (or A&W) Program**) which has already successfully enabled the efficient deferral of $216.5 million of distribution network asset repex while managing risk and maintaining reliability and security of our distribution network.

5.16.1.1 IT outcomes for the 2015-20 RCP

The IT non-network capex allowance for the 2015-20 RCP provided for a significant uplift to undertake a very large portfolio of work in order to:

- maintain 'business as usual' services and manage our key system risks through a large technology refresh program including replacing the legacy customer and billing systems, a program that began in the 2015-20 RCP and will extend into the 2020-25 RCP;
- enable us to meet regulatory obligations and requirements, including RIN reporting improvements; and
- leverage these initiatives to deliver the highest priority strategic objectives. A large scale multi-period program to improve our end-to-end asset and work management capabilities was proposed but only part of our proposed capex was allowed for in the 2015-20 RCP.

The IT non-network actual/forecast capex for the 2015-20 RCP is $313.4 million, $27.7 million (9%) above the AER allowance of $285.7 million, refer Table 5.38.

Table 5-38: Comparison of IT expenditure, AER allowance to actual/forecast June 2020, $ million

	2015/16	2016/17	2017/18	2018/19	2019/20	TOTAL
Allowance	62.4	60.3	49.7	52.4	60.9	**285.7**
Actual and forecast	45.7	59.0	66.7	68.6	73.5	**313.4**

The most significant changes to the IT portfolio plan are highlighted in Figure 5-26 and summarised below:

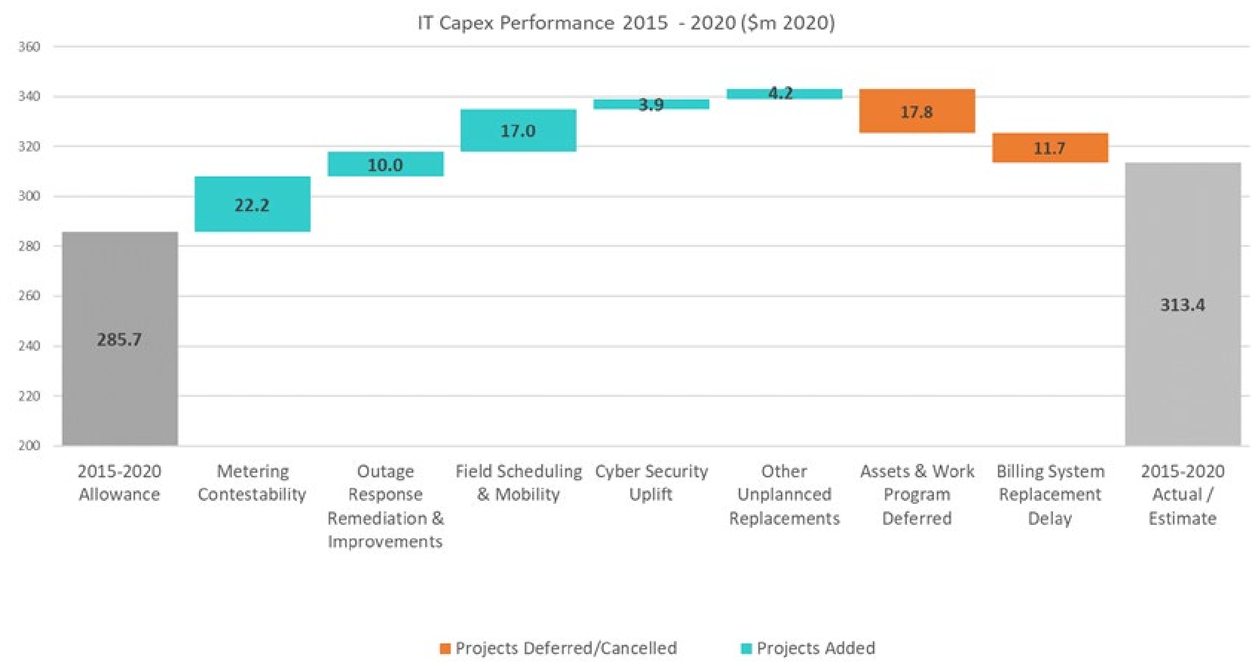
- **Meter contestability implementation** – Implementing the 'Power of Choice' meter contestability requirements was not funded as part of the allowance for the 2015-20 RCP as the NER change was after the start of the 2015-20 RCP and compliance was required by January 2018.
- **Outage response remediation and improvements** – During the 2016 wide spread power outages, customer demand for timely, relevant and accurate information increased significantly. This was reinforced by a review and requirements by the ESCoSA.[70] As a result, a number of our systems needed remediation, augmentation, replacement or increased integration to improve our response to customers.
- **Field scheduling and mobility** – Three factors drove higher than expected expenditure for field scheduling and mobility:
  - **Customer demand for accurate and timely information, particularly during outages** – To meet the requirements detailed above we needed to significantly increase information flowing from field staff back to customers and this meant increasing our mobile capabilities and the number of mobile devices.

[70] *ESCoSA Distribution Licence Compliance Review – SA Power Networks 27-28 December 2016 severe weather event June 2017. Following the December 2016 blackouts, ESCoSA and SA Power Networks agreed to the implementation of a series of customer data improvements to enable the provision of accurate information to customers across all communication channels.*

- **Greater than expected risk identified on the network led to shifts in how we manage our work** – Our foundational asset data collection and analysis program led to the identification of a higher than anticipated asset risk and a resultant larger than expected number of defects that required remediation. To manage this risk as efficiently as possible we implemented improved work planning and mobile capabilities while starting to develop an improved scheduling system.
- **Our enterprise system for field work scheduling and management needed to be replaced** as it went out of support in 2018.

- **Cyber security** – The pilot and foundational implementation of the enterprise cyber security function carried out during the 2015-20 RCP identified increased and evolving cyber risks in our operating environment. Our capability needs to be increased to minimise this risk.
- **Other unplanned replacements** – Given the evolving environment a number of other small business systems needed replacement or significant remediation during the period including, for example, the public lighting system (to allow more flexible billing arrangements for LEDs and smart street lights) and the payroll system (to comply with the Australian Taxation Office Single Touch Payroll requirements).
- **Assets and works delayed** – The program of work that was originally planned to be completed in the 2015-20 RCP was altered. When we started to collect more asset data, we realised that consolidating our geographic information systems (**GIS**) environment was integral to providing a manageable and scalable data foundation and this was unable to be completed in the 2015-20 RCP. As a result , we did not complete as much of this work as originally planned. The work we did not complete is still an essential part of the overall A&W Program and is hence included in our Proposal.
- **Billing systems replacement delay** – The billing replacement program originally planned for completion in the 2015-20 RCP, was delayed due to the impact of the simultaneous major outages, the large-scale customer systems remediation and the meter contestability implementation work. Additional work, above planned, is thus required for completion of the program in the 2020-25 RCP.

Figure 5-26: IT Capex Performance during the 2015-20 RCP



SA Power Networks is continually seeking to deliver technology services in cost-effective, innovative and agile ways while keeping pace with the rapid changes in our market place and in customer use of digital technologies. Leading into 2015, the IT function was restructured and re-recruited to facilitate a focus on delivering quality core services. This structure is reviewed, refreshed and adapted every year.

Our IT Improvement Program has been successfully driving changes in how we deliver and manage technology. Our agile delivery processes ensure that the focus is on delivering the 'minimum viable and sustainable product' each time and implementing the most cost-effective service outcome possible. These processes also facilitated a shift to a much more customer centric approach ensuring the customer is 'front of mind'. A centralised Corporate Portfolio Management Office (**CPMO**) has streamlined the governance process for organisational business improvement and IT projects to ensure that we are doing 'the right projects' and delivering the appropriate benefits. Taken together these changes have enabled us to deliver the large program of works for the 2015-20 RCP effectively.

Our proposed forecast capex for the 2015-20 RCP was focused on managing risk and compliance. However, the work has also generated some significant cost savings to customers, particularly through the efficient deferral of repex.

The benefits are categorised in Table 5.39. The total gross financial benefits for IT non-network capex for the 2015-20 RCP is expected to be $274.3 million over 2015-20 and 2020-25 RCPs.

Table 5-39: Financial benefits from IT non-network capex incurred in the 2015-20 RCP (June 2020, $ million) and 2020-25 forecast benefits

Benefits category	2015-20 Benefits	2020-25 Benefits	2015-25 Total benefits
Cost avoidance and deferral	75.6	163.7	**239.3**
Cost reduction	10.3	24.7	**35.0**
Total	**85.9**	**188.4**	**274.3**

Efficient use of improved data and technology has increased our understanding of our assets, and their condition, risk profiles and direct customer impact, and allowed the selection of more tailored and appropriate repair, refurbish and replacement strategies, while managing the asset risk level across the network. Based on the improved information and processes we have efficiently deferred approximately $66.5 million in repex in the 2015-20 RCP (of the $75.6 million in benefits) and an estimated $150 million in deferrals (of the $163.7 million in benefits) will be realised in the 2020-25 RCP, helping to keep prices down for our customers. Additional avoidance benefits ($22.8 million) will be realised from the other IT improvements during the 2020-25 RCP.

Key cost reductions have come from increased labour productivity through implementing system improvements in a number of areas including:

- organisational risk and incident management process;
- human resources – staff onboarding and training process;
- field scheduling – mobility improvements;
- finance, procurement, travel and expense management; and
- consolidating a number of applications and avoiding future IT upgrade costs.

The cost reductions total $10.3 million in the 2015-20 RCP and are expected to grow to $24.7 million in the 2020-25 RCP. These savings are reflected across the proposed work programs for the 2020-25 RCP.

5.16.1.2 2020-25 IT forecasting approach

The IT non-network capex forecast has been developed by following a comprehensive investment planning and forecasting process as defined in the SA Power Networks' Business Planning and Budgeting, and Capital Project Evaluation and Approval Procedures and subject to the standard CPMO Framework for selecting the 'Right Projects, Right Way and Right Value'.

