FINAL DECISION

SA Power Networks Distribution Determination 2020 to 2025

Attachment 5 Capital expenditure

June 2020

AUSTRALIAN ENERGY REGULATOR

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Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to SA Power Networks for the 2020–25 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

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 12 – Classification of services

Attachment 13 – Control mechanisms

Attachment 14 – Pass through events

Attachment 15 – Alternative control services

Attachment 17 – Connection policy

Attachment 18 – Tariff structure statement

Attachment A – Negotiating framework

Contents

5 Capital expenditure

Capital expenditure (capex) refers to the money required to build, maintain or improve the physical assets needed to provide standard control services. Generally, these assets have long lives and the distributor will recover capex from customers over several regulatory control periods. A distributor's capex forecast contributes to the return of capital and return on capital building blocks that form part of its total revenue requirement.

Under the regulatory framework, a distributor must include a forecast of total capex that it considers is required to meet or manage expected demand, comply with all applicable regulations, and to maintain the safety, reliability, quality, security of its network (the capex objectives).

We must decide whether or not we are satisfied that this forecast reasonably reflects prudent and efficient costs and whether it is a realistic expectation of future demand and cost inputs (the capex criteria). We must make our decision in a manner that will, or is likely to, deliver efficient outcomes that benefit consumers in the long term (the National Electricity Objective).

The AER capital expenditure assessment outline explains the obligations of the AER and distributors under the National Electricity Law and Rules (NEL and NER) in more detail. It also describes the techniques we use to assess a distributor's capex proposal against the capex criteria and objectives. The outline is published on our website.[1] This attachment sets out our final decision on SA Power Networks' total capex. The following appendices provide our detailed analysis:

- Appendix A - Capex driver assessment
- Appendix B - Contingent project
- Appendix C - Modelling adjustments to cost escalations

We have based our final decision on our analysis of the information, including SA Power Networks' revised proposal and stakeholder submissions. In this attachment, unless otherwise noted, we use real $2019–20 million end of year.

5.1 Final decision

We do not accept SA Power Networks' forecast capex, as we are not satisfied that SA Power Networks' total net revised capex forecast of $1693.4 million ($2019–20) reasonably reflects the capex criteria.[2] Our substitute estimate of $1595.8 million is 6 per cent below SA Power Networks' forecast and is 4 per cent below its estimated expenditure over the 2015–20 regulatory control period. Table 5.1 outlines our final

1 AER, *AER capital expenditure assessment outline for electricity distribution determinations*, February 2020.

2 The net capex forecast excludes customer contributions and asset disposals.

decision. We are satisfied that our substitute estimate reasonably reflects the capex criteria and it allows SA Power Networks to maintain the safety, service quality and reliability of its supply, consistent with its legislative obligations.

Table 5.1 Final decision on SA Power Networks' total net capex forecast ($ million, 2019–20)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
SA Power Networks' proposal	$346.6	$355.2	$336.3	$332.6	$322.6	$1693.4
Final decision	$330.4	$335.1	$314.6	$312.4	$303.3	$1,595.8
Difference	-$16.3	-$20.1	-$21.7	-$20.2	-$19.2	-$97.5
Percentage difference (%)	-5%	-6%	-6%	-6%	-6%	-6%

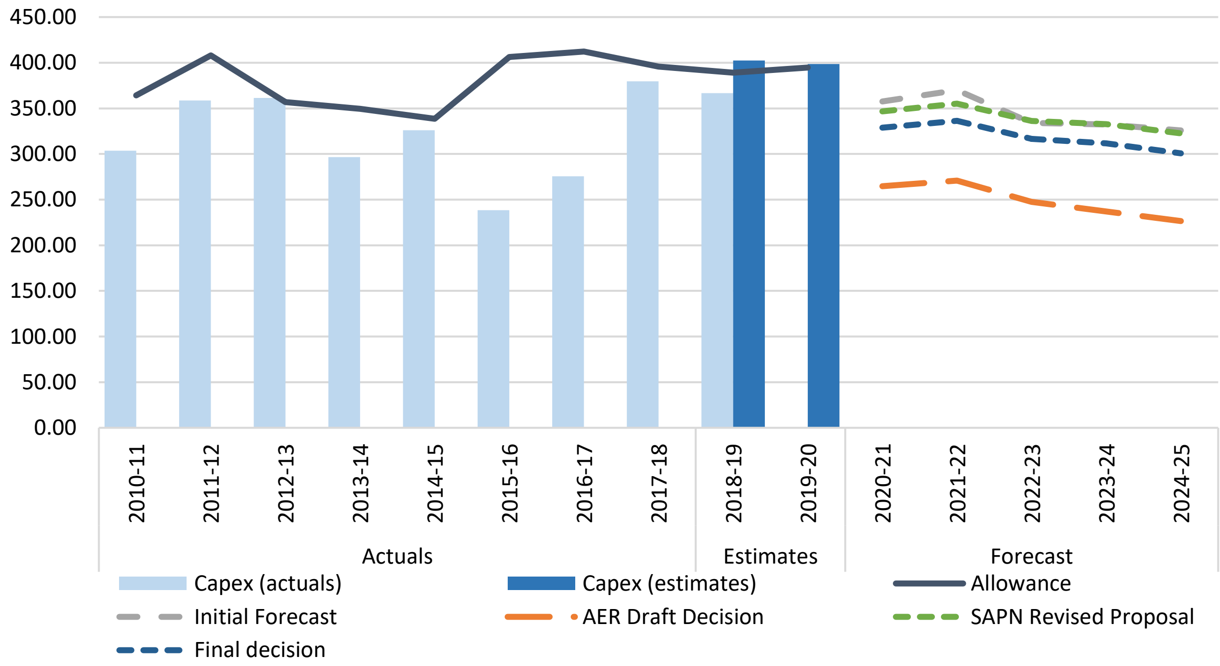
Source: AER analysis.

Notes: Numbers may not sum due to rounding. The figures above do not include equity raising costs, capital contributions and asset disposals. See attachment 3 for our assessment of equity raising costs.

5.2 SA Power Networks' revised proposal

SA Power Networks' revised net capex forecast of $1693.4 million over the 2020–25 period is $34 million (2 per cent) higher than its expected net capex over the 2015–20 period. Figure 5.1 outlines SA Power Networks' historical capex performance against its 2020–25 initial, revised capex forecast and our final decision.

Figure 5.1 SA Power Networks' historical vs forecast capex snapshot ($ million, 2019–20)

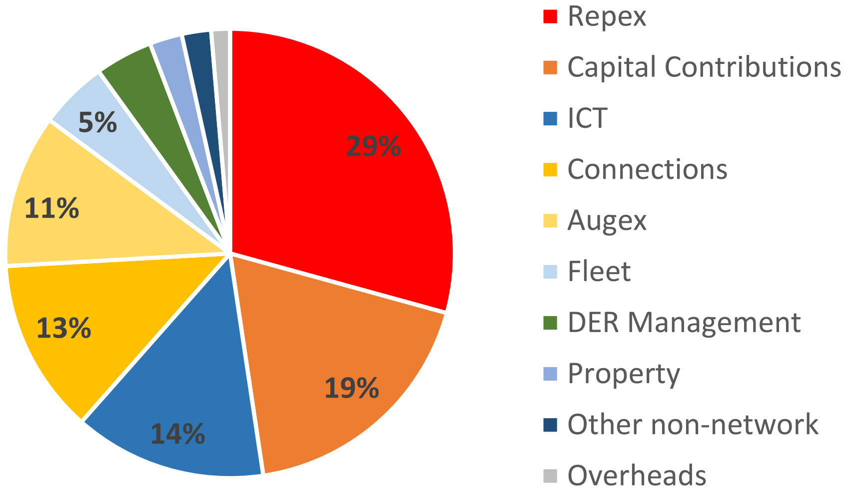


Source: AER analysis.

Note: SA Power Networks' actual and estimated capex is based on SA Power Networks' recast category analysis RIN data.

The key drivers of SA Power Networks' capex revised proposal are represented in Figure 5.2 below.

Figure 5.2 Key drivers of SA Power Networks' gross capex



Source: AER analysis.

5.3 Reasons for final decision

Based on the information before us and weighing up a number of factors, we are not satisfied that SA Power Networks' revised capex forecast reasonably reflects the capex criteria. We applied the assessment approach set out in the *AER capital expenditure assessment outline*,[3] which is published on our website. Appendix A sets out how we applied our assessment techniques and how we came to our position.

We have assessed the revised proposal and acknowledge SA Power Networks' efforts in responding to our draft decision concerns. A number of stakeholders, such as Business SA,[4] Consumer Challenge Panel (CCP14),[5] Energy Consumers Australia (ECA),[6] SA Government[7] and SA Power Networks' Customer Consultative Panel have

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3 AER, *AER capital expenditure assessment outline for electricity distribution determinations*, February 2020.

4 Business SA, Response to the AER's draft decision on SA Power Networks 2020–25 revenue determination, 15 January 2020, p.5.

5 CCP14, *Advice to the AER on the SA Power Networks' regulatory determination 2020–25*, February 2020, 27 February 2020, p.7.

6 Energy Consumers Australia, *SA Power Networks' revised revenue proposal 2020–25*, public, 22 January 2020, p.4.

commended SA Power Networks on its positive consumer engagement when preparing its revised proposal. SA Power Networks engaged with its stakeholders and has either accepted elements of our draft decision or has responded to our concerns, by providing new and additional analysis, to support its capex forecast. The new supporting analysis, such as business cases and accompanying quantitative analysis, has established the prudency and efficiency of a number of capex drivers, such as Distributed Energy Resources (DER) management capex, Information Communication Technology (ICT) capex, connections capex and fleet capex.

Our outstanding concerns relate to SA Power Networks' replacement expenditure (repex), property capex and one of its reliability augmentation expenditure (augex) programs:

- SA Power Networks has not justified a step-up from its revealed historical repex. Our substitute estimate is 11 per cent lower than SA Power Networks' revised proposal. We have identified that some of its assumptions and inputs continue to overstate the risk to be mitigated, and its cost benefit analysis do not support some of its proposed projects. In making our repex decision, we have had regard to SA Power Networks' "Assets and Works" program, which is included in our substitute estimate, which will allow SA Power Networks to find further repex efficiencies.
- Even though SA Power Networks property forecast is a significant improvement from its initial proposal, we continue to have some concerns with its forecasting methodology. For example, SA Power Networks did not explain why there is an annual increasing trend in its property expenditure in its forecast period. It also did not provide a bottom-up build to justify its minor works and did not demonstrate that the timing of its projects is prudent. Therefore, we have arrived at a substitute estimate, that we are satisfied is prudent and efficient, which is based on SA Power Networks' historical expenditure.
- For SA Power Networks' proposed reliability augex, while we have some remaining concerns with the cost-benefit analysis, we have placed more weight on stakeholder support. There was clear stakeholder support for SA Power Networks to undertake its low reliability feeders program, which we have included as part of our substitute estimate. Conversely, for the hardening the network program, we have maintained our draft decision position. There was limited stakeholder support and the benefits of the program appear overstated.

[7] South Australian Government, *Submission on the SA Power Networks revised regulatory proposal for 2020–25*, 14 January 2020, public, p.1.

Table 5.2 Capex driver assessment for 2020–25 ($2019–20, million)

Category	Revised proposal	AER Final decision	Difference ($)	Difference (per cent)
Repex	$649.5	$580.0	-$69.5	-11%
Augex	$233.5	$217.7	-$15.8	-7%
DER Management	$82.2	$82.2	$-	0%
Gross Connections	$611.3	$611.3	$-	0%
ICT	$279.4	$279.4	$-	0%
Property	$50.7	$46.1	-$4.5	-9%
Fleet	$97.3	$97.3	$-	0%
Other non-network	$41.7	$41.7	$-	0%
Capitalised overheads	$62.1	$60.2	-$1.9	-3%
Superannuation adjustment	-$33.6	-$33.6	$0.0	0%
Gross Capex	**$2,074.2**	**$1,982.4**	**-$91.7**	**-4%**
Less capital contributions	-$362.1	-$362.7	-$0.5	0%
Less disposals	-$18.7	-$18.7	$-	0%
Less modelling adjustments		-$5.3	-$5.3	
Net Capex	**$1,693.4**	**$1,595.8**	**-$97.5**	**-6%**

Source: AER analysis.

Notes: Numbers may not add due to rounding. Table excludes equity raising costs. The final decision position includes modelling adjustments relate to SA Power Networks' Consumer Price Index (CPI) and real cost escalation assumptions.

Table 5.3 summarises our findings and the reasons for our final decision by capex driver. This reflects the way we have assessed SA Power Networks' total capex forecast. However, we use our findings on the different capex drivers to assess a distributor's proposal as a whole and arrive at a substitute estimate for total capex where necessary.

It is important to note that in forming a view on the prudent and efficiency of the total capex forecast, we assess certain capex drivers, which made up of programs and projects. We do not determine or set which programs or projects a distributor should or should not undertake. Once we set a capex forecast, it is up to the distributor to prioritise its capex program given its circumstances over the course of the regulatory control period.[8]

[8] AER, capital expenditure assessment outline for electricity distribution determinations, February 2020.

Our assessment concluded that some of the capex drivers associated with SA Power Networks' proposal, such as repex, augex and non-network expenditure are likely to be higher than an efficient level and therefore are not likely to form a part of a capex forecast that reasonably reflect the capex criteria,[9] taking into account the capex factors and the revenue and pricing principles.[10]

We therefore formed a substitute estimate of total capex, which is discussed in appendix A. We are satisfied that our substitute estimate represents a total capex forecast that reasonably reflects the capex criteria and it forms part of an overall distribution determination that is likely to contribute to the achievement of the National Electricity Objective to the greatest degree.

Table 5.3 Summary of our findings and reasons

Issue	Reasons and findings
DER Management capex[11]	We accept SA Power Networks' DER Management revised capex forecast. SA Power networks has addressed our concerns, particularly around the benefits of its Low Voltage (LV) monitoring program as well as the quality of supply remediation program.
Augmentation Capex (augex)	We have included in our substitute estimate all of SA Power Networks' revised augex proposal, with the exception of the hardening the network reliability program. We have accepted SA Power Networks low reliability feeders program, which had significant stakeholder support. As for its hardening the network program, there were limited stakeholder support and the evidence before us does not support SA Power Networks' claim that the program will address recurrent, rather than one-off outages. Therefore, we have not included this program as part of our substitute estimate, We are satisfied that $217.7 million for SA Power Networks' augex meets the capex criteria and is sufficient for SA Power Network to maintain the reliability and safety of its network.
Customer connections capex	SA Power Networks has demonstrated that its net customer connections capex forecast and its customer contributions forecast are prudent and efficient. Stakeholders have requested a review of the observed increase in connections forecast relative to the current period (2015–20), SA Power Networks has demonstrated that a greater number developments are forecast to be constructed in areas outside the existing network and would therefore require

9 We must accept a capex forecast if we are satisfied it is reasonably required to meet the capex criteria, See NER, cl. 6.5.7(c).

10 The revenue and pricing principles are set out in the NEL, s 7A, and we are required to have regard to them under s 16(2).

11 Distributed Energy Resources commonly refers to solar PV, storage, electric vehicles, and other consumer appliances that are capable of responding to demand or pricing signals. Increasing DER penetration represents a change in the way that consumers interact with electricity networks and the demands that it places on networks. DER management expenditure is the expenditure which seeks to manage the growing effects of higher penetration of DER on the network, in particular the effects of solar PV and the impact on distributor's ability to control voltage.

Issue	Reasons and findings
	feeder extensions, incurring greater connection costs. We have reviewed a sample of SA Power Networks' projects and found its forecast aligns with independent sources of information.
Replacement capex (repex)	SA Power Networks has not established that its repex forecast is prudent and efficient. Our substitute estimate is 7 per cent higher than its actual repex over 2014–19 years. SA Power Networks' revised repex forecast continues to overstate the risk to be mitigated and therefore the repex required to mitigate those risks. For example, for SA Power Networks' poles forecast, there is insufficient evidence of a change in the underlying condition that would justify an increase in the repex forecast. In addition, for a number of projects, SA Power Networks either overstated the assets' failure or did not consider sufficient options, despite evidence pointing to a substantially cheaper repair options that are available to it. Our substitute estimate is based on the evidence before us. We are satisfied that our substitute estimate is sufficient for SA Power Networks to maintain the safety and reliability of its network.
ICT capex	We accept SA Power Networks' ICT revised capex forecast, which includes its Assets and Work program and the SAP upgrade. For the Assets and Work program, we acknowledge that SA Power Networks has largely responded to our draft decision concerns and provided supporting analysis, however, we do not consider that the benefits it forecasts, mainly repex deferrals, have been incorporated in its revised repex forecast. The calculation method overstates the repex requirements in the counterfactual, being the absence of the Asset and Work program. In light of the evidence before us, we have accepted the Assets and Work program, subject to an adjustment to repex.
Fleet capex	In its revised proposal, SA Power Networks has largely responded to our draft decision concerns and reduced its fleet forecast by 19.3 million or 19.8 per cent from its initial proposal. While we still have some minor concerns with aspects of its fleet forecast, such as the way costs have been allocated, the issues are not sufficiently material to warrant not accepting SA Power Networks' fleet forecast overall. We have included $97.3 million for fleet capex in our substitute estimate of total capex.
Property capex	In our draft decision, we did not include any property capex in our substitute estimate, as there were significant gaps in SA Power Networks' supporting justification. In its revised proposal, SA Power Networks has provided further analysis and business cases, which was a significant improvement to its initial proposal. SA Power Networks has demonstrated a need to upgrade or refurbish some of its existing property portfolio over the forecast regulatory control period. However, the evidence before us does not justify a forecast that is higher than SA Power Networks' actual expenditure over the 2015–18 period. Our substitute estimate is in-line with its revealed expenditure.

