SA Power Networks

# Attachment 5
# Capital expenditure

## 2020-25 Revised Regulatory Proposal

20 December 2019


### This section outlines:

› our proposed capital works program and expenditure for the 2020-25 Regulatory Control Period.

## Company information

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

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## Disclaimer

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

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

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

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## Note

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

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

| Document | Description |
|---|---|
| | Regulatory Proposal overview |
| Attachment 1 | Annual revenue requirement and control mechanism |
| Attachment 2 | Regulatory Asset Base |
| Attachment 3 | Rate of Return |
| Attachment 4 | Regulatory Depreciation |
| ***Attachment 5*** | ***Capital expenditure*** |
| Attachment 6 | Operating expenditure |
| Attachment 7 | Corporate income tax |
| Attachment 8 | Efficiency Benefit Sharing Scheme |
| Attachment 9 | Capital Expenditure Sharing Scheme |
| Attachment 10 | Service Target Performance Incentive Scheme |
| Attachment 11 | Demand management incentives and allowance |
| Attachment 12 | Classification of services |
| Attachment 13 | Pass through events |
| Attachment 14 | Alternative Control Services |
| Attachment 15 | Negotiated services framework and criteria |
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| Attachment 17 | Tariff Structure Statement Part B - Explanatory Statement |
| Attachment 18 | List of Proposal documentation |

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# 5 Capital expenditure

## 5.1 Introduction

On 31 January 2019, SA Power Networks submitted its 2020-25 Regulatory Proposal together with supporting documents and information (together the **Original Proposal**) to the Australian Energy Regulator (**AER**) in accordance with the National Electricity Rules (**NER** or **Rules**), setting out (amongst other things) the capital expenditure (**capex**) we require to manage our distribution network in a safe, reliable and prudent manner for the regulatory control period (**RCP**) from 1 July 2020 to 30 June 2025.

The AER published a draft decision in response to our Original Proposal on 8 October 2019 (**Draft Decision**) in accordance with clause 6.10.1(a) of the NER. In its Draft Decision, the AER was not satisfied our total net capex forecast of $1719.7 million (including fleet disposals), reasonably reflected the capex criteria set out in the NER.

SA Power Networks has carefully considered the AER's Draft Decision on capex and, in accordance with clause 6.10.3 of the NER, has prepared this Attachment with various supporting documents in response. This Attachment 5 is a key component of our 2020-25 Revised Regulatory Proposal (**Revised Proposal**).

Our revised capex forecast incorporates the capital investment we propose to make in relation to the provision of standard control services (**SCS**) during the 2020-25 RCP.

In our Original Proposal, we explained the reasons for the variation between the actual capex we incurred and the AER's capex allowance for the 2020-25 RCP. We also explained the processes, inputs and methodologies we used to develop our forecast capex for the 2020-25 RCP. These explanations have not been repeated in detail in this Revised Proposal, except where necessary to explain our revised capex forecast.

Where the AER accepted programs from our Original Proposal or where we have accepted the AER's Draft Decision, no further documentation has been submitted for these programs within our Revised Proposal.

All dollars in this Attachment are in real June 2020 terms and include business overheads and escalators, unless specified otherwise. There are minor variances between the Original Proposal, the AER's Draft Decision and our Revised Proposal due to escalation adjustments (explained in Section 5.2.7 of this Attachment). The total capex forecast contained within this Attachment has been reconciled in the following models:

- 5.1 Revised Regulatory Proposal capex model
- 5.2 Revised Proposal capex reconciliation model

## 5.2 SA Power Networks' revised capital expenditure forecast

### 5.2.1 Our revised capital expenditure forecast for the 2020-25 RCP

The forecast total capex for our 2020-25 Revised Proposal is $1,712.0 (before disposals) subject to the AER approving our Assets and Works (Stage 2) IT program.

Our Revised Proposal capex forecast is $29 million (2%) lower than our Original Proposal capex forecast and is $450 million (26%) higher than the AER's Draft Decision.

Table 5-1 and Figure 5-1 summarise our Revised Proposal compared to the AER's Draft Decision and our Original Proposal. All amounts are before fleet disposals as these are separately accounted for in the post tax revenue model (**PTRM**).

**Table 5-1: SA Power Networks' Original and Revised Proposals compared to the AER's Draft Decision (June 2020, $ million)**

| | Our Original Proposal | AER Draft Decision | Our Revised Proposal | Difference to Draft Decision $ |
|---|---|---|---|---|
| **Capex** | 1,741.1 | 1,262.5 | 1,712.0 | 449.5 |

*Note: Excludes Fleet disposals.*

In developing our Revised Proposal capex forecast we have taken into consideration the AER's comments and customer and stakeholder feedback on our Original Proposal. In response we have made some changes to how we prepared our Revised Proposal capex forecast. In particular, we have:

- undertaken extensive stakeholder engagement with our key stakeholders including SA Power Networks' Consumer Consultation Panel (**CCP**), other reference group members, State Government, and the AER;
- revised the capex model provided with the AER's Draft Decision[1];
- prepared a capex reconciliation model that reconciles our Original Proposal to the AER's Draft Decision and our Revised Proposal[2];
- prepared supporting documents[3] for replacement expenditure (**repex**), augmentation expenditure (**augex**), connections, and property have developed an IT investment addendum. These documents set out our response to the AER Draft Decision and how we have revised our forecast;
- developed a document that explains the interrelationship between our distributed energy resources (**DER**) related programs[4];
- engaged Cutler Merz to undertake an independent review of our condition-based risk management (**CBRM**) models and applied the recommended calibrations[5]. We also conducted a workshop with AER staff and Cutler Merz to step through the CBRM model inputs and assumptions to we explain how the models calculate risk;
- engaged BIS Oxford Economics (**BISOE**) to update the gross customer connections forecast that is now based on our historical regulatory information notice (**RIN**) data. BISOE has also provided a detailed response[6] addressing the concerns raised in the AER's Energy Market Consulting associates (**EMCa**) report[7]; and
- developed improved business cases that clearly identify the need, options and cost benefit analysis and sensitivity analysis for a number of specific projects and programs.

### 5.2.2 Capex components

Our Revised Proposal capex forecast is comprised of the following expenditure components (as illustrated in Figure 5.1 below):

- Replacement (repex) – for the replacement of aged/poor condition assets to maintain the reliability and safety of the network;
- Augmentation (augex) – for upgrades or improvements to the network to meet our regulatory obligations;
- Customer connections – expenditure associated with the connection of our customers to our network: and
- Non-Network – expenditure relating to Information Technology (**IT**), Operational Technology (**OT**), Property, Fleet, Plant and Tools.

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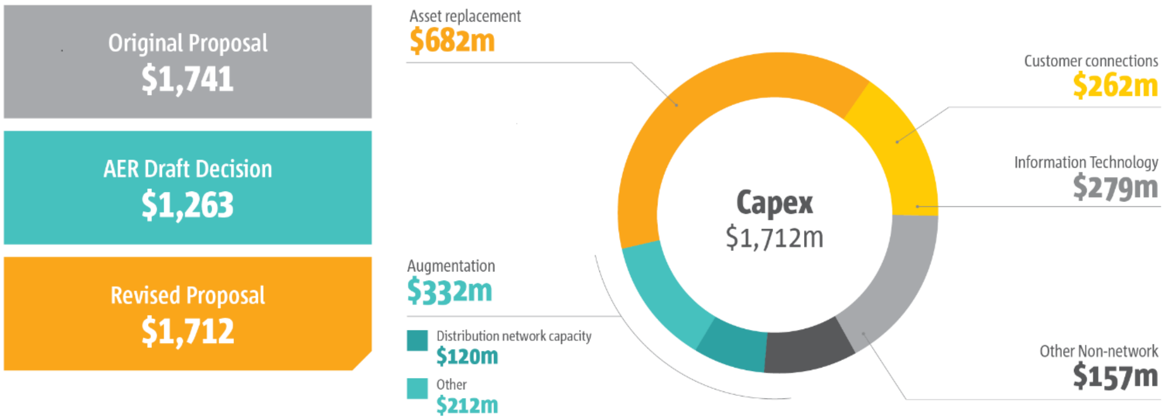
[1] *Supporting Document 5.1: Revised Regulatory Proposal capex model.*
[2] *Supporting Document 5.2: Revised Proposal capex reconciliation model.*
[3] *Supporting Documents 5.4: Repex addendum; 5.14 DER management expenditure overview; 5.11: Connections 2020-25 Response to AER's Draft Decision; 5.21: 2020-25 Property Capex Forecast Regulatory Justification; 5.26: IT investment plan addendum.*
[4] *Supporting Document 5.14: DER management expenditure overview.*
[5] *Supporting Document 5.5: Cutler Merz CBRM Model value of consequence independent report.*
[6] *Supporting Document 5.13: BIS Oxford Economics, Response to EMCA report.*
[7] *EMCa: Review of aspects of SA Power Network's capital expenditure (Final, September 2019).*

**Figure 5-1: Revised capex forecast for the 2020-25 RCP (June 2020, $ million) before disposals**




### 5.2.3 Capex profile

Our network is the oldest in the National Electricity Market (**NEM**). We have held our charges below the consumer price index (**CPI**) for 20 years and are continually benchmarked by the AER as providing the most efficient whole-of-state distribution services in the NEM. This means we have to work harder to find further improvements, particularly when:

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

In developing our capex forecasts, we have considered a range of challenges facing our industry and distribution networks in particular. We have engaged broadly with customers and stakeholders to ensure we understand their perspectives.

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

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

When developing our Revised Proposal, we have taken these factors into consideration along with the AER's concerns and our stakeholders' feedback. Our Revised Proposal is prudent and efficient, and remains consistent with what we are forecasting to spend in the current RCP despite the additional challenges facing our business. Figure 5-2 and Table 5-2 shows our capex expenditure profile over the 2010-25 period.

**Figure 5-2: Capex expenditure profile 2010-2025 (June 2020, $ million)**

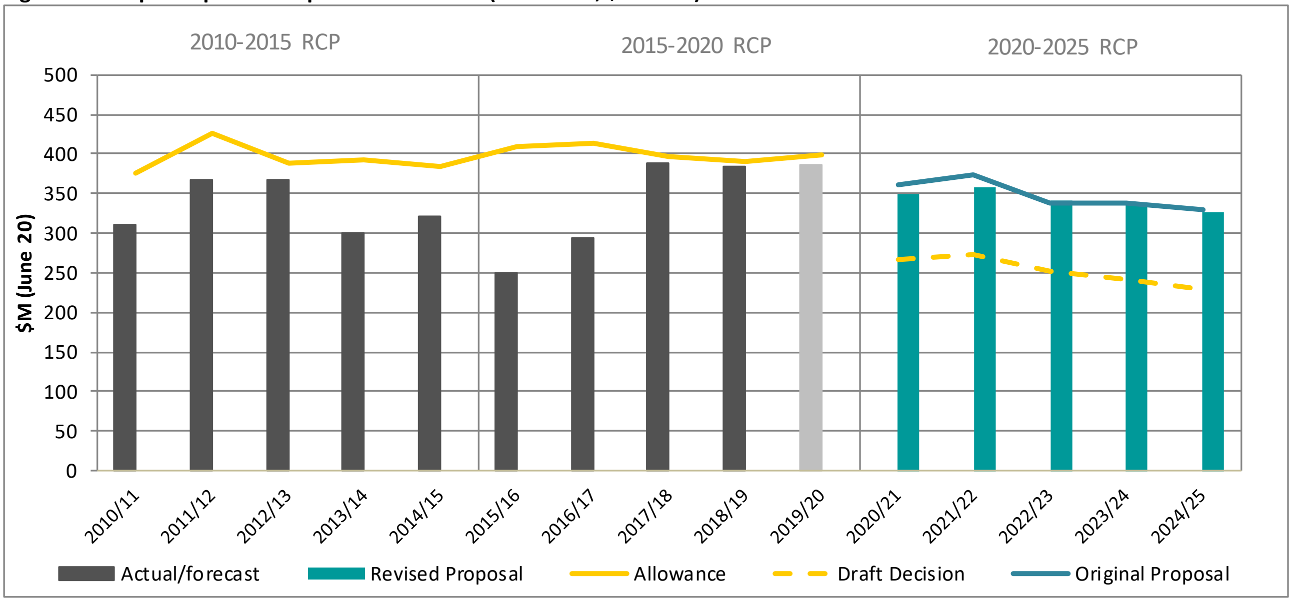



**Table 5-2: Capex expenditure actual and forecast 2010-2025 (June 2020, $ million)**

| | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Repex** | 70 | 93 | 102 | 109 | 103 | 93 | 110 | 154 | 153 | 150 | 135 | 137 | 139 | 137 | 134 |
| **Augex** | 150 | 160 | 157 | 105 | 126 | 59 | 68 | 94 | 86 | 85 | 66 | 70 | 65 | 66 | 64 |
| **Connections (net)** | 27 | 41 | 44 | 35 | 39 | 30 | 33 | 34 | 37 | 35 | 50 | 52 | 55 | 53 | 51 |
| **IT** | 25 | 31 | 30 | 31 | 49 | 45 | 59 | 66 | 67 | 74 | 72 | 72 | 49 | 44 | 42 |
| **Property** | 12 | 23 | 18 | 12 | 5 | 8 | 7 | 12 | 9 | 9 | 9 | 10 | 10 | 11 | 11 |
| **Fleet** | 20 | 19 | 19 | 18 | 18 | 16 | 15 | 20 | 21 | 21 | 13 | 18 | 23 | 25 | 20 |
| **Operational tel** | 1 | 1 | 1 | 3 | 7 | 10 | 8 | 11 | 15 | 14 | 5 | 2 | 3 | 5 | 7 |
| **Other**[8] | 3 | (2) | (5) | (14) | (26) | (12) | (7) | (2) | (3) | (3) | (2) | (3) | (4) | (4) | (4) |
| **TOTAL CAPEX** | **307** | **367** | **366** | **300** | **322** | **249** | **293** | **389** | **385** | **386** | **349** | **358** | **342** | **337** | **326** |

## 5.2.4 AER's Draft Decision

The AER did not accept our forecast capex for the 2020-25 RCP as they were not satisfied the total net capex forecast of $1,719.7 million (including fleet disposals), reasonably reflected the capex criteria[9]. The AER's substitute estimate of $1,246.9 million is 27.5 per cent below our forecast of $1,719.7 million ($1,741.1 million before fleet disposals), and it is 25 per cent below our forecast expenditure over the 2015–20 RCP.

The AER formed the view that SA Power Networks did not provide sufficient evidence to satisfy the AER of the prudency and efficiency of our forecast capex. The primary reasons for the AER's Draft Decision were: [10]

- Overstated risk or benefits in analysis to support our forecast.
- In some cases there was insufficient information to enable a decision. For example, unclear need identification, options analysis and cost benefit analysis.
- A lack of rigor in the testing of reasonableness of the forecast.
- Limited identification of the interrelationships that may exist between programs and projects.
- Inconsistency in the program level build-up between the asset management plans, reset RIN and the Original Proposal.

[8] Non-network 'Other' consists of plant and tools and a negative superannuation adjustment.

[9] *AER, Draft Decision for SA Power Networks Distribution Determination 2020-2025, Attachment 5: Capital expenditure (**Attachment 5**), page 9.*

[10] *Ibid, page 11.*

### 5.2.5 What we have heard and how we have responded

Table 5-3 below outlines the key issues raised by the AER and our customers and how we responded when developing our Revised Proposal capex forecast for the 2020-25 RCP.