The approach can be summarised as a bottom-up build-up of initiatives followed by a number of iterations to progressively refine the portfolio based on additional inputs from customer and stakeholder feedback (including IT Deep Dive workshops), top down portfolio, dependency and deliverability analysis and detailed business case development. Several initiatives from business cases have been deferred to the 2025-30 RCP as a result of our dependency and prioritisation analysis.

Each of the proposed IT business cases address the following:

- alignment with NER capex and opex objectives;
- benefits to customers;
- the demonstrated risk of continuing without the changes;
- sets out several options with evidence-based cost estimates; and
- selection of the most prudent and efficient option based on NPV and measured risk.

The IT portfolio value for the 2020-25 RCP is based on the final preferred option (ie the option that delivers the greatest net benefit) for each business case.

For more information on our governance processes and forecasting methodology refer to Supporting Document 5.32 - IT Investment Plan 2020-25.

5.16.1.3 IT non-network capex forecast for the 2020-25 RCP

Our IT systems enable us to provide distribution services to our customers. The proposed investments will ensure that our IT systems continue to be fit for purpose, safe, secure and reliable during the 2020-25 RCP and in future RCPs.

We require forecast capex of $284.6 million (June 2020) for the 2020-25 RCP (Table 5-40). This represents a reduction of 9.2% on actual/forecast capex for the 2015-20 RCP. The majority of the expenditure is in the first two regulatory years of the 2020-25 RCP as the current replacement programs (i.e. billing systems) are being completed. Following this capex is forecast to decrease to more historic levels (Figure 5-27).

Table 5-40: Forecast IT expenditure for the 2020-25 RCP (June 2020, $ million)

	2020/21	2021/22	2022/23	2023/24	2024/25	TOTAL
IT	72.5	72.9	48.5	45.5	45.2	**284.6**

Figure 5-27: Actual and forecast IT capex 2014/15 to 2024/25

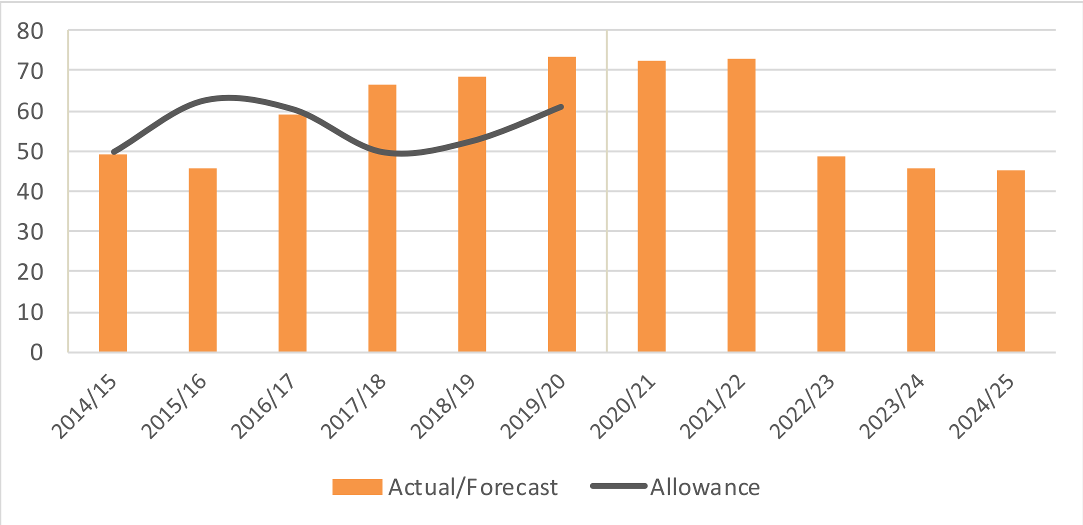


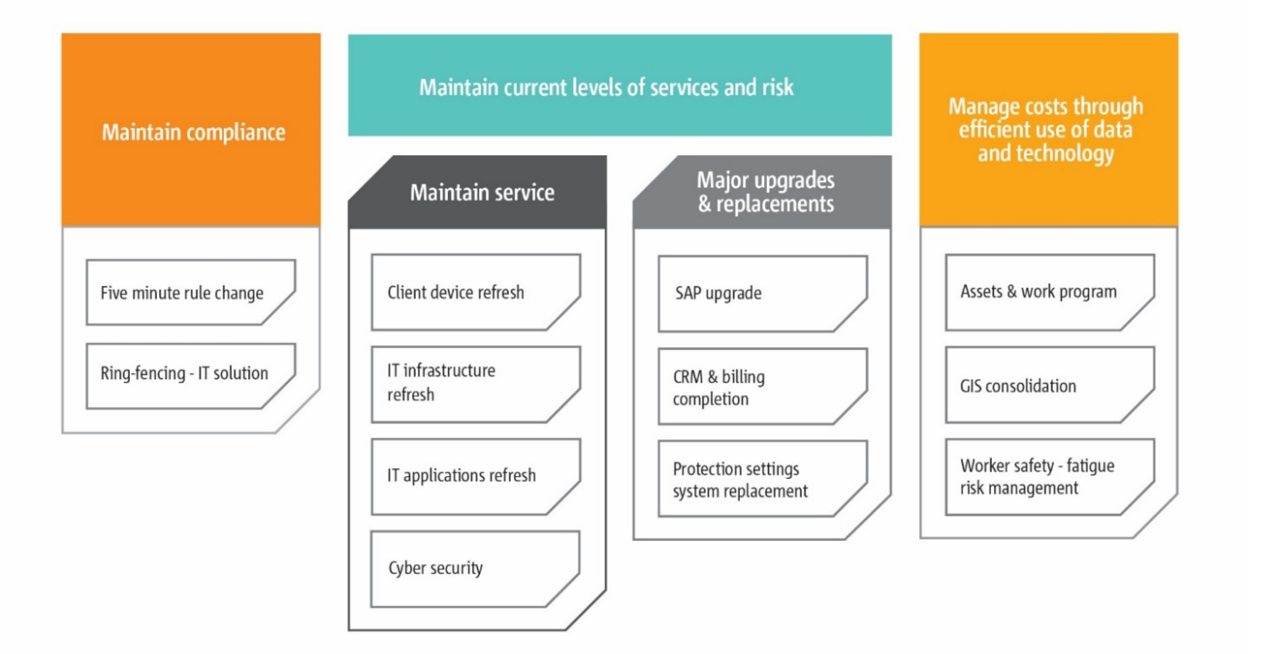
Table 41 presents the capex and benefits by IT Investment Plan objective[71] as described in further detail in Supporting Document 5.32 - IT Investment Plan 2020-25. Over 70% of the capex ($206.5 million) is concerned with maintaining current levels of service and managing IT risk though replacement and updates to existing IT applications and infrastructure and hence has lower levels of tangible benefits. The majority of the benefits ($138.7 million over 10 years) arise from the initiatives aimed at efficiently using data and technology to manage (and minimise) our business and network costs.

Table 5-41: IT capital programs for the 2020-25 RCP by IT Investment Plan objective (June 2020, $ million)

IT Investment Plan Objective		Capex $M	Benefits	
			2020-25	2020-30
A	Maintain compliance and meet new compliance requirements	12.3	0.3	0.7
B	Maintain current levels of service and manage IT technology risk	206.5	28.2	63.7
C	Manage business and network costs through efficient use of data and digital technology	65.7	74.5	138.7
Total		**284.6**	**103.0**	**203.1**

Figure 5-28 shows how our IT business cases are categorised within our IT investment Plan objectives.

Figure 5-28: Business cases by IT investment Plan objective



A summary of each of these IT business cases is set out below by reference to our IT Investment Plan objectives.

5.16.1.4 Maintain compliance with regulatory obligations and requirements

Meeting existing and new regulatory obligations and requirements is a key obligation for SA Power Networks to ensure it is able to comply with, and maintain, its Distribution Licence and registrations under the NER, and prudently and efficiently operate the distribution network and provide services to customers, and is a significant activity requiring regular IT investment.

[71] *IT objectives to 'maintain compliance', 'maintain current levels of service and risk' and 'manage costs through efficient use of data and technology'.*

Key activities in the 2020-25 RCP include implementing the Five Minute Settlement[72] Rule Changes and providing an IT solution to ensure ongoing compliance by SA Power Networks with its ring-fencing obligations minimise non-compliance risk and the potential harm to competition that would result from non-compliance, and demonstrate the adequacy of SA Power Networks compliance processes and procedures.

After the implementation of the Five Minute Settlement Rule Change:

- customers will be able to access to 5-minute meter reads via the customer access to billing data portals;
- bills will be calculated using 5-minute meter reads; and
- customers will be able to take advantage of tariffs that are enabled by 5-minute meter reads.

In relation to the IT component of our ring fencing compliance program, stronger system-based controls will be implemented to address deficiencies identified following our 2018 ring-fencing compliance audit. This will ensure that customers are protected with the assurance:

- that the potential harm to competition that would result from non-compliance is addressed by SA Power Networks affiliated entities not obtaining an unfair advantage over other suppliers of electricity related services;
- that all regulated funds are being spent on the provision of direct control services to them; and
- non-regulated affiliates do not have access to confidential regulatory information or customer information.

5.16.1.5 Maintain current levels of service and risk

Safe, secure and reliable IT services are maintained through regular replacement, upgrade and update of the key IT assets. Our IT Asset Management Plan provides the framework for how we manage our IT assets to deliver the most value for our customers and stakeholders through balancing risk and cost.

The inevitable transition to cloud infrastructure, applications and services is changing our asset management approaches and decreasing capex but increasing operating costs. Unfortunately, these capex/opex tradeoffs are not completely offset by the associated benefits and therefore have been included as proposed capex and step changes in opex. Attachment 6 – Operating expenditure, details the expected capex/opex tradeoff step changes associated with Cloud infrastructure.