Issue	Reasons and findings
Other non-network capex	For other non-network capex, the difference between our draft decision and SA Power Networks' revised proposal relates to the Advanced Distribution Management System (ADMS) hardware and software upgrade program. SA Power Networks provided a new business case, which noted that the current version is not compatible with newer versions of operating systems.[12] The forced change in operating system necessitates an update to the ADMS software by 2023.[13] It also submitted that it is no longer proposing considering implementing additional modules (such as DERMS) as part of this project, and confirmed that it is proposing any additional licensing cost for new functionality. These submissions established that SA Power Networks' preferred option is prudent and efficient. We have included all of other non-network capex in our substitute estimate.
Capitalised overheads	We have made consequential adjustments to overheads to reflect the lower support requirements of direct capex for our substitute estimate. Consistent with our draft decision, we accept SA Power Networks' proposed negative superannuation adjustment which has been attributed to its capitalised corporate overheads.
Asset disposals	SA Power Networks' asset disposals are solely composed of fleet disposals. We have accepted SA Power Networks' fleet forecast. Therefore, we have not made any consequential adjustments to SA Power Networks' asset disposals.
Modelling adjustments	In our final decision, we have made modelling adjustments to reflect actual CPI rather than the estimated value for 2018–19 year. We have also made adjustments to SA Power Networks' real cost escalations. The modelling adjustments result in a reduction of 10.5 million or 0.6 per cent below SA Power Networks' revised capex forecast. We discuss this further in Appendix C of this final decision.
Contingent project	We accept both of SA Power Networks' proposed contingent projects. For the electricity system security contingent project, SA Power Networks and Australian Energy Market Operator (AEMO) provided us new information and analysis, which establishes appropriate triggers and the need of the project. As for the 2019–20 Bushfire Review contingent project, we are satisfied that SA Power Networks may incur capex to address bushfire risk, as electricity infrastructure is a focus area for the South Australian government's Independent review into South Australia's 2019–20 bushfire season.

12 SA Power Networks, *Supporting documentation 5.32 - ADMS Business case - 2020–25 Revised Regulatory Proposal*, 10 December 2019, p.7.

13 SA Power Networks, *Supporting documentation 5.32 - ADMS Business case - 2020–25 Revised Regulatory Proposal*, 10 December 2019, p.7.

Issue	Reasons and findings
Demand forecasts	In our draft decision, we accepted SA Power Networks' demand forecasts. Our final decision maintains the draft decision, as SA Power Networks has established that its demand forecasts reflect reasonable expectation of demand over the 2020–25 period. SA Power Networks applied spatial demand forecast methodology that is broadly consistent with AEMO's approach.

A Capex driver assessment

This appendix sets out our findings and views by capex category. In each of these sections, we explain our assessment of the amount of capex that we have included in our total substitute estimate that we are satisfied reasonably reflects the capex criteria.

We used various qualitative and quantitative assessment techniques to assess the different elements of SA Power Networks' proposal to determine whether its proposal reasonably reflects the capex criteria.

More broadly, we also take into account the revenue and pricing principles set out in the NEL.[14] In particular, we take into account whether our overall capex forecast will provide SA Power Networks with a reasonable opportunity to recover at least the efficient costs it incurs to:

- provide direct control network services
- comply with its regulatory obligations and requirements.[15]

When assessing capex forecasts, we also consider:

- that the prudency and efficiency criteria in the NER are complementary and reflect the lowest long-term cost to consumers to achieve the expenditure objectives[16]
- past expenditure was sufficient for the distributor to manage and operate its network in previous periods, to the extent that it achieved the capex objectives[17]
- the capex required to provide for a prudent and efficient distributor's circumstances to maintain performance at the targets set out in the service target performance incentive scheme (STPIS)[18]
- the annual benchmarking report, which include measures of total cost efficiency and overall capex efficiency, including consideration to a distributors' inputs, outputs and its operating environment
- the various interrelationships between the total capex forecast and other constituent components of the determination, such as forecast opex and STPIS interactions.[19]

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14 NEL, ss. 7A and 16(2).

15 NEL, s. 7A.

16 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 8–9.

17 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 9.

18 The STPIS provides incentives for distributors to further improve the reliability of supply only where customers are willing to pay for these improvements.

19 NEL, s. 16(1)(c).

A.1 Total capex consideration

Our substitute estimate of SA Power Networks' total capex forecast for the 2020–25 regulatory control period is $1595.8 million. We have relied on the various assessment techniques described in *AER capital expenditure assessment outline*, which is published on our website.[20] In reaching this decision, we have considered all the information before us including, but not limited to, submissions from Adelaide Plains council, AEMO, AGL, Business SA, CCP14, Clean Energy Council (CEC), City of Victor Harbour, Council of Streaky Bay, Cross Border Commissioner, Dynamic Analysis, ECA, Energy and Water Ombudsman SA (EWOSA), Lower Eyre Peninsula, Origin Energy, Port Pirie, Far North Letter, Regional Council of Goyder, South Australian Financial Counsellors Association (SAFCA), United Communities (UC) and the energy project (TEP) joint submission, SA Power Networks' Consumer Consultative Panel, South Australian Council of Social Service (SACOSS), SA Government, Tatiara Council, Total Environment Centre (TEC), Tumby Bay and Yorke Peninsula.

In summary, some submissions, such as Origin's, have commended SA Power Networks for its proactive approach in response to the growth in DER. The CEC and TEC encouraged us to accept SA Power Networks' DER Management expenditure. AGL recommended caution regarding the approval of one of SA Power Networks' DER Management expenditure, as it noted that pre-mature investments may lead to stranded assets, if policy makers have not settled on an appropriate distribution market design. We have also received extensive support for SA Power Networks' low reliability feeder program, which demonstrates stakeholder support for reliability improvement at the edge of grid. Others, such as Origin and SACOSS, questioned whether there is a need for this program, given SA Power Networks is meeting all of Essential Services Commission of SA's (ESCoSA) reliability standards.

Another key theme in the submissions is the concept of future 'bow-wave' of investment, and 'intergenerational equity issues' that could arise. Several submissions, such as those from SA Power Networks' Consumer Consultative Panel and SACOSS, noted the conflict between affordable energy prices and a future 'bow-wave' of replacement expenditure, seeking the AER's expertise on the right balance. We discuss our views on the intergenerational equity problems and our assessment of the 'bow wave' in Section A.2.3.

In coming to our position of certain capex categories, we took into account the interrelationships between the effects that individual capex categories may have on one another. For example, in coming to our final decision on capex, we have considered the impact that SA Power Networks' proposed ICT related Asset and Works program will have on its repex forecast.

[20] AER, *AER capital expenditure assessment outline for electricity distribution determinations*, February 2020.

We also had regard to the overall performance of network and SA Power Networks' response to the existing incentive schemes, such as the STPIS and the Capital Expenditure Sharing Scheme (CESS). Our review demonstrates that SA Power Networks has outperformed its SAIDI and SAIFI targets over the first four years of the current period (2015–20), while underspending its capex forecast. In the absence of new regulatory obligation, these two indicators, occurring simultaneously, provide us confidence that SA Power Networks revealed recurrent-type expenditures, such as repex and recurrent ICT, are likely to be reflective of its future requirements, unless SA Power Networks demonstrates otherwise.

A.2 Replacement expenditure

Repex must be set at a level that allows a distributor to meet the capex objectives, which in the absence of specific jurisdictional requirements, requires maintaining network performance levels.

Replacement can occur for a variety of reasons, including when:

- an asset fails while in service or presents a real risk of imminent failure
- a condition assessment of the asset determines that it is likely to fail soon (or degrade in performance, such that it does not meet its service requirement) and replacement is the most economic option[21]
- the asset does not meet the relevant jurisdictional safety regulations, and can no longer be safely operated on the network
- the risk of using the asset exceeds the benefit of continuing to operate it.

The majority of network assets will remain in efficient use for far longer than a single regulatory control period (many network assets have economic lives of 50 years or more). As a result, a distributor will only need to replace a portion of its network assets in each regulatory control period. Our assessment of repex seeks to establish the proportion of SA Power Networks' assets that will likely require replacement over the 2020–25 regulatory control period and the associated capital expenditure.

A.2.1 Final decision

We do not accept SA Power Networks' revised repex forecast of $649.5 million ($2019–20). Our substitute estimate is $580.0 million, which is 11 per cent lower than SA Power Networks' revised repex forecast.[22] We are satisfied that our substitute estimate forms part of a total capex forecast that meets the capex criteria.

21 A condition assessment may relate to assessment of a single asset or a population of similar assets. High value/low volume assets are more likely to be monitored on an individual basis, while low value/high volume assets are more likely to be considered from an asset category wide perspective.

22 A breakdown of the repex forecast is found in the AER final decision capex model in the NW Projects Capex $June 2020 tab. See, AER, *SA Power Networks 2020–25 - Final Decision - Capex model*, May 2020.

We have included in our substitute estimate all of SA Power Networks' revised repex forecast with the exception of a number of adjustments. Our substitute estimate is derived by:

- Applying the latest five years of actuals (2014–2019) as a historical average for SA Power Networks' poles and pole top structures repex forecast.
- Excluding SA Power Networks' forecast repex for the North Terrace cable ducts and the Northfield Gas Insulated Switchgear (GIS) programs in our substitute estimate for capex.

A.2.2 SA Power Networks' revised proposal

In its revised proposal, SA Power Networks has included $649.5 million as its repex forecast, which makes up 38 per cent of its total capex forecast. SA Power Networks' revised proposal is two per cent above its initial proposal and 22 per cent above our draft decision. It also represents a 9 per cent step up from its estimated historical spend over the current period (2015–20).

In its revised proposal, the key adjustments to SA Power Networks repex forecast are as follows:

- it largely maintained its initial forecast for its poles, the Northfield GIS program and the North Terrace cable ducts program.[23]
- it increased its forecast for service lines and pole top structures by 19 and 18 per cent respectively.
- It reduced its initial forecast for transformer, switchgear, overheads conductors and underground cables asset groups. [24]
- It largely accepted our decision on SCADA, including telecommunication, and it maintained its initial repex forecast for its zone substations protection relays.

A.2.3 Reasons for final position

We have applied several techniques to assess SA Power Networks' revised repex forecast, which includes having regard to stakeholder submissions, repex modelling results, trend analysis and a bottom-up engineering review of SA Power Networks' business cases.

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[23] This is based on AER analysis, which compares the initial regulatory determination workbook and its revised regulatory information notices information. See, SA Power Networks, Response to Information Request #075 - Revised Regulatory Proposal, December 2019.

[24] This is based on AER analysis, which compares the initial regulatory determination workbook and its revised regulatory information notices information. See, SA Power Networks, *Response to Information Request 075 - Revised Regulatory Proposal*, December 2019.

Stakeholder submissions on repex

A key theme in stakeholder submissions was the issue of the future 'bow-wave' of investment, and the 'intergenerational equity issues' that could arise. A bow-wave is said to occur when repex that should be undertaken now is deferred into the future. The bow-wave principle refers to the idea that if repex continues to be deferred in the short-term, then future repex requirements may need to significantly increase to deal with an ageing asset population. Intergenerational equity issues raised by stakeholders refer to the current generation receiving the benefit of lower prices at the expense of future generations having a less reliable network and/or a higher cost burden. Hence, the term, 'kicking the can down the road' referred to in several submissions.

While some submissions, such as the SAFCA, UE and the energy project mentioned the intergenerational equity issues from the perspective of future generations potentially being worse off (with lower prices now), there were several submissions (such as AGL, ECA, the CCP14 and EWOSA) who also viewed these issues in the converse, meaning that a plan for the future network needs to be developed to ensure that future generations are not exposed to unnecessary investments that could be borne in the next period (2020–25).

A number of submissions raised concerns with the risk of unnecessary asset replacement. In this case, all generations could be worse-off. This is because if a more efficient solution exists than simply replacing the asset on a like-for-like basis, and the asset is simply replaced and has a much shorter useful life, all consumers are worse off through a high Regulatory Asset Base (RAB) with all generations paying higher prices than necessary for the provision of electricity services. Submission from CCP14 submitted that it was not clear if SA Power Networks has considered new technologies, such as the impact of DER penetration and its proposed investment in control systems, network monitoring and the like, which may drive synergies in asset failure risk in its replacement decisions.[25] The ECA noted that technological change means that investments needed to be made carefully to avoid assets being stranded in the future.[26]

Our assessment of the bow-wave

We do not agree with SA Power Networks that there is an impeding 'bow-wave' of investment, and that this should be a cause for concern. This is because:

- the bow-wave of investment is a static representation of a distributor replacement decision, as the network exists today. Once advances in technology, including investments in ICT systems, are included in the replacement decision, an impeding major step up in future investment due to a deteriorating network is unlikely;
- the age of an asset is not the key determinant in replacement decisions – asset condition and the network risk are;

25 CCP14, *Advice to the AER on the SA* Power Networks' Regulatory Determination 2020–25 Revised Proposal, 27 February 2020, p.26.

26 Energy Consumer Australia, *SA Power Networks revised revenue proposal 2020–25*, January 2020, p.4.

- while SA Power Networks' assets are aging, the condition of its asset population has not deteriorated due to its effective inspection practices;
- advances in asset management practices such as new inspection technologies or asset intervention practices can have a significant impact on asset life and tend to reduce any potential for a replacement bow-wave; and
- we have clarified the intended meaning behind SA Power Networks' statement that the current replacement rate would equate to an average asset life of 200 years,[27] which was noted as a concern in submissions to the draft decision.[28] SA Power Network has confirmed that the intended meaning is not that an asset would last, on average, 200 years as described in its revised proposal. The intended meaning is that it would take 200 years to replace all of SA Power Networks assets.[29] We do not consider the time it takes to replace its population to be useful metric when justifying forecast repex.

The bow-wave is not a new concept and has been raised with economic regulators, including the AER, over many years. For instance, the bow-wave problem was raised by ETSA Utilities (SA Power Networks' former name) in its regulatory submission to ESCoSA, for the 2005-2010 regulatory control period.[30]

One of the key reasons that the bow wave has not materialised is advances in asset replacement practices. Over the years, distributors have found many innovative approaches when managing their assets, which extend the assets' life. For example, SA Power Network currently plates and re-plates its Stobie poles, with a single plate extending the life of the pole by 20 years or more. Detection of pole defects has also improved considerably with better inspection practices such direct corrosion measurement on steel poles. Such practices reduce the likelihood of unassisted pole failure, and can defer future replacement costs.

We acknowledge that SA Power Network has some of the oldest assets in the National Electricity Market (NEM), particularly for its Stobie poles. SA Power Networks has indicated, due to their unique nature, could last up to a maximum of 120 years in low corrosion zone environments.[31] However, age is not the key determinant in replacement decisions. Good industry practice, as set out in industry standards, indicates that a prudent asset manager replaces assets based on its condition and risk, the latter being the probability of an adverse outcome occurring. Asset condition, in

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27 SA Power Networks, *Attachment 5 - Capital Expenditure - 2020–25 Revised Regulatory Proposal*, 10 December 2019.

28 SA Power Networks' Consumer Consultative Committee, *Response to the SA Power Networks Customer Consultative Panel to SA Power Networks' Revised Proposal to the AER*, 23 December 2019, p.6.

29 SA Power Networks, *Response to information request #095 - average asset age*, 25 February 2020, p.1.

30 PB Associates, *South Australian Electricity Distribution Price Review: Prepared for Essential Services Commission of South Australia*, September 2004, p.87.

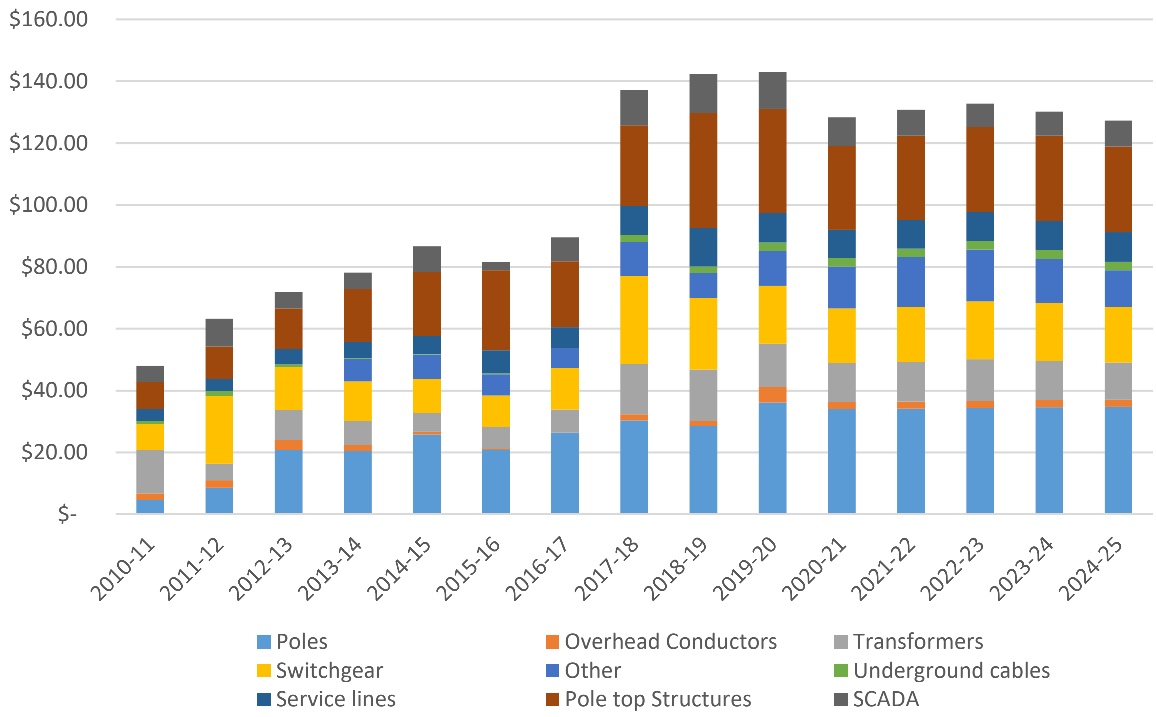
31 In an information request response, SA Power Networks has confirmed that 60 per cent of its pole population is in low corrosion zones. See, SA Power Networks, *Response to AER questions from CBRM workshop*, 6 January 2018, p.4.

turn, is affected by factors such as its physical environment, geographic location, asset maintenance, network configuration and operating conditions.

Trend analysis

Figure 5.3 shows the SA Power Network's repex profile overtime, from 2010–11 to 2024–25.