**Table 5-3: AER capex Draft Decision for the 2020-25 RCP (June 2020, $ million)**

| Issue | What we heard | How we responded |
|---|---|---|
| **Governance and forecasting methodology** | Governance and management framework led to an overstated total capex forecast. | We have improved our forecasting methodology for our Revised Proposal in order that our forecast better reflect the replication of our governance and budgeting process. |
| **Repex** | Some repex lacks cost benefit analysis. The CBRM models are a black box and they overstate risk.<br>Historical trend forecasts include forecasts for the last two years of the 2015-20 RCP which are significantly higher than actuals | We have prepared business cases with cost benefit analysis for three repex projects. We have engaged extensively with the AER to provide better clarity on our CBRM forecasting methodology. In addition we engaged CutlerMerz to undertake an independent review of each of our CBRM models.<br><br>We have revised our historical trend forecasts to incorporate the audited 2018/19 actual results. |
| **DER Management augex** | Did not account for the interrelationships that may exist between DER related programs | We have prepared a detailed explanation of the interrelationships between our DER related projects to demonstrate that they are complementary, not overlapping.<br><br>We have developed a more efficient solution for the Low Voltage (**LV**) monitoring program which results in opex reductions. |
| **Other augex** | Forecasts for some programs either lack robust option analysis, overstate the benefits or do not establish the need to undertake a project | We undertook additional engagement with our stakeholders to better understand their concerns.<br><br>We have developed more robust options analysis and cost benefit analysis and reviewed benefits to provided better evidence for specific projects.<br><br>We engaged Oakley Greenwood to review the outcomes of the ESCoSA 'willingness to pay' survey. This review demonstrated that when considering the survey results on a comparative basis with our own engagement, there is significant support for the poor reliability feeder program. |
| **Customer connections** | Accepted capital contributions however they identified unsupported assumptions in the (gross) connections forecast. BISOE forecast is a black box. | SA Power Networks and BISOE have engaged with the AER to better explain the forecasting methodology. We have revised the basis of the connections forecast to align with RIN data. |

| Issue | What we heard | How we responded |
| --- | --- | --- |
| **Information, Communications and Technology (ICT)** | The AER accepted the recurrent ICT capex as it was in-line with historical expenditure. The AER accepted four of eight non-recurrent projects. Not all options were explored. | We have undertaken further engagement with our stakeholders on the four projects that were not accepted. We have considered the AER's concerns and have refined our business cases accordingly. |
| **Operational Telecommunications** | The AER accepted our OT as it was consistent with historical expenditure. The AER did not accept our Advanced Distribution Management System (**ADMS**) project because we did not sufficiently establish the need to undertake the upgrade, or provide any options analysis or cost-benefit assessment to support the proposed investment | We have developed a robust business case for the ADMS software and hardware replacement project to address the AER's concerns. |
| **Property** | The AER did not provide any property related capex as it considered that there was insufficient evidence to support the forecast | We have improved our forecasting methodology by performing cost-benefit analysis of some major projects and a top-down analysis and validation of the overall property expenditure. This has resulted in a forecast that is more in line with our historical expenditure. |
| **Fleet** | The AER's assessment is that we are the most costly provider of fleet per employee as our vehicle service life and unit rate assumptions exceeded efficient costs. | We do not accept the findings of this analysis, which considers capex in isolation of other factors. The size of our distribution network is a significant contributor to the volume of fleet required, with the need to efficiently access urban and rural assets to maintain safety and reliability of the network for all customers.<br><br>To support our Revised Proposal, we have conducted analysis of our fleet capex on a circuit kilometre basis, which we consider a more reasonable measure of fleet requirements. |
| **Contingent project** | The AER considered our proposed triggers to be reasonable but indicated that it did not have sufficient information to support the contingent project. The AER also indicated that we had not provided sufficient details in relation to the nature of the regulatory obligation to which the contingent project would be responding. | Since submitting our Original Proposal, further details and information have become available from subsequent meetings and dialogue with the Australian Energy Market Operator (**AEMO**). AEMO has identified specific operational challenges, begun to quantify when they may occur, and begun to determine mitigation measures in South Australia, including certain actions that it considers will need to be taken by SA Power Networks during the 2020-25 RCP. Additional information in support of the contingent project is provided in this Revised Proposal. |

### 5.2.6 How our revised capex forecast compares

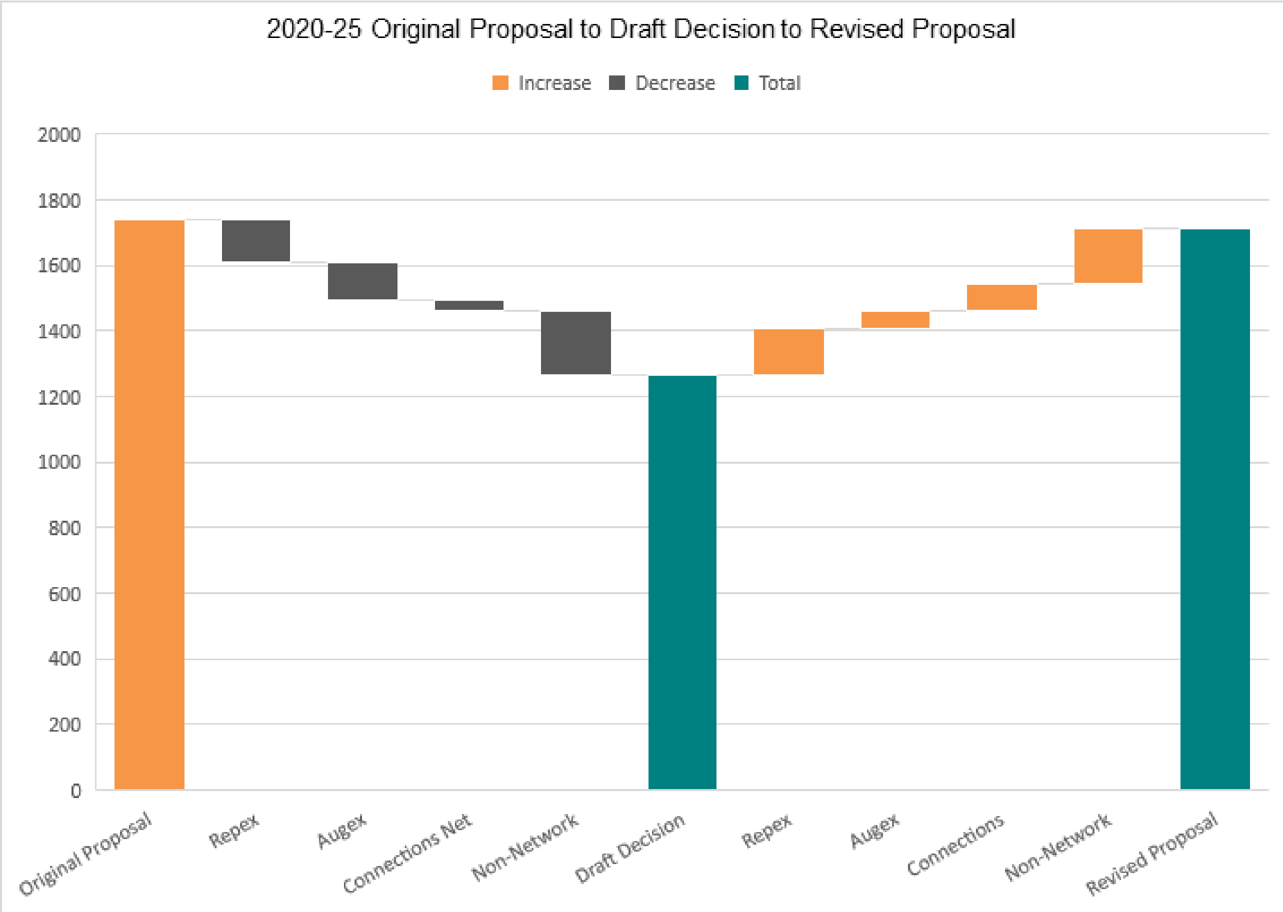
Table 5-4 outlines our Revised Proposal compared to the AER's Draft Decision and our Original Proposal.

**Table 5-4: SA Power Networks' Original and Revised Proposals compared to the AER's Draft Decision (June 2020, $ million)**

| Capex category | Original Proposal | AER Draft Decision | Revised Proposal | Difference to Draft Decision $ |
|---|---|---|---|---|
| **Repex** | 669.5 | 538.5 | 682.2 | 143.8 |
| **Augex** | 390.9 | 277.4 | 331.7 | 54.2 |
| **Connections (net)** | 213.2 | 176.3 | 261.7 | 85.3 |
| **Non-Network** | 467.4 | 270.3 | 436.5 | 166.2 |
| **Total** | **1,741.1** | **1,262.5** | **1,712.0** | **449.5** |

Figure 5-3 below provides a breakdown of how our Revised Proposal compares with our Original Proposal and the AER's Draft Decision.

**Figure 5-3: SA Power Networks' Original and Revised Proposals compared to the AER's Draft Decision (June 2020, $ million)**




### 5.2.7 Escalations

#### Background

SA Power Networks operates in a dynamic industry, providing a complex range of electricity services to customers. Our internal workers and the external contractors that we procure have diverse skills. Much of our work is performed on or near energised assets in a high-risk environment, where public and worker safety is paramount. As the services that customers demand have evolved, and continue to evolve, with technology, so too must the skill-sets of the workers that we seek to retain and / or acquire from labour markets and the contractors that we engage from time to time.

The prices that we pay for labour (wages) are influenced by various factors:

- for internal labour and labour rates embedded in the prices of contractor services, a key influence is the market for labour, that is, factors such as competition from other firms and industries for staff with particular skills; and
- for contractor services, the overall price is also subject to more specific influences such as the extent of competition among contractor services providers, the specialist nature of the work, the extent to which work is subject to long-term or short-term contracting, the urgency of the work and various non-price safety and quality related factors that may drive the decision to engage one contractor over another.

To ensure that we cover our likely labour costs, we must predict how future movements in labour markets will affect labour prices, over the duration of a 5 year RCP. Given the complexity of predicting market movements our current practice is to:

- seek the perspectives of expert independent labour market forecasters, consistent with the approach of all regulated network businesses; and
- not depend solely on a single forecaster’s approach, consistent with what has been the regulatory practice.

## Original Proposal

For the purposes of our Original Proposal on forecast capital expenditure (**capex**):

- we engaged independent expert forecasters, BISOE to forecast real labour price movements in South Australia over the 2020-25 RCP using the following Wage Price Indices (**WPI**):
  - for internal labour, the measure was the WPI for the utilities sector titled, ‘Electricity, Gas, Water and Waste Services’ (**EGWWS**); and
  - for all contracted services, the measure was the WPI for the construction sector titled, ‘Construction’. This was on the basis that most of the capital work on our network that we contract out to external service providers involves labour intensive activities which appropriately match the activities and skills reflected in the construction sector.[11] For consistency across all capex, we also applied the ‘construction’ WPI to escalate labour in contracted services specific to ICT works;
- rather than rely solely on the expectations of our own forecaster, we proposed that for internal labour the AER apply an average of BISOE’s forecast and that of the forecaster engaged by the AER, Deloitte Access Economics (**DAE**);
- as we do not have access to DAE’s forecast for the construction industry sector to calculate an average for contracted services, our Original Proposal applied BISOE’s forecast only to contracted services. We expected that the AER would obtain a construction sector forecast from DAE to then average together with BISOE’s forecast; and
- our proposed real labour price growth forecasts were those set out in Table 5-5.

**Table 5-5: SA Power Networks' Original Proposal—Real labour escalators for the 2020-25 RCP**

| Application | Forecast | 2020-21 | 2020-22 | 2022-23 | 2023-24 | 2024-25 |
|---|---|---|---|---|---|---|
| **Internal Labour** | DAE | 0.40% | 0.60% | 0.70% | 0.57% | 0.57% |
| | BISOE | 1.16% | 1.53% | 1.72% | 1.62% | 1.36% |
| | **Average** | 0.78% | 1.07% | 1.21% | 1.09% | 0.96% |
| **Contracted services - all** | BISOE | 0.69% | 1.38% | 1.65% | 1.29% | 0.89% |

11 For example, contracting is typically undertaken for labour intensive activities such as preparatory work, construction and / or logistics work such as trenching, earthmoving, civil construction, traffic management, etc.

### AER Draft Decision and stakeholder views

In their submissions to the AER on our Original Proposal, some stakeholders questioned if SA Power Networks' real labour price growth forecasts were reasonable, given their views that wages growth in South Australia had recently been, and was likely to remain, subdued. This was based on their opinions, with no alternative forecasts being provided to the AER.

The AER's Draft Decision did not approve several aspects of our Original Proposal as it pertained to capex:[12]

- Averaging labour price growth forecasts—the AER did not approve our proposal (across capex and opex) of continuing to apply the AER's standard approach from previous regulatory determinations of using an average of two forecasters (in this case, the forecasts of BISOE and DAE) and instead determined that it would rely solely on the forecasts of its own consultant, DAE. The AER's considerations are outlined in section 6.4.3.2.1 of Attachment 6 – Operating Expenditure, Revised Proposal.
- Contracted services—the AER did not apply any real labour price escalation for any contracted services, on the basis that:
  - it had requested existing contracts that contain forecast escalations matching the forecast escalations proposed by SA Power Networks for the 2020-25 RCP and, in its view, SA Power Networks was unable to provide any existing contracts or service agreements to demonstrate that the proposed real cost escalations are reflective of SA Power Networks' agreed contracts; and
  - it did not accept the application of a 'construction' WPI for escalating ICT related contracted services.

### Our further engagement with customers and stakeholders

Since the publication of the AER's Draft Decision, we engaged further on this topic with customers and stakeholders for the purposes of our Revised Proposal, via two meetings with the SA Power Networks CCP).[13] The general feedback we received, particularly from stakeholders representing vulnerable customers, was that they felt many South Australians had not experienced real wage increases.[14] There was no feedback on the more specific issue raised by the AER regarding contracted services.

We appreciate there is general complexity in understanding the drivers of labour price movements in South Australia and the circumstances of external contracting, particularly for specific and specialist skilled sectors like ours as compared to other parts of the State's economy. We are also conscious of ensuring that the costs of service provision to our customers are not higher than they need to be.

Our views with respect to labour costs are that:

- SA Power Networks needs to at least be able to recover our reasonably expected efficient costs over the 2020-25 RCP;
- because this involves predicting movements in complex labour markets, the least risky and more accurate approach to enable cost recovery, while at the same time minimising costs, is to seek the views of an independent expert labour market forecaster, and to have regard to more than one forecast, as we have proposed to do; and
- with more specific regard to contracted services, ensure that our procurement processes are reasonable and rigorous so that our choice of contractors reflects best value (in price and non-price

[12] AER, Draft Decision, Attachment 5, pp.20 to 21.

[13] Meetings held on 22 November 2019 and 27 November 2019.

[14] This is based on SA Power Networks' recollection of views expressed at those meetings, as no formal minutes of those meetings were taken.

terms) for the works we seek to procure. We assert that our processes are reasonable, prudent and efficient, and in line with best practice.[15]

## Our Revised Proposal

SA Power Networks does not accept the AER's Draft Decision in respect of real labour price growth, and our Revised Proposal is as follows:

1. We maintain our position that the AER should apply an average of BISOE and DAE's forecasts in all circumstances in which a real labour price growth forecast is applied to escalate costs. Our substantive reasoning on this issue is detailed in section 6.4.3.2.1 of our Opex Attachment to our Revised Proposal.

2. We maintain our position that the AER should apply real labour price growth forecasts to contracted services. The AER's Draft Decision to deny the application of forecasts for the 2020-25 RCP of real labour price growth on the basis of not observing these forecasts in contracts is unreasonable on several grounds.

3. We have revised our approach to escalating contracted services for ICT works, and propose the AER apply the 'all industries' WPI rather than the 'construction' WPI used in our Original Proposal. This addresses the AER's concern by using a WPI that is more appropriate to the specific skills and circumstances of contracted ICT services.

### *Averaging labour forecasts*

This aspect of our Revised Proposal applies equally to all real labour price escalation in capex and in opex. The details of our Revised Proposal and how we have addressed the AER's concerns from its Draft Decision are set out in section 6.4.3.2.1 of the Opex Attachment to our Revised Proposal, and in summary:

- To address the AER's concerns about the accuracy of forecasts, we engaged independent experts BISOE to comment on the methodology applied by the AER in arriving at its Draft Decision, in a report titled '*Review of AER Forecast Comparison*'.[16] BISOE's report contains the detailed analysis and recommendations supporting our Revised Proposal.
- SA Power Networks does not accept the AER's Draft Decision to solely use the forecasts of DAE, and we maintain our position that the AER should apply an average of the real labour price growth forecasts for the South Australian industry sectors produced by BISOE and DAE. The AER Draft Decision to rely solely on DAE's forecast is:
  - generally inconsistent with best practice regulation;
  - an imprudent approach to predicting SA Power Networks' reasonably expected costs, given there is no direct evidence on the performance of the two forecasters with respect to the South Australian industry sectors; and
  - likely to result in less accurate forecasts, given several flaws and omissions in the AER's analysis of the historical performance of the forecasts for the national utilities sector produced by DAE and BISOE.

With more specific regard to real labour price escalation in capital expenditure, our Revised Proposal is that an average of DAE and BISOE's forecasts be applied with respect to:

- the utilities sector WPI (EGWWS) for South Australia, in order to escalate internal labour costs—our reasoning is detailed in section 6.4.3.2.1 of our opex attachment;
- the construction sector WPI (construction) for South Australia, in order to escalate general contracted services costs—our reasoning is detailed below. Further, as we do not have access to

[15] Our procurement processes are aligned to the Chartered Institute of Procurement and Supply (CIPS) and we have been awarded the CPIS Corporate Certification Standard.

[16] BISOE, *Review of AER Forecast Comparison: Report prepared for SA Power Networks*, November 2019.

DAE's forecast for this industry sector, our Revised Proposal applies BISOE's forecast only. We expect the AER will, for its Final Decision, obtain a construction sector forecast from DAE to average together with BISOE's forecast.

- the all-industries WPI for South Australia, in order to escalate contracted services pertaining to ICT—our reasoning is detailed below.

***Forecasts for contracted services***

Prior to its Draft Decision, the AER submitted an information request to SA Power Networks on this topic. Our response outlined several factors for why the reasonableness of a forecast of real labour price growth cannot be determined by examining current contracts and agreements. The AER did not provide any indication that it was unsatisfied with our explanations and we therefore did not have any opportunity to respond further. We also observe that the AER's Draft Decision does not demonstrate any evidence that it directly engaged with our explanations, as the Draft Decision does not mention if the AER agreed or disagreed.