5.16.1.6 Maintain service programs

Our core IT non-network recurrent expenditure consists of a set of inter-related ongoing annual workstreams designed to enable the day-to-day functioning of all our customer, network and business services. These include services and assets related to enterprise cyber security; client device refreshes (workstations, mobile phones etc.); small to medium business application refresh and upgrades; and IT infrastructure refresh (including data centre and networks).

Our IT asset and service portfolio has increased significantly during the period but IT has effectively used a number of cost management strategies to ensure we are continuing to provide the most efficient service possible, and as a result we have reduced our maintain service capex in the 2020-25 RCP compared to the actual/forecast capex for the 2015-20 RCP (although these are partially offset by opex increases due to cloud related capex/opex tradeoff step changes detailed in Attachment 6 – Operating expenditure).

The value these IT non-network recurrent initiatives deliver needs to be considered as a whole as they act together to deliver significant 'business as usual' benefits to customers which include ensuring that:

[72] *The five minute settlement rule changes commence in 2021 and requires us to make changes to processes and systems dealing with the management of metering and metering data. The full extent of the impact will not be available until AEMO finalise the relevant metering related industry procedures.*

- current customer and business service levels will be maintained;
- our IT systems are reliable, secure and available – particularly during customer outages;
- we are able to continue to deliver the efficient asset replacement deferral savings to customers while managing our risk; and
- we will be able to respond to emerging cyber security threats in a timely manner.

5.16.1.7 Major IT upgrade and replacement programs

During the 2020-25 RCP a number of our large core systems will be entering 'end of support life' and need to be replaced to maintain the current levels of service. The largest projects are our SAP upgrade and the completion of our CRM and Billing System replacement.

As SAP is our core enterprise customer, work and business system, not undertaking this upgrade in a timely manner will place core business services at significant risk. Key benefits to customers include:

- customers will continue to be able to log outage events and receive information on outages;
- customer connections services will continue to be able to meet market and regulatory service levels;
- field work will continue to be efficiently managed and scheduled; and
- information on assets will continue to be updated and managed.

In addition, on the completion of our CRM and Billing System replacement program:

- customers will be able to continue to receive their electricity bills;
- customer electricity bills will remain accurate;
- the new system will support the anticipated increases in tariff complexity; and
- customers will have more control and be able to choose and enact different tariffs.

5.16.1.8 Manage our business and network costs through efficient use of data and digital technology

The IT enabled strategic business improvements for the 2020–25 RCP are predominantly built on, and related to, the success of the foundational asset management improvements we implemented during the 2015-20 RCP (through the A&W Program). These activities gave an improved picture of network asset risk allowing us to cost-efficiently reduce asset risk to levels agreed by the OTR.

5.16.1.9 A&W Program

The objective of the A&W Program in the 2020-25 RCP is to enable SA Power Networks' Strategic Asset Management Plan and efficiently defer an additional $100.3 million of network repex plus a further saving of $34.5 million in other avoidance and efficiency benefits through better bundling and management of work over the 2020-30 period (the totals for the 2020-25 RCP are $68.6 million in deferral and $4.4 million in other benefits). Implementing the next stage of the A&W Program will enable us to deliver services our customers value and maintain the quality, reliability and security of supply at a reduced price to customers.

Additional intangible benefits for customers will include:

- a better understanding of our assets to improve managing service levels to our customers;
- more timely, responsive and accurate communication with customers;
- improved forecasts and regulatory compliance by providing actual information for RIN reporting;
- improved lead times and efficiencies in end-to-end work delivery; and
- mitigated risks of changing the work mix from relatively few, large scale projects to smaller, higher volume maintenance and asset replacement activities.

5.16.1.10 GIS consolidation

Consolidating our two existing enterprise Geographic Information Systems (GIS) into one is a prerequisisite for achieving major benefits from the A&W Program.

The benefits of our GIS consolidation program for customers are as follows:

- minimise costs for the support and maintenance of our GIS technologies; and
- be able to derive greater benefits and therefore lower costs from the A&W Program through:
  - better planning and scheduling for jobs by improved currency and use of spatial information; and
  - enabling improved risk-based asset management through more accurate location modelling of risk and opportunities.

5.16.1.11 Worker safety: Fatigue risk management

As the nature of our workload and our environment is changing we need to implement more effective tools for managing the increasing risk of fatigue, to keep our people and community safe and to continue to meet our legistative requirements.

Our worker safety: fatigue and risk management project will improve our controls for mitigating fatigue-related risks. This will assist us to reduce the likelihood of injury or death of our workers, contractors or customers due to a fatigued worker performing field work.

5.16.1.12 Customer and stakeholder engagement outcomes

We discussed our approach to IT investment at a deep dive workshop with customers and stakeholders in 2018. Feedback largely focused on concerns around our proposed level of investment in IT, and whether this investment could be directly linked to customer, rather than business, outcomes[73].

While we acknowledge customer concerns about the extent of investment in IT, the reality is that without IT, we simply could not meet customer needs and expectations, or manage our business. Customers and stakeholders have also asked for us to continue to find efficiency improvements, which ongoing investment in IT is critical in delivering. To address customer and stakeholder concerns, we have ensured that our proposed IT non-network capex was vigourously evaluated against the NER objectives and criteria for the 2020-25 RCP and is below our actual/forecast capex for the 2015-20 RCP.

5.16.1.13 Summary

Our proposed IT investment will enable the delivery of better outcomes for our customers at a lower price through reliable, safe, secure and efficient IT capabilities that are required to deliver distribution services. Our IT investment is enabling the delivery of tangible savings to customers and will continue to do so in the 2020-25 RCP. Our IT investment will continue to facilitate a targeted customer-focused value-based approach to managing the risk of our network assets in a dynamic electricity environment. We are currently undergoing a significant planned IT replacement program and our IT capex will reduce significantly over the 2020-25 RCP as this is completed. Finally, we have been rigorous and thorough in the development of our IT business cases to ensure we are selecting the most prudent, efficient and NER compliant options available to us, in particular understanding the impact and the benefits to the customer.

For further information on our IT capex for the 2020-25 RCP refer to Supporting Document 5.32 - IT Investment Plan 2020-25 and the corresponding business cases, which are available on request.

[73]*Refer Supporting Document 0.15 – Think Human IT Deep Dive Workshop Report*

5.16.2 Network operational IT

Network operational IT capex is required to enable continuous day to day operation and monitoring of our distribution and telecommunications network.

The network operational IT capex forecast for the 2015-20 RCP is $30.2 million, $0.1 million above the AER allowance of $30.1 million, refer Table 5-42.

Table 5-42: : Comparison of network operational IT expenditure, AER allowance to actual/forecast (June 2020, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	TOTAL
Allowance	11.8	8.2	5.2	2.5	2.4	**30.1**
Actual and forecast	10.4	8.3	11.5	0.0	0.0	**30.2**

In the 2015-20 RCP we completed the imlementation of our ADMS and commenced the integration of our OMS into the ADMS. We also upgraded our telecommunications network control (**TNC**) and transferred our field and emergency switching communications over to the Government Radio Network.

SA Power Networks' network operational IT program forecast expenditure for the 2020-25 RCP is summarised in Table 5-43.

The network operational IT program is a continuation of existing programs, totalling $22.2 million (June 2020 $). Refer to Table 5-44 for details of our proposed network operational IT program for the 2020-25 RCP.

Table 5-43: Forecast Network operational IT expenditure for the 2020-25 RCP (June 2020, $ million)

	2020/21	2021/22	2022/23	2023/24	2024/25	TOTAL
Network operational IT	5.1	2.5	2.7	5.2	6.8	**22.2**

Table 5-44: Network operational IT programs for the 2020-25 RCP (June 2020, $ million)

Programs	Description	$M	Asset Plan[74]
TNC management	TNC manage the monitoring, control and restoration of the telecommunications networks across South Australia	2.8	3.3.08
UPAX/Business telephone network	Maintenance of the voice network deployed throughout the state for operational telephony	2.2	3.3.07
OT security	Cyber program to segregate, monitor and protect the OT networks that support critical operational functions	5.0	3.3.09
ADMS/OMS upgrade	ADMS hardware and software upgrade	12.2	Supporting Document 5.23

Supporting Document 5.7 – Strategic Asset Mangement Plan and Supporting Document 5.8 – Powerline Asset Management Plan, provide detailed information on our asset management practices, forecasting approach and modelling outputs for each asset class and related programs. Further information can be provided through the provision of individual asset plans on request.

Each of our proposed network operation IT programs for the 2020-25 RCP are described in further detail below.

[74] Available on request.

5.16.2.1 TNC management

SA Power Networks has an extensive telecommunications network comprising several different networks which are utilised for the carriage of SCADA, tele-protection, mobile radio, business telephony and operational telephony (UPAX: Utilities PABX) services throughout South Australia.

For SA Power Networks to efficiently manage its extensive telecommunications networks and infrastructure, we operate a TNC centre responsible for the 24/7, monitoring, control and restoration of the telecommunications networks across South Australia.

In order for the TNC to effectively manage the differing and complex telecommunications networks, there is a need to have complex Telecommunications Network Management (**TNM**) practices, as the networks are a critical enabler of a reliable, safe and secure distribution network.

The primary TNM activities are:

- **Maintenance (quality)** – performing repairs and upgrades to the telecommunications network as required.
- **Operation (availability)** – keeping the network operating within the required availability, including monitoring the network to detect alarms in ‘real time’.
- **Restoration (restoring service)** – performing efficient repairs to faulted parts of the network across South Australia.

We are proposing a business as usual approach for the 2020-25 RCP to upgrade our systems as required. For further information refer to our TNC management systems AP 3.3.08 which is available on request.

5.16.2.2 UPAX/PABX (Business telephone network)

SA Power Networks has a comprehensive voice network deployed throughout the state for operational telephony. The network is comprised of two Private Automatic Branch Exchange (**PABXs**) nodes. Both PABX systems are remotely monitored and managed and is programmed to report system abnormalities and failures to the TNOC management platforms.