Figure 5.3 - SA Power Networks' repex by asset group from 2010–11 to 2024–25 ($ million, 2019–20)



We requested an explanation of SA Power Networks' asset management and inspection practices that led to the historical rectification of defects and the apparent increasing trend in repex from 2010 to 2018, as observed in Figure 5.3. In response, SA Power Networks stated the following:

> Prior to 2010 asset inspections were not being completed within the 5/10 [five and 10 year] cycles. Following the 2009 Victorian Bushfire Royal Commission, the SA Power Networks network was brought into cycle over 7 years following a risk based approach, starting with High Bushfire risk areas (BFRA) from 2010, Medium BFRA from 2012 and non BFRA from 2015. Additionally, after a spate of pole failures poles [sic] within 2km of the coastline, these assets were also targeted, resulting in very high defect find rates. The network was

> substantially brought into cycle in 2017, and has subsequently been kept in cycle since 2018.[32]

This response confirms that the historical increasing trend in repex was primarily driven by a need to bring SA Power Networks' asset population into a steady state cycle of inspection and replacement. We have observed that SA Power Networks' asset management practices have improved over-time, as it sought to address its backlog of defects, but based on its own statement, it has now reached a steady state. This raises the question of whether SA Power Networks' historical expenditure is sufficient or whether an upward trend in the forecast period reflects its actual needs at the total repex level.

SACOSS, in its submission, noted the different approaches to forecasting based on historical averages or trends. SACOSS submitted that there is difficulty with all approaches. On one hand, it questioned our approach in the draft decision, stating that relying on the low-repex in 2015–17 may have underestimated the repex requirements. On the other hand, it also questioned SA Power Networks' methodology to forecast its true repex requirement in the absence of one of its ICT proposed programs, the 'Assets and Works' program. SACOSS submitted that a ten-year upward trend would overstate the repex requirements.[33] Based on the evidence before us and in the presence of the CESS, we have maintained that a repex that is consistent with SA Power Networks' historical revealed costs, is the best estimate in the circumstance because:

- SA Power Networks has effective asset management practices that allow it to address high priority defects first, while deferring low priority defects until it is efficient to attend to them. We have found that the majority of SA Power Networks' low priority defects are not addressed immediately, and it can take 18 months or more to address them, particularly when there are enough defects in the same location to justify a bundled work solution.[34] This demonstrates SA Power Networks' ability to efficiently defer most of its low priority defects, a practice that accords with good asset management and good works management.
- Our own review of SA Power Networks' open defects, meaning the known defects that are yet to be addressed, indicates that the majority of its existing open defects, particularly for poles and pole top structures, are low priority. The defects either have a low likelihood of failure or are associated with a low consequence if they failed. This demonstrates SA Power Networks' ability to address high priority defects first but also that a continuing or increasing trend in repex is not likely in the forecast period.

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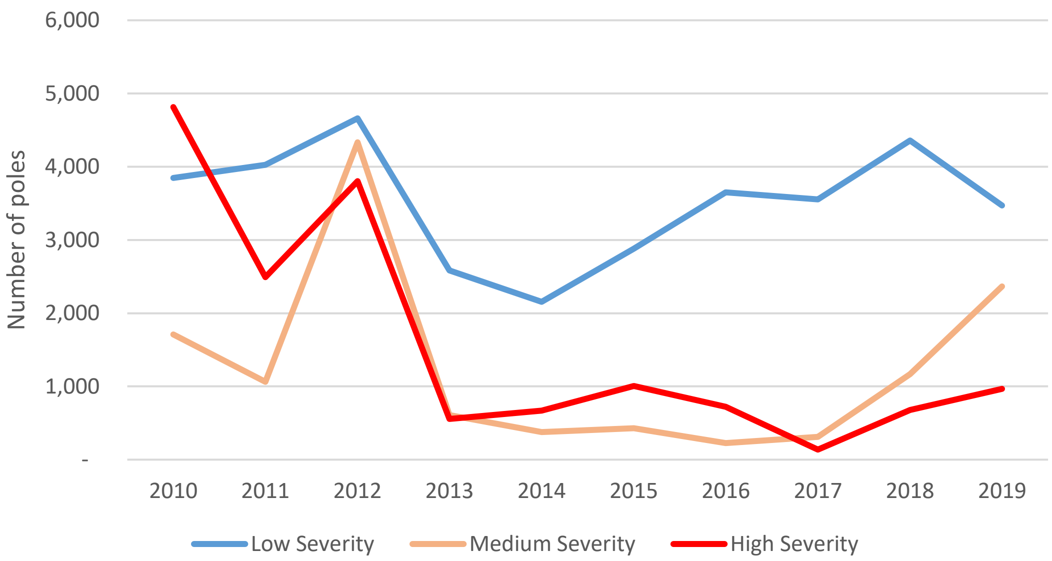
32 SA Power Networks, *Response to AER analysis and questions*, 11 February 2020.

33 SACOSS, *Submission to the Australian Energy Regulator on SA Power Networks' 2020–25 Revised Regulatory Proposal*, 16 January 2020, p.20.

34 AER analysis, *SA Power Networks Response to Information Request #039 - Question 37 and Question 38 - Data*, 31 May 2019.

- SA Power Networks is unlikely to require an increasing trend of repex for it to maintain the safety and reliability of the service over the forecast period. In the absence of a specific jurisdictional requirement, a distributor is required to propose a capex forecast that maintains, but not improves, the performance of its service.[35] We have observed that, from 2009 onwards, SA Power Networks has consistently outperformed its output targets, such as the SAIFI targets, which indicates that its asset management practices and its existing expenditure have contributed to an improvement in service level outcomes associated with asset failures over-time.
- We sought to understand whether there were any underlying problems with the condition of SA Power Networks poles assets. This is the biggest driver of the forecasted increase in repex. SA Power Networks provided severity scales of its poles over time.[36] The data showed that poles in severe condition have declined over time. Even though SA Power Networks indicated that its defect find rate has increased, Figure 5.4 demonstrates that while the find rate has increased, we observed that find rate of medium or high severity defects has declined over time for Stobie poles. In 2010–2012 years, there was an average of 3704 poles with high severity defects, compared to an average of 593 poles with high severity defects in 2017–2019. This evidence confirms the effectiveness of SA Power Networks' asset management practices over the 2010–2018 years.

Figure 5.4 - Change in SA Power Networks' pole severity over time



- We have approved SA Power Networks' ICT capex, which includes a $44.9 million "Assets and Works" program that, as acknowledged by SA Power Networks itself, will enable it to defer, prioritise and target its replacement program more efficiently over the forecast period.

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35 NER cl.6.5.7.

36 Severity is a metric that measure the condition of SA Power Networks' poles.

Repex modelling results

Even though poles are usually part of modelled repex under our standard modelling approach, in this final decision and consistent with the draft decision, we have excluded Stobie poles due to their unique nature. SA Power Networks' revised proposal includes $225 million in modelled repex, which includes the five asset groups of switchgear, transformers, service lines, overhead conductors and underground cables. Consistent with the draft decision and with the AER repex model outline,[37] we have tested SA Power Networks' asset categories and compared its repex forecast against the following four scenarios:

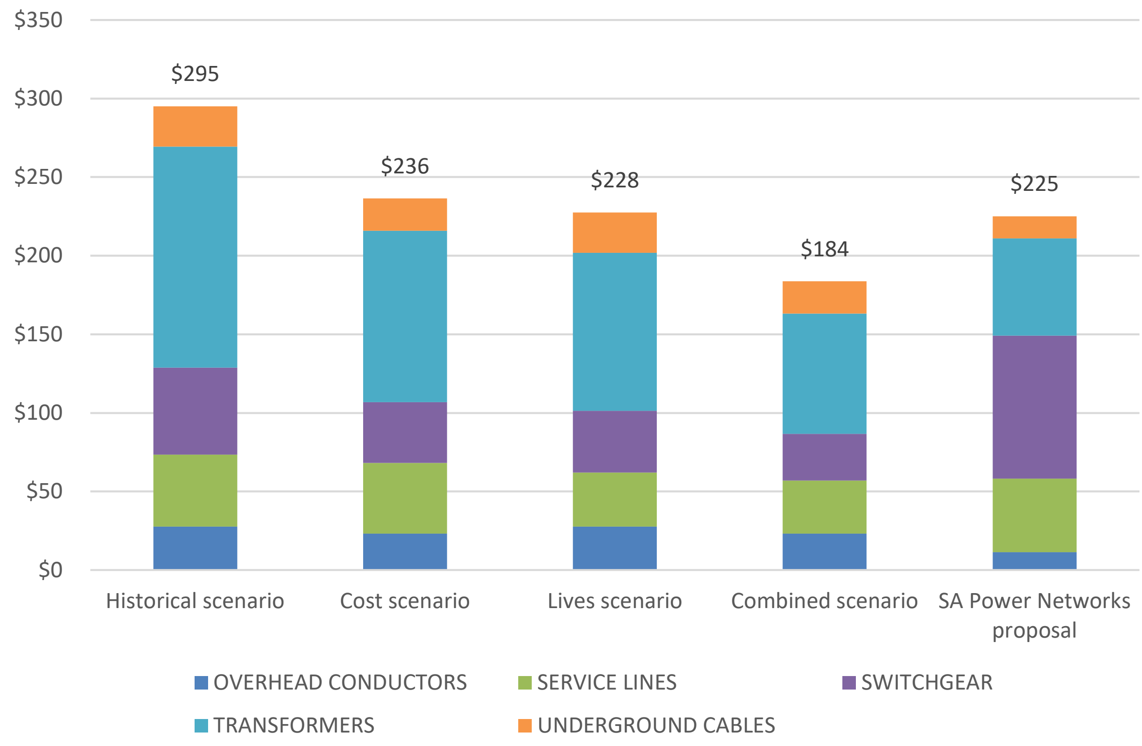
- Historical scenario - historical unit costs and calibrated expected replacement lives
- Cost scenario - comparative unit costs and calibrated expected replacement lives
- Lives Scenario - historical unit costs and comparative expected replacement lives
- Combined scenario - comparative unit costs and comparative expected replacement lives.

Figure 5.5 below shows SA Power Networks' proposed modelled repex compared with the four scenarios. In this final decision, SA Power Networks' proposal of $225 million is $11 million lower than the repex model threshold, which is the cost scenario in this final decision.[38]

[37] AER, *Repex model outline for electricity distribution determinations*, February 2020.

[38] Consistent with our standard approach, the repex modelling threshold is the higher of the cost and lives scenarios.

Figure 5.5 - SA Power Networks' modelled repex forecast versus the four modelled scenarios ($ million, 2019–20)



While the draft decision noted that the forecast for switchgear, transformers and underground cables were higher than what the repex model predicted. The final decision repex modelling results show that switchgear and service lines are the asset groups that are higher than the model's prediction.

In its revised proposal, SA Power Networks has recommended that we make some adjustments to the application of the repex model. We agreed with some of SA Power Networks' recommendations and have made adjustments to modelling, but disagreed with others.[39] The final decision modelling results reflect the following assumptions:

- We have relied on the most recent four years of actual repex over the current period (2015–19) as the calibration period for this final decision. In the draft decision, we used relied on 2014–18 as the calibration period.[40]
- SA Power Networks also submitted that some of the underground cable categories were excluded from the draft decision modelling.[41] We have modelled two categories that were previously excluded in the draft decision modelling. We have maintained our draft decision and excluded a set of transformer asset categories,

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[39] SA Power Networks, *Supporting document 5.4 - Repex Addendum - 2020–25 Revised Regulatory Proposal*, 10 December 2019, p.39.

[40] AER, *SA Power Networks 2020–25 - Draft decision - Repex model*, October 2019.

[41] SA Power Networks, *Supporting document 5.4 - Repex Addendum - 2020–25 Revised Regulatory Proposal*, 10 December 2019.

as SA Power Networks has confirmed that these asset categories are not available within the AER defined transformer asset categories.[42]

- For its transformers asset group, we have observed a change in the asset age profile data when comparing 2017–18 to 2018–19 category analysis RIN data. SA Power Networks advised that for its 2018–19 category analysis RIN reporting, it sought to improve its asset age profile data and relied on data directly from its SAP and its geospatial systems.[43] Based on SA Power Networks' response, which is consistent with its basis of preparation, we are satisfied that its updated data is the most accurate and therefore, we have relied on it for the final decision repex modelling results.
- SA Power Networks recommended that we adjust the blending of replacement and refurbishments costs for its Email/Westinghouse indoor circuit breakers, as it is a one-off program of life extension[44]. We do not consider the proposed approach to be justified. Our view is that the calibration period should reflect the distributors' practices over the calibration period as much as possible. Therefore, we have maintained our draft decision modelling approach.[45]

Despite our draft decision concerns with SA Power Networks' forecasting methodology, being the reliance on its Condition Based Risk Management (CBRM) model for transformer and modelled switchgear, SA Power Networks' revised modelled repex forecast compares favourably with the repex modelling threshold, suggesting it compares well with its peers on unit costs and replacement lives for its modelled repex component. For its underground cables group, SA Power Networks has reduced its forecast for underground cables by 56 per cent and provided us supporting analysis that establish the prudency and efficiency of its 11 kV bare paper insulated lead cables cable program.

Even though the switchgear and service lines' forecast are higher than the model predicts as shown in Figure 5.5, the overall revised repex forecast is lower than the repex model threshold. On balance, we are satisfied that SA Power Networks' forecast modelled repex of $225 million, which excludes poles repex, forms part of a total capex forecast that reasonably reflects the capex criteria.

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42 The categories are transformers that are kiosk mounted; > 22 kV; > 60 kVA and < = 600 kVA, pole mounted; > = 22 kV & < = 33 kV; < = 60kVA and pole mounted; > = 22 kV & < = 33 kV; < = 60kVA, which are reported in other repex in the Category Analysis RIN. See, SA Power Networks, *Response to AER preliminary repex modelling results for SA Power Networks*, 21 June 2019.

43 SA Power Networks, *Response to Information Request 093 - Category Analysis RIN age profile data*, 12 February 2020, p.2.

44 SA Power Networks, *Supporting document 5.4 - Repex Addendum - 2020–25 Revised Regulatory Proposal*, 10 December 2019, p.39.

45 SA Power Networks, *Supporting document 5.4 - Repex Addendum - 2020–25 Revised Regulatory Proposal*, 10 December 2019, p.39.

Bottom-up review

In this section, we discuss our remaining concerns with SA Power Networks' revised repex forecast and how we have arrived at our substitute estimate. For other elements of the repex forecast, which were discussed in the draft decision, such as the SCADA and protection repex.[46] SA Power Networks has accepted our draft decision for the majority of its telecommunication projects.[47] Any outstanding concerns with the protection relays' forecast are immaterial, therefore, we have included SA Power Networks' revised forecast for SCADA and protection repex in our substitute estimate for capex.

SA Power Networks' poles repex

In the revised proposal, SA Power Networks included $171 million ($2019–20) for the replacement of poles.[48] SA Power Networks' revised poles forecast did not change from its initial proposal. Poles represents 26 per cent of its repex forecast, the largest component of its forecast, and reflects a 23 per cent step up from its actual spend over the current period (2015–20).

SA Power Networks forecast its poles repex using its CBRM. In our draft decision, we raised a number of concerns with some of the CBRM assumptions as well as lack of a peer review of the key inputs in the model, which overstates the risk to be mitigated. SA Power Networks responded to our concerns by commissioning Cutler Merz to undertake an independent review of the model.[49]

We have reviewed the information provided and maintain the view that the overall forecast risk to be mitigated, and the forecast repex to address this risk, is overstated. Our substitute estimate is based on the historical average of SA Power Networks' poles repex over the 2014–19 regulatory years. We consider the historical average to be the best estimate in the circumstances. In coming to this position, we had regard to the SA Government submission, who noted that the increases are not justified other than general re-modelling.[50]

We have come to this position based on the following evidence:

- SA Power Networks' CBRM, which is used for forecast poles repex. We have reviewed the assumptions noted in the Cutler Merz report. We consider that some assumptions overstates the risk to be mitigated.

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46 AER, *Draft Decision - SA Power Networks Distribution Determination 2020–25 - Attachment 5 - Capital Expenditure*, October 2019, p.57.

47 SA Power Networks, *Supporting documentation 5.4 – Repex addendum – 2020–25 Revised Regulatory Proposal*, 10 December 2019, p.26.

48 Stobie poles are unique to South Australia. They consist of a concrete core with two outer steel beams.

49 SA Power Networks, *Supporting documentation 5.5 – Cutler Merz – CBRM model value of consequence independent report – 2020–25 Revised Regulatory Proposal*, 10 December 2019.

50 South Australian Government, *Submission on the SA Power Networks revised regulatory proposal for 2020–25,* 14 January 2020, public, p.1.

- When we assess data on the actual pole condition, as opposed to SA Power Networks' forecasting model, we find that the condition of its poles and risk of failure has not changed. In fact, the majority of the detected defects are of low priority, according to SA Power Networks' own classification.

Review of the CBRM assumptions

We acknowledge the usefulness of the CBRM as a forecasting tool. It comprehensively accounts for an individual asset's characteristics, such as condition and environmental factors to obtain a risk of individual assets, which is then aggregated to an asset population. We consider that SA Power Networks' implementation of the CBRM accords with good industry practice. However, our review of the model has revealed some shortcomings, such as the model's calibration when compared to the observed risk levels. These shortcomings have impacted the CBRM's ability to produce a robust forecast at this stage of its development. We encourage SA Power Networks to further develop, expand and refine its application of CBRM to support its future repex forecasts.

In its revised proposal, SA Power Networks commissioned Cutler Merz to independently verify the CBRM inputs.[51] Our assessment of the Cutler Merz review identified risk inputs to be overstated. In particular:

- the scope of the Cutler Merz review was limited to reviewing only the value of consequence.[52] The absence of a detailed review of likelihood of a consequence, which is a critical variable, is likely to inflate the risk.[53] This is despite our draft decision concern that the likelihood of consequence did not appear to have been taken into account in the modelling.
- safety risk is inflated. Cutler Merz use safety risk in the nuclear industry as a proxy for safety risk in electricity networks. In particular, Cutler Merz apply the findings from the Sizewell B Inquiry as the basis to explain one of the key variables (the disproportionality factor) [54] in the model. This Inquiry assumes that the scale of consequence in the electricity and the nuclear industry are directly comparable. We do not agree with this assumption. A distributor is unlikely to face a situation where the failure of an asset could result in large numbers of people being exposed to

[51] SA Power Networks, *Supporting Document 5.5 - Cutler Merz - CBRM model value of consequence independent report*, 10 December 2010.