The AER's Draft Decision to disallow forecasts for real labour price escalation in contracted services over the 2020-25 RCP unless those forecasts can be observed in existing contracts, is unreasonable and ignores important factors. To expand on the matters raised in our response to the information request mentioned above, we identify the following:

- Our proposed real labour price escalators are a forecast for the 2020-25 RCP. These are based on the expert independent view of forecasters, BISOE (and DAE), on the labour market conditions that will prevail during 2020-25.
- The purpose of applying escalators to contracted services, as it is for internal labour, is to ensure that we form a realistic expectation as to the cost inputs we require to achieve the expenditure objectives in the NER.[17] Further, the Revenue and Pricing Principles in the National Electricity Law entitle us to recover at least our efficient costs.
- SA Power Networks' current contracts / agreements for capex related external contracted services are irrelevant to indicating likely growth in real labour prices over the 2020-25 RCP:
  - the price and non-price terms reflected in our current contracts / agreements for contracted services are a function of the prevailing labour market, contractor services market, and specific work requirements prevailing predominantly in the 2015-20 RCP; and
  - of our current capex related contracts / agreements, 90 percent (in number and cost terms) will have expired by the end of the 2020 year, including the two largest contracts which have a combined value of over $100 million.
- It is misleading for the AER's Draft Decision to appear to suggest that its disallowance of our forecast is due to our failure to provide the AER with contracts. Rather, existing contracts (covering works over the 2015-20 RCP) are simply irrelevant to the issue of forecast real growth in labour prices for the 2020-25 RCP, and cannot serve as a basis for indicating the reasonably expected cost input that SA Power Networks is entitled under the NER to recover.[18]
- The fact that SA Power Networks has largely not yet already formed contracts / agreements for the 2020-25 RCP is also reasonable and prudent, noting that:
  - the capital works that we undertake over the 2020-25 RCP will depend on the revenue allowances provided in the AER's Final Decision for the 2020-25 RCP, which will only be made in April 2020;
  - the AER's revenue allowances, and the extent to which these divert from our Revised Proposal, will guide how we prioritise works for the 2020-25 RCP. Further, over the course of a RCP, we may again reasonably need to re-prioritise further depending on the circumstances (e.g. changes in demand or exports, new construction developments, incidences of climatic events) that arise over the RCP; and

[17] Clauses 6.5.6 an 6.5.7 of the NER.

[18] Clause 6.5.7(c) of the NER.

- having forecasts of real labour price growth developed by an independent expert forecaster at the time of the AER's final decision for the 2020-25 RCP, may then provide useful information to SA Power Networks in assessing the prices proposed by external contractors in their tenders and negotiations for our work—ensuring that costs are no more than what we would expect, having broad regard to these independent forecasts.

- No useful information can be garnered from examining historical contracts (ie those covering a period before the 2020-25 RCP), including because:
  - most of our past contracts have been for short-term work, often for specific jobs which may require only a few months of work and therefore long-term escalation rates will not be reflected in these contracts. In short-term contracts, covering a few months or a couple of years, escalation rates may not be relevant as typically contractors will, in their tenders, build-in their expectations as to movements in their input costs over this space of time; and
  - our two largest historical contracts which cover a large proportion (almost 25%) of our capex related contracted services costs (combined value greater than $100 million) and which are for powerline construction and maintenance services, cover a period of only 3 years. In fact, these two contracts contain clauses for labour parity with our internal staff—that is, movements in labour prices will match those applied to our internal staff (which will be escalated using our current Enterprise Bargaining agreements). Further, potential use of such parity clauses in future may be the subject of Enterprise Bargaining negotiations.
- The real labour price escalators that are the subject of the AER's Draft Decision, reflect growth in real prices, rather than stating the total prices / rates themselves that will be provided to external contractors which we procure[19]:
  - the price / rate that is agreed with an external contractor will depend on the results of our procurement processes at the specific time in which these processes are undertaken, in assessing the nature and urgency of the work required, the extent of available competitors to that services provider, and other non-price (e.g. quality, assurance, insurance etc) factors considered as part of our procurement processes; and
  - for these reasons, there may be cases where an agreement / contract signed over the course of the 2020-25 RCP may reflect escalations that differ to or exceed those which are the subject of our Revised Proposal, as these only serve to reflect the average of expected growth in real labour prices rather than specific cases. This also indicates the imperative of applying forecast escalations, in order to cover our input costs over the 2020-25 RCP.

***Choice of WPI for contracted ICT services***

SA Power Networks agrees with the concern raised in the AER's Draft Decision of applying a construction sector WPI to escalate real labour prices for contacted ICT services. We revised our approach and propose that the AER accept the application of the 'all industries' WPI as being most relevant to the circumstances of contracted ICT services. This is noting that:

- Contracted ICT services typically cover a broad range of specialist technical skill-sets and these:
  - typically require knowledge of working in an environment of an essential services utility providing multiple complex services to customers, and in some cases specific knowledge of electricity systems (eg works involving utility asset management and field maintenance, outage management, supervisory control and data acquisition (**SCADA**), ADMS, and other systems);
  - typically are performed by system professionals, such as enterprise architects, solution designers, ICT engineers, system integrators etc. The nature of these required skill-sets differ to those that would be reflected in the construction sector and other indices reported by the Australian Bureau of Statistics (**ABS**); and
  - are increasingly, over time, needing to be procured onshore, based on the generally increasing expectations that essential services utilities in Australia have appropriate cyber security protections.

[19] Noting that capex-related contracted service contracts are mostly for labour related services, with any significant materials sourced from SA Power Networks.

- We sought the view of an independent expert labour market forecaster, BISOE, as to the appropriate WPI to apply to the contracted ICT services that SA Power Networks procures, and expects to procure, over the 2020-25 RCP. Their view, as detailed in their report, *'Utilities and Construction Wage Forecasts to 2024/25 for SA Power Networks'* (supporting document 6.5) is that the 'all industries' WPI for South Australia is the most appropriate WPI to use to escalate SA Power Networks' contracted ICT labour and that this WPI will cover the broad spectrum of the outsourced services that we typically procure for ICT works.[20]

In summary:

- For the reasons set out above, and in the Opex attachment to this Revised Proposal, and in our supporting documents, our Revised Proposal is to apply averages of DAE and BISOE's forecast labour price growth escalators to our forecast capex for the 2020-25 RCP.
- Our Revised Proposed escalators are those set out in Table 5-6. We expect that the AER will procure the latest updated forecasts from its own forecaster, DAE, for all these escalators and apply an average utilising the forecasts produced by BISOE.
- Our proposed forecasts set out in Table 5-6, have been updated since our Original Proposal to reflect the latest economic conditions, as detailed in an updated labour escalation report from BISOE (Supporting Document 6.5).[21]

**Table 5-6: SA Power Networks Revised Proposal—Real labour escalators for the 2020-25 RCP**

| Application | Forecast | 2020-21 | 2020-22 | 2022-23 | 2023-24 | 2024-25 |
|---|---|---|---|---|---|---|
| **Internal labour** | DAE | 0.41% | 0.37% | 0.34% | 0.45% | 0.44% |
| | BISOE | 1.11% | 1.28% | 1.44% | 1.60% | 1.33% |
| | Average | 0.76% | 0.83% | 0.89% | 1.02% | 0.89% |
| **Contracted services - general** | BISOE | 0.30% | 0.68% | 1.26% | 1.37% | 0.75% |
| | DAE | Not available to SA Power Networks | | | | |
| | Average | To be calculated by AER pending DAE forecast | | | | |
| **Contracted services - ICT** | DAE | 0.30% | 0.50% | 0.60% | 0.70% | 0.60% |
| | BISOE | 0.82% | 1.02% | 1.31% | 1.37% | 0.90% |
| | Average | 0.56% | 0.76% | 0.95% | 1.04% | 0.75% |

## 5.3 Replacement capex

### 5.3.1 Overview

Repex is non-demand driven capex for the replacement of assets with their modern equivalent either at the end of the asset's life, or prior, based on the asset's risk of failure and the extent to which such failure would compromise safety or our ability to meet our service obligations.

SA Power Networks has the oldest distribution network in the NEM and we are identifying increasing numbers of defects on our network. The average age of our network assets continues to rise, despite significant increases in repex since the early 2000s. In the early 2000s, our repex spend was very low – but the average age of our network assets was also relatively young – just over 20 years – and asset failures and defect rates were not high. In 2019, the *average* age of our assets is now nearly 45 years and by the end of the 2020-25 RCP it will be nearly 50 years. In light of the higher defect rates of this older fleet of assets, we are now spending in the order of $150 million of repex per annum to maintain safety and reliability of supply.

[20] SA Power Networks, *Revised Regulatory Proposal for 2020-25—Supporting Document 6.5*, BIS Oxford Economics, Utilities and construction wage forecasts to 2024/25 for SA Power Networks, p.2

[21] The DAE forecasts are derived from *Deloitte Access Economics - Labour Price Growth Forecasts prepared for the AER - 24 June 2019.*

Yet we are currently only turning over our assets at less than 0.5% per annum, implying an <u>average</u> asset life of more than 200 years. This is clearly not sustainable, and asset replacement rates must continue to rise until we reach an equilibrium between asset replacement and asset ageing.

However, we do not replace assets simply because they are old – we replace based on factors including asset condition and consequence of asset failure. As outlined in our Original Proposal, our asset management approach has become increasingly more sophisticated over the last 20 years. We have evolved from:

- only replacing assets after they have failed; to
- replacing assets on a simplistic defect priority basis – open to interpretation and applied subjectively by individual asset inspectors; to
- developing a risk-based approach – valuing defect risk, but based on only limited location and asset condition data; to
- our current 'value and visibility' approach, which we started rolling out across our organisation from 2017. This approach has only become possible after collecting more comprehensive data on every asset in our network – and this was only completed late in 2018. We will continue to update our asset condition data in accordance with our asset inspection cycles. We can now better assess the risk value of every defective asset identified by assessing the type of defect, the probability of that asset failing and the consequence of that asset failing, taking into account its location in the network and the consequent community and bushfire risk, reliability of supply risk, environmental risk and other factors.

This asset management evolution relies not only on having better asset condition data but also through developing better (IT) tools to analyse the asset data and to better prioritise resources to address the highest value risks first and therefore spend repex more efficiently. But we are only at the early stages of implementing 'value and visibility'. Automating and better integrating improved and updated asset risk information into our daily work processes requires further IT development for which we have an IT program – denoted Assets and Work.

In the current 2015-20 RCP we have been implementing our foundational Asset and Work - Stage 1 (previously Enterprise Asset Management), commencing the transition of asset management from high level management of 1,500 feeders and basing maintenance decisions on history, to identifying and managing more than two million individual assets and using current condition data to manage assets based on risk and value.

Investing in Assets and Work Stage 2 in the 2020-25 RCP will enable further improvements in our understanding of asset risk and value and commence automation and integration of work selection and prioritisation. This will enable an efficient deferral of some repex on an ongoing basis and a range of other efficiency benefits thus allowing us to moderate the upward repex trend while maintaining the safety and reliability of our network.

However, in its Draft Decision the AER did two things:

- it reduced our repex forecast to nearly 20% below current period expenditure; and
- it did not approve our Assets and Work program on which our original forecast was predicated.

We are deeply concerned with these decisions and we have worked hard to clarify and address the specific concerns raised by the AER and its consultants, EMCa, who also assessed the repex forecast from our Original Proposal. We address these concerns in a Repex Addendum (Supporting Document 5.4), to this Attachment.

Our proposed revised forecast for repex in the 2020-25 RCP is summarised in Table 5-7 below. The revised forecast is \$682.2 million, \$12.7 million higher than our Original Proposal forecast of \$669.5 million and it is \$23.5 million higher than our forecast expenditure in the current 2015-20 RCP.

**Table 5-7: SA Power Networks' Original and Revised Proposals repex forecast compared to the AER's Draft Decision (June 2020, $ million)**

| Repex | Original Proposal | AER Draft Decision | Revised Proposal |
|---|---|---|---|
| Option 2 - Proposal | 669.5 | 538.5 | 682.2 |

This revised forecast is predicated on the AER approving IT funding in the 2020-25 RCP for our Assets and Work Stage 2 program. The Assets and Work program is discussed further in section 5.6 and a revised business case, addressing the AER's concerns with this program, is provided in Supporting Document 5.31.

If the AER does not approve funding for Assets and Work Stage 2 we will require further repex funding in accordance with what we are now denoting as Option 1 - Base Case forecast, to maintain network risk.

In developing the total repex forecast for each of our Original Proposal[22] and our Revised Proposal we considered two options:

- Option 1 – Base Case forecast; and
- Option 2 – Proposal with Assets and Work.

The 'Option 1 – Base Case' repex forecast was primarily developed using a combination of CBRM, historical trend and historical average methodologies to develop an efficient repex forecast. Other minor programs use bottom up forecasting and net present value (**NPV**) models for specific programs.

The trend analysis demonstrably represents a prudent and efficient forecast on the basis of further analysis using the AER's repex model which together with independent analysis undertaken by Frontier Economics confirms we are at the beginning of a bow wave for our asset replacement program. As the average age of our network assets increase and asset condition deteriorates, all things being equal, replacement expenditure must increase to maintain risk and service levels in line with regulatory obligations.

The total repex forecast for Option 1 – Base-Case, is shown in Table 5-8.

**Table 5-8: SA Power Networks' Original and Revised repex forecast compared to the AER's Draft Decision (June 2020, $ million)**

| Repex | Original Proposal | AER Draft Decision | Revised Proposal |
|---|---|---|---|
| Option 1 – Base-case forecast | 669.5 | 538.5 | 740.7 |

The 'Option 2 - Proposal with Assets and Work' repex forecast was also developed using a combination of CBRM, and top down historical average methodologies. We undertook detailed bottom up analysis to develop our Assets and Work program to derive benefits in the form of a repex reduction. The difference between Option 1 and Option 2 is the difference between the trend forecast and the historical average forecast for those asset classes which used a trend forecast in Option 1 and is comparable to the benefits forecast to be delivered by the Assets and Works program.

As noted above, subject to the AER approving Assets and Work Stage 2, we propose a total repex forecast in the 2020-25 RCP based on historical 2015-20 average repex. However, if the AER does not approve Assets and Work Stage 2 then our repex forecast would revert to our Option 1 Base Case forecast which is based on trend.

**Stakeholder feedback**

We presented the AER Draft Decision substitute repex forecast, our Option 1 and Option 2 to our stakeholders (the SA Power Networks CCP and other key stakeholders including the AER), in a workshop on 25 October 2019. When presenting each option, we clearly explained the pricing impact on customer bills.

[22] Noting we did not explicitly present 'Option 1 – Base case' in our Original Proposal.

Given our ageing asset base, our stakeholders were concerned the AER's Draft Decision forecast may result in a deterioration in the safety and reliability of the network. They were also concerned the Draft Decision forecast may result in intergenerational inequity, with many stakeholders commenting on whether the "can was being kicked down the road".

Stakeholders accepted that an increasing level of expenditure based on trend (Option 1) appeared reasonable.

In relation to Option 2 – Proposal with Assets and Work, stakeholders appreciated the complexity of the Assets and Work program and its interrelationship with the repex forecast, as well as SA Power Networks' efforts to manage potentially increasing expenditure requirements.

Following detailed discussions, stakeholders supported Option 2 – Proposal with Assets and Work.

Several stakeholders commented:

> *"Option 2 is reasonable - provide your reasons and what I'd hope is that the AER continue to apply same rigour to your proposal and consider feedback provided in stakeholder submissions."*
>
> *"SAPN should be commended for putting up a modest proposal."*
>
> *"It's complicated, but the idea that the Assets and Work program stops is unacceptable. Nothing suggests you should stop improving your practices… we'd be able to support you going back to AER with your updated business case – ensure you demonstrate it is in long term interest of customers."*

These sentiments were echoed in subsequent meetings with the SA Power Networks CCP and other reference group members, and we have committed to ongoing engagement with our stakeholders on this important topic.

**Long term repex profile**

Our 'Option 1 – Base Case' repex forecast is the efficient level of expenditure required to meet our regulatory obligations and requirements in the 2020-25 RCP to maintain a safe and reliable network.

We understand that the AER's Draft Decision substitute repex forecast was based on the average historical repex from 2013/14 to 2017/18. We do not believe a 20% reduction to repex is prudent or efficient when the average age of our assets continues to increase and is approaching 50 years. It will not enable us to meet our regulatory obligations and requirements to maintain a safe and reliable network. Our stakeholders support this view.

Figure 5-4 below shows our increased repex and, contrary to statements made by EMCa and echoed by the AER in its Draft Decision about underspending allowances, demonstrates we have spent close to, or exceeded, our repex allowances in all but the first two years of the 2015-20 RCP.

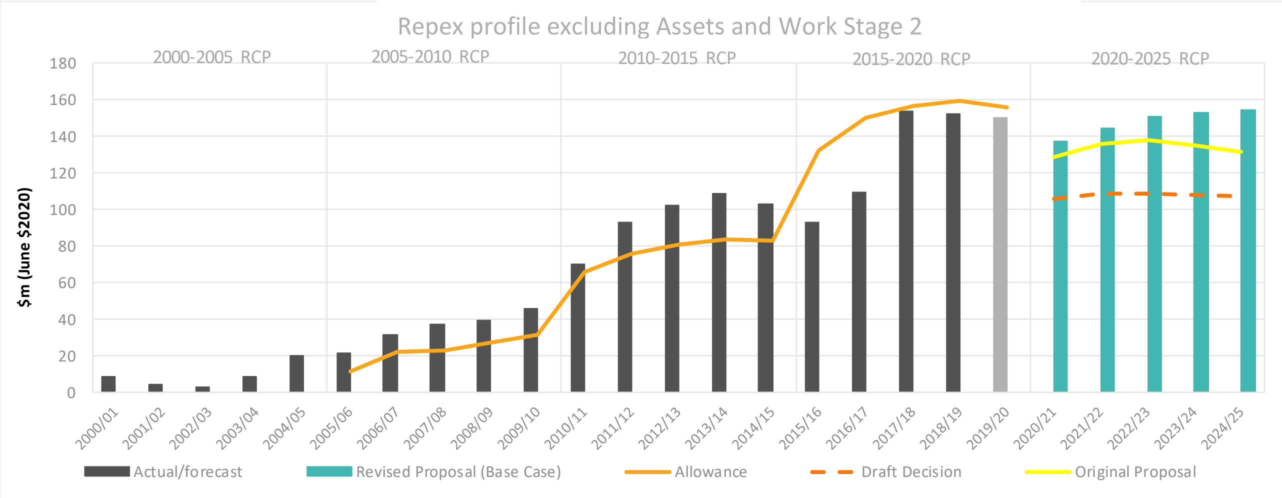
These two years were abnormal and reflected anomalous conditions which affected our actual replacement expenditure levels. The 2015/16 regulatory year was materially impacted by the financing uncertainties arising from the AER at the time first making a Preliminary Decision in April 2015 for the 2015-20 RCP. This decision provided for an unexpected, materially ($300 million) lower revenue allowance than anticipated.