The operational voice network (**UPAX**) (Utilities PABX) provides voice services for specific substations and limited radio sites throughout South Australia. This network is utilised for critical operational communications between field crews in substation and the NOC for switching, emergency calls and general site works.

In the 2020-25 RCP, we are proposing a business as usual approach based on our historic expenditure to upgrade our systems and service contracts. For further information refer to our Operational Telephony AP 3.3.07 which is available on request.

5.16.2.3 Operational Technology (OT) security

As explained above, we have an extensive telecommunications network comprising many different networks throughout South Australia. As utility industries migrate to internet protocol (**IP**) based technologies the exposure to internet and remote based threats has increased significantly. As such, security is fundamental to the delivery of electricity distribution services. An ongoing prudent investment in security is required to ensure the IT and OT systems and data that enable us to deliver services to our customers remain secure, reliable and available.

A strong security capability that proactively prevents, detects and responds to security threats will provide safe and available information and control systems and a level of service expected by our customers.

A security failure compromising the integrity or availability of our systems increases the risk that SA Power Networks will be unable to:

- maintain the safety and reliability of its distribution network; and
- comply with its regulatory obligations and requirements.

This is because the unauthorised access to, or unavailability of our systems and information for operating the distribution network or supporting critical business processes may lead to:

- unplanned network outages;
- prolonged outages during routine or emergency asset maintenance;
- compromised, delayed and/or cancelled customer connections/projects;
- compromised safety of staff and/or customers;
- disclosure of sensitive customer, corporate and/or asset information; and/or
- financial loss.

To maintain the highest industry standards of security monitoring and preparedness as required by a critical infrastructure organisation, we are deploying a business wide security upgrade with a focus on segregating, monitoring and protecting the OT networks that support critical operational functions.

For further information refer to our OT cyber AP 3.3.09 which is available on request.

5.16.2.4 ADMS/OMS upgrade

The Schneider Electric ADMS has been in operation at SA Power Networks since April 2015. The functionality of the system is presently being extended to include the integration of the outage management system (**OMS**).

The ADMS system is scheduled to have a hardware refresh in 2020/21 as the hardware has reached its end-of-life. The hardware refresh will also ensure sufficient performance to run the integrated OMS within the ADMS.

Whilst the ADMS hardware is being replaced in 2020/21, to manage risk and minimise cost we will continue operating on the current version of the ADMS software until the integration of the OMS is complete. On this basis the software upgrade has been deferred to 2023/24 when the Microsoft support for the current software[75] runs out. If the software is not upgraded the existing systems will become vulnerable to cyber-attacks, significantly increasing the risk on the network.

The energy sector has received considerable attention in regard to cyber security by government agencies within Australia and overseas, primarily due to the high risk associated with a cyber security incident in this sector. The Australian Cyber Security Centre (**ACSC**) and AEMO have both provided guidelines for management of cyber security in the energy sector. It is likely that AEMO's Australian Energy Sector Cyber Security Framework (**AESCSF**) will be the basis of new rules relating to cyber security management for NEM participants in 2019.

As a prudent network operator, we currently meet the 'Essential Eight' measures as defined by the ACSC and utilised by the AESCSF. However, over the 2020-25 RCP, the existing operating systems used by the ADMS will become unsupported. If the software is not upgraded it will then fail the 'Essential Eight' recommendation that all unsupported operating systems should not be used.

5.16.3 Property

We own and lease a range of properties across the State to support our regulated activities, including a mix of office and depot accommodation. Property capex relates to the acquisition, maintenance, refurbishment and disposal of our commercial, industrial and metropolitan and country depots. Substation property and line easement capex forecasts are incorporated separately within network repex and augex and detailed in Sections 5.12 and 5.13 above .

[75] The version of the ADMS uses the Windows 7 operating system for the user workstations and the Windows Server 2012 operating system.

The strategic intent for our property management is the provision of fit-for-purpose, safe and compliant property assets to enable the business to achieve its strategic priorities and operational objectives.

The key challenges for SA Power Networks' property management include:

- implementation of strategic property management, including revision to our service delivery model to improve the delivery of work programs;
- provision of fit-for-purpose, safe and legislatively compliant properties to enable the efficient and delivery of the business' of planned work; and
- ensuring ongoing compliance with regulatory obligations and requirements across the property management lifecycle.

The current profile and composition of our property portfolio is shown in Table 5-45.

Table 5-45: SA Power Networks' property portfolio

Property type	Owned	Leased	Total
Commercial	3	6	9
Industrial	6	4	10
Metropolitan Depots	6	0	6
Country Depots	22	2	24
Total	**37**	12	49

5.16.3.1 Property outcomes for the 2015-20 RCP

The property actual/forecast expenditure for the 2015-20 RCP is $54.4 million, $26.1 million (32%) below the AER allowance of $80.5 million, refer Table 5-46.

Table 5-46: Comparison of property expenditure, AER allowance to actual/forecast (June 2020, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	TOTAL
Allowance	17.7	14.8	14.0	14.5	19.6	**80.5**
Actual and forecast	8.3	7.4	12.0	11.2	15.4	**54.4**

The property program for the 2015-20 RCP was developed on the basis of a rigorous condition-based assessment of all properties within the portfolio. Significant investment has been made during the 2015-20 RCP to address the outcomes of the condition-based assessment, including the condition based refurbishment of the Streaky Bay, Port Pirie, Angle Park, Marleston South, Murray Bridge and Kadina Depots.

In addition to the above work, we have been prudently addressing safety concerns through many of our metropolitan and regional depots.

However, we have delayed some large property refurbishments to later in the 2015-20 RCP (or into the 2020-25 RCP) until we have greater clarity and certainty on the use and function of some properties, for example:

- there has been a revision to our service delivery model which is changing the functionality of depots; and
- the needs of some business units are changing based on the evolving technologies and the future use of the distribution network.

In the 2020-25 RCP, we are forecasting the completion of work that commenced in the 2015-20 RCP and have prioritised refurbishment of the other industrial properties. We also need to replace some large mechanical services (emergency generator) in the Keswick office building, that supports our Network Operations Centre.

5.16.3.2 Property forecasting approach

The scope and quantum of our foreast property capex for the 2020-25 RCP is based on a rigorous property condition review completed by specialist Quantity Surveyors and cost estimators to determine estimates associated with the condition of all SA Power Networks properties in metropolitan and regional locations, being 49 in total.

Whilst significant improvements have been made in the overall condition of the property portfolio, our internal Property Services department has identified significant investment is still required for the 2020-25 RCP to deliver optimal property services to support field operations.

Property capex represents the most cost-effective use of funds to maintain property assets in a reasonable fit-for-purpose state and be compliant with building and work health and safety codes as they may apply. We aim to:

- maintain a consistent and equitable standard of repair across all sites;
- undertake ongoing reviews of all sites to identify and classify capital requirements;
- consult with site stakeholders on an ongoing basis to identify specific needs; and
- ensure buildings are compliant with all relevant legislative requirements.

Consultants MRS Property were also engaged and worked closely with our internal stakeholders to identify:

- all relevant property assets (owned and leased);
- forecast work structure and workforce numbers to ascertain associated employee numbers and projected growth;
- existing and forecast capacity per site;
- planned building maintenance and repair; and
- property efficiencies and necessary improvements.

This dual approach is based on asset condition and an outlook that factors in the effective and safe provision of services associated with each facility and how they interact with others. The refined approach reflects the most prudent and efficient service model at each location, underpinned by common design and cost approaches, and driven by efficient service outcomes.

The resultant forecast property capex estimates have been developed by means of:

- a phased approach of consultation with SA Power Networks staff;
- a property condition review prepared by Rider Levett Bucknall;
- a rigorous review of resultant capex projects by Property Services and MRS Property, in the context of the property management lifecycle; and
- ongoing verification and discussion with SA Power Networks stakeholders,

to ensure a well-considered and relevant plan with prudent and cost-effective outcomes.

Substation property and line easement capex forecasts are excluded from this review and incorporated separately within our repex and augex forecasts.

Our property capex forecasting methodology is explained in further detail in Supporting Document 5.31 – Property Services capital expenditure 2020-2025.

5.16.3.3 Customer and stakeholder engagement outcomes

In response to customer and stakeholder feedback, we have actively reduced our proposed property capex by $14 million, by revising the scope of our planned work.

5.16.3.4 Property capex forecast for the 2020-25 RCP

The provision of a fit-for-purpose, functional, safe and compliant property is paramount to ensure our employees have the right facilities available to them and that these facilities meet modern standards, comply with all regulatory obligations and requirements, and provide a safe work environment.

Our forecast capex for property for the 2020-25 RCP is $61.5 million (June 2020 $), refer to Table 5-47.

Table 5-47: Forecast property expenditure for the 2020-25 RCP (June 2020, $ million)

	2020/21	2021/22	2022/23	2023/24	2024/25	TOTAL
Property	13.8	17.9	11.1	9.5	9.2	**61.5**

The major property works for the 2020-25 RCP is listed in Table 5-48.

Table 5-48: SA Power Networks' proposed major property works for the 2020-25 RCP

Location	Nature of works proposed
Angle Park North	Refurbishment of the logistics warehouse, including toilet upgrades and an fire services upgrade. New fit out in multiple buildings, replacement of storage facilities, substantial replacement of pavements
Clare	Demolition and rebuild of existing Office, reclad workshop, upgrade lighting, and replacement of pavements
Gumeracha	Demolition of existing Office, building of a new office and workshop
Keswick	Ongoing refurbishment program of the corporate Head Office including replacement of external cladding.
Marleston North	Transformer Workshop: roof and wall replacement, extension of lunchroom, toilet refurbishment, air-conditioning replacement. Refurbishment to a number of other building on site, including the substation workshop, welding workshop, substation store, and oil plant. Upgrade to traffic flow, pavements and site storage facilities.
St Marys	Refurbishment of the main office; upgrades to the toilets, workshops and storage sheds. Replacement of pavements.
Seaford	Build new depot and logistics hub.
Yorketown	Rebuild existing office accommodation.