[52] Cutler Merz notes that any review of the Probability of failure and probability of consequence was limited to where it was necessary to determine the reasonableness of the value of consequence. See SA Power Networks, *Supporting documentation 5.5 – Cutler Merz – CBRM model value of consequence independent report – 2020–25 Revised Regulatory Proposal*, 10 December 2019.

[53] AER, *Draft decision – SA Power Networks Distribution Determination 2020–25 – Capital Expenditure*, October 2019, p.46.

[54] The disproportionality factor is an index used to represent an organisations' appetite to spend more than the calculated value of the safety risk to reduce that risk. It is usually multiplied by the average value of consequence to ensure that any uncertainty is accounted for. In previous decision and the repex guidance note, we have relied on values between 3 (workers) to 6 (public). The use of values beyond those are likely to overestimate the expenditure required.

fatal conditions (such as escaping radiation) for long periods of time as is the case in the nuclear industry. The use of the nuclear industry assumptions, such as the one relied on in the Sizewell B Inquiry are not relevant in the distribution network context, as they are likely to overestimate the safety risk and the expenditure needed to mitigate those risks.

- the bushfire risk is overstated. Cutler Merz assess that the value of consequence for catastrophic bushfire of $515 million (or 7 million per annum) to be reasonable. We consider the bushfire consequence to be overstated for a number of reasons. Firstly, Cutler Merz compare the bushfire consequence in Victoria and NSW directly to South Australia, without taking into account the differences such as population density, dwelling distributions, climate conditions and vegetation between those states. Secondly, Cutler Merz rely on the nuclear industry disproportionality factors assumptions for the safety component of bushfire. Lastly, the bushfire consequence is overstated, when compared to the derived value of consequence to CSIRO's bushfire mitigation cost benefit analysis, which was provided in support of SA Power Networks' bushfire augex program.[55]

We requested that SA Power Networks test the accuracy of the CBRM forecasts with historical outcomes. We were provided with one year of comparison, with the modelled results varying quite significantly from actuals across a number of CBRM modelled categories.[56] SA Power Networks stated that it was unable to provide more than one year of data. We have reviewed the data provided and the modelled risk is 23 per cent higher than actual risk for poles. This further reduced our confidence in the CBRM's results. Therefore, we examined SA Power Networks' actual pole condition data to see whether we could observe a deterioration that would lend support to SA Power Networks' request for a step up its forecast poles repex.

Pole condition

SA Power Networks submit that an increase in its asset age, means an increase in defects and therefore, an increase in repex is required. To test this assumption, we reviewed SA Power Networks' defect data.

Figure 5.6 shows the trend in the set of prioritised open defects (i.e. defects which are yet to be rectified). Defects that have been rectified are not included.[57] The prioritisation is based on SA Power Networks' own classification. The figure below shows that 90 per cent of identified defects were assigned a low-medium priority.[58] An increase in defects does not necessarily mean an increase in repex, as some of these defects may not require poles to be replaced. The trend of lower priority defects is also

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55 CSIRO has indicated that the total annual bushfire risk due to all of SAPN's assets are around $19 million per annum, which would translate to $1.9 million per annum on poles.

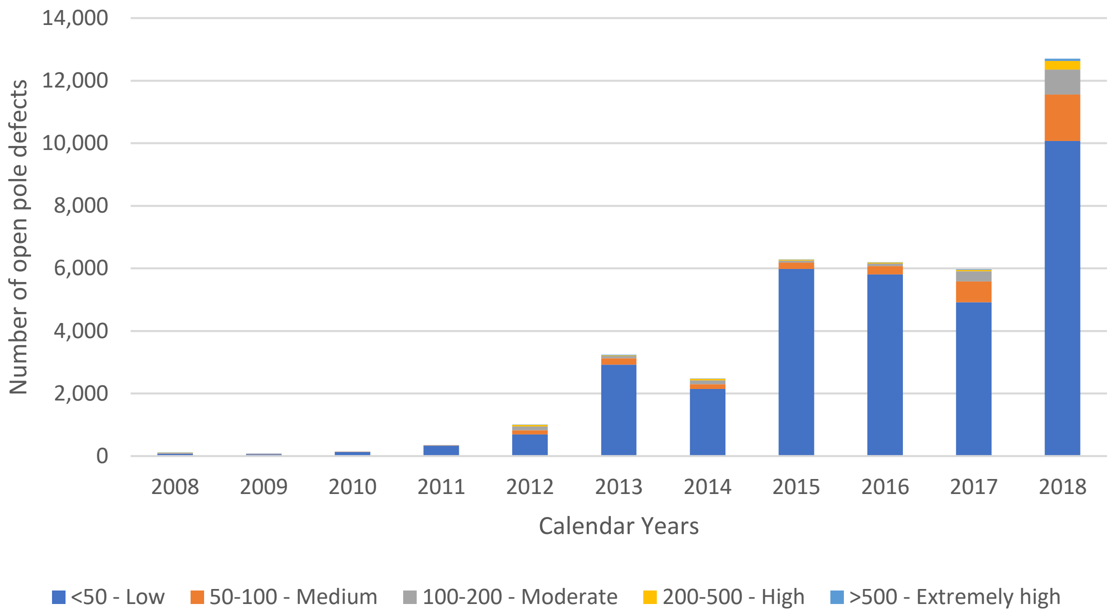
56 Transformers, protections assets, switchgear and poles.

57 The data sample provided did not include defects that were closed/rectified. SA Power Networks, *Response to Information Requestion 039-Q37&Q38-Data*, 31 May 2020, Public.

58 SA Power Networks, *Response to Information Requestion 039-Q37&Q38-Data*, 31 May 2020, Public.

likely to be reflective of SA Power Networks' effective inspection practices which allows it to identify defects early and better prioritise its defects. SA Power Networks itself has acknowledged the effectiveness of its updated inspection practices.

Figure 5.6 – SA Power Networks' prioritisation of open pole defects from 2008 to 2019



SA Power Networks provided us further information about the severity of its poles condition.[59] The data demonstrates that SA Power Networks' poles are categorised as high to medium severity has decreased over-time, as shown in Figure 5.4, meaning that SA Power Networks inspection and asset management practices has allowed it to improve the underlying condition of its pole population, as it reached a steady state of inspection and replacement.

SA Power Networks has not established that there is a deterioration in its asset condition. We have relied on its revealed costs over the 2014–19 regulatory years, of $131 million, as an indicator for SA Power Networks' future needs.

In arriving at our final decision on poles repex, we have had regard to Frontier Economics' analysis that was provided as part of SA Power Networks' revised proposal. Frontier Economics argued that it is not appropriate to use a historical simple average to set the repex allowance as it disregards the age profile of the asset.

We disagree with the Frontier Economics analysis on several grounds:

- We have considered SA Power Networks' asset age profile for five asset groups, as shown in Figure 5.5 above, which covers two of three asset groups, conductors

59 SA Power Networks, *Response to the AER repex analysis*, 20 February 2020, public.

and underground cables that are identified in the Frontier Economics' report. We have complemented the repex modelling analysis with a trend analysis, which compares a distributors forecast to its historical average. We consider that the historical average inherently takes into account of a distributors' asset condition given condition-based replacement volumes is an input in SA Power Networks' replacement decision (as observed in its reliance on the Value and Visibility tool). SA Power Networks' inspection, replacement and maintenance practices have improved, and are likely to keep improving over time, given its proposed and approved Assets and Works program.

- Frontier Economics submitted older assets require more repex. This statement is not consistent with the principles of good asset management practice as it fails to recognise asset condition as the primary indicator or repex. While asset condition is a key driver of the repex required to maintain network services, it is also influenced by factors such as network configuration, network loading, environmental conditions, and operational conditions. In the absence of condition information, age of an asset is only a proxy for its condition (at best).
- Frontier Economics argued that a reduction in the repex forecast will result in more in-situ failures. However, this statement assumes that SA Power Networks' proposed repex is efficient. The rate of in-service failure depends on the design, maintenance practices, inspection practices, replacement practices, and the operating environment of the assets.
- Frontier Economics submitted that every non-redundant asset must eventually be replaced. Therefore, a reduction in the repex forecast shifts out the cost of replacing these assets into future periods. We disagree with this statement. First, it assumes that the cost to replace will remain unchanged relative to the benefit, which does not take into account changes in technology. Secondly, it assumes that deferral is inherently inefficient, as it assumes that assets will be required in perpetuity. It does not take into account economic trends of non-network options or the potential for asset retirement given industry-wide developments such as DER.

Our view is that the Frontier Economics report does not provide well-founded arguments to support a higher than historical repex forecast. Therefore, we have considered SA Power Networks' asset management and inspection practices in forming our view about the efficient and prudent level of poles repex.

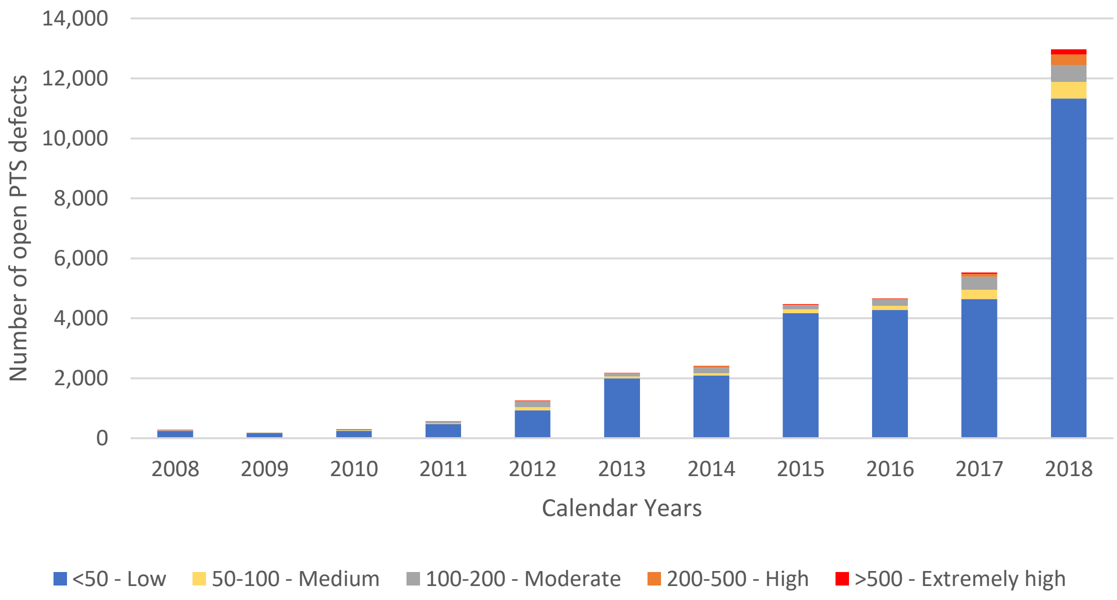
SA Power Networks' pole top structures

SA Power Networks has forecast $137 million for the replacement of its pole top structures assets in its revised proposal. This is $21 million increase from its initial proposal. SA Power Networks' forecast is based on a historical average over all five years in the current period (including the estimate for 2019–20). In its revised proposal, SA Power Networks agreed with the concerns we raised in the draft decision position.

It disagreed with our forecasting approach.[60] Our forecasting approach was to apply the last five years of historical actual spend, and not include any estimates.

We have maintained our draft decision position. Our trend analysis shows a step up of 5 per cent in the forecast period when compared against historical actual spend over five years (not including any estimates). Further, the evidence before us highlights that the increase, which is observed in the 2018–19 year, is unlikely to be sustained into the future. Similar to poles, SA Power Networks has provided us its outstanding defect data, which shows that 90 per cent of its outstanding pole top structures defects are either assigned a low or medium value according to SA Power Networks' own classification. Figure 5.7 demonstrates that despite having more defects, the outstanding defects do not require urgent replacement as the likelihood of failure is low or, if the assets fails, it is unlikely to have a consequential impact on safety or reliability.

Figure 5.7 – SA Power Networks' prioritisation of outstanding Pole Top Structure (PTS) outstanding defects



While we observe that SA Power Networks' actual spend in 2018–19 is unusually high compared to its most recent actuals (58 per cent higher than its four year average as shown in Figure 5.8), consistent with the draft decision, our substitute forecast is based on the most recent five-years of actual spend. This results in a substitute estimate which is 5 per cent below SA Power Networks' revised forecast for pole top structures repex.

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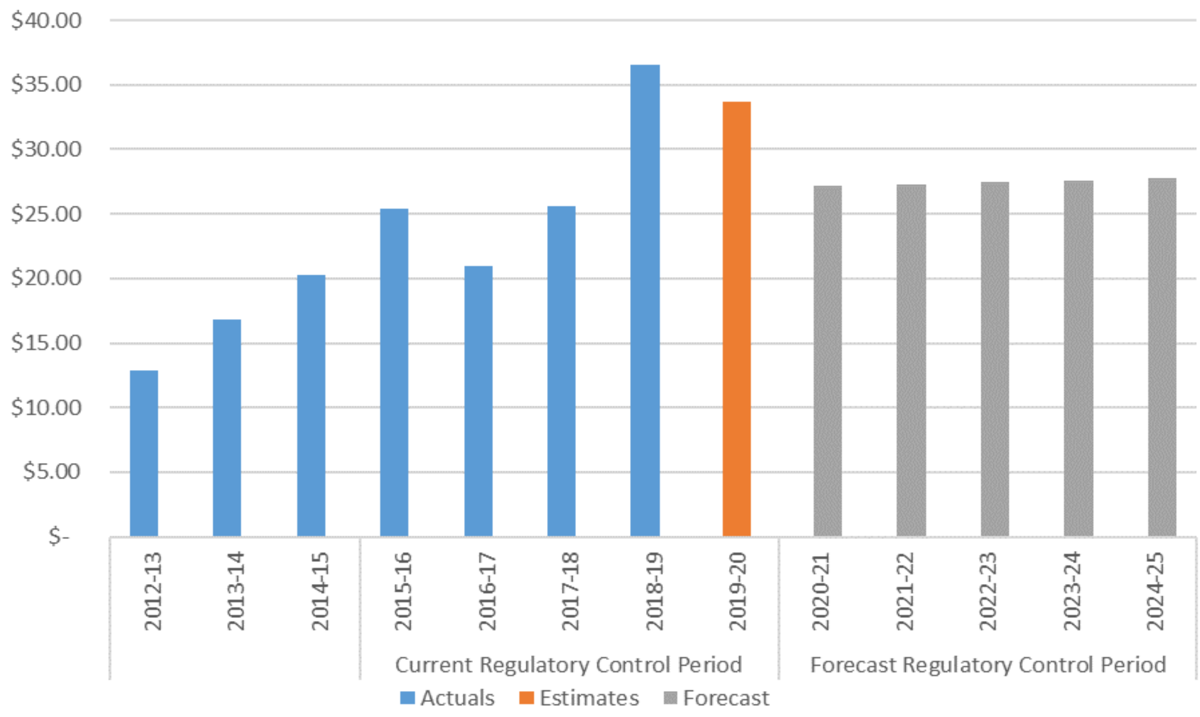
60 SAPN, *Supporting documentation 5.4 – Repex Addendum – 2020–25 Revised Regulatory Proposal*, 10 December 2019, p.25.

Figure 5.8 – Comparison of SA Power Networks' pole top structures forecast compared to its actuals and estimate ($ million, $2019–20)



Northfield Gas Insulated Switchgear replacement

In our draft decision, we did not accept that the Northfield GIS project was prudent and efficient for a number of reasons. Based on the information before us, SA Power Networks has not established that the project is required in the forecast period, particularly the timing of the project.

While SA Power Networks has responded to some of our concerns in its revised proposal, we remain of the view that SA Power Networks has not demonstrated that the replacement of its 66 kV GIS in Northfield of $11.7 million ($2019–20) is required in the 2020–25 period for the following reasons:

- Incomplete cost-benefit analysis – even though SA Power Networks was offered a long-term repair solution, at a significantly lower costs compared to its repex forecast, before SA Power Networks submitted its revised proposal,[61] SA Power Networks disregarded this cheaper long-term repair option, as it stated that the repair option was invasive, costly and could damage the infrastructure.[62] However, SA Power Networks has not provided evidence to substantiate this general statement.

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[61] SA Power Networks, *Response Information Request 82 – Northfield 66kV GIS Gas Leak Repair Works*, 8 January 2020, p. 5.

[62] SA Power Networks, *Supporting document 5.4 – Repex Addendum*, 10 December 2019, p. 29.

- Insufficient option analysis – SA Power Networks did not consider alternative options other than the replacement of the GIS. For example, SA Power Networks has not considered other options, particularly non-replacement options. Based on the evidence, the entire GIS unit is not suffering from any other signs of pre-mature failure. The only evidence is that there were three gas leaks in 3 flanges over three years. GHD, SA Power Networks' consultant, advised that a complete replacement would need to occur when the system experiences 5 to 6 leaks per annum. [63]
- Overstated probability of failure – In its probability of failure modelling, SA Power Networks assumed that the mean age of failure to be equal to the equipment design life.[64] Over a large normally distributed population of this equipment type, the majority of the units should operate without failure for its design life. The assumption that the design life is the same as the mean age of failure overstates the likely probability of failure for this unit in its 'do-nothing' option.
- Overstated consequence of failure – SA Power Networks noted that once the GIS fails it exposes approximately 16,000 customers without supply at times of high demand for two years.[65] The most likely failure scenario is the failure of one or at most two outgoing feeder sections, which could be controlled with adequate pre-planning of a contingency. Furthermore, SA Power Networks' consultant, GHD, noted that the complete failure of GIS is extremely rare.[66]

Based on the information before us, SA Power Networks did not establish that its revised proposed Northfield GIS replacement project is required over the forecast RCP, meaning it is not prudent. As such, we have not included this project as part of SA Power Networks' capex substitute estimate.

North Terrace cable ducts replacement

In its revised proposal, SA Power Networks included approximately $10 million ($2019–20) for its North Terrace cable ducts replacement as a subset of overall CBD ducts and manholes program. SA Power Networks submitted that the program is to address the low availability of spare cable ducts on North Terrace in the CBD.[67] SA Power Networks noted that there is a cost-saving benefit in bringing the works forward.[68]

In our draft decision, we did not consider this program to be prudent and efficient. We did not include it in our substitute estimate for a number of reasons, in particular that

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63 GHD recommended that the SA Power Networks should undertake a complete replacement when the trend in leaks is five to six gas leaks per annum. SA Power Networks, *Northfield 66kV GIS Replacement Business case*, 10 December 2019.