When SA Power Networks prepared its 2016 calendar year budget in mid 2015 it only had this Preliminary Decision to guide its 2016 budget process. Budgets were set lower in 2016 reflecting this uncertainty. The Final Decision was not published until October 2015, after the 2016 budget had been approved by SA Power Networks' Board.

Capex in the 2016/17 regulatory year was also materially impacted by unprecedented weather, the worst storm year on record in South Australia. A record number of nine major event days occurred in this regulatory year, leading to resources being diverted from the asset replacement program to emergency response and repairs operating activities.

Also, over the first two years of the period we delayed some replacement expenditure as we transitioned to our 'value-based replacement' approach using our Valuing and Visibility Tool.

**Figure 5-4: Option 1 – Base case repex forecast (June 2020, $ million)**



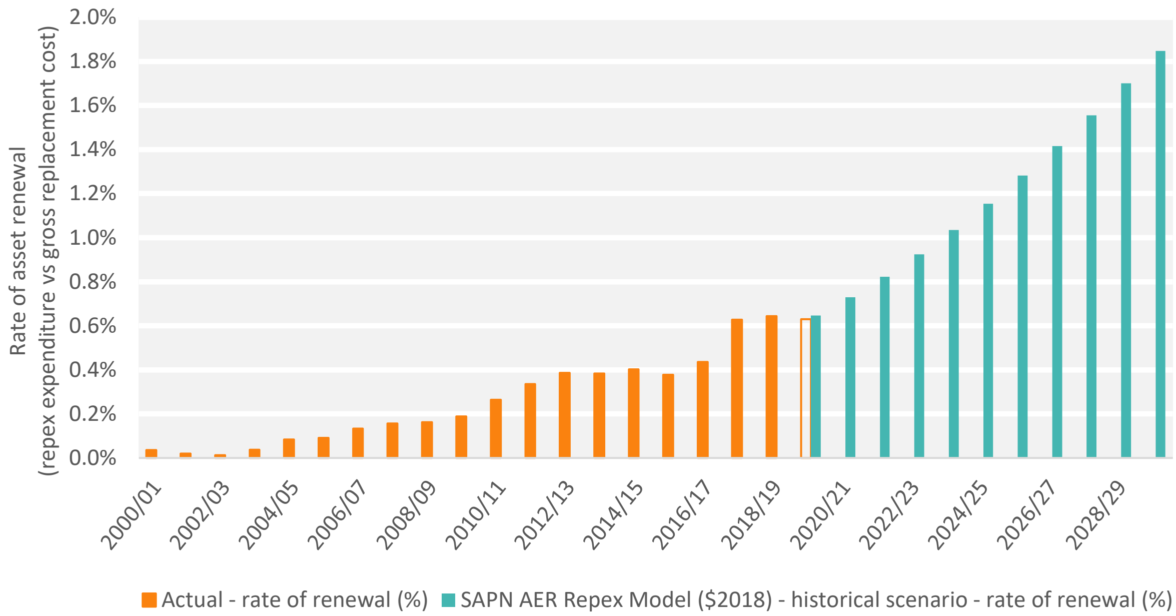

*Note: 2020-25 excludes the recategorised conductor and cable minor repairs.*

While there are short-term fluctuations in repex, the long-term expenditure trend demonstrates an upwards trajectory as the average asset age continues to increase. Over the period 2000 – 2019, our repex has increased from near zero to over $150 million per annum to in the current RCP to manage the increasing risk exposure of failure across the larger proportion of the asset base.

The current RCPs level of repex is still low relative to the substantial asset base that forms our network. The current asset replacement rate is below 0.5% of asset replacement value per annum, and the mean age of the total asset base is still increasing by about one year per annum. The current replacement rate implies an average asset life of more than 200 years. This is unsustainable over the long run, especially given the increasing use of electronic assets with lives as short as 10-15 years, and therefore our repex will need to increase in the future.

An increasing trend for repex is validated by forecasts developed using the AER's Repex Model (Figure 5-5).

**Figure 5-5: AER Repex Model – Long term repex trend**



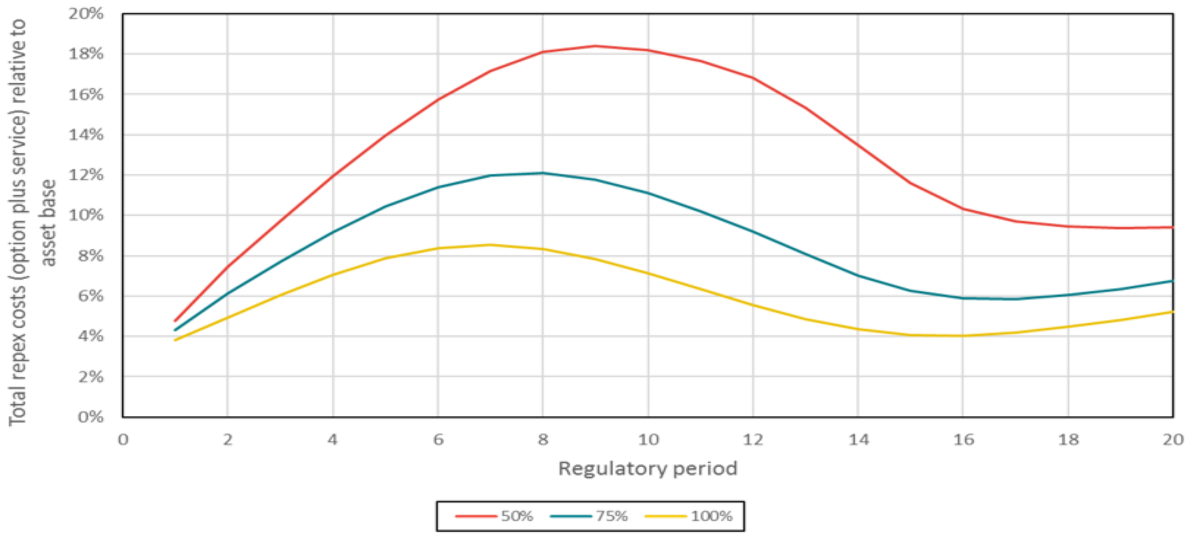

We have used the AER Repex Model to project the proportion of network assets (by replacement value) that will require replacement over the next 10 years. The AER Repex Model forecasts replacements based on age and observed historical failures and replacements. It also assumes a continuation of current asset and works practices. The results show repex requirements increasing by 200% over 10 years.

Independent analysis by Frontier Economics[23] on the long-term implications of repex allowances also indicates an increasing requirement for repex to address the ageing asset base. Figure 5-6 displays the cost of repex related to SA Power Networks' poles that Frontier's modelling suggests over each 10 year period,[24] relative to the value of the asset base—showing the implications of allowing differing levels of funding to undertake required repex (as determined by Frontier's modelling). The yellow line displaying 100% means that all required expenditure is funded and there are no in situ failures. These figures take into account both the cost of undertaking repex (option cost) and the estimated failure premium to reflect additional costs of asset failures in terms of network reliability and safety, including bushfires (service cost). Figure 5-6 shows the 'bow-wave' as assets age and are replaced, followed by a trough during the period when the old assets have been replaced and the age profile becomes weighted towards younger assets.

[23] Frontier Economics, *The long-run implications of regulatory repex allowances*, December 2019, p 31.

[24] Each 10 year period is displayed in increments of 2.

**Figure 5-6: Frontier Economics – Long term replacement expenditure trend for poles**




*Source: Frontier Economics analysis.*

*Note: Vertical axis represents total repex expenditure (option costs plus service costs – including the safety/reliability cost associated with in situ replacements) relative to the total replacement value of the asset class.*

Frontier's analysis shows that SA Power Networks will require higher levels of expenditure, increasing over multiple regulatory periods, as assets reach end of life. In particular, Frontier's analysis identifies that the lumpiness of the investment in SA Power Networks' network assets during the 1950s and 1960s has created a large 'bow wave' of assets that will need to be replaced as they reach the end of their useful lives. This will dictate minimum asset replacement requirements over coming regulatory periods.

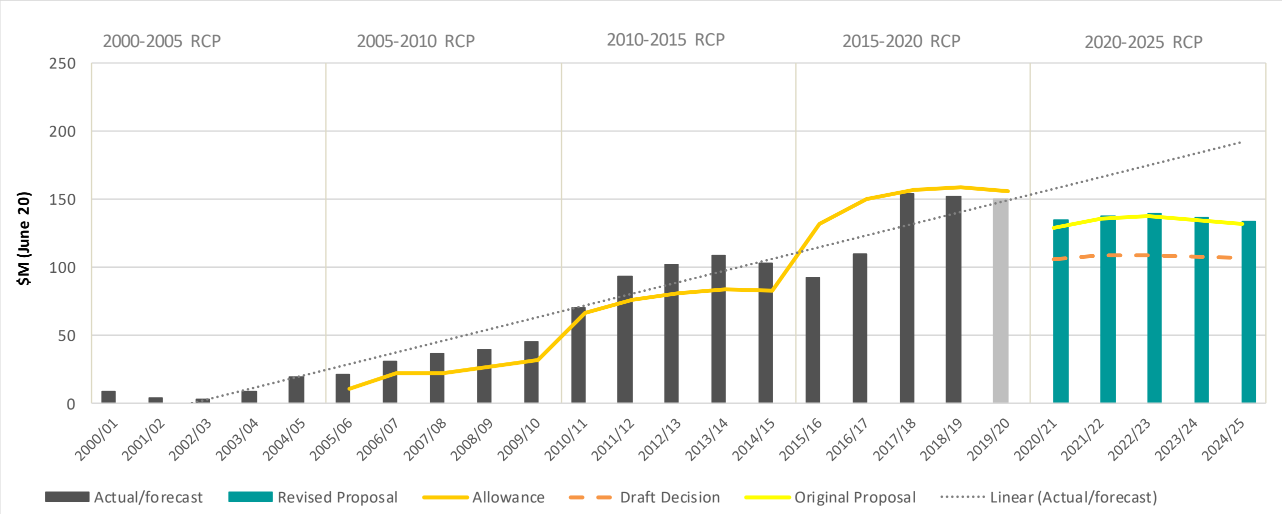
Frontier's analysis also draws attention to the intergenerational equity trade-offs for customers arising from decisions to undertake lower than required levels of repex via conceptual propositions using data from a sample set of SA Power Networks' asset classes. In summary, Frontier finds that:

- not replacing network assets that are identified as needing replacement will result in more incremental in-situ asset failures, and more assets that need to be replaced in future RCPs, pushing more cost burden onto future generations of customers; and
- replacing assets after they have failed is also more costly for customers than orderly replacement as part of a repex program. This is because replacing an asset after it has failed will result in consequences to network safety and reliability for customers.

Through the implementation of Assets and Work - Stage 2, we believe we can maintain the safety and reliability of our network in the 2020-25 RCP with annual repex at similar levels as 2017/18 and 2018/19 expenditure levels[25]. Figure 5-7 shows our repex expenditure profile over the 2000-25 period with the Assets and Work Stage 2 repex adjustment.

[25] Figure shows a lower level of expenditure in the 2020-25 RCP due to some conductor and cable programs now being treated as opex.

**Figure 5-7: Option 2 – Proposal repex forecast (June 2020, $ million)**




*Note: 2020-25 excludes the recategorised conductor and cable minor repairs.*

**Our network performance**

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

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

This level of repex reflects the increasing number of asset defects occurring within our network due to age, service and environmental conditions.

While we have significantly increased our repex over the past 20 years, our overall long-term performance trend in managing safety and reliability must be considered steady at best. Supporting Document 5.4.1: Managing SA Power Networks' Ageing Assets, contains a series of charts displaying our performance since 2005/06 on the following indicators:

- Number of high voltage outages – increasing;
- Outages from equipment failure – steady
- Shocks from our infrastructure – increasing
- Fire starts – increasing
- Pole failures – increasing
- Pole top failures – steady
- Conductor failures – steady
- Reliability performance – underlying duration performance is steady but the customer experience is deteriorating.

We need to continue to invest in repex to maintain safety and reliability performance.

Supporting Document 5.4.1: Managing SA Power Networks' Ageing Assets, also supports that we have been prudent and efficient with our past expenditure:

- We have the oldest distribution asset in the NEM;
- We have very low regulatory asset base (**s**) growth compared with our peers; and
- We have the second highest capital productivity of NEM distributors.

As explained above, we will need to increase repex in subsequent RCPs to maintain network safety and performance. However, investing in our Assets and Work (IT) program now, will improve our efficiency in spending repex in the years to come – which will keep costs down for consumers in the long-term.

**AER's Draft Decision for repex**

The AER did not accept our forecast repex related capex for the 2020-25 RCP as they were not satisfied the forecast of $669.5 million (including safety repex) reasonably reflected the capex criteria. The AER's substitute estimate of $538.5 million is below our Original Proposal.

The AER's primary concerns were:[26]

- Overstated risk in the CBRM models.
- Insufficient evidence to support the inclusion of last two years of the current RCP, where the historical trend is used to derive forecast repex.
- Estimates for the last two years of the current RCP represent a significant step up from the average of the 2013–18 regulatory years.

For high volume assets, where detailed asset condition data is available, we apply CBRM models. We have undertaken CBRM modelling across four major asset classes:

- Poles;
- Zone substation circuit breakers;
- Zone substation power transformers; and
- Zone substation protection relays.

The CBRM models enables us to optimise the volume of repex based on risk.

The CBRM forecasting methodology uses a bottom-up assessment of an asset population, determining the individual condition of each asset, the consequences of its failure and the resulting risk it creates. By aggregating this information, CBRM provides the ability to granularly analyse the impacts of numerous intervention strategies to determine the optimal choice of action that achieves a desired asset management outcome. However, for the CBRM to work effectively it requires a significant level of information on the asset population which is why we have only used the CBRM modelling for these four asset classes.

**AER's concerns with the CBRM modelling**

In its Draft Decision the AER expressed a number of concerns with our CBRM models. The AER's concerns with our repex forecast were principally focused on characteristics of the CBRM methodology we used to forecast poles, circuit breakers, protection relays and power transformers. The AER also had concerns that our governance process did not adequately test the prudency and efficiency of our proposed capex.

We have addressed each of the AER's concerns in detail in our Repex Addendum (Supporting Document 5.4). In summary, we have responded to the AER concerns by undertaking the following actions:

- We have had our CBRM inputs independently verified[27];
- We have implemented most of the recommendations from the CBRM independent verification, including changes to values used for risk consequences and the likelihood of consequences occurring following an asset failure, and updated our CBRM results and repex forecast;
- We reviewed our modelled risks against recent actual risk incurred data where available and adjusted our assumptions to align to actual risk where a difference was found;
- We have held workshops with the AER to walk through the model; and

[26] AER, Attachment 5, pp 43-44
[27] Supporting Document 5.5: CBRM Model value of consequence independent report.

- While our CBRM implementation is an open, non-proprietary, transparent system, where all inputs, outputs and assumptions can be seen and tested, it is tightly integrated into our corporate IT systems (to facilitate operational decision making). In order to make the model more accessible and transparent, we have developed a set of excel spreadsheets which replicate not only the interventions (provided previously) but now provide all modelling steps after the Health Index calculation (this step is still reliant on connection to our corporate systems).

**How our revised repex forecast compares**

Table 5-9 details our Original Proposal and Revised Proposal repex for the 2020-25 RCP for each repex category, compared to the AER's Draft Decision.

**Table 5-9: SA Power Networks' Original and Revised Proposals repex forecasts compared to the AER's Draft Decision (June 2020, $ million)**

| | Original Proposal | AER Draft Decision | Revised Proposal | Difference to Draft Decision $ |
|---|---|---|---|---|
| **Proposed repex – Option 2** | **669.5** | **538.5** | **682.2** | **143.8** |
| Poles | 165.2 | 120.1 | 180.7 | 45.1 |
| Overhead line components | 94.7 | 93.6 | 109.1 | 15.6 |
| Switchgear (powerline) | 52.0 | 41.8 | 54.2 | 12.4 |
| Service lines | 41.7 | 41.3 | 49.1 | 7.8 |
| Other powerline | 97.3 | 95.6 | 87.2 | (6.5) |
| Zone substation power transformers | 26.8 | 18.7 | 30.0 | 11.3 |
| Zone substation circuit breakers | 60.5 | 44.5 | 58.1 | 13.6 |
| Zone substation protection relays | 16.4 | 12.9 | 16.3 | 3.4 |
| Other substation and CBD | 47.2 | 41.4 | 43.3 | 1.9 |
| Telecommunications | 30.5 | 24.0 | 24.8 | 0.8 |
| Northfield GIS | 11.8 | 0 | 11.8 | 11.8 |
| PILC cables | 14.4 | 4.7 | 7.1 | 2.7 |
| North Terrace cable ducts | 10.7 | 0 | 10.5 | 10.5 |

Details of our Original Proposal, the AER's Draft Decision and our Revised Proposal for each of these categories are set out below. In some categories we largely accept the AER's decision – and only revise our forecasts to include latest actual 2018/19 data. In other areas we have more substantial differences and address these more comprehensively in the Supporting Document 5.4 - Repex Addendum.