5.16.4 Fleet

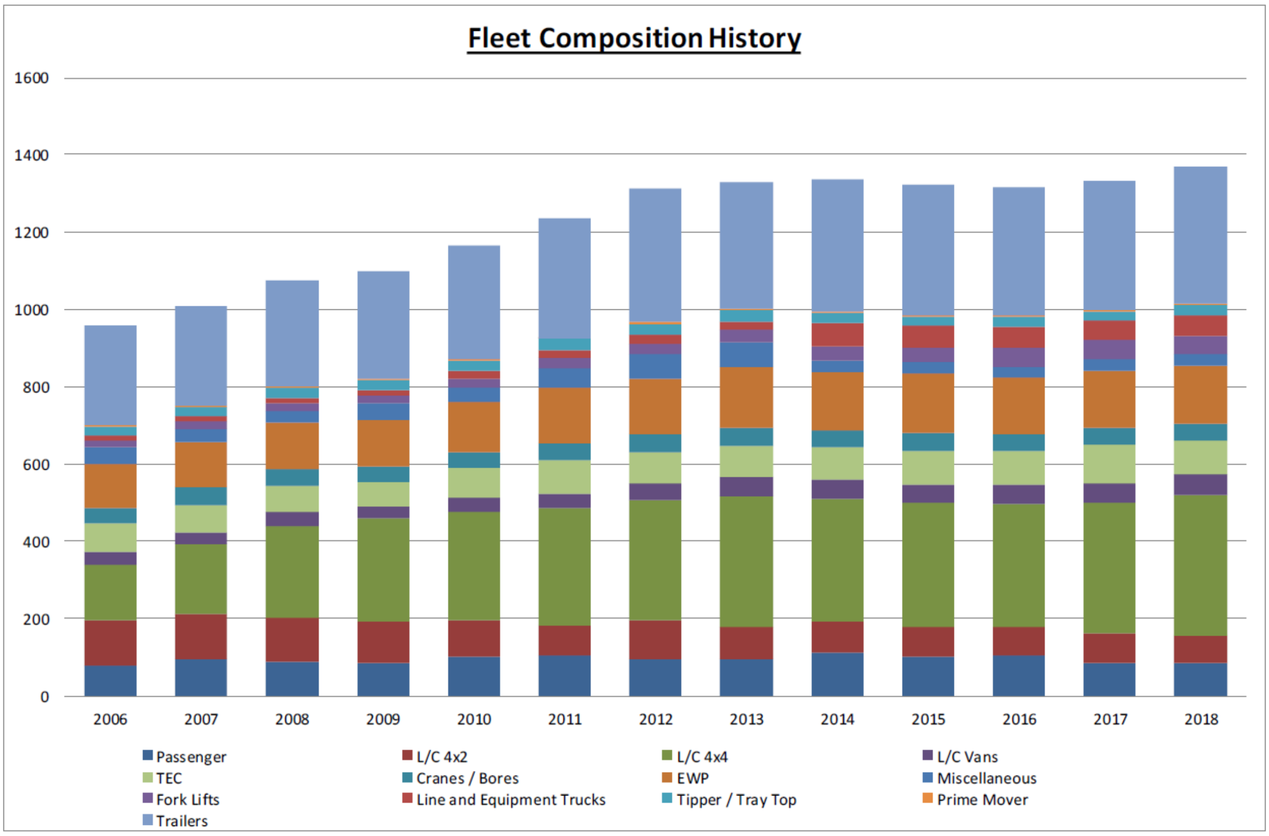
We maintain a fleet of specialised vehicles that provide a safe and efficient work environment for our field crews. This enables them to work at height and on live components of the network, reducing customer power outages and restoring power quickly and safely.

Our workforce responds to damaged equipment brought down by storms, fallen trees, vehicular impacts and other events. With over 82,000km of powerlines , more than 73,000 street transformers, and a service area of 178,000 square kilometres, we require a fleet that can access all of the assets that service our customers.

Our fleet includes Elevated Work Platforms (**EWPs**), Crane Borers; Heavy Commercial trucks, Passenger and Light Commercial vehicles. The Fleet expenditure is incurred to replace assets on a cyclical nature based on age, kilometres travelled and condition. As the fleet ages, maintenance costs increase, and risks associated with safety and performance also increase.

The fleet composition over 2006 to 2018 is aligned with the increased work program and corresponding employee growth as shown in the Figure 5-29.

Figure 5-29: Fleet composition history



5.16.4.1 Outcomes for the 2015-20 RCP

The fleet actual/forecast expenditure for the 2015-20 RCP is $93.1 million, $41.7 million (31%) below the AER allowance of $134.8 million, refer Table 5-49.

Table 5-49: Comparison of fleet expenditure, AER allowance to actual/forecast (June 2020, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	TOTAL
Allowance	43.0	23.9	16.8	19.6	31.4	**134.8**
Actual and forecast	16.1	15.2	19.9	21.3	20.6	**93.1**

The fleet expenditure program across the 2015-20 RCP was driven by:

- heavy and light vehicle replacement requirements; and
- compliance with regulatory obligations and requirements.

During the 2015-20 RCP, we have operated in a highly competitive supply market for fleet and associated equipment. This has contributed to delivering a lower overall fleet cost during the 2015-20 RCP. We have also initiated an enhanced standardisation philosophy, where many safety features are included within the standard vehicle specifications that were once optional extras. Together these factors have contributed to lower overall fleet costs which are now included within the base price.

In addition to this, in the lead up to the 2015-20 RCP we had forecast to grow fleet to support the significant uplift in our capital works program (and replacement and refurbishment works in particular). This uplift in vehicle acquisition did not fully eventuate due to the increased use of external contractors.

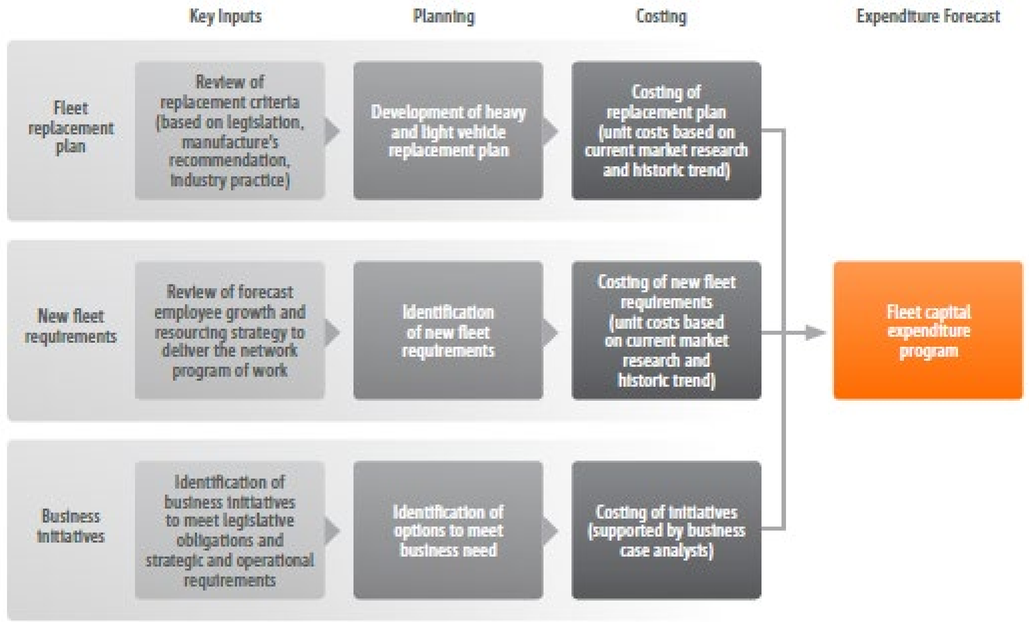
5.16.4.2 Fleet forecast approach

For the 2020-25 RCP, we have used a comprehensive zero-based approach to determine our fleet requirements. This approach is outlined in Figure 5-30.

Key elements of the capex forecast are:

- our fleet replacement plan for heavy and light vehicles which accord with our replacement criteria. The replacement criteria are primarily based on age, kilometres or condition, and are driven by legislative requirements, manufacturers' recommendations and/or industry practice; and
- key business initiatives which are driven by strategic and operational business requirements and various regulatory obligations and requirements including:
  - the *Work, Health and Safety Act 2012* (SA);
  - the Electricity Act and regulations;
  - the *Road Traffic Act 1961* (SA) and regulations that prescribe vehicle standards, mass, loading requirements and other safety measures in relation to light vehicles; and
  - the *Heavy Vehicle National Law*.

Figure 5-30: Fleet expenditure forecast methodology



Fleet vehicles are replaced regularly in accordance with our replacement criteria. Our analysis over many years has shown that for the heavy commercial components of fleet there is a correlation between increasing age and increasing maintenance and running costs, safety concerns and potential for loss of productivity.

Our replacement criteria were endorsed by the AER in the 2015 Determination, and the same criteria will be applied for the 2020-25 RCP, except for a change to the replacement criteria for trailers to shift from a 20 year cyclical replacement to 15 years. This change was implemented in 2018 and was driven by an increasing number of trailers being replaced early due to poor condition and safety concerns and the need to ensure that our vehicles are fit for purpose, and compliant to enable the efficient and effective delivery of the network program of work.

Our current fleet replacement criteria are shown in Table 5-50.