64 SA Power Networks, *response to IR055 - Q1 - GHD - Northfield 66kV GIS condition assessment - final report*, 26 June 2019.

65 SA Power Networks, *Supporting document 5.4 – Repex Addendum*, 10 December 2019, p. 28.

66 SA Power Networks, *response to IR055 - Q1 - GHD - Northfield 66kV GIS condition assessment - final report*, 26 June 2019, p.51.

67 SA Power Networks, *Supporting document 5.4 – Repex Addendum*, 10 December 2019, p. 27.

68 SA Power Networks, *Information Request 82A – Repex*, 8 January 2020 p. 5.

SA Power Networks had not undertaken any cost benefit analysis to justify the proposed program.

In its revised proposal, SA Power Networks provided a business case and cost benefit analysis to support this program. SA Power Networks confirmed that this project was not requested, nor approved in the 2015–20 regulatory control period, which was one of our draft decision concerns. While we are satisfied that this project is not a re-proposed deferral, however, we remain concerned about the prudency and efficiency of this replacement program, and maintain our draft decision position to not include this project as part of our substitute estimate. In particular, we note that:

- SA Power Networks' costing of its options appears biased towards its preferred replacement option. SA Power Networks' 'do nothing' business as usual option completes the works reactively. The expenditure for this option is 200 per cent higher than its historical expenditure on CBD ducts and manholes over the 2015–20 regulatory control period.[69] This makes SA Power Networks' preferred option, which would include constructing the parallel duct network prior to a potential third-party works, seemingly more attractive.
- in its preferred option, SA Power Networks overstates the probability of cable failure and its escalation over time, thus overstating the need to undertake this project in the forecast period.
- there is insufficient evidence to support the prudent timing of this project, particularly the assumed cost saving in bringing the works forward. We requested evidence to demonstrate that there is a clear indication of timing and the associated benefit in bringing the duct replacement forward. However, correspondence indicated that there continues to be uncertainty about the timing, which results in an uncertainty about the potential cost savings.[70] Given this uncertainty, we consider that SA Power Networks has not established that the prudent timing of this project.

Based on the above, we have not included an allowance for the North Terrace duct replacement program as part of CBD ducts and manholes expenditure in our substitute estimate. Our substitute estimate for this category of expenditure in total is in-line with SA Power Networks' revealed costs for the ducts and manhole replacements over the 2015–20 period. We consider that our substitute estimate is sufficient to meet the ongoing efficient costs of completing unplanned and urgent duct replacement works, in line with its SA Power Networks' business as usual practice.

While we consider certain projects, such as the North Terrace duct replacement, in determining our substitute estimate, we do not determine which programs or projects a

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69 AER analysis of SA Power Networks, *Response to information request #082 - Confidential*, January 2020, and SA Power Networks, *5.7.1 – North Terrace Cable Ducts Replacement model, December 2019 – Confidential*, December 2019.

70 SA Power Networks, *Response to Information Request #088 - Repex ducts - follow-up question,* 30 January 2020.

distributor should or should not undertake. Once we set a forecast, it is up to SA Power Networks, to prioritise its capex program within the total capex forecast given its circumstance, which are subject to change, over the course of the regulatory control period.

A.3 Information and Communications Technology (ICT)

Information and communications technology refers to all devices, applications and systems that support business operation. Expenditure for ICT is categorised broadly as either replacement of existing infrastructure (for reasons due to end of life, technical obsolescence, or added capability of the new system) or the acquisition of new assets for a business need.

A.3.1 Final decision

SA Power Networks has established that its ICT forecast of $279.4 million would form part of a total capex forecast that reasonably reflects the capex criteria. We have included these amounts in our substitute estimate of total capex.[71]

A.3.2 SA Power Networks' revised proposal

SA Power Networks initial proposal included $284.6 million for its ICT capex, of which $149 million is for recurrent expenditure and $135.5 million for non-recurrent expenditure. In our draft decision, we accepted SA Power Networks recurrent expenditure, but did not accept its non-recurrent expenditure, which comprised eight programs. Our bottom up review concluded that SA Power Networks had not justified that four of these programs were prudent and efficient. Our draft decision included expenditure of $53.8 million for the remaining four programs.

SA Power Networks' revised non-recurrent forecast is $131.8 million. In its revised proposal, SA Power Networks adjusted its forecast as follows:

- removed the Worker Safety program ($5.8 million);
- scaled down its Assets and Work program (from $56.5 million to $44.9 million);
- re-proposed all other programs; and
- proposed a new cyber security program, the Utilities Cyber Maturity Uplift ($5.6 million).

A.3.3 Reasons for final position

SA Power Networks has demonstrated that its Assets and Works program is Net Present Value (NPV) positive, that upgrading its SAP software over the coming RCP is

[71] A breakdown of the ICT capex forecast is found in the AER final decision capex model in the IT Capex $June2020 tab. See, AER, *SA Power Networks 2020–25 - Final Decision - Capex model*, May 2020. The numbers may differ due to modelling adjustments, such as real cost escalations and CPI adjustment.

least cost, and that the Ring Fencing compliance ICT program is NPV positive for regulated consumers. We also consider that the new Utilities Cyber Maturity Uplift is a prudent and efficient response to emerging cyber security threats.

However, SA Power Networks has not demonstrated that its revised repex forecast has sufficiently incorporated the repex deferrals it expects to achieve through its Assets and Work program. In forming our substitute estimate for repex, we have taken these deferrals into consideration.

Stakeholders were broadly supportive of the Assets and Works program, given the repex deferrals benefits it includes. However, some questioned the robustness of its assumptions and the compatibility between its claimed benefits and the claimed consequences of an ageing network. Regarding the SAP Upgrade, some stakeholders remained concerned that SA Power Networks had not quantified all benefits from upgrading, but appreciated that SA Power Networks has now explored alternative options. Concerns remain about the Ring Fencing Compliance project, including that SA Power Networks should have complied over the current period (2015–20).[72]

Below we discuss the reasons for our decision based on further review of each business case proposed.

Assets and Work

This program invests in ICT systems to improve the way SA Power Networks manages the allocation of its repex tasks, allowing it to better prioritise work on the basis of risk and cost. This will allow it to keep risk at a given target while spending less on repex than would otherwise be necessary. In this way, repex tasks are deferred. The program also forecasts benefits from 'bundling' repex tasks together and other ICT efficiency benefits.

Our draft decision found that SA Power Networks had not justified the efficiency of this program, on the basis that:

- SA Power Networks did not account for the eventual cost of deferred repex work, and we found that deferral length would need to be unrealistically long (39 years) for the program to be NPV positive based on SA Power Networks' other assumptions; and
- the forecast level of repex deferrals depended too heavily on the judgement of subject matter experts to determine the level of repex deferrals, without empirical validation.

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[72] Dynamic Analysis, *Technical Report on SA Power Networks Revised Proposal*, January 2020 pp. 11-12; South Australian Government, *Submission to the AER on the SA Power Networks' Revised Regulatory Proposal 2020–25*, January 2020 pp. 2-3; Origin Energy Retail, *Submission Letter*, January 2020, p.2; Energy Project, *What's Fair? An Equity Perspective*, January 2020, p.45; SA Power Networks Consumer Consultative Panel, *Response to SA Power Networks' Revised Proposal to the AER*, January 2020 p.8; CCP 14, *Advice to the AER on the SA Power Networks' Regulatory Determination 2020–25 Revised Proposal*, February 2020, pp. 25-26; SACOSS, *Submission to the AER on SA Power Networks' 2020–25 Revised Regulatory Proposal*, January 2020, p.10.

It was also not evident that SA Power Networks had accounted for these deferrals in its repex forecast.

We accept SA Power Networks' revised Assets and Work program, based on the further information it has provided. However, we remain unsatisfied that SA Power Networks has factored the repex deferrals it forecasts into its repex forecast.

SA Power Networks submitted a scaled-down program, of $44.9 million and a revised business case in response to our concerns with its NPV analysis. It accepted the need to account for the eventual cost of deferred repex work and provided validation of its method for estimating improvements in its key 'Work Selection Effectiveness' metric. By extending its forecast over an additional five years, correcting errors in its previous deferral forecasts, and valuing benefits due to 'bundling', SA Power Networks has established that the revised program is likely NPV positive.

However, SA Power Networks has not demonstrated that its repex forecast accounts for the deferrals it forecasts. The Assets and Work program comprises two stages. Stage 1 involves improving the way SA Power Networks estimates risk, and is expected to defer $142 million ($2017) over 2020–25, regardless of whether stage 2 goes ahead. The new capex proposed is for stage 2, which is now forecast to defer between $52.7 million and $58.5 million ($2019–20) over 2020–25.[73] Our draft decision identified that all these deferrals need to be accounted for.

In response, SA Power Networks adopted a new method for forecasting repex. It argued that, in the absence of Assets and Work stage 2, repex for poles and other high volume assets would increase in line with an upwards 'historical trend'.[74] If Assets and Work stage 2 does go ahead, SA Power Networks maintained its original forecast for high volume assets, which uses a 'historical average' method and CBRM for poles. The revised proposal argues that the difference between these two forecasts is the effect of deferrals as a result of Assets and Work stage 2.

We do not consider that the 'historical trend' method reflects a reasonable forecast of prudent and efficient costs in the absence of Assets and Workstage 2. SA Power Networks adopts this method because it considers that repex costs will continue to rise as result of its ageing network, if stage 2 does not go ahead. But this fails to consider that SA Power Networks expects to achieve $142 million in deferrals over 2020–25 as a result of work already done under stage 1 alone. It also fails to consider the actual condition of its assets in determining the upward the trend. SA Power Networks

[73] SA Power Networks, *Repex Addendum*, December 2019, p. 14,identifies both these forecasts, stating that the repex forecast was reduced by $58.5 million to account for deferrals, and deferrals themselves were estimated at $52.7 million based on the difference between a 'historical trend' and a 'historical average' method for high volume assets.

[74] SA Power Networks, *Repex Addendum*, December 2019, p. 12; SA Power Networks, *Assets and Work Program Business Case Addendum*, December 2019, p. 37.

provided a graph identifying a repex forecast without both stage 1 and stage 2 deferrals, but did not explain how this forecast was produced.[75]

Stakeholders such as SACOSS and the CCP14 questioned the historical trend approach. In particular, SACOSS submitted that the historical trend approach is likely to overstate the repex requirements.[76]

Based on the evidence before us, we have accepted the Asset and Works program, subject to an adjustment to the repex forecast. We are satisfied that our substitute repex forecast, together with the Assets and Work program, provide SA Power Networks sufficient capex to maintain the safety, quality, reliability and security of its assets and the supply of its service.

SAP S4 Upgrade

SA Power Networks forecasts $26.9 million to upgrade its Enterprise Resource Planning software, SAP, to the latest version (S4). SA Power Networks' current version will become unsupported in 2025.

Our draft decision did not include this program, as SA Power Networks' options analysis did not consider the alternative of retaining its existing version of SAP under a third party support model.

The revised business case provided detailed consideration to adopting third party support to delay upgrading.[77] This analysis establishes that commencing an upgrade over 2020–25 is least cost, and that retaining third party support indefinitely would not be feasible. The considerations involved are specific to SA Power Networks' use of SAP and its licensing arrangements.

However, we note our concern that SA Power Networks and Enerven share use of SAP, but that no costs for this project have been allocated to Enerven. It would be consistent with the Cost Allocation Guidelines and SA Power Networks' Cost Allocation Method (CAM) if these costs were allocated between the entities according to an appropriate allocator (e.g. SAP licenses).[78] However, these costs alone are not significant enough to warrant a reduction to SA Power Networks' overall ICT forecast.

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75 After receiving the Revised Proposal we asked SA Power Networks to explain how the forecast excluding stage 1 deferrals had been accounted for, and SA Power Networks referred to this graph without substantiating the forecast itself. SA Power Networks, *Response to information request 080*, 3 January 2020, p. 6.

76 CCP 14, *Advice to the AER on the SA Power Networks' Regulatory Determination 2020–25 Revised Proposal*, February 2020, pp. 25-26; SACOSS, *Submission to the AER on SA Power Networks' 2020–25 Revised Regulatory Proposal*, January 2020, p.10.

77 SA Power Networks, *SAP Business Case Addendum*, December 2019.

78 AER, *Distribution Cost Allocation Guidelines,* June 2008; SA Power Networks, *Cost Allocation Method 2018,* January 2018.

Ring Fencing Compliance

SA Power Networks proposed $3.8 million to ensure its related entity Enerven did not have access to material in breach of Ring Fencing obligations.

Our draft decision did not include this program, since SA Power Networks did not consider the alternative of complying by completely excluding Enerven from its shared ICT systems.

In its revised business case, SA Power Networks quantified the revenue that Enerven contributes to SA Power Networks for use of its shared systems that would be forgone if it were excluded from them.[79] This established that SA Power Networks' preferred ICT capex based solution is lower cost to regulated customers in NPV terms than excluding Enerven from its system entirely.

Utilities Cyber Maturity Uplift

SA Power Networks proposed a new program of $5.6 million in response to emerging cyber security industry standards.[80] We consider that this a reasonable forecast of efficient costs in relation to the improvement in capability and risk reduction it would provide. SA Power Networks has demonstrated that this program reasonably reflects the capex criteria. However, since these standards are yet to become a regulatory obligation we have not included the associated proposed opex step change. This is consistent with the different method the NER prescribe to assess opex.[81]

Deliverability Considerations

Our draft decision also identified concerns with the deliverability of overall ICT capex proposed by SA Power Networks. Energy Market Consulting associates (EMCa) was concerned at the lack of contingency time included in the forecast, as it appeared that programs were forecast for back-to-back delivery.[82]

SA Power Networks responded by providing more detailed work planning schedules that did show contingency time had been accounted for.[83] This included a KPMG report endorsing SA Power Networks' capacity to deliver the portfolio of projects proposed.[84]

The $279.4 million SA Power Networks forecasts for ICT capex is also now broadly consistent with the actual portfolio of work SA Power Networks has delivered over the

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79 SA Power Networks, *Ring-fencing Compliance IT Solution Business Case Addendum*, December 2019.

80 SA Power Networks, *Revised Proposal – Attachment 5 – Capital Expenditure*, p. 69.

81 AER, *SA Power Networks 2020–25 - Final Decision - Attachment 6 - Operating Expenditure*, April 2020, p. 29.

82 Energy Market Consultants Associates, Review of aspects of SA Power Networks' capital expenditure, September 2019, pp. 28-31.

83 SA Power Networks, *IT Investment Plan Addendum*, December 2019, pp. 28-32; p.40.

84 KPMG, *Independent Review of the Deliverability of SA Power Networks' Regulatory Resubmission for IT Expenditure*, December 2019.

previous five years for which we have actuals, incorporating new data ($283.3 million).[85]

For these reasons, we do not consider there is a need to adjust SA Power Networks' revised ICT capex forecast to allow for delays in delivery.

A.4 DER management capex

Distributed energy resources (DER) commonly refer to solar photovoltaic (PV), storage, electric vehicles, and other consumer appliances that are capable of responding to demand or pricing signals. Increasing DER penetration represents a change in the way that consumers interact with electricity networks and the demands that it places on networks. DER management expenditure is the expenditure which seeks to manage the growing effects of higher penetration of DER on the network, in particular the effects of solar PV and the impact on a distributor's ability to manage voltage within standards.

A.4.1 Final decision

We are satisfied that SA Power Networks' forecast of $82.2 million for those augmentation programs we classified in our draft decision as DER management expenditure,[86] would form part of a total capex forecast that reasonably reflects the capex criteria. We have included the amount in our substitute estimate of total capex.

A.4.2 SA Power Networks' revised proposal

SA Power Networks has revised its DER management expenditure forecast to $82.2 million for the 2020–25 regulatory control period. This represents a 23 per cent decrease relative to its $106.6 million original proposal.

In its revised proposal, SA Power Networks adjusted its forecast as follows:

- It accepted our draft decision for the voltage regulation program, a reduction of $7 million from its initial proposal[87];
- It revised its forecast LV monitoring program from $18 million to $5.2 million which also includes a $1.3 million to its opex proposal; [88] and
- It revised its quality of supply program from $46.3 to $42.2 million.

[85] AER Analysis based on Category Analysis RIN data, 2014-15 - 2018-19, escalated for CPI inflation.

[86] SA Power Networks has included the proposed expenditure within the as a DER category within the augex forecast in its revised proposal. SA Power Networks, *Attachment 5: Capital expenditure – 2020–25 revised regulatory proposal*, December 2019, pp. 44–47.

[87] AER, *Draft Decision - SA Power Networks Distribution Determination 2020–25 - Attachment 5 - Capital Expenditure*, October 2019, p. 29.

[88] SA Power Networks, *Attachment 5: Capital expenditure – 2020–25 revised regulatory proposal*, December 2019, pp. 45–46; SA Power Networks, *Revised Proposal – Supporting document 5.15 – LV transformer monitoring business case*, 10 December 2019, p. 8.

A.4.3 Reasons for final position

For the LV monitoring and the quality of supply programs, SA Power Networks' revised proposal addressed our concerns for those programs, which are discussed in turn below.

LV monitoring

In our draft decision, we did not include SA Power Networks LV transformer monitoring program in our substitute estimate. In response to our draft decision, SA Power Networks has reduced its forecast by 71 percent. It also provided us a more holistic view of its DER Management expenditure, which shows the interrelationships between its LV monitoring project and other DER Management programs.[89] We consider that it has reasonably calculated the benefits, particularly the foregone annual installations of temporary monitors. In coming to our final decision, we have had regard to stakeholder submissions, who expressed support for the revised LV monitoring program, recognising SA Power Networks' work in re-evaluating its proposal.[90] Based on the evidence before us, SA Power Networks has established the prudency and the efficiency of its proposed program, therefore, we have included it in our substitute estimate for capex.

Quality of supply remediation program

Our draft decision noted that SA Power Networks has not justified the full forecast expenditure for this program, particularly the scope of the program and the changes that the Tariff Structure Statements as well as its 'enforcement' of the AS4777 standards will have on this program. We, including our consultant EMCa, noted that SA Power Networks has not identified any interrelationship between the LV monitoring program and the quality of supply program.[91]

In response to our draft decision, SA Power Networks re-evaluated the program's scope of work and revised its forecast. SA Power Networks relied on additional years of historical data to determine the scope of the program. In addition, SA Power Networks also incorporated the benefits from the LV transformer monitoring program,

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[89] SA Power Networks, *Revised Proposal - Supporting document 5.14 - DER management expenditure overview*, December 2019.