### 5.3.2 Poles

Stobie poles are unique to South Australia and have been used to support overhead distribution lines for 95 plus years. Stobie poles consist of a concrete core with two outer steel beams connected by bolts to ensure strength. Sizes of Stobie poles may vary from 9 metres in length for LV applications to greater than 15 metres for sub-transmission applications.

**What we originally proposed**

SA Power Networks' original forecast repex for the 2020-25 RCP was $111.4 million for pole replacement, $35.1 million for pole refurbishment and $18.8 million for line clearance rectification (originally categorised as safety repex). The total forecast for poles (including line clearance rectification) was $165.2 million.

The pole replacement program involves the like for like replacement of poles that cannot be refurbished.

The pole refurbishment program involves welding steel plates to the Stobie pole steel channel at the base of the pole.

The line clearance rectification program is a safety related program to address our regulatory obligations and requirements. We are required to comply with the minimum clearances for conductors as specified in the Electricity (General) Regulations 2012 (SA). The line clearance rectification work is driven by the identification of defects which are prioritised following a risk assessment. All breaches of regulated clearances must be rectified.

**The AER's Draft Decision and how we responded**

The AER's Draft Decision for poles was $120.1 million (*including* line clearance rectification), $45.1 million below our original forecast.

The AER provided commentary on the approach used for determining forecasts for pole replacements. The Draft Decision rejected our proposed forecast for the following reasons[28]:

- Overstated risk and general issues with CBRM as described above;
- Forecasts for the Line Clearance program were not developed using CBRM, yet SA Power Networks claimed all Poles expenditure was developed using CBRM;
- Pole failure rates are stable excluding significant events;
- No sensitivity analysis was provided to address any bias of inputs in CBRM models; and
- No evidence to demonstrate increase in defects represents an increase in network risk.

We have revised our forecasts, taking into consideration this feedback. The actions that we have undertaken are explained in detail in Supporting Document 5.4: Repex Addendum.

For the line clearance rectification program the expenditure in our Original Proposal ($18.5 million[29]) is based on our historic expenditure related to remediating overhead power lines that do not meet statutory clearances during the current RCP. The expenditure is included in the CBRM model to avoid 'double-counting' and overstating risk.

**Our revised forecast**

SA Power Networks' revised forecast for the poles programs is $180.7 million, $60.6 million higher than the AER substitute forecast, as detailed in Table 5-10 below.

**Table 5-10: Forecast poles repex for the 2020-25 RCP (June 2020, $ million)**

| | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| Pole replacement | 25.2 | 25.4 | 25.6 | 25.7 | 25.9 | **127.8** |
| Pole refurbishment | 7.4 | 7.42 | 7.5 | 7.5 | 7.5 | **37.3** |
| Line clearance rectification | 3.1 | 3.1 | 3.1 | 3.1 | 3.1 | **15.5** |
| **Total** | **35.7** | **36.0** | **36.1** | **36.4** | **36.5** | **180.7** |

**Supporting evidence**

Table 5-11 lists the supporting evidence for the revised poles program included in our Revised Proposal.

[28] AER, Attachment 5, pages 50 to 51.
[29] $23.2 million is incorrect as it equates to 6 calendar years.

**Table 5-11: Supporting evidence for the poles repex**

| Document reference | Document name | Program it relates to |
|---|---|---|
| 5.4 | Repex Addendum | Repex - Poles |
| 5.5 | CBRM Model Value of Consequence Independent Report | CBRM poles model |

### 5.3.3 Overhead line components

The overhead line components category[30] covers a variety of assets that enable overhead conductors to be securely attached to their support structures, support other pole mounted equipment and connect the overhead conductors to other equipment. Overhead line components include cross arms, insulators, overhead switchgear, joints and taps, and other minor components.

**What we originally proposed**

SA Power Networks' Original Proposal included a forecast of $94.7 million for overhead line components replacements for the 2020-25 RCP.

**The AER's Draft Decision and how we responded**

The AER's Draft Decision on overhead line components was $93.6 million. The AER determined that we had not demonstrated a need to increase our overhead line components repex in the 2020–25 RCP over and beyond its actual current levels. The AER substitute estimate is based on the historical expenditure for pole top structures across the 2013-18 period.

We have exceeded forecast expenditure in 2018/19 on the basis that our Value and Visibility tool assessed that the highest risk, lowest cost work required prioritising expenditure for pole top structures thereby increasing category expenditure and optimising remaining expenditure across our asset classes. We have revised our forecast to reflect this.

**Our revised forecast**

SA Power Networks revised forecast for the overhead line component program is $109.1 million as detailed in Table 5-12 below.

**Table 5-12: Forecast for overhead line components repex for the 2020-25 RCP (June 2020, $ million)**

| | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| Overhead line components | 21.6 | 21.7 | 21.8 | 21.9 | 22.1 | **109.1** |

**Supporting evidence**

Table 5-13 lists the supporting evidence for the revised pole top structures program included in our Revised Proposal.

**Table 5-13: Supporting evidence for the pole top structures repex**

| Document reference | Document name | Program it relates to |
|---|---|---|
| 5.4 | Repex addendum | Repex |

[30] Note in the RIN, overhead switchgear and overhead line components together form 'pole top structures'.

### 5.3.4 Switchgear

Switchgear consists of overhead switchgear[31] and switching cubicles.

**What we originally proposed**

SA Power Networks' Original Proposal included a forecast of $52.0 million for switchgear (excluding zone substation switchgear) for the 2020-25 RCP.

**The AER's Draft Decision and how we responded**

The AER's Draft Decision for switchgear was $41.8 million, $10.2 million below our original forecast.

The AER determined that we had not demonstrated a need to increase our overhead switchgear repex in the 2020–25 RCP over and beyond its actual current levels. The AER substitute estimate is based on the historical expenditure for overhead switchgear across the 2013-18 period.

We do not accept the AER's Draft Decision for switchgear. We have revised our historical forecast to reflect our 2018/19 actual expenditure which has resulted in an increase in the 2020-25 RCP forecast.

**Our revised forecast**

SA Power Networks revised forecast for the switchgear program is $54.2 million as detailed in Table 5-14 below.

**Table 5-14: Forecast for switchgear repex for the 2020-25 RCP (June 2020, $ million)**

| | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| Switchgear overhead | 7.4 | 7.4 | 7.5 | 7.5 | 7.6 | **37.4** |
| Switchgear ground level | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | **2.3** |
| Switchgear ground level (safety) | 3.3 | 3.4 | 3.4 | 3.4 | 3.4 | **16.9** |
| **Total** | **10.7** | **10.8** | **10.8** | **10.9** | **11.0** | **54.2** |

**Supporting evidence**

Table 5-15 lists the supporting evidence for the revised switchgear program included in our Revised Proposal.

**Table 5-15: Supporting evidence for switchgear repex**

| Document reference | Document name | Program it relates to |
|---|---|---|
| 5.4.1 | Revised Reset RIN data templates | Repex – switchgear |

### 5.3.5 Service lines

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

[31] Note in the RIN, overhead switchgear and overhead line components together form 'pole top structures'.

**What we originally proposed**

SA Power Networks' Original Proposal included a forecast of $41.7 million for service lines (including the aluminium neutral service lines) for the 2020-25 RCP.

**The AER's Draft Decision and how we responded**

The AER's Draft Decision for service lines was $41.3 million, noting the difference between our original forecast and the Draft Decision relates to overhead and escalation adjustments.

While we largely accept the AER's Draft Decision for service lines, we have revised our forecast to include 2018/19 actual expenditure and forecast expenditure 2019/20 equivalent to 2018/19 actuals.

**Our revised forecast**

SA Power Networks revised forecast for the service lines is $49.1 million as detailed in Table 5-16 below.

**Table 5-16: Forecast service lines repex for the 2020-25 RCP (June 2020, $ million)**

| | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| Service lines (incl neutral screen replacements) | 9.6 | 9.8 | 9.8 | 9.9 | 10.0 | **49.1** |

### 5.3.6 Other powerline assets

'Other powerline assets' incorporates all of the other components of powerlines including cables, conductors, distribution transformers, reclosers and manholes and ducts (excluding North Terrace cable ducts).

**What we originally proposed**

SA Power Networks' Original Proposal included a forecast of $97.3 million for the other powerline asset replacements for the 2020-25 RCP.

**The AER's Draft Decision and how we responded**

The AER's Draft Decision for the other powerline asset replacements was $95.6 million.

We largely accept the AER's Draft Decision for other powerline related assets. However, we have revised our forecasts to include 2018/19 actual expenditure, this has resulted in a reduction in expenditure for some programs.

**Our revised forecast**

SA Power Networks' revised forecast for the powerline program is $87.2million as detailed in Table 5-17 below.

Table 5-17: Forecast other powerline repex for the 2020-25 RCP (June 2020, $ million)

| Other powerline | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| Cable | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | **7.6** |
| Conductor | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | **12.0** |
| Ancillary line equipment | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 | **2.6** |
| Regulators | 0.9 | 1.2 | 1.2 | 1.3 | 1.3 | **5.9** |
| Reclosers | 2.7 | 2.7 | 2.7 | 2.7 | 2.8 | **13.6** |
| Distribution transformers | 7.8 | 7.9 | 7.9 | 8.0 | 8.0 | **39.6** |
| Elizabeth transformer stations | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | **2.4** |
| Distribution Earthing | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | **0.5** |
| CBD ducts and manholes (excl North Tce ducts) | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | **3.1** |
| **Total** | **16.9** | **17.4** | **17.6** | **17.6** | **17.7** | **87.2** |

### 5.3.7 Zone substation power transformers

Substation power transformers provide transformation of electricity from sub-transmission voltages to distribution voltage levels and are located at the zone electricity supply substations.

**What we originally proposed**

SA Power Networks' Original Proposal included a forecast of $26.8 million for zone substation power transformers replacements for the 2020-25 RCP.

As the substation power transformers age and deteriorate, they become more prone to failure. A failure of a transformer may result in unplanned supply interruptions to a very large number of customers.

We place a high emphasis on asset management of power transformers due to the high cost of the asset and the consequence of failure, through condition and performance monitoring with routine inspections and maintenance and refurbishment to extend the asset service life and a long-term replacement program.

Our power transformer forecast in the 2020-25 RCP is based on our CBRM modelling.

**The AER's Draft Decision and how we responded**

The AER's Draft Decision for zone substation power transformers was $18.7 million, $8.1 million below our original forecast.

The AER was concerned that we were proposing a 58 per cent increase for our zone substation power transformers. The AER and its consultant EMCa were also concerned that our CBRM model overstated risk as explained in section 5.3.1 above.

We have revised our forecast, taking into consideration this feedback. The actions that we have undertaken are explained in detail in Supporting Document 5.4: Repex Addendum.

**Our revised forecast**

SA Power Networks revised forecast for the zone substation power transformer programs is $30.0 million, $11.3 million higher than the AER substitute forecast as summarised in Table 5-18 below.

Table 5-18: Forecast zone substation power transformer repex for the 2020-25 RCP (June 2020, $ million)

| | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| Power transformers | 6.5 | 6.2 | 6.6 | 5.8 | 4.9 | **30.0** |

**Supporting evidence**

Table 5-19 lists the supporting evidence for the revised zone substation power transformers programs included in our Revised Proposal.

Table 5-19: Supporting evidence for the zone substation power transformers repex

| Document reference | Document name | Program it relates to |
|---|---|---|
| 5.4 | Repex Addendum | Repex – Power transformers |
| 5.5 | CBRM Model Value of Consequence Independent Report | CBRM power transformer model |

### 5.3.8 Zone substation circuit breakers

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

**What we originally proposed**

SA Power Networks' Original Proposal included a forecast of $60.5 million (excluding the Northfield GIS) for zone substation circuit breaker replacements for the 2020-25 RCP[32].

**The AER's Draft Decision and how we responded**

The AER's Draft Decision for zone substation circuit breakers was $44.5 million, $18.5 million lower than our original forecast.

The AER provided commentary on the approach used for determining forecast expenditure for the replacement program of circuit breakers. The Draft Decision rejected our proposed circuit breaker forecast for the following reasons:

- The total switchgear forecast expenditure is a step-up of 25 per cent from actuals over 2013–18 regulatory years;
- Circuit breaker repex was the main driver for the increase, with a 38 per cent increase from actuals over 2013–18 regulatory years;
- Circuit breaker replacement volumes were determined using the CBRM model and therefore the general concerns with CBRM as stated above in section 5.3.1 apply to this expenditure; and
- Significantly overstated risk as calculated out to 2030 rather than 2025 even though risk calculated at 2025 is already overstated.

We have revised our forecast, taking into consideration this feedback. The actions that we have undertaken are explained in detail in Supporting Document 5.4 – Repex Addendum.

**Our revised forecast**

SA Power Networks revised forecast for the zone substation circuit breaker program is $58.1 million, $13.6 million higher than the AER substitute forecast as summarised in Table 5-20 below.

[32] AER, Attachment 5, page 61.

**Table 5-20: Forecast zone substation circuit repex for the 2020-25 RCP (June 2020, $ million)**

| | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| Circuit breakers | 11.5 | 11.1 | 12.2 | 12.2 | 11.2 | **58.1** |

**Supporting evidence**

Table 5-21 lists the supporting evidence for the revised zone substation circuit breakers programs included in our Revised Proposal.

**Table 5-21: Supporting evidence for the zone substation circuit breakers repex**

| Document reference | Document name | Program it relates to |
|---|---|---|
| 5.4 | Repex Addendum | Repex – Circuit breakers |
| 5.5 | CBRM Model Value of Consequence Independent Report | CBRM Circuit Breakers model |

### 5.3.9 Zone substation protection relays

Protection relays control assets in the high voltage network to automatically protect personnel and the network in the event of fault conditions.

**What we originally proposed**

SA Power Networks' Original Proposal included a forecast of $16.4 million for zone substation protection relay replacements for the 2020-25 RCP.

**The AER's Draft Decision and how we responded**

The AER's Draft Decision for zone substation protection relays was $12.9 million, $3.5 million below our original forecast.

The AER provided commentary on the approach used for determining forecasts for protection relay replacements, data networks and network telecommunications planning labour capitalisation. The Draft Decision rejected our proposed forecast for the following reasons: [33]

- The substation protection relays forecast was based on the SA Power Networks' Protection CBRM model. The AER determined that our CBRM models overstate risk and also had regard to general issues with SA Power Networks' CBRM as described above in section 5.3.1;
- The data networks project was not supported by appropriate analysis eg failure rate or cost-benefits; and
- Actuals associated with the labour for project management, engineering and/or design of a network telecommunications solution was 47 per cent lower than the forecast. No justification was provided for what is driving the increase in these costs.

We have revised our forecast, taking into consideration this feedback. The actions that we have undertaken are explained in detail in Supporting Document 5.4 – Repex Addendum.

**Our revised forecast**

SA Power Networks' revised forecast for the zone substation protection relay programs is $16.3 million, $3.4 million higher than the AER substitute forecast as summarised in Table 5-22 below.

[33] AER, Attachment 5, page 58.

**Table 5-22 Forecast zone substation protection relays repex for the 2020-25 RCP (June 2020, $ million)**

| | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| Protection relays | 3.4 | 3.4 | 3.3 | 3.1 | 3.2 | **16.3** |

**Supporting evidence**

Table 5-23 lists the supporting evidence for the revised zone substation protection relay program included in our Revised Proposal.

**Table 5-23: Supporting evidence for the zone substation protection relays repex**

| Document reference | Document name | Program it relates to |
|---|---|---|
| 5.4 | Repex Addendum | Repex – Protection relays |
| 5.5 | CBRM Model Value of Consequence Independent Report | CBRM Protection model |

### 5.3.10 Other substation assets

Other substation assets incorporates all the other components of substations including AC and DC supplies, substation infrastructure (buildings etc), surge arrestors and CBD related works.

**What we originally proposed**

SA Power Networks' Original Proposal included a forecast of $47.2 million for our other substation assets for the 2020-25 RCP.

**The AER’s Draft Decision and how we responded**

The AER’s Draft Decision for the other substation asset replacements was $41.4 million.

We accept much of the AER’s Draft Decision for other substation related assets with the difference largely attributed to the change in overheads and labour escalation.

**Our revised forecast**

SA Power Networks’ revised forecast for the other substation assets programs is $43.3 million, $1.9 million higher than the AER substitute forecast as detailed in Table 5-24 below.