Table 5-50: Fleet replacement criteria

Fleet category	Current replacement criteria	Proposed replacement criteria
Elevated working platform	10 year replacement	10 year replacement
Cranes	10 year rebuild, 14 year replacement	10 year rebuild, 14 year replacement
Heavy commercial vehicles	15 year replacement	15 year replacement
Trailers	15 year replacement (previously 20 years)	15 year replacement
Other specialist equipment	20 year replacement	20 year replacement
TEC vehicles	3 year replacement / 90,000km	3 year replacement / 90,000km
Passenger vehicles	5 year replacement / 150,000km	5 year replacement /150,000km
Light commercial vehicles	5 year replacement / 150,000km	5 year replacement /150,000km

Given that the key fleet replacement criteria is based on age, this introduces a cyclic nature to the replacement of vehicles and results in some regulatory years having a higher number of replacements than others. Similarly, we find that some RCPs may have higher number of replacements than others.

5.16.4.3 Fleet capex forecast for the 2020-25 RCP

SA Power Networks vehicles travel circa 19 million kilometres per annum. It is critical for business efficiency that our fleet is fit for purpose, reliable and importantly are in good condition to ensure safe travel and work operation. In addition, as mentioned above, our fleet must comply with our replacement criteria and other applicable regulatory obligations and requirements.

Further detail about the fleet capex program for the 2020-25 RCP can be found in the Strategic Fleet Plan 2020-25 provided as Supporting Document 5.30. The plan outlines the scope of work which has been considered, which includes:

- planning undertaken in accordance with the Fleet Lifecycle Model; and
- replacement criteria aligned to legislative requirements, manufacturers' recommendations and industry practice.

Our forecast fleet capex is based on the cyclic replacement specified in our replacement criteria, we are not proposing a need for any additional vehicles in the 2020-25 RCP.

Our forecast fleet capex for the 2020-25 RCP is shown in Table 5.51 and is required in order to comply with our fleet replacement criteria and other applicable regulatory obligations and requirements.

Table 5-51: Forecast fleet expenditure for the 2020-25 RCP (June 2020, $ million)

	2020/21	2021/22	2022/23	2023/24	2024/25	TOTAL
Fleet	17.2	22.6	25.6	28.9	22.4	**116.6**

5.16.5 Other

5.16.5.1 Plant and tools

Plant and tools expenditure capex relates to the replacement or purchase of additional tools and equipment necessary to manage and undertake works on our distribution network.

Our plant and tools actual/forecast capex for the 2015-20 RCP is $21.0 million, $13.5 million (39%) below the AER allowance of $34.5 million, as shown in Table 5-52.

Table 5-52: Comparison of plant and tools expenditure, AER allowance to actual/forecast (June 2020, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	TOTAL
Allowance	8.8	6.9	5.4	5.5	7.8	**34.5**
Actual and forecast	2.6	3.0	5.3	5.2	4.9	**21.0**

The forecast underspend is largely due to a larger use of external contractors than originally planned.

Our forecast plant and tools capex for the 2020-25 RCP is shown in Table 5-53 and is consistent with expenditure in the 2015-20 RCP.

Table 5-53: Forecast plant and tools expenditure for the 2020-25 RCP (June 2020, $ million)

	2020/21	2021/22	2022/23	2023/24	2024/25	TOTAL
Plant and tools	5.4	4.5	3.7	3.4	3.9	**20.9**

5.16.5.2 Superannuation

Superannuation capex relates to a regulatory adjustment required to correctly account for the capital allocation of the superannuation contributions that we are required to make to the Electricity Industry Superannuation Scheme (**EISS**) and other superannuation schemes in the 2020-25 RCP.

An annual regulatory adjustment is required to SA Power Networks' regulatory accounts due to differing regulatory and accounting treatments:

- For regulatory purposes, the superannuation cost recognised is the cash employer contributions paid each regulatory year.
- For accounting purposes, the superannuation expense recognised is the expense calculated in accordance with AASB 119 Employee Benefits.

The employer cash contributions are different from the accounting expense. Generally, the accounting expense is higher than the cash contributions. This is because the accounting expense includes movement in the accounting superannuation provision, for which cash payments are not required yet.

SA Power Networks' labour rates for costing to capital projects include a component to recover the accounting expense for the labour hours spent on capital works. However, as the accounting superannuation expense is generally greater than the cash employer contributions, the accounting costing of labour to capital is higher than it should be for regulatory purposes.

In order to recognise the appropriate level of capex for regulatory purposes, this excess of the accounting cost of superannuation over the cash paid must be reversed, by way of a regulatory adjustment. The negative adjustment of $38.3 million is based on the regulatory adjustment for superannuation in the 2017/18 regulatory year.

Table 5-54: Forecast superannuation adjustment for the 2020-25 RCP (June 2020, $ million)

	2020/21	2021/22	2022/23	2023/24	2024/25	TOTAL
Superannuation	(7.5)	(7.6)	(7.7)	(7.8)	(7.8)	**(38.3)**

5.17 Proposed contingent capex overview

5.17.1 Rule requirements

Clause 6.6A.1 of the NER allows SA Power Networks to include in its Proposal, proposed contingent capex which SA Power Networks considers is reasonably required for the purpose of undertaking a proposed contingent project.

The proposed contingent capex for a proposed contingent project is then only included in SA Power Networks' allowed revenue where the trigger event for the proposed contingent project occurs and an application is made to the AER to amend the distribution determination for the 2020-25 RCP.

If SA Power Networks is seeking a determination by the AER that a proposed contingent project is a contingent project for the purposes of the distribution determination for the 2020-25 RCP (which is the case in our Proposal), our building block proposal must contain:[76]

- a description of the proposed contingent project, including the reasons why SA Power Networks considers the project should be accepted as a contingent project for the 2020-25 RCP;
- a forecast of the capex which SA Power Networks considers is reasonably required for the purposes of undertaking the proposed contingent project;
- the methodology used for developing that forecast and the key assumptions that underlie that forecast;
- information that reasonably demonstrates that the undertaking of the proposed contingent project is reasonably required in order to achieve one or more of the capex objectives;
- information that demonstrates the proposed contingent capex for the proposed contingent project complies with the requirements set out in clause 6.6A.1(b)(2) of the NER including that the proposed contingent project:
  - is not otherwise provide for in the total forecast capex for the 2020-25 RCP;
  - reasonably reflects the capex criteria (taking into account the capex factors) in the context of the proposed contingent project; and
  - exceeds either $30 million of capex or 5% of the value of SA Power Networks annual revenue requirement for the 2020/21 regulatory year, whichever is the larger amount (for SA Power Networks, this will be the later amount (ie approximately $40 million);
- the trigger events which are proposed in relation to the contingent project and an explanation of how each of those events addresses the matters referred to in clause 6.6A.1(c) including (amongst other things) that the occurrence of the event is probable during the 2020-25 RCP but the inclusion of capex is not appropriate under clause 6.5.7 of the NER because:
  - it is not sufficiently certain that the event will occur; and
  - the costs associated with the event are not sufficiently certain.

5.17.2 Proposed contingent project for the 2020-25 RCP

SA Power Networks proposes to include proposed contingent capex in its distribution determination for the 2020-25 RCP, which it considers is reasonably required for the purpose of undertaking the proposed contingent project in response to new or altered requirements, directions or other obligations placed on SA Power Networks by AEMO in order to comply with AEMO's responsibility to maintain security of supply within South Australia. From hereon we refer to this as the “Electricity System Security” project.

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[76] *NER clause S6.1.3(14).*

5.17.2.1 Background

AEMO is responsible under clause 4.3.1 of the NER for maintaining power system security, which involves (amongst other things) having emergency control schemes available and in service to restore the power system to a satisfactory operating state, and significantly reduce the risk of outages and disruptions, following certain events.[77] AEMO is also responsible for coordinating the provision of emergency frequency control schemes by NSPs and determining the settings and intended sequence of response by those schemes. In addition, clause 4.3.2(b) requires AEMO to develop, update and maintain load shedding procedures and schedules specifying the emergency frequency control schemes for each participating jurisdiction, including South Australia.

To assist AEMO in meeting and carrying out these obligations and responsibilities, clause 4.3.4 of the NER requires a NSP to use reasonable endeavours to exercise its rights and obligations in relation to its networks so as to co-operate with and assist AEMO in the proper discharge of its power system security responsibilities. In particular, NSPs must cooperate with AEMO in relation to the design, procurement, commissioning, maintenance, monitoring, testing, modification and reporting to AEMO in respect of, any emergency frequency control scheme which is applicable in respect of the NSP's distribution system. NSPs must also arrange and maintain controls, monitoring and secure communication systems to facilitate a manually initiated, rotational load shedding and restoration process in certain circumstances.