[90] CCP14, *Advice to the AER on the SA Power Networks' regulatory determination 2020–25*, February 2020, p. 23; Total Environment Centre, *Submission on SA Power Networks draft decision*, January 2020, p. 1; AGL, *Submission on SA Power Networks draft decision 2020–25*, January 2020, p. 4; Business SA, *Response to the AER's draft decision on SA Power Networks 2020–25 revenue determination*, January 2020, p. 6; Clean Energy Council, *Clean Energy Council submission to the SA Power Networks 2020–2025 regulatory proposal*, January 2020, p. 2; South Australian Government, *Submission on the SA Power Networks revised regulatory proposal for 2020–25*, January 2020, p. 1; SAFCA, Uniting Communities and the Energy project, *Joint submission on SA Power Networks draft decision 2020–25*, January 2020, p. 41; SA Power Networks Consumer Consultative Panel, *Response of the SAPN Customer Consultative Panel to SA Power Networks' Revised Proposal to the AER*, December 2019, p. 9.

[91] Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, p. 78.

which it expects from 2023–24.[92] Based on the additional analysis, we are satisfied that SA Power Networks' revised forecast is reasonable, having addressed concerns we raised in our draft decision.[93] We note that SA Power Networks forecasts efficiency improvements resulting from the quality of supply program will be realised in the 2025–30 regulatory control period.[94]

A.5 Augmentation expenditure

Augmentation is typically triggered by the need to build or upgrade the network to address changes in demand and network utilisation. However, it can also be triggered by the need to upgrade the network to comply with quality, safety, reliability and security of supply requirements.

A.5.1 Final decision

Of SA Power Networks' $315.8 million revised augex forecast, we have assessed $233.5 million as part of standard augex.[95] SA Power Networks has not demonstrated that its forecast augex of $233.5 million is prudent and efficient. We have instead included a substitute estimate of $217.7 million for augex, which is 7 per cent lower than SA Power Networks' augex forecast. We are satisfied that this amount reasonably reflects the capex criteria.

A.5.2 SA Power Networks' proposal

SA Power Networks revised its augex forecast to $233.5 million for the 2020–25 regulatory control period. This represents a 12 per cent decrease relative to its initial augex proposal.

In its revised proposal, SA Power Networks adjusted its augex forecast as follows:

- It accepted our draft decision for the Athol Park - Woodville 66 kV line, maintaining underlying reliability, SCADA to substations, substation security and fencing and its CBD 33 kV to 11 kV conversion programs;
- It revised its forecast for the Myponga - Square Water Hole 66 kV line and its protection compliance programs; and
- It maintained its forecast for two reliability programs, namely the low reliability feeders program and hardening the network.

92 SA Power Networks, *Attachment 5: Capital expenditure – 2020–25 revised regulatory proposal*, December 2019, p. 46.

93 AER, *Attachment 5: Capital expenditure – Draft decision – SA Power Networks 2020–25*, October 2019, p 5–27–28.

94 SA Power Networks, *Revised Proposal – Supporting document 5.35 – Low voltage & quality of supply remediation capital expenditure (augex) forecast*, December 2019, pp. 6–7.

95 We have classified the remaining $82.2 million as DER management expenditure, consistent with our Draft Decision.

A.5.3 Reasons for final position

We have included in our substitute estimate all of SA Power Networks' revised augex proposal, with the exception of the Hardening the Network reliability program. We discuss separately SA Power Networks’ proposed reliability programs and the other augmentation projects that we reviewed.

Reliability programs

SA Power Networks reproposed the Low Reliability Feeders and Hardening the Network programs that we did not include in our draft decision.[96] It acknowledges that it is not required under the NER to undertake these two programs, but undertook further consultation with stakeholders and has reproposed the programs based on customer support.[97] A key part of our review has been assessing customer support through stakeholder submissions. On balance, there is more support for the low reliability feeders program:

- There was clear support for both reliability programs from Business SA, six district councils and one other organisation.[98] A further two councils and three other organisations including SA Power Networks’ Consumer Consultative Panel indicated support for the Low Reliability Feeders program only.[99]
- The South Australian Government and SACOSS did not support the programs, noting that ESCoSA had already made its determination on reliability.[100] Other submissions including CCP14 noted that the proposed reliability augex was an

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96 The Low reliability feeders program is aimed at improving reliability for customers on its worst performing feeders. The Hardening the Network program is aimed at improving reliability in locations that are consistently affected by Major Event Days. SA Power Networks has little or no incentive to improve reliability in the specific areas under the Service Target Performance Incentive Scheme.

97 SA Power Networks, Attachment 5: Capital expenditure – 2020–25 revised regulatory proposal, December 2019, pp. 51–53.

98 Business SA, *Response to the AER's draft decision on SA Power Networks 2020–25 revenue determination*, January 2020, p. 6; Port Pirie Council, *Submission on SA Power Networks draft decision 2020–25*, December 2019, p. 1; District Council of Tumby Bay, *Submission on SA Power Networks draft decision 2020–25*, January 2020, p. 1; Yorke Peninsula Council, *Submission on SA Power Networks draft decision 2020–25*, January 2020, p. 1; Tatiara Council, *Submission on SA Power Networks draft decision 2020–25*, January 2020, pp. 1–2; Regional Council of Goyder, *Submission on SA Power Networks draft decision 2020–25*, December 2019, p. 1; Lower Eyre Peninsula Council, *Submission on SA Power Networks draft decision 2020–25*, January 2020, p. 1; Regional Development Australia Far North, *Submission on SA Power Networks draft decision 2020–25*, December 2019, p. 1.

99 SA Power Networks Consumer Consultative Panel, *Response of the SAPN Customer Consultative Panel to SA Power Networks' Revised Proposal to the AER*, December 2019, pp. 9–10; SAFCA, Uniting Communities and the Energy project, *Joint submission on SA Power Networks draft decision 2020–25,* January 2020, pp. 43–44; Energy and Water Ombudsman SA, *Submission on SA Power Networks draft decision 2020–25*, January 2020, p. 2; City of Victor Harbor, *Submission on SA Power Networks draft decision 2020–25*, January 2020, p. 1; Adelaide Plains Council, *Submission on SA Power Networks draft decision 2020–25*, January 2020, p. 1.

100 South Australian Government, *Submission on the SA Power Networks revised regulatory proposal for 2020–25*, January 2020, p. 2; South Australian Council of Social Service, *Submission to the AER on SA Power Networks’ 2020–25 Revised Regulatory Proposal*, January 2020, pp. 39–41.

increase on historical expenditure,[101] or otherwise suggested we review the reliability programs in detail.[102]

SA Power Networks provided some evidence that the works proposed through the programs would address recurrent rather than one-off outages.[103] We recognise that outages appear to have been recurrent on these feeders. However the accompanying model for the Hardening the Network program does not provide a sufficient amount of detail to ascertain whether many of the historical outages are occurring recurrently in the same location.[104] We therefore consider the benefits of the Hardening the Network program appear overstated.

We also compared SA Power Networks' reliability forecast with its historical expenditure. A reliability augex program that includes the proposed low reliability feeders program and capex to maintain reliability is comparable with reliability augex in the 2015–20 regulatory control period.[105] We are satisfied with this level of expenditure as SA Power Networks has revealed that it will spend this amount with incentives in place. We have included the low reliability feeders program in our substitute forecast.

Other augmentation projects

SA Power Networks' revised proposal addressed our concerns for the following augmentation projects, which we have included in our substitute forecast:

- **Myponga – Square Water Hole 66kV line** - SA Power Networks explained that its revised sensitivity analysis reflects a conscious effort to use the most conservative option for each relevant parameter.[106] We are satisfied that the proposed Myponga – Square Water Hole 66kV line will achieve a positive net market benefit across a range of scenarios. We had particular regard to the revised load factor assumptions and figures adopted to measure value of customer reliability (VCR).
- **Rural feeder protection[107]** - SA Power Networks has responded to our draft decision by providing evidence of historical back-up protection failures, and

[101] CCP14, *Advice to the AER on the SA Power Networks' regulatory determination 2020–25*, February 2020, pp. 23–24; Origin Energy, *Submission on the SA Power Networks revised regulatory proposal for 2020–25*, January 2020, p. 2.

[102] Council of Streaky Bay *Submission on SA Power Networks draft decision 2020–25*, December 2019, pp. 1–2; Town of Gawler, *SA Power Networks 2020–25 revised proposal – reliability expenditure - response from the Town of Gawler*, January 2020, p. 1.

[103] SA Power Networks, *Revised Proposal – Supporting document 5.17 – 2020–2025 reliability & resilience programs, - hardening the network*, December 2019, pp. 53–63.

[104] SA Power Networks, *Revised Proposal – Supporting document 5.17.1 – Hardening the network regulatory model*, December 2019.

[105] SA Power Networks expects to incur $53.2 million on reliability capex in the 2015–20 regulatory control period. The Low Reliability Feeders in addition to capex to maintain reliability is $47.6 million. SA Power Networks, *Attachment 5: Capital expenditure – 2020–25 regulatory proposal*, January 2019, p. 68; SA Power Networks, *Attachment 5: Capital expenditure – 2020–25 revised regulatory proposal*, December 2019, p. 55.

[106] SA Power Networks, *Revised Proposal – Supporting document 5.10 – Myponga to Square Waterhole business case*, December 2019, p. 4.

[107] This program was referred to in the draft decision as Protection Compliance.

modelling that assesses the merit of installing reclosers or fuses on each relevant feeder. We found that it has reasonably calculated the impact the proposed solutions would have on reducing risks associated with safety, transformer damage, and bushfire starts.[108] We are satisfied that it would be prudent for SA Power Networks to continue its existing program to address protection issues.

A.6 Customer connections

Connections capex is expenditure incurred to connect new customers to the network and, where necessary, augment the shared network to ensure there is sufficient capacity to meet the new customer demand.

A.6.1 Final decision

SA Power Networks has established that its gross connections forecast of $611.1 million would form part of a total capex forecast that reasonably reflects the capex criteria.[109] We are also satisfied that its capital contributions forecast is prudent and efficient.

A.6.2 SA Power Networks' revised proposal

SA Power Networks has revised its net connections capex forecast to $280.1 million for the 2020–25 regulatory control period. This represents a 39 per cent increase relative to its initial proposal. The increase is due to an increase in forecast gross connections and a decrease in forecast customer contributions. SA Power Networks' revised proposal includes a contributions forecast of $333.1 million,[110] which is a below our draft decision and SA Power Networks' initial proposal. SA Power Networks has noted that the capital contribution reduction is driven by an adjustment to the WACC, which increases the customer’s incremental revenue rebate and lowers the total forecast customer contributions.[111]

A.6.3 Reasons for final position

A number of stakeholders supported further review into the revised forecast, recognising the proposal was an increase over historical expenditure.[112] Based on our

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108 SA Power Networks, *Revised Proposal – Supporting document 5.19 – Rural Feeder Protection business case*, December 2019, pp. 10–13.

109 This includes 'other contributions' of $37.8 million for recoverable works and contributions towards embedded generation assets. SA Power Networks, *Attachment 5: Capital expenditure – 2020–25 revised regulatory proposal*, December 2019, p. 64.

110 The customer contributions relate to connections capex only.

111 SA Power Networks, *Attachment 5: Capital expenditure – 2020–25 revised regulatory proposal*, December 2019, p. 60.

112 South Australian Council of Social Service, *Submission to the AER on SA Power Networks’ 2020–25 Revised Regulatory Proposal*, January 2020, pp. 23–38; AGL *Submission on SA Power Networks draft decision 2020–25*, January 2020, p. 3; CCP14 *Advice to the AER on the SA Power Networks' regulatory determination 2020–25*, February 2020, p. 24; Dynamic Analysis, *Technical Report on SA Power Networks Revised Proposal*, January

concerns in the draft decision,[113] we have focused our review on the proposed expenditure on major connections. We reviewed a sample of major projects in SA Power Networks and BIS Oxford Economics' (BIS) major project list that forms the bottom-up forecast,[114] and found:

- SA Power Networks and BIS' list of projects, construction timeframes and estimated project values align with independent sources of information we have obtained as a cross-check.
- on balance, projects forecasted to be undertaken in the forecast period are reasonably likely to have more complex connection arrangements. For example, relative to the 2015–20 regulatory control period, a greater number developments are forecast to be constructed in areas outside the existing network and would therefore require feeder extensions, incurring greater connection costs.

SA Power Networks provided additional information on its calculations of forecast customer contributions.[115] We are satisfied that a change in SA Power Networks' current period (2015–20) WACC of 4.3 per cent to 2.6 per cent in the forecast period has a material impact on forecast customer contributions.[116]

A.7 Property capex

The property portfolio for SA Power Networks includes 30 depots, 6 located throughout the Adelaide metropolitan area and 24 located in regional cities and country/rural areas. SA Power Networks also has 9 commercial and 10 industrial properties in the metropolitan area, both owned and leased.

A.7.1 Final decision

Our final decision is to include a substitute estimate for property capex of $46.1 million, a reduction of $4.5 million from SA Power Networks' revised proposal. Our substitute estimate is based on a constant allowance of $9.2 million per year, which is equal to SA Power Networks' average actual property capex of the current regulatory control period (2015–16 to 2018–19) .We consider a total $46.1 million of property capex is sufficient for SA Power Networks to address its needs for the 2020–25 period.

2020, p. 11; South Australian Government, *Submission on the SA Power Networks revised regulatory proposal for 2020–25*, January 2020, p. 2; Origin Energy, *Submission on the SA Power Networks revised regulatory proposal for 2020–25*, January 2020, p. 2; SAFCA, Uniting Communities and the Energy project, *Joint submission on SA Power Networks draft decision 2020–25,* January 2020, pp. 50–61; SA Power Networks Consumer Consultative Panel, *Response of the SAPN Customer Consultative Panel to SA Power Networks' Revised Proposal to the AER*, December 2019, p. 11.

113 AER, *Attachment 5: Capital expenditure – Draft decision – SA Power Networks 2020–25*, October 2019, p 5–41.

114 SA Power Networks, *Revised Proposal – Supporting document 5.12 – BIS Oxford Economics gross customer connections expenditure forecasts to 2025–26*, November 2019, pp. 34–39.

115 SA Power Networks, *Response to Information Request 078*, 23 December 2019.

116 SA Power Networks originally forecast a WACC of 2.6 per cent in its connections model.

A.7.2 SA Power Networks' revised proposal

SA Power Networks' revised proposal of $50.7 million is $10.8 million lower than its initial proposal. SA Power Networks has applied a base-trend methodology to forecast its total revised property capex forecast. SA Power Networks provided a number of business cases, including quantitative models, to support some of its projects. In addition, to support its overall property capex forecast, SA Power Networks provided analysis which shows that over the past 10 years, SA Power Networks has been one has one of the lowest property capex in the NEM on the per customer and per line length basis.[117]

A.7.3 Reasons for final decision

Our draft decision of including no property expenditure as part of our substitute estimate was based on the information before us. In its revised proposal, SA Power Networks has provided a range of business cases for its some of its projects, which is a significant improvement from its initial proposal. Based on this new information, we are comfortable that SA Power Networks has demonstrated a need to upgrade or refurbish some of its existing property portfolio over the forecast regulatory control period. However, the evidence before us does not justify a forecast that is higher than its revealed costs.

In coming to this decision, we undertook an assessment of both SA Power Networks' top-down and bottom-up forecasting methods to support its property forecast, which are discussed in turn below.

Top-down forecasting methodology

SA Power Networks has applied a top-down base-trend methodology, to forecast its revised property capex. It based the first year of the forecast period on the average actual expenditure over the 2015–16 to 2018–19 years. It submitted that the linear trend is necessary to achieve the overall work program in the period.[118] No further information was provided to explain or support the annual increase and no evidence has been provided to explain why its needs are increasing.

As the forecast upward linear trend was unexplained, we requested further evidence that support the timing of its projects. We expect that SA Power Networks should be able to forecast the timing of property works. SA Power Networks submitted that its forecast is largely 'indicative' and that it was unable to provide forecast timing for any works.[119] SA Power Networks also explained that its cost-benefit models are not used to define optimal timing[120] and that the "aim of [the] cost-benefit modelling is to tell

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[117] SA Power Networks, Revised Regulatory Proposal Attachment 5.21 – 2020–25 Property Capex Forecast Regulatory Justification, December 2019, pp. 38-42.

[118] SA Power Networks, Response to AER Information Request 087, 22 January 2020, p. 4.

[119] SA Power Networks, *Response to AER Information Request 087*, 22 January 2020, pp. 4-5.

[120] SA Power Networks, *Response to AER Information Request 087*, 22 January 2020, p. 5.

whether [it] 'notionally' could do the project now or whether it is more beneficial to defer another year."[121]

As various stakeholders have observed,[122] SA Power Networks has a demonstrated a history of re-proposing projects.[123] For example, SA Power Networks has identified that works at Seaford, Angle Park North, Marleston North, Keswick and Clare were originally planned to be undertaken in the current regulatory control period. However, for various reasons each of these projects has been delayed. SA Power Networks has stated that $19.2 million ($2019–20) of its property forecast reflects projects that an allowance was made for the current regulatory control period that it has reproposed.[124] It is unclear why SA Power Networks has not undertaken this work in the current period (2015–20).

In response to an information request, SA Power Networks state, "[t]here are many other factors that guide timing decisions"[125] than the cost-benefit results. Such factors will likely continue to influence expenditure decisions in the forecast regulatory control period, which may lead further deferrals.

Figure 5.9 shows SA Power Networks' actual capex, which has been relatively stable in the current period (2015–20), at an average of $9.2 million per year. It also shows, consistent with stakeholder submissions from South Australian Government[126] and ECA[127] who raised regarding SA Power Networks' ability to deliver these projects, that SA Power Networks has overstated its previous property forecast, which is demonstrated in the underspend relative to its forecast.

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121 SA Power Networks, *Response to AER Information Request 087*, 22 January 2020, p. 5.

122 CC14, *Advice to the AER on the SA Power Networks Regulatory Determination 2020–25 Revised Proposal*, 15 January 2020, p. 19; Energy Consumers Australia, *Submission to the AER re SA Power Networks revised proposal*, 22 January 2020, p. 2.