Table 5-24: Forecast other substation and CBD repex for the 2020-25 RCP (June 2020, $ million)

| Other substation and CBD | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| Auxiliary DC supplies | 0.6 | 0.6 | 0.6 | 0.6 | 0.3 | **2.8** |
| Mobile substations | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | **1.4** |
| Substation insurance spares | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | **7.5** |
| Substation Infrastructure | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | **7.0** |
| Surge Arrester | 0.3 | 0.3 | 0.3 | 0.3 | 0.2 | **1.5** |
| AC Panels and auxiliary supply | 0.7 | 0.7 | 0.7 | 0.7 | 0.6 | **3.3** |
| Other (substation cables) | 0.7 | 0.2 | 0.2 | 0.2 | 0.2 | **1.6** |
| Substation asset removal | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | **1.1** |
| CBD maintenance projects (CBD Safety) | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | **2.0** |
| Instrument transformers | 0.5 | 0.6 | 0.6 | 0.6 | 0.6 | **3.0** |
| Pipework substations | 1.9 | 1.9 | 1.9 | 1.9 | 1.9 | **9.5** |
| Disconnectors | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | **2.1** |
| CBD pilot cables | 0.6 | - | - | - | - | **0.6** |
| **Total** | **9.3** | **8.6** | **8.6** | **8.6** | **8.1** | **43.3** |

### 5.3.11 Telecommunications

Telecommunications program incorporates 48V DC systems, radio systems, optical fibre network and data networks required for the operational management of our electricity network and support of our business systems.

**What we originally proposed**

SA Power Networks' Original Proposal included a forecast of $30.5 million (excluding safety related expenditure) for telecommunications replacements for the 2020-25 RCP.

**The AER's Draft Decision and how we responded**

The AER's Draft Decision for telecommunications was $24.0 million, $6.5 million below our original forecast.

We accept much of the AER's Draft Decision with the difference being attributed to a change in overheads and labour escalations.

**Our revised forecast**

SA Power Networks' revised forecast for the telecommunications programs is $24.8 million as summarised in Table 5-25 below.

Table 5-25: Forecast telecommunications repex for the 2020-25 RCP (June 2020, $ million)

| | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| Telecommunications | 4.1 | 4.1 | 3.8 | 3.8 | 3.8 | **19.7** |
| Mobile radio | 0.6 | 0.7 | 0.3 | 0.8 | 0.7 | **3.0** |
| Telco structures | 0.3 | 0.3 | 0.3 | 0.3 | 0.9 | **2.1** |
| **Total** | **5.0** | **5.1** | **4.4** | **4.9** | **5.4** | **24.8** |

### 5.3.12 Northfield 66kV Gas Insulated Switchgear

Northfield Substation is a critical supply point for Adelaide's Eastern Suburbs' electrical supply, feeding 108,000 households and businesses. It is a Connection Point shared between SA Power Networks and ElectraNet.

The 66kV switchgear at the Northfield Substation was built in 1988. After 30 years of continuous service in an outdoor environment, it is in very poor mechanical condition and subject to accelerated ageing. There is significant external corrosion which has initiated five failures of gas seals. Attempts to seal the sulphur hexafluoride gas (**$SF_6$**)* leaks from the GIS, as recommended by independent parties and facilitated by the manufacturer, has not been successful.

* $SF_6$ is critical insulating gas to enable the safe operation of the switchgear.

**What we originally proposed**

SA Power Networks' Original Proposal included a forecast of $11.8 million for the Northfield Substation GIS replacement for the 2020-25 RCP.

The Northfield 66kV GIS project is based on prudent risk management and involves a multi-staged approach to address the risks associated with the 66kV GIS at Northfield Substation, through:

- Refurbishing the GIS by treating the corrosion to slow down the rate of degradation and re-seal the failed flanges to stop the present gas leaks.
- Building part of the final air insulated switchgear (**AIS**) replacement solution in 2023 to minimise the consequences should the existing GIS fail unexpectedly, or its condition deteriorate beyond a level appropriate to keep it in-service.
- Finalising the replacement solution at a time when the performance or condition of the existing GIS makes it unacceptable to keep it in-service.

**The AER's Draft Decision and how we responded**

In its Draft Decision the AER did not accept any expenditure for the Northfield GIS project. Based on the information provided, the AER was of the view that we did not sufficiently establish that the proposed GIS replacement project was prudent or efficient solution.

The AER's Draft Decision rejected our proposed forecast for the following reasons:

- SA Power Networks' independent engineering report indicated that short term interventions are likely to improve the likelihood of the existing GIS achieving its designed 'service life' and that these interventions can be reasonably achieved;
- SA Power Networks' preferred option assumes that the GIS will last until 2030 with short term interventions. This implies that the timing is not prudent;
- SA Power Networks is overstating the risk in its 'do-nothing' option as there was an assumption that the GIS would fail in the current RCP, yet the GIS would be subject to the same interventions during the 2020–25 RCP; and
- SA Power Networks has demonstrated that it is complying with reporting schemes and South Australian and Commonwealth legislation with regard to the release of $SF_6$, which is one of the risks associated with the condition of the GIS.

We have considered the AER's concerns, along with the additional information that has become available after we submitted our Original Proposal. We have developed a more comprehensive business case (Supporting Document 5.6 – Northfield 66kV GIS Replacement Business Case), that seeks to address the concerns raised above. The business case is NPV positive. The actions that we have undertaken are explained in detail in Supporting Document 5.4 – Repex Addendum.

**Our revised forecast**

SA Power Networks' revised forecast for the Northfield GIS program is $11.8 million consistent with our Original Proposal.

**Table 5-26: Forecast Northfield GIS repex for the 2020-25 RCP (June 2020, $ million)**

| | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| Northfield GIS | 1.2 | 4.0 | 4.7 | 1.9 | - | **11.8** |

**Supporting evidence**

Table 5-27 lists the supporting evidence for the Northfield GIS project included in our Revised Proposal.

**Table 5-27: Supporting evidence for the Northfield GIS repex**

| Document reference | Document name | Program it relates to |
|---|---|---|
| 5.4 | Repex Addendum | Repex |
| 5.6 | Northfield 66kV GIS Replacement Business Case | Northfield 66kV GIS |
| 5.6.1 | Northfield 66kV GIS Replacement model | Northfield 66kV GIS |

### 5.3.13 Paper insulated lead covered cables

The Adelaide Business Area (**ABA**) forms part of the Adelaide Central Business District (**CBD**). This geographic area has the most stringent of the reliability targets of the regulatory feeder categories and we have an obligation to use our best efforts to meet these benchmarks.

The distribution network in the ABA is about 97 percent underground. Cable installation began in 1955, with the original UG cables being Paper Insulated Lead Covered (**PILC**). The population of PILC cables is ageing and is leading to a loss in network reliability.

**What we originally proposed**

SA Power Networks' Original Proposal included a forecast of $14.4 million for the PILC cable replacement program for the 2020-25 RCP.

In our Original Proposal we included a program to replace 7.6 kilometres of the worst sections of 11kV PILC cables in the 2020-25 RCP to address the reliability, security of supply and service standard conditions that result from the deteriorating condition of the cables.

The high failure rate of these cables has resulted in SA Power Networks failing to meet reliability targets for CBD Feeders, including system average interruption duration index (**SAIDI**) in 2016/17, 2017/18 and 2019/20 YTD. The CBD system average interruption frequency index (**SAIFI**), target was also exceeded in the 2017/18 period and we have exceeded the 2019/20 target.

Analysis has shown that replacement of the 200 worst sections (in terms of having the worst condition and the highest failure rates) would improve SAIFI performance in the CBD by 15 percent (and likewise SAIDI, assuming the same system outage duration).

**The AER's Draft Decision and how we responded**

The AER's Draft Decision for the PILC cable replacement program was $4.7 million, $9.7 million below our original forecast of $14.4 million because the AER considered we did not establish that the proposed repex forecast was prudent and efficient.

The AER's substitute estimate allows us to replace the 2.3 kilometres that were identified, by SA Power Networks' consultant, to have the highest likelihood of failure.

When we discussed this program with the SA Power Networks CCP and other stakeholders they expressed concern that Adelaide CBD reliability targets were not being met, and they were supportive of SA Power Networks undertaking a prioritised PILC cable replacement program.

We have revised our supporting evidence, taking into consideration this feedback and prepared a new business case which is NPV positive. The actions that we have undertaken are explained in detail in Supporting Document 5.4 – Repex Addendum.

#### Our revised forecast

SA Power Networks revised forecast for the PILC cable replacement program is $7.1 million, $2.7 million higher than the AER substitute forecast of $4.4 million as detailed in Table 5-28 below.

**Table 5-28: Forecast PILC cable repex for the 2020-25 RCP (June 2020, $ million)**

| | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| PILC cables | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | **7.1** |

#### Supporting evidence

Table 5-29 lists the supporting evidence for the PILC cable project included in our Revised Proposal.

**Table 5-29: Supporting evidence for the PILC cable repex**

| Document reference | Document name | Program it relates to |
|---|---|---|
| 5.4 | Repex Addendum | Repex |
| 5.8 | 11kV Paper Insulated Lead Cable Replacement Business Case | PILC cables |
| 5.8.1 | 11kV Paper Insulated Lead Cable Replacement model | PILC cables |

### 5.3.14 North Terrace cable ducts

The duct infrastructure on North Terrace in Adelaide CBD enables the installation and replacement of underground cables without disrupting the above ground footpaths and business activities in the CBD.

#### What we originally proposed

SA Power Networks' Original Proposal included a forecast of $11.1 million for the North Terrace cable duct replacement program for the 2020-25 RCP as a subset of the $13.9 million CBD ducts and manholes program. The North Terrace cable duct program proposed to replace the existing ducts along North Terrace between King William Street and George Street.

#### The AER's Draft Decision and how we responded

In its Draft Decision the AER made no allowance for the North Terrace cable duct replacement program.

The AER's Draft Decision rejected our proposed forecast for the following reasons: [34]

- The AER specifically assessed the North Terrace duct replacement program;
- The North Terrace duct replacement program had already been approved in the 2015-20 RCP, yet SA Power Networks deferred the program in its entirety;

[34] AER, Attachment 5, pages 55 to 56.

- SA Power Networks stated that the whole program is reliability driven yet had not provided any cost-benefit analysis to account for unserved energy or value of customer reliability; and
- SA Power Networks' Asset Management Plan stages duct replacements subject to budget availability, demonstrating a lack of robust testing during the proposal stage.

We would like to clarify that the North Terrace duct replacement program was not requested, nor approved in the 2015-20 RCP or any prior RCP.

When this program was discussed with the SA Power Networks CCP and other stakeholders, there was strong support for replacing ducts to ensure that existing businesses are able to operate with confidence and without extensive disruption, and that new businesses are able to establish in the popular North Terrace precinct.

We have revised our supporting documents, taking into consideration this feedback and prepared a new business case which is NPV positive. The actions that we have undertaken are explained in detail in Supporting Document 5.4 – Repex Addendum.

**Our revised forecast**

SA Power Networks revised forecast for the North Terrace cable duct component of the CBD duct and manholes program is $11.1 million as detailed in Table 5-30 below.

**Table 5-30: Forecast for the North Tce ducts repex for the 2020-25 RCP (June 2020, $ million)**

| | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| North Terrace cable ducts | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 11.1 |

**Supporting evidence**

Table 5-31 lists the supporting evidence for the North Terrace project included in our Revised Proposal.

**Table 5-31: Supporting evidence for the North Terrace ducts repex**

| Document reference | Document name | Program it relates to |
|---|---|---|
| 5.4 | Repex Addendum | Repex - North Tce ducts |
| 5.7 | North Terrace Cable Ducts Replacement Business Case | North Tce ducts |
| 5.7.1 | North Terrace Cable Ducts Replacement model | North Tce ducts |

## 5.4 Augmentation capex

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

Augex comprises the following key components:

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

- **Power Line Environmental Committee (PLEC)** – expenditure to underground parts of the network in accordance with State Government legislation.

### 5.4.1 Our revised augex forecast summary

Our revised forecast for augex related capex for the 2020-25 RCP is $332 million, $58.9 million lower than our Original Proposal forecast of $390.9 million as shown in Table 5-32 below.

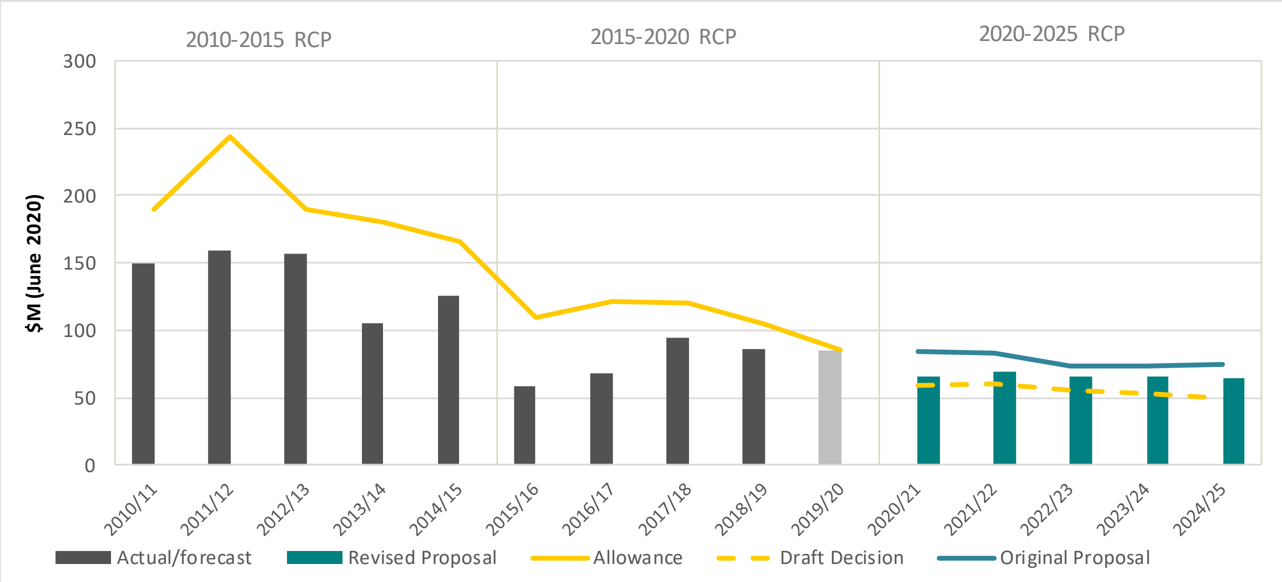
**Table 5-32: Summary of Original and Revised Proposals augex forecast compared to the AER's Draft Decision (June 2020, $ million)**

| | Original Proposal | AER Draft Decision | Revised Proposal |
|---|---|---|---|
| **Augex** | 390.9 | 277.4 | 332.0 |

### 5.4.2 Augex profile

Figure 5-8 shows SA Power Networks' total augex for the 2010-15 and 2015-20 RCPs, along with the total forecast augex that we consider will be required during the 2020-25 RCP in order for us to achieve the capex objectives.

**Figure 5-8: Augex expenditure profile 2010-25 (June 2020, $ million)**




### 5.4.3 AER's Draft Decision for augex

The AER did not accept our forecast augex related capex for the 2020-25 RCP as they were not satisfied the forecast of $390.9 million reasonably reflected the capex criteria. The AER's substitute estimate of $277.4 million is 29% below our forecast.

The AER's primary concerns with our augex forecast were:

- Overstated benefits in analysis to support the forecast.
- For some projects and programs, we had not provided sufficient detail and information to support our proposal. The AER encouraged us to address the issues they identified in our Revised Proposal.
- Some programs were not required, or more likely could be deferred.
- The AER observed that there is lack of a top-down challenge which would identify the interrelationships that exist between the DER related programs and projects[35].

[35] *AER, Attachment 5, page 32.*

We have undertaken a number of workshops and meetings with the AER staff regarding our augex forecast and we have appreciated the AER's willingness to engage with us and provide feedback on our Original Proposal. We have addressed many aspects of the AER's feedback and this Section of the Capital Expenditure Attachment, along with our supporting documents, aims to address the AER's concerns.

### 5.4.4 How our revised augex forecast compares

Table 5-33 summarises our Original Proposal and our Revised Proposal augex forecast for the 2020-25 RCP, compared to the AER's Draft Decision.

**Table 5-33: SA Power Networks' Original and Revised augex forecast compared to the AER's Draft Decision (June 2020, $ million)**

| Augex category | Original Proposal | AER Draft Decision | Revised Proposal | Difference to Draft Decision $ |
|---|---|---|---|---|
| **Distributed Energy Resources** | 112.0 | 79.2 | 86.4 | 7.2 |
| **Capacity** | 74.4 | 55.5 | 65.5 | 10.0 |
| **Reliability** | 64.9 | 32.6 | 62.9 | 30.6 |
| **Strategic** | 17.2 | 8.8 | 8.8 | 0.0 |
| **Safety** | 57.5 | 38.0 | 44.1 | 6.1 |
| **Environment** | 9.7 | 9.7 | 9.7 | 0.0 |
| **PLEC** | 55.2 | 53.6 | 54.3 | 0.7 |

### 5.4.5 Distributed Energy Resources

Distributed Energy Resources (**DER**) includes solar photovoltaic, storage, electric vehicles, and other consumer appliances that can respond 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.

South Australia has the highest ratio of rooftop solar generation to operational consumption of all the NEM regions, and this is forecast to remain the case for the next ten years[36].

In October 2019, South Australia recorded its lowest state-wide demand on record, at 432 MW. AEMO is now forecasting that state-wide minimum demand will reach zero at certain periods as early as 2024 as rooftop solar capacity continues to grow[37].

DER management expenditure is the expenditure which seeks to manage these growing effects of higher penetration of DER on the network, in particular the effects of solar, and the cumulative impact it has on our ability to manage voltage within standards.

**What we originally proposed**

SA Power Networks originally proposed four programs totaling $112 million ($106.6 million excluding business overheads), relating to the DER transition. These programs were:

- Quality of supply (**QoS**) program ($46.3 million) - a program to investigate QoS inquiries received from customers, implement corrective action including network augmentation where required, to manage the low voltage network in compliance within regulatory obligations.
- LV Management ($31.8 million) - a new program to develop new operational systems and business processes to facilitate management of solar, battery storage and virtual power plants.