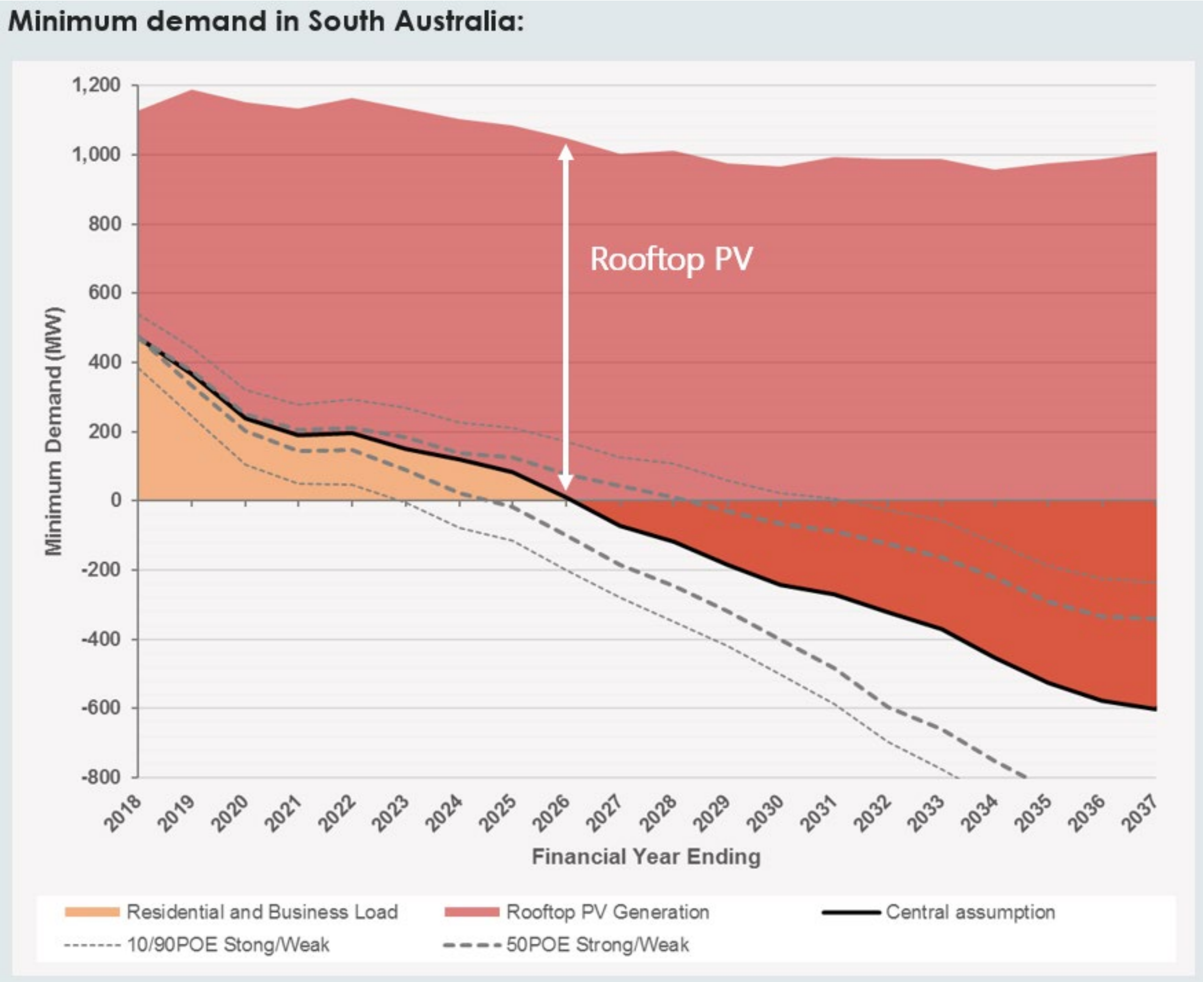
AEMO has put in place various emergency frequency control schemes and associated load shedding procedures for South Australia. This includes an under-frequency load shedding (**UFLS**) scheme. This scheme ensures that the distribution system can automatically disconnect predetermined blocks of load if power system frequency falls below specified thresholds. In the event of a sudden loss of significant generation, the system automatically disconnects load to restore the balance between supply and demand, thereby arresting the decay of system frequency and preventing a catastrophic collapse of the electricity system.

Recent AEMO modelling suggests that as early as 2023, there will be sufficient DER within South Australia to supply the entire State at minimum demand levels as demonstrated by Figure 5-31.[78] This increase in DER within South Australia will render the existing UFLS scheme ineffective. For example if the current system operates at low load times it is likely to exacerbate any threat to power system security, by tripping net generation on the distribution network instead of load.

[77] *NER 4.3.6(c).*

[78] *AEMO, 2018 Electricity statement of opportunities: A report of the National Electricity Market, August 2018.*

Figure 5-31: Minimum demand in South Australia



As a result of this modelling, SA Power Networks has recently met with AEMO to discuss the implications of such low demand on AEMO's ability to maintain power system security. In these meetings, AEMO has indicated that it is likely to require SA Power Networks to implement changes to the existing UFLS scheme, and potentially take other steps, in order to support AEMO’s ability to maintain security of supply with increasing levels of DER.

5.17.2.2 Description of proposed contingent project

The proposed contingent project involves undertaking certain actions or projects required to implement changes to the existing UFLS scheme and/or implement additional measures as required by AEMO to maintain security of supply during the 2020-25 RCP with increasing levels of DER.

At this stage, it is anticipated that AEMO will require SA Power Networks to implement at least the following two changes:

- **Redesign and rebuild the existing UFLS scheme** – As mentioned above, the existing UFLS scheme requires a distributed control system to automatically disconnect predetermined blocks of load, at feeder level, in the event that power system frequency falls below specified thresholds. The system currently operates without regard to the amount of distributed energy supplied through the feeder.

  The redesign of the existing UFLS scheme will involve building additional capability into SA Power Networks' distributed control system to determine the volume and direction of load flow on the feeder before the control system automatically disconnects as a result of the frequency falling below the specified level. The changes to the distributed control system will ensure that only those feeders drawing energy from the national electricity grid are disconnected, omitting those feeders serving as net generation sources.

This component of the project will involve replacing and recommissioning 625 existing under-frequency protection relays with units that support load flow determination and the ability to selectively enable under-frequency operation.

The proposed contingent capital expenditure for this proposed contingent project assumes that AEMO will not require SA Power Networks to expand the scope of the existing UFLS scheme to new locations although this is also possible.

- **Establish the capability to shed DER** – In the event of circumstances existing where there is significant potential for separation of South Australia from the national electricity grid, and such separation would render AEMO unable to maintain system security in South Australia owing to low operational demand (and even with the above changes to the UFLS scheme implemented), it is likely that AEMO will seek to adjust the generation mix within South Australia to ensure that power system security can be maintained.

  To control the generation mix with increasing levels of DER, AEMO is likely to require SA Power Networks to establish the capability to disconnect or reduce the output of DER in a controlled manner so as to achieve a target reduction in the power output of such generators. This could be seen as analogous to load shedding at times when AEMO forecasts insufficient generation reserves.

  AEMO may also require new capabilities to prevent DER from reconnecting immediately following a major outage or 'system black' event, as high levels of DER can impede the system restart process.

  This component of the proposed contingent project work would involve establishing a central control system to coordinate embedded generation output (constraint, disconnection and permissive re-connection).

  This assumes the central control system will be established as a module within the existing distribution management system, and that the control system will utilise existing distributed field devices. There is no provision for deploying additional embedded generation SCADA control systems.

It is also obviously possible that AEMO may require additional works to be undertaken that have not yet been foreseen.

SA Power Networks considers that the proposed contingent project should be accepted as a contingent project for the 2020-25 RCP because of uncertainty about the relevant trigger events occurring and the size and cost of the proposed contingent project. In addition:

- the proposed contingent project is reasonably required to be undertaken in order for SA Power Networks to comply with AEMO requirements in relation to the "Electricity System Security" project, and to ultimately meet the expected demand for our distribution services and maintain the reliability and security of the distribution system in a changing operating environment;[79]
- the proposed contingent capex:
  - is not otherwise provided for in our total forecast capex for the 2020-25 RCP;
  - reasonably reflects the capex criteria, taking into account the capex factors); and
  - exceeds the applicable materiality threshold;

- the proposed contingent project and proposed contingent capex, and related information able to be provided at this stage meets the requirements of the Price Reset RIN; and

[79] *NER 6.5.7(a)(1)(2) and (3).*

- the trigger events proposed below in relation to the project are appropriate.

SA Power Networks has not yet had the opportunity to discuss the proposed contingent project with customers and stakeholders as we have only become aware of this possibility during the last month. We propose to consult with customers and stakeholders concerning the AEMO Security of Supply project and the proposed contingent project following the submission of our Proposal and as further information becomes available, and we will address any matters raised by customers and stakeholders in our Revised Proposal due in December 2019.

5.17.2.3 Proposed contingent capex

The proposed contingent capex associated with this proposed contingent project is estimated to be in excess of $79.2 million (June2020$). This includes $78.7 million for the redesign and rebuild of the UFLS scheme and $0.5M for the establishment of the capability to shed DER. This reflects the efficient costs of an efficient and prudent operator in carrying out the proposed contingent project and clearly exceeds the materiality threshold in clause 6.6A.1(b)(2)(iii) of the NER as set out in Table 5-55.

Table 5-55: Proposed contingent capex for the 2020-25 RCP

Forecast Project Cost	5% of the proposed ARR for the 2020/21 regulatory year	Materiality Threshold
$79.2 million	$39.2 million	Exceeded

A breakdown of the possible works and our current high level estimate costs associated with the redesign and rebuild of the UFLS scheme is available on request.

SA Power Networks has used a bottom up approach to develop the proposed contingent capex associated with the project. SA Power Networks will refine the forecast cost estimate once we receive further details from AEMO concerning the scope of the required response to the Electricity System Security project and the likely timing for the commencement and completion of the proposed contingent project and provide the updated information to the AER.

A detailed project scope and cost estimate will be undertaken before any amendment to the distribution determination for the 2020-25 RCP is sought from the AER should the specified trigger event occur during the 2020-25 RCP.

5.17.2.4 Trigger event

The trigger event which is proposed in relation to the proposed contingent project is as follows:

- SA Power Networks receives a notification from AEMO requiring SA Power Networks to implement measures that AEMO determines are required to ensure AEMO's continued ability to maintain security and reliability of supply within South Australia with increasing levels of DER.
- Successful completion of the RIT-D (or equivalent economic evaluation) in relation to the required investment including an assessment of credible options and the identification of the preferred option.
- SA Power Networks Board commitment to proceed with the project subject to the AER amending the distribution determination for the 2020-25 RCP pursuant to the NER.

5.18 Deliverability

SA Power Networks currently employs around 1,750 full time equivalent (**FTE**) workers to deliver distribution services (including alternative control services (**ACS**)). This includes field workers, professional and para-professional staff (eg engineers, technical officers etc), corporate and support staff. We expect to maintain this level of workforce during the 2020-25 RCP.

Strategies have been developed to ensure the availability of an an optimum mix of skills and resources required to deliver the regulated work program. For example, we undertake annual programs to recruit and train powerline/substation apprentices and university graduates to maintain the skill and knowledge base of our trade skilled and professional workforce.

SA Power Networks retains a base level of in-house resources to deliver regulated services and manages workload peaks and troughs through employing supplementary labour resources or sub-contracting parcels of work to external suppliers. SA Power Networks has contracts with a number of suppliers in the market to provide resources or skills when required.