123 SA Power Networks has underspent its property forecast over the current (2015–20) and previous periods.

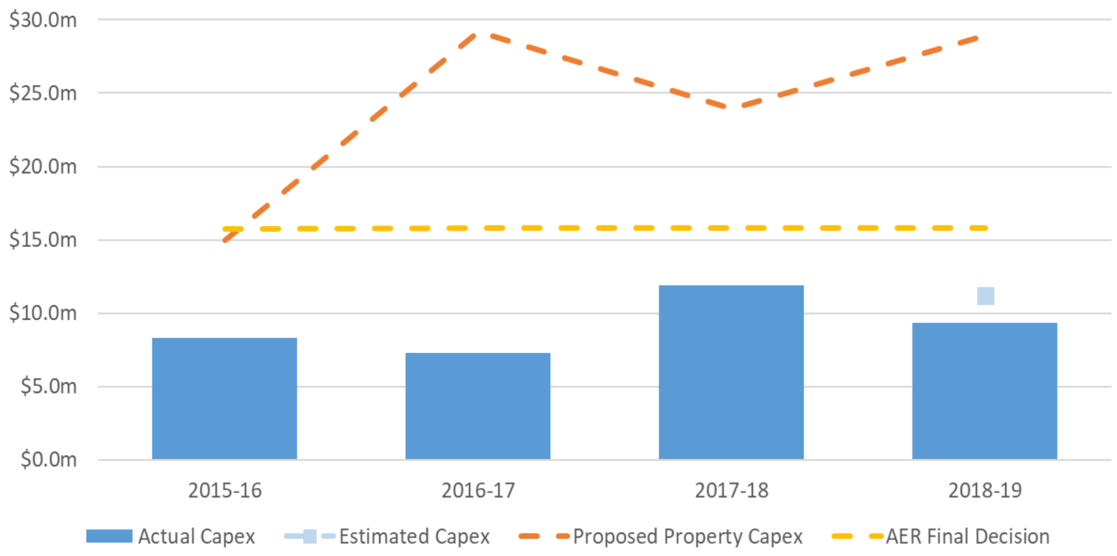
124 SA Power Networks, *Response to AER Information Request 079*, 8 January 2020.

125 SA Power Networks, *Response to AER Information Request 087*, 22 January 2020, p. 5.

126 South Australian Government, *Submission to the AER on the SA Power Networks' Revised Regulatory Proposal 2020–25*, Jan 2020, p. 3.

127 Energy Consumers Australia, *Submission to the AER re SA Power Networks revised proposal*, 22 January 2020, p. 2.

Figure 5.9 - SA Power Networks' property capex for the current regulatory control period ($ million, $2019–20)



Source: SA Power Networks, RIN submissions; AER Analysis.

Given the significant variation between SA Power Networks' forecast property capex and what it actually incurred, we sought to understand whether SA Power Networks' bottom-up forecasting methodology provides sufficient justification to support the top-down forecasting approach.

Bottom-up forecasting methodology

SA Power Networks' revised forecast is allocated approximately equally into two categories, 'major projects' and 'minor projects'. While we consider that making such a distinction between major and minor projects is reflective of its property costs, we do not consider SA Power Networks' definitions to be appropriate. In our view, a clearer defined criteria, such as a defined cost threshold, is preferred over an ambiguous delineation.[128] Nevertheless, we have assessed the projects as proposed.

Major Projects

SA Power Network has provided business cases for its major projects.[129] We have reviewed the business cases for its major projects and consider that SA Power Networks has made significant improvements in justifying its proposed major projects (except for the Keswick project). The business cases now include:

- detailed sections explaining the need for each project

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128 For example, it is unclear why the proposed works at the Clare depot has been classified as a major project, while proposed works at Angle Park South, Elizabeth, Marleston South, PT Augusta and Yorketown sites are not, even though these works are greater in forecast value than the Clare depot.

- consideration of alternative options including remediation and ‘do-nothing’ options
- cost benefit analysis of each option to determine the most economically efficient outcome. [130]

While we have some concerns about the reasonableness of some of the risk-cost assumptions, we consider them to be immaterial in the context of this aspect of the forecast.

Minor Projects

Our draft decision stated that, prima facie, the minor projects forecast was not substantiated.[131] Given that SA Power Networks has only provided brief descriptions of the minor projects, we therefore remain of this view.

The cost and descriptions of some of the items lend themselves to further review. It is likely that when SA Power Networks undertakes its annual budgeting process, which includes business case assessment, then it may identify projects that its minor projects do not represent economic investments.

We generally review SA Power Networks’ historical expenditure for minor projects to test the reasonableness of the forecast. However, SA Power Networks did not provide such data when we requested.[132] Therefore, SA Power Networks has not demonstrated that the minor works forecast is likely to be reasonable. Based on our assessment of the material provided, SA Power Networks did not provide a bottom-up build for approximately half of its total property forecast. We have not attempted to build our own bottom-up forecast to form our substitute estimate. However, we have instead formed our view on a level of property capex we consider is prudent and efficient, which is consistent with its historical expenditure.

A.8 Fleet capex

Fleet capex covers expenditure for purchasing new vehicles and related items, including mounted plant. Fleet incorporates light fleet (passenger and light commercial vehicles) and heavy fleet. Heavy fleet typically comprises elevated work platforms (EWPs), crane borers and other heavy commercial vehicles.

130 In some cases SA Power Networks has undertaken cost-benefit analysis over different components of the total scope of proposed works, rather than undertaking the analysis at an overall level. For example, SA Power Networks has separately considered the cost and benefits of replacing the pavements at a site as opposed to the replacement of buildings.

131 AER, SA Power Networks 2020–25 - Draft Decision – Attachment 5 – Capital expenditure, October 2019, pp. 5-82-83.

132 AER, *Response Information Request 087 - Property capex*, 22 January 2020.

A.8.1 Final decision

We are satisfied that SA Power Networks' fleet capex of $97.3 million would form part of a total capex forecast that reasonably reflects the capex criteria. We have included these amounts in our substitute estimate of total capex

A.8.2 SA Power Networks' revised proposal

Our draft decision noted that SA Power Networks did not establish its forecast was efficient costs, based on our investigations of efficient service lives, unit rates and accounting for the proportion of Standard Control Services (SCS) use. After adjusting to our concerns, our substitute estimate was $79.9 million, which was 36.7 million lower than its initial proposal.

In its revised proposal, SA Power Networks has revised its forecast to be 97.3 million, which is $19.3 million below its initial proposal. SA Power Networks adjusted its fleet capex forecast compared to our substitute as follows:

- retaining a ten year service life for 14 metre tall EWPs, where our substitute used 15 years.
- reversing the change we had made to account for SCS usage.
- adjusting unit rates to apply based on vehicle classifications, rather than make and model.
- reversing the change we had made to account for private use of senior staff vehicles.

A.8.3 Reasons for final position

In its revised fleet proposal, SA Power Networks accepted many of our adjustments to service lives and unit rates. This included extending service life to 15 years for EWPs larger than 14 metres, and applying unit rates and service lives for senior staff vehicles the same as those used for light commercial vehicles. We consider that this largely addresses the concerns we raised in our draft decision.

Stakeholders welcomed the lower fleet proposal, but questioned whether any increase above actuals was justified, given the significant underspend over 2015–20.[133]

Below we discuss the reasons for our fleet decision by category:

[133] South Australian Government, *Submission to the AER on the SA Power Networks' Revised Regulatory Proposal 2020–25*, January 2020 p. 3; Energy Consumers Australia, *Submission on SA Power Networks' Revised Revenue Proposal 2020–25*, January 2020, p.2; Dynamic Analysis, *Technical Report on SA Power Networks Revised Proposal*, January 2020, p. 12.

EWPs

Our draft decision adjusted forecast EWP replacement costs based on assuming a 15 year service life for larger EWPs, where SA Power Networks had assumed 10 year service lives across its EWP fleet. SA Power Networks accepted that this change in service lives would be efficient for its EWPs larger than 14 metres, but argued that for its 14 metre tall EWPs a 10 year service life remained efficient.[134] The revised NPV analyses it submitted indicate that, for 14 metre EWPs, a 10 year service life is marginally lower cost. On this basis, we accept SA Power Networks' decision only to extend life for its EWPs taller than 14 metres, and hence its revised forecast.

SCS Usage

Our draft decision revised down SA Power Networks' fleet forecast to account for the percentage of vehicle usage for purposes other than SCS. SA Power Networks reversed this change, arguing that allocating the whole capex cost of vehicles to SCS was consistent with its CAM.[135]

We continue to consider that allocating fleet capex costs between service classifications based on use is more in keeping with the Cost Allocation Guidelines underpinning the CAM framework. However, this issue is not materially significant not to accept SA Power Networks' fleet forecast overall.

Unit Rates

Our draft decision found that SA Power Networks' method of calculating unit rates based on a selection of invoices was unlikely to result in a forecast of efficient costs, since it resulted in assumed unit rates materially higher than average unit costs historically. SA Power Networks' revised proposal changed its method to align unit costs with historical unit costs, but on the basis of matching vehicle classifications rather than replacing vehicle models like for like.[136] We are satisfied with the accuracy of this method.

Private Use of Senior Staff Vehicles

Our draft decision made a range of adjustments to SA Power Networks' forecast of senior staff vehicle costs. These included aligning unit rates and service lives with those of corresponding vehicle types in the light commercial vehicles category, and adjusting SCS capex for an estimate of the percentage of private use. SA Power Networks accepted revisions to its forecast in all these areas aside from revising for private use.[137] It argued these capex costs would alternatively need to be funded through an increase in staff salaries and hence operational expenditure. In our view,

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134 SA Power Networks, *Revised Proposal – Attachment 5 – Capital Expenditure*, December 2019, pp. 77-79.

135 SA Power Networks, *Revised Proposal – Attachment 5 – Capital Expenditure*, December 2019, pp. 81-83.

136 SA Power Networks, *Revised Proposal – Attachment 5 – Capital Expenditure*, December 2019, pp. 79-81.

137 SA Power Networks, *Revised Proposal – Attachment 5 – Capital Expenditure*, December 2019, p. 81.

this would be the better treatment. However, this issue is not sufficiently material to warrant not accepting SA Power Networks' fleet forecast overall.

B Contingent Project

Contingent projects are significant network augmentation projects, of uncertain timing. Capex associated with contingent projects does not form a part of our assessment of the total forecast capex that we approve in this determination. However, they are linked to unique investment drivers (rather than general investment drivers such as expectations of load growth in a region) and are triggered by a defined 'trigger' event. The occurrence of the trigger event must be probable during the relevant regulatory control period.[138]

If, during the regulatory control period, SA Power Networks considers that a trigger event has occurred, then it may apply for additional allowable revenue. At that time, we will assess whether the trigger event has occurred and whether the project meets a threshold of $30.0 million or 5 per cent of the annual revenue requirement in the first year of the 2020–25 regulatory control period. If both conditions are satisfied, we will determine the efficient incremental revenue that is likely to be required in each remaining year(s) of the regulatory control period as a result of the contingent project, and amend the revenue determination accordingly.[139]

B.1 Assessment approach

In reviewing both of SA Power Networks' proposed contingent projects against the NER requirements,[140] we considered whether:

- the proposed contingent project is reasonably required in order to achieve any of the capex objectives.[141]
- the proposed contingent project capital expenditure is not provided for elsewhere in the capex proposal.[142] Most relevantly, a distributor must include forecast capex in its proposal which it considers is required in order to meet or manage expected demand for standard control services over the regulatory control period.[143]
- the proposed contingent project reasonably reflects the capex criteria, taking into account the capex factors.[144] Importantly this requires the expenditure to be efficient.
- the proposed contingent project capital expenditure exceeds the defined threshold.[145]

138 NER, cl. 6.6A.1(c)(5).
139 This is as per the process for assessing an application to undertake an approved contingent project, set out in NER, cl. 6.6A.2.
140 NER, cl. 6.6A.1.
141 NER, cl. 6.6A.1(b)(1).
142 NER, cl. 6.6A.1(b)(2)(i).
143 NER, cl. 6.5.7(a)(1).
144 NER, cl. 6.6A.1(b)(2)(ii).
145 NER, cl. 6.6A.1(b)(2)(iii).

- the trigger events are appropriate. This includes having regard to the requirements for trigger events as set out in the NER. The NER require the trigger event:
  i. to be reasonably specific and capable of objective verification.[146]
  ii. to be a condition or event which, if it occurs, make the project reasonably necessary in order to achieve any of the capex objectives.[147]
  iii. to be a condition or event that generates increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the distribution network as a whole.[148]
  iv. is described in such terms that it all that is required for the revenue determination to be amended.[149]
  v. is probable during the 2015–20 regulatory control period but the inclusion of the project in the total forecast capex is not appropriate because either it is not sufficiently certain that the event or condition will occur during the regulatory control period; or the costs associated with the event or condition are not sufficiently certain.[150]

We also considered the interaction between the total forecast capex included in our revenue determination and projects proposed as contingent projects. Where a project is included in total forecast capex, it cannot also be included as a contingent project.[151] Further, the case for a contingent project needs to take into account the extent to which the forecast capex included in our revenue determination already caters for changes in the drivers that have an interrelationship with the contingent project.

B.2 Final decision

We have accepted both the Electricity System Security and Bushfire Review contingent projects. We consider both projects are reasonably required to maintain the reliability and safety of the network and to comply with applicable regulatory obligations or requirements and would be a prudent and efficient investment in the network.

We consider that, subject to the amendment noted in this determination for the trigger, the Electricity System Security contingent project satisfies 6.6A.1(b) of the NER.

146 NER, cl. 6.6A.1(c)(1).
147 NER, cl. 6.6A.1(c)(2).
148 NER, cl. 6.6A.1(c)(3).
149 NER, cl. 6.6A.1(c)(4).
150 NER, cl. 6.6A.1(c)(5).
151 NER, cl. 6.6A.1(b)(2)(i).

B.3 Revised proposal

Electricity System Security

SA Power Networks reproposed its Electricity System Security contingent project with updated triggers and contingent capex.

The purpose of this contingent project is to address potential issues in the under frequency load shedding (UFLS) scheme. SA Power Network indicated that AEMO modelling suggests that due to increasing levels of DER, the existing UFLS scheme will be ineffective.[152] To address this risk, SA Power Networks anticipates that AEMO, as part of its responsibility to maintain power system security, will require a redesign and rebuild of the existing UFLS scheme and to establish capability to shed DER.[153]

Contingent project trigger

SA Power Networks proposed the following triggers for its system security contingent project:

- SA Power Networks receives a notification from AEMO which requires SA Power networks to implement any of the following options in order to comply with its applicable regulatory obligations or requirements:

  (a) changes to, or in connection with, any emergency frequency control scheme; and/or

  (b) any other 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 distributed energy resources,

  in a timeframe that necessitates investment within the 2020–25 regulatory control period, where those changes or measures are required at or in relation to:

  i. one or more specific zone substations (e.g. the replacement of under-frequency load shedding (UFLS) relays); or

  ii. central systems that control any UFLS scheme; or

  iii. systems to control specific large-scale embedded generators; or

  iv. any other specific components or elements of the distribution network; or

  v. any combination of the above

- Successful completion of the Regulatory Investment Test-Distribution, or an equivalent economic evaluation, in relation to the required investment including an assessment of credible options and the identification of the preferred option.

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152 AER, *Attachment 5: Capital expenditure – Draft decision – SA Power Networks 2020–25*, October 2019, p. 112.

153 AER, *Attachment 5: Capital expenditure – Draft decision – SA Power Networks 2020–25*, October 2019, p. 116.

- SA Power Networks commitment to proceed with the project subject to the AER amending the distribution determination for the 2020–25 regulatory control period pursuant to the NER.[154]

Contingent project capex

SA Power Networks proposed the replacement of 572 existing under-frequency protection relays to ensure the continued operation of the UFLS. This is a reduction from 625 in its initial proposal. This replacement of the relays are required as part of SA Power Networks and AEMO expectation that the UFLS scheme will require a redesign and rebuild.[155]

SA Power Networks proposed two options to implement the required functionality in the relays. Option 1 utilises existing protection relays wherever possible with an expected cost of $40.1 million, and option 2 upgrades all relays to the modern standard with an expected cost of $79.2 million. The feasibility of the two options will depend on AEMO's final specifications. SA Power Networks has assumed the minimal option will be acceptable.

Bushfire Review

SA Power Networks proposed a Bushfire Review contingent project as part of a submission to its revised proposal. As a result of 2019 bushfires in South Australia, SA Power Networks noted that it expected a two part review into current bushfire preparedness and a longer term review into increasing bushfire risk being posed by climate change.[156]

SA Power Networks also noted that on 7 January 2020, it met with the South Australian government and ESCOSA to discuss bushfire risk management practices. During the meeting the state government indicated a desire to investigate how effectively electricity infrastructure is being managed in view of increasing fire risk being experienced during the current fire season.[157]

Since SA Power Networks submitted its Bushfire Review contingent project, the South Australian government commenced its Independent review on the 2019/20 bushfire season (the Review). The Review will be led by Mr Mick Keelty. The terms of reference identified prevention of bushfire ignitions and electricity infrastructure as an area of focus.[158]

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154 AER, *Attachment 5: Capital expenditure – Draft decision – SA Power Networks 2020–25*, October 2019, p. 97.

155 AER, *Attachment 5: Capital expenditure – Draft decision – SA Power Networks 2020–25*, October 2019, p. 91.

156 SA Power Networks, *SA Power Networks Distribution Determination 2020–25: new information regarding capital expenditure which may be required to mitigate bushfire risks*, 15 January 2020, p. 1.

157 SA Power Networks, *Addendum to attachment 5 capital expenditure of the revised proposal*, February 2020, p. 1.

158 South Australia Government, *Terms of reference 2019/20 Bushfire Review*, January 2020, p. 2.

Contingent project trigger

SA Power Networks proposed the following triggers for its Bushfire Review contingent project:

- Publication of a final report by the 2019–20 Bushfire Review which includes a recommendation that new investment is required to be undertaken by SA Power Networks to reduce the risk of fire starts or improve bushfire safety in high and/or medium bushfire risk areas;
- Imposition of a new or changed regulatory obligations or requirement on SA Power Networks which requires SA Power Networks to commence to undertake investment in relation to its distribution network to reduce the risk of fire starts or improve bushfire safety in high and/or medium bushfire risk areas during the 2020–25 regulatory control period; and
- Successful completion of the RIT-D in relation to the investment required to satisfy the new or changed regulatory obligation or requirement including an assessment of credible options and the identification of the preferred option.