[36] *AEMO, South Australian Electricity Report, 2018*
[37] *Ibid*

- LV transformer monitoring program ($18.9 million) - an extension of an existing program to install remotely-readable monitors on our network to enable us to monitor in real time the fluctuating load on areas of our LV network.
- Voltage regulation program ($15 million) - a proposal to replace eight zone substation transformers with modern equivalents, to conform to our obligations and manage voltage issues arising from increased DER on our network.

We originally categorised our DER related programs within their driver expenditure categories, ie LV transformer monitoring, voltage regulation and maintain QoS expenditure were categorised as Capacity expenditure while the LV Management program was categorised as Strategic expenditure.

**The AER's Draft Decision and how we responded**

The AER did not accept our forecast DER related capex for the 2020-25 RCP as it was not satisfied the forecast of $112 million reasonably reflected the capex criteria. [38] The AER's substitute estimate of $79.2 million is 29% below our original forecast.

The AER accepted that our strategic LV management program reasonably reflected the capex criteria however the AER were unable to support our full proposal for the QoS, LV transformer monitoring and the voltage regulation programs. [39] The AER asserted that we failed to identify how the combination of these programs could work together to manage voltage issues and that while the interrelationships were considered, they were not fully recognised in the Original Proposal.

We acknowledge that the interrelationships between the DER programs could have been considered more explicitly. In response to the AER's feedback we reviewed our DER related programs and we have prepared Supporting Document – 5.14 DER management expenditure overview. This document provides this clarification, detailing the interdependencies between the DER related programs in our Revised Proposal that are required to (a) efficiently manage the impact of an increasing uptake of DER such as rooftop solar during the period, and (b) manage and maintain the LV part of the network, from street transformer to customer premises.

***LV management program***

We accept the AER's Draft Decision in relation to our LV management program (referred to as the 'DSO transition' program in the Draft Decision).

***LV transformer monitoring***

We note the AER has classified this program as being driven by DER. However, this program is actually driven by capacity (load) concerns. Under clause 6.5.7(a) of the NER, we are required to include capex in order to:

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

[38] *AER, Attachment 5, page 21.*
[39] *Ibid, page 23.*

The lack of visibility on our LV network limits our ability to proactively manage the LV network in areas where at times the load is exceeding the design rating of the network.

In the time since our Original Proposal was lodged in January 2019 we have undertaken significant further work on the LV transformer monitoring program in an effort to address the questions raised by the AER and our stakeholders. The revised program differs from our original programs in a number of areas, primarily:

- The use of alternative permanent transformer monitors with a much lower unit cost.
- We have leveraged our existing transformer survey work program to enable a more efficient roll out and installation strategy.
- We have reviewed and substantially reworked and improved the financial modelling of costs and benefits used in the business case.

As a result, we have revised our LV transformer monitoring program from $18.9 million down to $5.2 million. In Attachment 6 (Operating Expenditure) and we have also incorporated an opex reduction of $1.3 million over the five year RCP to reflect: (a) an opex step change of replacing our existing survey work program (opex) with the permanent monitoring rollout (capex); and (b) consequential efficiency savings arising from the permanent monitoring program related to a reduced cost of investigating and improving capacity planning in the LV network. The revised program is explained in greater detail in Supporting Document 5.15 – LV Transformer Monitoring Business Case.

Our SA Power Networks CCP and other stakeholders agree there is a need for improved visibility of our LV network and are supportive of this revised approach to the LV transformer monitoring program.

***Business as usual (BAU) QoS***

We have revised our forecast for BAU QoS expenditure in light of the most recent data on actual expenditure in this area, which confirms a rising trend but at a slightly lower rate than our original forecast. The AER noted in its Draft Decision that EMCa's view is that, if the AER is to approve the LV transformer monitoring program, the "identified benefit of monitoring should be realised through lower investigation costs incurred through the business as usual QoS program".[40] Our revised forecast takes into account that identified benefit because we have also adjusted the forecast to take into account efficiency gains associated with the permanent LV transformer monitoring program in 2023/24 and 2024/25. Refer to Supporting Document: 5.35 - Low Voltage and Quality of Supply Remediation Capital expenditure (augex) Forecast.

Our revised forecast for BAU QoS expenditure in 2020-25 is $42.2 million, which is $4.1 million lower than our Original Proposal and $1.9 million higher than the AER's Draft Decision.

When the Quality of Supply program was discussed with our SA Power Networks CCP and other stakeholders, including our DER Integration Working Group, there was broad support for ensuring that increasing voltage issues are addressed.

***Voltage regulation***

We accept the AER's decisions in its Draft Decision for the voltage regulation program. Using the lower unit rate (to reflect the cost of the 200 Ampere units as opposed to the 300 Ampere units), our modelling results in a similar conclusion as the AER Draft Decision.

[40] *Ibid, page 28.*

**Our revised forecast**

SA Power Networks' revised forecast for the DER related programs and the LV transformer monitoring program is $86.4 million, $7.2 million higher than the AER substitute forecast of $79.2 million as outlined in Table 5-34 below.

**Table 5-34: Revised forecast DER augex for the 2020-25 RCP (June 2020, $ million)**

| | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| **QoS BAU** | 8.1 | 8.3 | 8.5 | 8.5 | 8.8 | 42.2 |
| **LV Management** | 5.9 | 8.9 | 6.6 | 6.1 | 4.0 | 31.7 |
| **LV Transformer Monitoring** | 0.6 | 1.8 | 2.1 | 0.7 | 0.0 | 5.2 |
| **Voltage regulation** | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 7.4 |
| **Total** | **16.1** | **20.5** | **18.7** | **16.8** | **14.3** | **86.4** |

**Supporting evidence**

Table 5-35 lists the supporting evidence for the revised DER related programs included in our Revised Proposal.

**Table 5-35: Supporting evidence for the revised DER related programs included in our Revised Proposal**

| Document reference | Document name | Program it relates to |
|---|---|---|
| 5.14 | DER management expenditure overview | BAU QoS; strategic LV management; LV transformer monitoring and voltage regulation |
| 5.15 | LV transformer monitoring business case | LV transformer monitoring |
| 5.35 | Low Voltage and Quality of Supply Remediation Capital expenditure (augex) forecast | BAU QoS |

## 5.4.6 Capacity

The capacity expenditure category consists of works required to meet or manage the expected demand for SCS over the 2020-25 RCP[41].

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

**What we originally proposed**

SA Power Networks originally proposed seven programs totaling $74.4 million (excluding the DER related programs) to manage the forecast capacity constraints on our network over the 2020-25 RCP. Within these programs there were two material projects:

(1) Myponga to Square Waterhole ($10 million) – a market benefit project to improve the security of supply to 28,900 customers on the Fleurieu Peninsula by constructing a new 66kV sub-transmission line between the Myponga substation and the Square Waterhole substation.

(2) Athol Park to Woodville ($8.4 million) – a project to address a forecast constraint on our Western suburbs 66kV sub-transmission network.

[41] *NER, clause 6.5.6(a)(1).*

**The AER's Draft Decision and how we responded**

The AER did not accept our forecast capacity related capex for the 2020-25 RCP as they were not satisfied the total forecast of $74.4 million reasonably reflected the capex criteria. The AER's substitute estimate of $55.5 million ($53 million excluding business overheads), is 25% below our forecast.

The material difference between our Original Proposal and the AER's Draft Decision is that the AER did not accept our proposed Myponga to Square Waterhole or Athol Park to Woodville projects.

***Myponga to Square Waterhole***

The AER engaged EMCa to review several aspects of our augex programs. EMCa undertook a review of our forecast capacity expenditure and highlighted several concerns with the Myponga to Square Waterhole and the Athol Park to Woodville projects. [42]

For the Myponga to Square Waterhole project EMCa raised the following concerns:[43]

- The load forecast indicates stable peak demand, but the modelling contains inconsistent load factor assumptions. The modelling also appears to use noncoincident peak load data when coincident data is likely to be more appropriate given the customer mix in the areas supplied by the existing feeders.
- SA Power Networks' consideration of alternative options was insufficient. EMCa considered that alternative solutions such as reliability improvement of the Willunga-Myponga line and enhancing Starfish Hill wind farm should be evaluated further.
- Sensitivity analysis is likely to determine that positive market benefits are unlikely to be realised under most reasonable scenarios.

A revised analysis was conducted for the Myponga to Square Waterhole project aimed at addressing concerns identified in EMCa's review[44]. Our analysis reflects a conscious effort to use the most conservative option for each relevant parameter. Even with this approach, a positive net market benefit has been demonstrated for the new Myponga to Square Waterhole 66kV sub-transmission line under most reasonable scenarios. The relative market benefit compared to a 'Do Nothing' base-case is positive for all sensitivities. If a higher value of customer reliability (**VCR**) rate comes into effect as indicated, it will further strengthen this business case. Our analysis is set out in Supporting Document: 5.10 - Myponga to Square Waterhole Business Case and Supporting Document 5.10.1 - Myponga to Square Waterhole model.

The EMCa review[45] made a further recommendation to consider a more detailed analysis of the alternative option of enhancing the Starfish Hill Wind Farm to operate in islanded configuration. This is not a viable solution and was not included in the revised analysis for two main reasons. First, Starfish Hill Wind Farm is a semi-scheduled generator that cannot be dispatched on request or for a specific output amount. Secondly, this solution would only benefit 15% (or 4,326) of the radial customers after including the support provided by the existing Kingscote back-up generating system. There is no benefit provided to the majority of the radialised customers (22,891) on the eastern side of the Fleurieu peninsula should the Willunga to Square Waterhole 66kV sub-transmission become faulted.

On this basis we have included the Myponga to Square Waterhole project in our Revised Proposal. Our stakeholders acknowledged the need for this program and asked that SA Power Networks consider all reasonable scenarios in delivering the project. These will be considered as part of the required RIT-D if the AER approves expenditure related to the project.

[42] *AER, Attachment 5, page 31.*

[43] *Energy Market Consultants Associates, Review of aspects of SA Power Networks' capital expenditure, September 2019, pp. 75-77.*

[44] *EMCa Review of SA Power Networks' Capital Expenditure, September 2019, pp. 73-77, 6.3.3*

[45] *EMCa Review of SA Power Networks' Capital Expenditure, September 2019, pp. 75, 6.3.3, 329*

***Athol Park to Woodville***

With regard to the Athol Park to Woodville 66kV sub-transmission line, EMCa considered our cost-benefit analysis should include more robust options and sensitivity analysis as follows:[46]

- Options analysis should be broadened to include options to defer the required capex, for instance, enabling dynamic line rating or changing the impedance of lines to alter power flows may be a lower cost solutions.
- Sensitivity analysis should include the effects of DER and other initiatives on peak load flows, because augmentation may not be the most appropriate solution in many scenarios.

We have undertaken further detailed analysis based on the options suggested above. The proposed Athol Park-Woodville 66kV line is, in our view, the least cost, technically feasible solution that resolves both the peak summer N-1 constraint and the N-1-1 constraints when performing planned outages in the Metro West Region. The line impedance solution is the only option that may theoretically resolve the N-1 constraint at a significant cost, but it does not enable the performance of planned outages under an N-1-1 scenario during non-summer/peak demand periods.

Additionally, any non-network options that can provide the same level of support as the proposed new line would likely be prohibitively expensive based on the capacity of generation required, assuming a suitable location could be found from a planning and environmental approvals perspective. Similarly, the constraining of existing market generators at Quarantine, OCPL and Dry Creek are likely to have significant adverse market impacts on available generator capacity during peak load events.

A detailed response addressing all of the concerns raised is available on request.

The Original Proposal submission for the Athol Park to Woodville sub-transmission line was based on the most up to date network model and forecast available. At the time, the total area load was forecast to grow steadily across a 20-year period, meaning that these constraints were forecast to become more severe over time. However, since that time the forecast has been updated and it indicates a slight decline in the total area load. This results in the identified constraints becoming less severe over time and therefore the project can be deferred to a future RCP. On this basis we accept the AER's decision to reject the Athol Park to Woodville 66kV sub-transmission project and we have consequently excluded that project from our Revised Proposal. The SA Power Networks CCP and other stakeholders agree.

**Our revised forecast**

SA Power Networks revised forecast for the capacity programs is $65.5 million, $10 million higher than the AER substitute forecast of $55.5 million as detailed in Table 5-36 below.

**Table 5-36: Revised forecast capacity augex for the 2020-25 RCP (June 2020, $ million)**

| Capacity | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| **Minor capacity** | 14.9 | 13.2 | 10.4 | 9.4 | 7.5 | 55.5 |
| **Myponga to Square Waterhole** | 0.0 | 0.0 | 0.0 | 3.8 | 6.2 | 10.0 |
| **Total** | **14.9** | **13.2** | **10.4** | **13.1** | **13.8** | **65.5** |

[46] *Energy Market Consultants Associates, Review of aspects of SA Power Networks' capital expenditure, September 2019, pp. 79-80.*

**Supporting evidence**

Table 5-37 summarises the supporting evidence for the capacity program (Myponga to Square Waterhole 66kV sub-transmission line) in our Revised Proposal.

**Table 5-37: Supporting evidence for the capacity program in our Revised Proposal**

| Document reference | Document name | Program it relates to |
|---|---|---|
| 5.14 | Myponga to Square Waterhole business case | Myponga to Square Waterhole |
| 5.14.1 | Myponga to Square Waterhole model | Myponga to Square Waterhole |

### 5.4.7 Reliability

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

**What we originally proposed**

SA Power Networks originally proposed three programs totaling $64.9 million ($61.7 million excluding business overheads), to manage reliability related issues. These programs were:

- Maintain underlying reliability ($34.6 million) - Remedial works undertaken to maintain the overall reliability of the network to meet the ESCoSA service standards for reliability as detailed in the EDC.
- Low reliability feeders ($14.9 million) - Remediation of the consistently (long term) worst performing power lines.
- Hardening the network ($15.4 million) - Remedial works to mitigate extended duration interruptions due to the impact of Major Event Days (MEDs) due to the impact of increasing number and severity of severe weather events.

**The AER's Draft Decision and how we responded**

The AER did not accept our forecast reliability related capex for the 2020-25 RCP as they were not satisfied the forecast of $64.9 million reasonably reflected the capex criteria. The AER's substitute estimate of $32.6 million ($31 million excluding business overheads) is 50% below our forecast.

***Maintain reliability***

The AER did not accept the proposed uplift in our maintain reliability program, nor did it accept the two customer focused reliability improvement programs - low reliability feeders and hardening the network.

The AER's primary reason for not accepting our maintain reliability program was that it was of the view we have managed our resources, steadily improving our performance in terms of SAIDI and SAIFI, excluding CBD performance[47]. It was also of the view that if we did incur additional costs due to the growing bat population, we could reallocate capex from other programs.

While we do not agree with the rationale behind the AER's Draft Decision, we will accept it as the difference between what we proposed and what the AER have allowed (-$2 million) is not considered material in terms of the total capex budget.

[47] *AER, Attachment 5, p. 33*

***Low reliability feeders***

In respect of the low reliability feeders program, the AER acknowledged we are required to identify and report our worst performing feeders to ESCoSA, however, it noted there is no direct obligation to improve the supply from these feeders.

The AER had regard to ESCoSA's recent review of our reliability standards. Based on the information before the AER, it formed the view that ESCoSA's review does not support the results of our stakeholder feedback for the low reliability feeder program. The ESCoSA review noted that the reliability standards for the 2020–25 RCP will require SA Power Networks to maintain reliability at current levels, rather than improve or reduce performance.[48]

An Oakley Greenwood 'willingness to pay' survey (commissioned by ESCoSA), found that a small number of customers were prepared to pay for some reliability improvement. In all other scenarios, 60% or more of customers sampled were not willing to pay any amount for reliability improvement.

The AER noted that Oakley Greenwood also assessed the economic efficiency of potential improvements and concluded that only one reliability improvement package had a net benefit – a 10% improvement to reliability on low reliability feeders, however, only 1 in 4 customers were willing to pay for this improvement.[49]

The AER did not accept the low reliability feeder program because there was no regulatory requirement to undertake the program and for the reasons set out above.

While we accept that we do not have absolute obligations to improve the supply to customers served from these worst performing feeders, we consider that there is a clear expectation in our state-based obligations that we will undertake some form of corrective action <u>where it is economic to do so</u>. We also consider that this interpretation is in line with the National Electricity Law objectives, as to not to do so in these circumstances would not be in the long-term interests of our customers.

During focused conversations with our SA Power Networks CCP in the preparation of the Revised Proposal, we discussed the concept of equity for our customers. The conversation focused on the fact that there are groups of customers, typically located in remote areas, who experience very poor reliability, significantly worse than what the average customer in that region experiences.

Following those conversations there was consensus amongst the CCP that it was unacceptable for some customers to experience such a vastly different level of service, and that we should propose expenditure in our Revised Proposal to improve reliability for those worst served customers.