In total, SA Power Networks' proposed work program for the 2020-25 RCP is similar in quantum and resource requirement to the program delivered in the 2015-20 RCP. SA Power Networks attests therefore that it has the resources and the skills to deliver our proposed work program in the 2020-25 RCP.

Shortened Forms

2010-15 RCP .... *2010-15 RCP*
2015-20 RCP .... *2015 Determination*
ABS .... *Australian Bureau of Statistics*
ACR .... *Adelaide Central Region*
ACS .... *alternative control services*
ADMS .... *advanced distribution management system*
AER .... *Australian Energy Regulator*
API .... *Application Programming Interface*
BFRAs .... *bushfire risk areas*
BISOE .... *BIS Oxford Economics*
CAM .... *Cost Allocation Method*
capex .... *capital expenditure*
CBRM .... *condition-based risk management*
CCP14 .... *AER's Consumer Challenge Panel*
CESS .... *capital expenditure sharing scheme*
CFS .... *South Australian Country Fire Service*
CPMP .... *Connection Point Management Plan*
CZ .... *corrosion zone*
DAE .... *Deloitte Access Economics*
DAPR .... *Distribution Annual Planning Report*
DC .... *direct current*
DER .... *distributed energy resources*
DEW .... *South Australian Government's Department of Environment and Water*
DGA .... *dissolved gas analysis*
DMIAM .... *demand management incentive allowance mechanisim*
DMIS .... *demand management incentive scheme*
DNSPs .... *distribution network service providers*
DP .... *degree of polymerisation*
DSPR .... *Distribution System Planning Report*
EISS .... *Electricity Industry Superannuation Scheme*
Electricity (General) Regulations .... *The Electricity (General) Regulations 2012 (SA)*
EMG .... *Executive Management Group*
ENA .... *Energy Networks Australia*
Environment and Protection Act .... *Environment Protection Act 1993 (SA)*
EPA .... *Environmental Protection Authority*
ESCoSA .... *Essential Services Commission of South Australia*
ETC .... *Electricity Transmission Code*
EWPs .... *Elevated Work Platforms*
FTE .... *full time equivalent*
HBFRAs .... *high bushfire risk areas*
HV .... *high voltage*
IDD .... *intelligent digital devices*
IEEE .... *Institute of Electrical and Electronics Engineers*
IP .... *internet protocol*
IT .... *information technology*
LV .... *low voltage*
MBFRAs .... *medium bushfire risk areas*
MEDs .... *Major Event Days*
MPFP .... *multi-lateral partial factor productivity*
MRV .... *maintenance risk value*
MTFP .... *Multi-lateral total factor productivity*
NBFRAs .... *non-bushfire risk areas*
NECF .... *National Energy Customer Framework*
NEM .... *National Electricity Market*

NEO .... *National Electricity Objective*
NER .... *National Electricity Rules*
NNOR .... *non-network options report*
NOC .... *network operations centre*
NPV .... *net present value*
NSAA .... *Network System Support Agreements*
opex .... *operating expenditure*
OT .... *Operational Technology*
OTR .... *Office of the Technical Regulator*
PABX .... *Private Automatic Branch Exchange*
PILC .... *paper insulated lead covered*
PLEC .... *Power Line Environment Committee*
PoE .... *probability of exceedance*
Proposal .... *2020-25 RCP*
QoS .... *quality of supply*
RAB .... *Regulatory Asset Base*
RCP .... *Regulatory Control Period*
repex .... *replacement expenditure*
RIN .... *Regulatory Information Notice*
RIT-D .... *Regulatory Investment Test – Distribution*
RTU .... *remote terminal units*
SAIDI .... *System Average Interruption Duration Index*
SCS .... *standard control services*
SRMTMP .... *Safety, Reliability, Maintenance and Technical Management Plan*
SSF .... *ESCoSA Service Standard Framework*
SWER .... *single wire earth return*
TNC .... *telecommunications network control*
TNM .... *Telecommunications Network Management*
UPAX .... *Utilities PABX*
URD .... *Underground residential development*
VCR .... *value of customer reliability*
VPPs .... *Virtual Power Plants*
WACC .... *weighted average cost of capital*

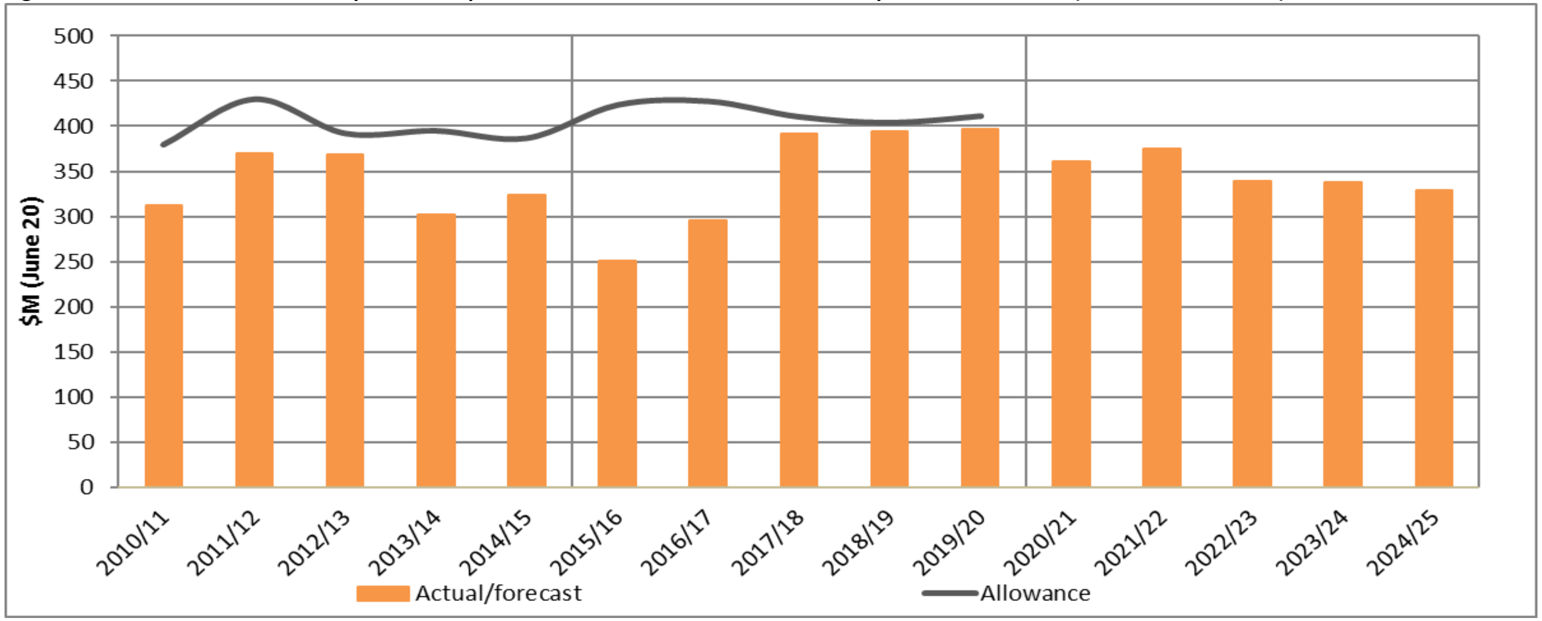
Appendix A – Capex expenditure profile 2010 to 2025

Table 5-56 and Figure 5-32 below illustrates the capex in the previous, current and forecast RCPs.

Table 5-56: **Actual and forecast capex for the previous, current and 2020-25 RCPs (June 2020, $ million)**

	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Replacement	70.6	93.9	103.0	109.4	103.4	93.6	110.4	154.6	154.6	156.5	129.0	135.8	137.9	135.1	131.7
Augmentation	150.8	160.9	158.4	105.7	127.1	59.0	68.5	94.7	101.1	98.0	84.9	83.0	73.4	74.2	75.4
Connections (net)	27.4	41.6	44.5	35.2	39.3	29.7	33.6	33.8	42.4	38.7	40.7	43.0	43.6	43.4	42.5
Network tota	**248.8**	**296.3**	**305.9**	**250.2**	**269.7**	**182.3**	**212.4**	**283.2**	**298.1**	**293.2**	**254.6**	**261.8**	**255.0**	**252.6**	**249.5**
IT	25.1	31.4	29.8	31.4	49.3	45.7	59.0	66.7	68.6	73.5	72.5	72.9	48.5	45.5	45.2
Property	11.9	23.3	18.2	12.4	5.1	8.3	7.4	12.0	11.2	15.4	13.8	17.9	11.1	9.5	9.2
Fleet	20.1	19.5	19.3	18.8	18.3	16.1	15.2	19.9	21.3	20.6	17.2	22.6	25.6	28.9	22.4
Network operational IT	0.7	0.7	0.5	3.4	7.2	10.4	8.3	11.5	0.0	0.0	5.1	2.5	2.7	5.2	6.8
Other[80]	5.5	(1.3)	(4.6)	(14.5)	(25.8)	(11.8)	(7.1)	(2.0)	(5.4)	(5.8)	(2.1)	(3.1)	(4.0)	(4.4)	(3.9)
Non-network tota	**63.4**	**73.5**	**63.2**	**51.5**	**54.1**	**68.7**	**82.8**	**108.1**	**95.7**	**103.8**	**106.4**	**112.7**	**83.9**	**84.7**	**79.7**
TOTAL CAPEX	**312.3**	**369.9**	**369.0**	**301.8**	**323.8**	**251.0**	**295.2**	**391.2**	**393.8**	**397.0**	**361.0**	**374.6**	**338.9**	**337.3**	**329.2**

Figure 5-32: **Actual and forecast capex for the previous, current and 2020-25 RCPs, compared to allowance (June 2020, $ million)**



80 Non-network 'Other' consists of plant and tools and a negative superannuation adjustment.