SA Power Networks proposed that, if either of these events were to occur during the next regulatory control period, it would be able to apply to the AER under clause 6.6A.2 of the NER to amend its distribution determination.[159]

Contingent project capex

SA Power Networks did not propose a capex forecast for its Bushfire Risk contingent project. Rather, it noted that it previously proposed $67 million in capex for bushfire risk mitigation and safety measures in its 2015–20 regulatory control period revised proposal this is a decrease on its 2015–20 initial proposal of $203 million.[160] On this basis, SA Power Networks considered capex to meet new bushfire related obligations would meet the materiality threshold for contingent projects.[161]

B.4 Reasons for final decision

In coming to our decision to accept both contingent projects we have assessed the triggers and the proposed contingent capex under the capex criteria. We discuss our assessment in turn below.

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159 SA Power Networks, *Addendum to attachment 5 capital expenditure of the revised proposal*, 15 February 2020, p. 7.

160 SA Power Networks, *Addendum to attachment 5 capital expenditure of the revised proposal*, February 2020, p. 6.

161 SA Power Networks, *SA Power Networks Distribution Determination 2020–25: new information regarding capital expenditure which may be required to mitigate bushfire risks*, 15 January 2020, p. 3.

B.4.1 System security

Assessment of triggers

We broadly accept SA Power Networks' revised proposal triggers. However, we do not consider SA Power Networks' removal of the requirement for a formal notification is reasonable. We also consider that the formal notification trigger should reference the NER requirements of Rule 5.20A which requires AEMO to transparently assess risks to power system operation caused by events that are unlikely, but would have high impacts if they were to occur. This is the Power System Frequency Risk Review (PSFRR).[162]

In our draft decision we accepted SA Power Networks' updated triggers. In its revised proposal, SA Power Networks proposed changes to the trigger events to reflect its better understanding of the outcomes from the AEMO studies and reviews.[163]

Following consultation with SA Power Networks, it was agreed that further refinements to the triggers should be included to reference the NER requirements of Rule 5.20A.[164]

We would expect, upon completion of its review under Rule 5.20A, if any changes to the UFLS scheme parameters are required, that AEMO would consult with SA Power Networks as required under Rule 5.20A.2(c) and formally notify SA Power Networks of the required changes. Such notification from AEMO would be in accordance with the requirements of Rule 5.20A, and would reference any decisions made by the Reliability Panel where relevant. This will ensure that the trigger is capable of objective verification. [165]

We are satisfied with the additional elements of the trigger as they better reflect more up to date information and the relevant NER requirements.

Assessment of capex

We accept SA Power Networks' updated forecast of $40.1 million. We are satisfied this meets the 5 per cent materiality threshold of $39.1 million.

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[162] In our recent determination on *ElectraNet's RIT-T South Australian Energy Transition - Determination that the preferred option satisfies the regulatory investment test for transmissions*, January, 2020 at page 34, we highlight the benefits for stakeholders of the transparent process required under Rule 5.20A. If AEMO believes that there is a cost-effective way of managing any of the risks it identifies in its PSFRR, it can recommend changes to emergency frequency control schemes (such as the South Australian UFLS scheme) or request that the Reliability Panel declare a risk as a protected event, In 2018, AEMO undertook its first PSFRR and did not identify any need to modify the South Australian UFLS scheme.

[163] AER, *Attachment 5: Capital expenditure – Draft decision – SA Power Networks 2020–25*, October 2019, p. 94.

[164] SA Power Networks, *Re: Electricity System Security contingent project*, 28 February 2020, p. 1 and SA Power Networks, *Re: SAPN Electricity System Security Contingent Project*, 18 May 2020

[165] NER, cl. 6.6A.1(c)(1).

We note SA Power Networks' proposed two options with a forecast of $40.1 million and $79.2 million for option 1 and option 2 respectively. Both options meet the materiality threshold for contingent projects.

The main difference in costs between the two options is that option 1 allows for greater use of existing protection relays and that dynamic arming is not required. Option 2 is largely consistent with its initial proposal where it proposed to replace and/or recommission 572 existing protection relays.

In our draft decision, we did not accept the proposed capex due to the limited information available. SA Power Networks acknowledged its initial proposal did not provide definitive details about anticipated distribution system changes and requirements, or the precise details of all capex to be undertaken, as the issue was still evolving and there had only been limited dialogue at that time with AEMO.

We have assessed the updated information provided by SA Power networks and we acknowledge that AEMO is further progressed in its review. AEMO also submitted that it supports this contingent project and considers that it is a low-cost measure to improve the capability of UFLS.[166]

AEMO will continue to work with SA Power Networks and ElectraNet to confirm the nature and timing of the risks and, as required, develop suitable detailed mitigation options in accordance with the NER requirements.

We also acknowledge that the capex will be contingent on successful completion of the Regulatory Investment Test-Distribution which may result in a different capex approach than outlined by SA Power Networks.

Based on the information available, we are satisfied that the proposed capex satisfies the capex objectives.

Final decision trigger

SA Power Networks receives formal notification or confirmation from AEMO that:

(a) the findings of AEMO's Power System Frequency Risk Review undertaken in accordance with the requirements of Rule 5.20A; or

(b) other relevant system security findings from AEMO, or where relevant the Reliability Panel,

i. requires SA Power Networks to implement any of the following options in order to comply with its applicable regulatory obligations or requirements:

ii. changes to, or in connection with, any emergency frequency control scheme; and/or

166 AEMO, *AEMO submission - draft distribution determination for SA Power Networks 2020–25*, 17 January 2020, p. 2.

iii. any other 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 distributed energy resources,

in a timeframe that necessitates investment within the 2020–25 regulatory control period, where those changes or measures are required at or in relation to:

i. one or more specific zone substations (e.g. the replacement of under-frequency load shedding (UFLS) relays); or

ii. central systems that control any UFLS scheme; or

iii. systems to control specific large-scale embedded generators; or

iv. any other specific components or elements of the distribution network; or

v. any combination of the above

- Successful completion of the Regulatory Investment Test-Distribution, or an equivalent economic evaluation, in relation to the required investment including details of the need to undertake the works, an assessment of credible options, and the identification of the preferred option.
- SA Power Networks commitment to proceed with the project subject to the AER amending the distribution determination for the 2020–25 regulatory control period pursuant to the NER.[167]

B.4.2 Bushfire Review

Assessment of triggers

We consider SA Power Networks' proposed triggers are reasonable. In assessing the triggers we have considered the circumstances that may result in SA Power Networks incurring additional costs to address bushfire risk. We are satisfied that the driver of the change in costs will be driven by the imposition of a requirement to address bushfire risk following the outcome of the Review.

The findings of the review and proposed actions will be reported to the State Government by the end of June 2020. As the review will look into the state's readiness to deal with any future bushfires. Any lessons learnt from the recent events will contribute to the creation of strategies to help mitigate the impact of bushfires on the community. The review will also explore preparation, prevention, response and recovery strategies for upcoming years and bushfire seasons.

We consider this review is similar in scope to the 2009 Victorian Bushfires Royal Commission terms of reference which included recommendations for the preparation and planning for future bushfire threats and risks. This led to several electricity infrastructure recommendations.[168]

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167 AER, *Attachment 5: Capital expenditure – Draft decision – SA Power Networks 2020–25*, October 2019, p. 97.

168 2009 Victorian Bushfires Royal Commission, *Final Report summary*, July 2010, p. 29.

Given the similarities, we are satisfied that it is probable for the trigger to be met during the 2020–25 regulatory control period.

We are also satisfied that the trigger does not apply to the whole of the network but rather limited to medium/high bushfire risk areas which satisfies the locational requirement. Based on this we are satisfied that the trigger is appropriate.[169] However, we have made an edit to the trigger to reflect the announcement of the Review.

Assessment of capex

We consider SA Power Networks' proposed Bushfire Review contingent project capex meets the criteria for contingent projects.

We note that SA Power Networks has not included a specific capex proposal but rather provided an indicative capex of $67 million for other bushfire related capex. We have considered this in the context of the contingent project and the current status of the Review. As noted above, electricity infrastructure is an area of focus for the Review.

We consider the driver of the capex is due to a change in regulatory obligation. We are satisfied that, if the trigger events occur, the proposed contingent project capex will be required to comply with applicable regulatory obligations.[170] However, the outcomes of the Review will not be available till after the commencement of the 2020–25 regulatory control period. We have taken into account the devastating bushfires that occurred across Australia in the summer of 2019/20, which resulted in serious loss of life, damage and destruction of property and serious detrimental impacts on the environment in South Australia and elsewhere. Given the circumstances, we are satisfied that the indicative level capex based on what SA Power Networks has previously proposed is a suitable starting point.

We also consider this indicative level of capex meets SA Power Networks' materiality threshold of $38 million. We also note that any amendment to the distribution determination must meet this materiality threshold.[171]

Submissions on this issue, including from consumer representatives, noted that although there was no new regulatory obligation, they recognised that it was possible given the review and that they preferred the use of a contingent project to address the potential change in regulatory obligation.[172]

CCP14 also noted that only incremental costs should be included given SA Power Networks will already receive capex that may indirectly address bushfire risk, such as

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169 NER, cl. 6.6A.1(c).

170 NER, cl. 6.5.7 (a)(2).

171 NER, cl. 6.6A.2 (b)(4).

172 SAFCA, *Uniting Communities and the Energy project, a submission on SA Power Networks' proposed additional bushfire expenditure in the 2020–25 revenue determination*, 6 March 2020, p. 13.

safety, network reliability and bushfire risk mitigation.[173] We also note that submissions identified the need for further consultation with community groups and the expectation that this will be undertaken as part of a RIT-D process.[174]

We consider these aspects should be clearly identified and assessed as part of any application by SA Power Networks for the bushfire review contingent project consistent with 6.6A.2 of the NER. We also note that incremental opex effects should also be considered. Further, SA Power Networks has included the successful completion of a RIT-D in its contingent project triggers.

173 CCP14, *Advice to AER on SA Power Networks' Regulatory Determination 2020–25 Additional submission contingent project an opex step change*, February 2020, pp. 3-5.

174 CCP14, *Advice to AER on SA Power Networks' Regulatory Determination 2020–25 Additional submission contingent project an opex step change*, February 2020, p. 6. SAFCA, *Uniting Communities and the Energy project, a submission on SA Power Networks' proposed additional bushfire expenditure in the 2020–25 revenue determination*, 6 March 2020, p. 13.

C Modelling adjustments

We have made a number of modelling adjustments in this final decision. We typically make these modelling adjustments in all our decisions. We have updated the estimated 2019–20 CPI figure with actual CPI, which was higher than SA Power Networks' forecast CPI at the time of submission. We have also made adjustments to SA Power Networks' real cost escalations. Both adjustments have in a difference of 0.6 per cent compared to SA Power Networks' revised proposal.

C.1 Real cost escalation adjustment

Consistent with our final decision on opex, we have applied an average of the utility industry state level the labour price growth rate forecasts from Deloitte and BIS Oxford Economics for SA Power Networks' internal labour costs.[175] This is a change from our draft decision.[176] While we have applied forecast labour price growth to SA Power Networks' labour costs in this final decision, we have not included any forecast labour productivity growth for the internal labour component of the forecast capex. We acknowledge that not taking into account productivity growth may overstate the growth in internal labour costs. We may consider adopting a more holistic approach in our next determination, which will consider taking into account forecast productivity improvements when determining real cost escalation.

In this final decision, we have maintained our draft decision and have not applied forecast labour price growth to contracted services for SA Power Networks' capex forecast.[177] In our draft decision, our main concern was that SA Power Networks had not provided evidence that the forecast growth in the construction Wage Price Index (WPI) will be representative of the growth in the costs of its contracts going forward. We requested that SA Power Networks provide any of its existing contracts to demonstrate the reasonableness of its forecast increase in the costs of its service contracts over the forecast period.[178] SA Power Networks did not provide that information or other evidence to support its price growth forecasts. In addition, our draft decision identified that SA Power Networks applied forecast construction industry WPI growth to its ICT capex forecast.[179]

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175 AER, Final decision - *SA Power Networks Distribution Determination 2020–25 - Attachment 6 - Operating expenditure*, May 2020, p.25.

176 AER, *Draft Decision - SA Power Networks Distribution Determination 2020–25 - Attachment 6 - Operating expenditure*, October 2019, p.21.

177 AER, *Draft Decision - SA Power Networks Distribution Determination 2020–25 - Attachment 5 - Capital expenditure*, October 2019, p.20.

178 SA Power Networks, *Information Request 69 - Escalation rate for contract labour*, 29 July 2019, p.1.

179 In an information request, SA Power Networks submitted that the application of a construction WPI to its ICT capex requires further consideration SA Power Networks, *Information Request 69 - Escalation rate for contract labour repex*, 29 July 2019, p. 2.

In its revised proposal, SA Power Networks maintained the application of a contractor price growth to its capex forecast. However, it divided its contractor price growth forecasts into two different escalators for services and ICT.

For services price growth, SA Power Networks provided a BIS Oxford Economics report advising the use of construction industry WPI growth for construction type activities. For ICT price growth, SA Power Networks relied on BIS Oxford Economics' advice to use forecast growth in the 'All Industries' WPI for South Australia.[180]

Based on all the information before us, we maintain our draft decision that CPI growth is the best estimate of the forecast growth in the price of contracted services for the following reasons:

- We consider that SA Power Networks' contracted services can be adjusted to address changes in the labour market and/or economic climate. SA Power Networks submitted that its capex contracts are typically short-term as these contracts typically cover specific jobs which may only require a few months of work.[181] Therefore, over the five year regulatory control period, a CPI growth is the best estimate, as it reflects SA Power Network's ability to manage overall contractor services cost which may fluctuate due to shortages or excess labour.
- We consider that forecasting labour price growth for contracted services, without taking into account productivity growth, would likely overstate the growth in the price of contracted services.
- There was a lack of a bottom-up evidence to support the premise that SA Power Networks, in fact, incurred contract price increases that align to WPI growth in the current period (2015–20) to indicate that these are a reasonably expected cost input for the forecast period, for example:
    - For services price growth, SA Power Networks explained that, as part of its procurement process, 25 per cent of its contract labour, which are found in two of its largest contracts, are subject to a labour parity clause; namely a clause that equalises its contract labour wages with that of internal staff in line with the current Enterprise Agreement (EA). To test SA Power Network's claim that there is parity between its contracted service labour and internal labour prices, we have reviewed SA Power Networks' EA and its largest contracts. The two sources were inconsistent, as the EA stipulates that labour parity only applies to labour hire, but not to contractors or subcontractors who are engaged on defined projects.[182] The RIN definitions are explicit that labour hire is captured as part of internal labour, therefore, would be associated with a labour price growth. This is different to

[180] SA Power Networks, *Supporting document 6.5 - BIS Oxford Economics - utilities construction wage forecasts to 2024–25*, 10 December 2019, p.2.

[181] SA Power Networks, *Information Request 69 - Escalation rate for contract labour*, 29 July 2019, p.1.

[182] SA Power Networks, *Clause 7.6 - Supporting documentation 18.7 - Utilities Management Pty Ltd Enterprise Agreement 2018*, August 2018, p.58.

contracted services. We sought to confirm the nature of these engagements, SA Power Networks confirmed that these large contracts were not, in fact, labour hire, but are providing contracted services only, therefore, any labour price parity is inconsistent with its own EA.[183]

- For ICT price growth, neither SA Power Networks nor BIS Oxford Economics indicated why the price of outsourced ICT services should grow in line with the 'All Industries' WPI for South Australia.[184] In addition, our review has identified evidence in existing ICT contracts, which demonstrates that SA Power Networks has agreed to a constant price over a number of years in the current period (2015–20) and a CPI growth that extends into the forecast period.[185] This evidence contradicts SA Power Networks' submission.[186]

Overall, we are satisfied that applying forecast labour price for internal labour costs combined with a forecast CPI growth for contracted services is sufficient for SA Power Networks to achieve the capex objectives and to recover its efficient costs.

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183 SA Power Networks has confirmed that any supplementary labour is captured in labour costs in accordance with the RIN definitions. See AER, *Expenditure forecast assessment guideline - Regulatory information notices for category analysis,* 2014, 7 March 2014. Definition of Labour costs includes the costs of labour hire, where labour hire means expenditure incurred under labour hire contracts only. See SA Power Networks, *Response to Information Request 084 - Contract Labour Escalation*, 16 November 2020.

184 SA Power Networks, *Supporting document 6.5 - BIS Oxford Economics - utilities construction wage forecasts to 2024–25*, 10 December 2019, p.23.

185 SA Power Networks, *Supporting document 18.12 - 2020–25 Regulatory Proposal*, August 2018, p.3.

186 SA Power Networks, *Attachment 5 - Capital Expenditure - 2020–25 Regulatory Proposal*, December 2019, p.20.

Shortened forms

Shortened form	Extended form
AEMO	Australian Energy Market Operator
ADMS	Advanced Distribution Management System
AER	Australian Energy Regulator
augex	augmentation expenditure
BFRA	bushfire risk area
CAM	cost allocation method
capex	capital expenditure
CCP14	Consumer Challenge Panel, sub-panel 14
CEC	Clean Energy Council
CESS	capital expenditure sharing scheme
CPI	consumer price index
CBRM	Condition Based Risk Management
DER	Distributed Energy Resources
distributor	distribution network service provider
EA	Enterprise Agreement
ECA	Energy Consumers Australia
EMCa	Energy Market Consulting associates
EWOSA	Energy and Water Ombudsman SA
EWP	elevated work platforms
GIS	Gas Insulated Switchgear
ICT	Information Communication Technology
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
opex	operating expenditure

Shortened form	Extended form
RAB	regulatory asset base
repex	replacement expenditure
RIN	regulatory information notice
SACOSS	South Australian Council of Social Service
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SAFCA	South Australian Financial Counsellors Association
SCADA	supervisory control and data acquisition
SCS	Standard Control Service
STPIS	service target performance incentive scheme
TEC	Total Environment Centre
UFLS	Under frequency load shedding
VCR	value of customer reliability
WACC	weighted average cost of capital
WPI	Wage price index