We engaged Oakley Greenwood to undertake further analysis based on the methodology used for the ESCoSA survey, refer to Supporting Document 5.18 - Oakley Greenwood - The Economic Efficiency of Improving Reliability on Low Reliability Feeders. In its report Oakley Greenwood compared the ESCoSA survey to our own analysis and submitted the following: [50]

> *"That work [analysis for ESCoSA] determined that the aggregate amount that people connected to LRFs were willing to pay to improve their reliability of supply by 10% was not sufficient by itself to fund the expenditure required to do so. However, the explicit willingness of other customers to subsidise this level of improvement in reliability, when made aware of the significantly poorer reliability that customers connected to LRFs experience, exceeded the cost of the projects proposed by SA Power Networks for this purpose.*

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[48] *Essential Services Commission of South Australia, SA Power Networks reliability standards review – Final Decision, January 2019, p. i.*
[49] *Oakley Greenwood, Economic assessment of electricity distribution reliability standard packages, June 2018, p. 39.*
[50] *Supporting Document 5.18 - Oakley Greenwood - The Economic Efficiency of Improving Reliability on Low Reliability Feeders, p. 1*

*In its original 2020-2025 Regulatory Proposal (January 2019), SA Power Networks proposed a smaller, targeted capex proposal than that considered in the ESCoSA review. The Australian Energy Regulator (AER) rejected that part of SA Power Networks' capex proposal. SA Power Networks is re-submitting the LRF program and has asked Oakley Greenwood (OGW) to assess the economic efficiency of the 2020-2025 LRF program in light of the findings of the study undertaken for ESCoSA.*

*Based on the levels of willingness to pay and willingness to subsidise determined in the ESCoSA study, it is our view that the proposed 2020-2025 LRF program – which focusses on a smaller set of LRFs and delivers a greater level of improvement than the program assessed in the ESCoSA study – is economically efficient."*

Oakley Greenwood also noted that "whilst it is natural for stakeholders to consider the equity impacts of any expenditure, it was their view that the National Electricity Objective (**NEO**) is very much underpinned by economic considerations."[51] Our analysis submitted with our Original Proposal in Supporting Documents 5.27 – Reliability and Resilience Programs – Low Reliability Feeders and 5.28 – Low Reliability Feeder Regulatory Model, clearly demonstrates the proposed low reliability feeders program is economically efficient.

Oakley Greenwood also noted that:

*"While there is no regulatory obligation on SA Power Networks to improve the reliability of these feeders, as the AER pointed out, there is also no reason why such improvements should not be undertaken where they are economically efficient. The results of our study indicate that customers' willingness to subsidise reliability improvements in for customers connected to LRFs exceeds the costs of those improvements, making such an expenditure economically efficient."*[52]

Refer to Supporting Document 5.18 - Oakley Greenwood - The Economic Efficiency of Improving Reliability on Low Reliability Feeders.

Based on the analysis contained in the Oakley Greenwood report which clearly demonstrates that customers <u>are</u> willing to pay for targeted reliability improvements for poorly served customers, our earlier direct engagement with regional customers where they called for improvements for localised pockets of reliability, and most recently, the unanimous support of the SA Power Networks CCP, we are resubmitting $14.8 million for our low reliability feeders program.

We have provided additional information in Supporting Document: 5.16 – 2020-25 Reliability and Resilience Programs - Low Reliability Feeders that explains how the benefits have been derived and we have included a real life before and after example. The supporting cost benefit analysis model Supporting Document 5.16.1 (confidential) which was previously provided with our Original Proposal, has been updated and resubmitted with our Revised Proposal.

***Hardening the network***

The purpose of the hardening the network program is to mitigate the impact of severe weather events thereby improving reliability of supply to customers in storm prone areas. In its 2015-20 Final Determination for SA Power Networks, the AER recognised supply reliability for these customers had declined in recent years and it accepted the hardening the network program as being prudent and efficient.

In its Draft Decision for the 2020-25 RCP the AER did not accept the hardening the network program. The AER had had number of concerns with this program, as follows:

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[51] *Supporting Document 5.18 - Oakley Greenwood - The Economic Efficiency of Improving Reliability on Low Reliability Feeders, p. 10*
[52] *ibid*

- While the AER recognised our reliability performance levels inclusive of MEDs have been declining from 2010 to date, it was of the view there are no absolute regulatory obligations to mitigate MED interruptions to customers.
- In a survey regarding customers support for hardening the network program, 58% indicated their support and 33% were uncertain. There were some concerns regarding synergies between this program and other programs, such as repex and bushfire management, which were also documented in the Original Proposal in Supporting Document 0.13 – AnnShawRungie Capex Deep Dive Workshops Report. In its view, there was insufficient evidence to indicate customer support, because of the limited sample size of the survey and the level of uncertainty from stakeholders in response to the question itself.
- The AER reviewed the information and modelling provided and it considered we had overestimated the effectiveness of the mitigation measures. The AER cited that examination of the historical fault records used in the analysis suggested that approximately 77% of faults are unique in nature, that is, they occurred at a unique location along a given feeder and are unlikely to reoccur. It noted that SA Power Networks assumes that it can address these faults with circa 80% effectiveness, and customers will see the full effect of that reliability improvement. In the AER's view, the effectiveness of the proposed measures were overstated because customers may still experience outages if faults occur at other locations along a feeder.[53]

***Our obligations and this program***

We acknowledge we do not have a specific obligation to mitigate MED interruptions to customers, however, as the AER have noted, we consider there is an expectation to implement mitigation solutions where economically viable and where there is suitable customer support.

We also acknowledge ESCoSA Service standards in clause 2 of the Code exclude unplanned interruptions that qualify as MED's. That said, there is an expectation that we will undertake some form of augmentation where it is economic to do so.

We consider this interpretation is in line with the National Electricity Objective in the National Electricity Law, which is to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to, amongst other things, the reliability and security of supply of electricity. To refrain from undertaking augmentation where it is economic to do so, and where it would assist in the mitigation of interruptions to customers, would not be in the long-term interests of our customers. Consequently, we consider that we have an expectation to undertake actions to mitigate long duration interruptions that occur during MEDs to these customers where it is prudent and efficient and economical to do so.

This proposal also satisfies the requirement in the NER to provide evidence to the AER (to accompany regulatory proposals) that SA Power Networks has "engaged with electricity consumers and has sought to address any relevant concerns identified as a result of that engagement". [54]

Following the AER's Draft Decision, we consulted further with the SA Power Networks CCP and key stakeholders, and received feedback from several stakeholders such as Business SA that the hardening the network program should be re-submitted to address the ongoing reliability concerns of pockets of customers and especially business customers, who are impacted by weather events. After further discussions with the SA Power Networks CCP involving the presentation of indicative customer bill impacts, there was not a consensus view about whether the program should be included in our Revised Proposal.

However, given the strong views of customers expressed in earlier regulatory proposal engagement (previously submitted to the AER) the ongoing customer feedback we receive via our social media and

[53] *AER, Attachment 5, P. 36*
[54] *NER, clause 6.8.2(c1).*

Talking Power platforms, and the net economic benefit of the proposed works, SA Power Networks considers there is sufficient economic justification and customer support to re-submit the Hardening the network program.

***Relationship of the hardening the network program to other programs***

Stakeholders questioned whether there were any synergies between this program and other programs, such as repex and bushfire management. These have been addressed in Section 8 of Supporting Document: 5.17 – 2020-25 Reliability and Resilience Programs - Hardening the Network. This business case has been revised and resubmitted with our Revised Proposal.

***Economic Benefit***

SA Power Networks disagrees with the AER that we have 'overestimated' the effectiveness of our reliability solutions and we ask the AER to review Section 5 – Program options considered (our methodology) and Section 6 – Cost benefit analysis, set out in the Revised Proposal Supporting Document 5.17 – 2020-25 Reliability and Resilience Programs - Hardening the Network and the associated cost benefit model Supporting Document 5.17.1.

We have considered various augmentation work options that will provide long-term sustainable performance benefits for the feeders targeted for hardening. These options reflect the methods we have been applying for the current successful hardening program. Furthermore, we have used an independent statistician to validate the scale of the improvement we can typically expect from these types of options (ie option effectiveness), and so we can have confidence in the scale of the improvements that should be realised through these approaches.

In the development of an optimal set of options for each feeder section, we have undertaken a detailed review of all the outage locations and causes (over the last eight years) for the feeders most impacted by MEDs and applied the most prudent and efficient (and proven) solutions for each feeder section to address the range of causes of the outages on that feeder.

The benefit of each solution was calculated within our hardening the network cost benefit model, based on mitigation of historical faults in each targeted section had the solution been in place and not on other faults at other locations on a feeder.

The AER's statement that "customers may still experience outages if faults occur at other locations along a feeder" does not consider that the proposed solutions are not meant to prevent faults at unique locations but prevent faults along certain sections of feeders.

It should also be noted that the current hardening the network program has been highly successful. Our current program has demonstrated reliability improvements for those customers who are consistently affected by MEDs and there is no reason to suggest that it would not continue to be successful in the future.

We are resubmitting $15.3 million for our hardening the network program. We have provided additional information in Supporting Document: 5.17 – 2020-25 Reliability and Resilience Programs - Hardening the Network, that explains how the benefits have been derived and we have included a real before and after example. The supporting cost benefit analysis model Supporting Document 5.17.1 which was previously provided with our Original Proposal, has also been submitted with our Revised Proposal.

**Our revised forecast**

As shown in Table 5-38, SA Power Networks' revised forecast for all three reliability programs is $62.9 million, $30.3 million higher than the AER substitute forecast of $32.6 million.

**Table 5-38: Revised forecast reliability augex for the 2020-25 RCP (June 2020, $ million)**

| Reliability | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| **Maintain reliability** | 6.5 | 6.5 | 6.6 | 6.6 | 6.7 | 32.8 |
| **Low reliability feeders** | 2.9 | 2.9 | 3.0 | 3.0 | 3.0 | 14.8 |
| **Hardening the network** | 3.0 | 3.0 | 3.1 | 3.1 | 3.1 | 15.3 |
| **Total** | **12.4** | **12.5** | **12.6** | **12.7** | **12.8** | **62.9** |

**Supporting evidence**

Table 5-39 details the supporting evidence for the revised reliability programs included in our Revised Proposal.

**Table 5-39: Supporting evidence for the revised reliability programs included in our Revised Proposal**

| Document reference | Document name | Program it relates to |
|---|---|---|
| 5.16 | Reliability and Resilience Programs - Low Reliability Feeders | Low reliability feeders |
| 5.16.1 | Low Reliability Feeder Regulatory Model | Low reliability feeders |
| 5.17 | Reliability and Resilience Programs - Hardening the Network | Hardening the network |
| 5.17.1 | Hardening the Network Regulatory Model | Hardening the network |
| 5.18 | Oakley Greenwood - The Economic Efficiency of Improving Reliability on Low Reliability Feeders | Low reliability feeders |

### 5.4.8 Strategic

The strategic expenditure category primarily includes a number of one-off strategic projects aimed at ensuring our ability to prudently and efficiently manage the distribution network.

**What we originally proposed**

SA Power Networks originally proposed four programs totaling $17.2 million[55] ($16.4 million excluding business overheads), to manage the security of the network. These programs were:

- Network Control SCADA to substations ($8.2 million) - Installation of SCADA to country substations for operational and reporting.
- Network Control SCADA (RTU) upgrade ($4.7 million) - Upgrade of aged SCADA RTUs.
- Network Control Network data capture ($2.9 million) - Data collection on the Adelaide CBD, Adelaide and North Adelaide area to support OMS, GIS and ADMS operations.
- Condition monitoring ($1.4 million) - Testing and on-line monitoring of priority assets.

**The AER's Draft Decision and how we responded**

The AER did not accept our forecast strategic related capex for the 2020-25 RCP as they were not satisfied the forecast of $17.2 million reasonably reflected the capex criteria. The AER's substitute estimate of $8.8 million ($8.4 million excluding business overheads), is 49% below our forecast.

The AER formed the view that the SCADA to substations program was not prudent or efficient because the benefits were overstated. [56] We undertook a further review of the benefits and we agree the benefits for

[55] Excludes the LV Management program $31.8 million which is now categorised into the DER expenditure category.
[56] *AER, Attachment 5, page 37.*

the remaining (smaller) substation sites are insufficient to justify the program on pure economic grounds. We accept the AER's decision.

**Our revised forecast**

SA Power Networks revised forecast for the strategic programs is $8.8 million, consistent with the AER's substitute estimate.

**Table 5-40: Revised forecast strategic augex for the 2020-25 RCP (June 2020, $ million)**

| Strategic | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| **Network control** | 1.4 | 1.6 | 1.6 | 1.4 | 1.4 | 7.4 |
| **Condition monitoring** | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 1.4 |
| **Low Voltage Management** | See Distributed Energy Resources | | | | | |
| **Total** | **1.7** | **1.9** | **1.9** | **1.7** | **1.7** | **8.8** |

### 5.4.9 Safety

Augmentation safety expenditure is required to prudently maintain the safety of the distribution system through the supply of SCS[57]. This expenditure requires the installation of new assets or the replacement of existing assets with improved technology and differs from safety repex which is for the replacement of 'like for like' assets and has been included in our repex forecast.

**What we originally proposed**

SA Power Networks originally proposed six programs totaling $57.5 million ($54.7 million excluding business overheads), to manage the safety of the network. These programs were:

- Substation lighting ($0.5 million) - Long term program to remediate substation lighting to ensure safe substation access for our workforce.
- Substation security and fencing ($12.5 million) - Long term program to remediate higher risk substation security fencing and security systems.
- Substation earth grids ($5.9 million) - Long term program to remediate non-compliant substation earthing systems.
- Protection compliance ($14.8 million) - Program to upgrade protection systems for compliance and system security.
- CBD 33kV to 11kV migration ($12.4 million) - Program to migrate our 33kV high risk network to the 11kV network to manage risk to personnel.
- Bushfire mitigation ($11.4 million) - Targeted program to manage the risk of bushfires starting from our infrastructure in High Bushfire Risk Areas (HBRAs).

**The AER's Draft Decision and how we responded**

The AER did not accept our forecast safety related capex for the 2020-25 RCP as they were not satisfied the forecast of $57.5 million reasonably reflected the capex criteria. The AER's substitute estimate of $38 million ($35.9 million excluding business overheads) is 34% below our forecast.

The AER accepted our bushfire mitigation program however it raised concerns with the substation security and fencing program, protection compliance and the CBD 33 kV to 11 kV conversion program. [58]

[57] *NER 6.5.7(a)(4).*
[58] *AER, Attachment 5, page 38.*

***Substation security and fencing***
The AER recognised we have an obligation to improve the security and fencing of our substations. However, it noted our forecast of $12.5 million was above our historical expenditure. The AER substituted an amount of $11.3 million consistent with our historic expenditure. We accept the AER's Draft Decision.

***Rural feeder protection***[59]

The AER did not accept our forecast for the rural feeder protection program (previously the protection compliance program) proposed for the 2020-25 RCP.

The AER noted we proposed a similar program in our 2015-20 Regulatory Proposal. The AER did not provide any allowance for this program in its previous determination because we could not demonstrate, in accordance with NER S5.1.9(c) and (f) that upstream assets would be damaged in the event that primary protection systems were to fail. The AER had the same concerns in its Draft Decision for the 2020-25 RCP.

The AER encouraged us to provide additional supporting material in our Revised Proposal. Specifically the AER specified it would require engineering analysis for a representative sample of feeders to demonstrate that the existing protection system on those feeders would not prevent upstream equipment damage in the event of a fault.

We have undertaken a significant amount of analysis on the rural feeder protection program since the AER's Draft Decision and as a result we have revised our program from $13.4 million down to $6.1 million through implementing more efficient protection solutions that are economically viable. Our stakeholders agree this program is required and support the more efficient approach.

This analysis is presented in Supporting Document 5.19 – Rural Feeder Protection Business Case and the associated model, Supporting Document 5.19.1.

***CBD 33kV to 11kV conversion project***

The AER did not accept our forecast of $12.4 million was prudent or efficient. The AER substituted an amount of $7.6 million. The AER raised the following concerns: [60]

- We did not provide condition reports that would demonstrate the poor condition of these assets. In response to an information request, we provided a hazard assessment analysis, which identified a range of hazards. The AER considered the hazards described do not justify the replacement of the substation.
- The AER noted that five out of seven substations have transformers that are less than 35 years of age. In other cases, it noted that we assume a technical life of 65 years for our transformers fleet. Therefore, in the absence of any condition reports, the AER surmised it is unlikely these transformers were in poor condition.
- Given we do not have a defined scope of works for this replacement, the AER considered that we had not demonstrated the forecast capex is the most efficient option.

The CBD 33kV to 11kV conversion is not based on condition alone, it is based on worker safety. Our CBD workforce have raised several safety concerns with the Adelaide CBD sites housing the cables and substations. We engaged Nova to undertake an external risk-based audit of the CBD substations, covering both 11kV and 33kV/11kV substations. The Nova audit identified numerous significant safety issues at these CBD substations, with the key safety issues being, unsafe access and egress and exposed live parts within very confined spaces. When this was discussed with the SA Power Networks CCP and other

[59] The protection compliance program has been renamed to the rural feeder protection program to better reflect the nature of the program.
[60] *AER, Attachment 5, page 39.*

stakeholders, they clearly understood the need for the work and were supportive of ongoing investment to improve conditions.

We consider just maintaining these substations would be unacceptable because it would not address the worker safety concerns that have been identified.

At the time we submitted our Original Proposal we had completed three 33kV to 11kV site conversions in the 2015-20 RCP. We have since completed a further two sites. As we have progressed these substation conversions, the average unit cost has reduced from $1.43 million to $1.15 million due to differing levels of complexity across the differing sites.

Given the lower unit rate, the AER's substitute forecast in its Draft Decision will enable us to undertake most of the planned programs in the 2020-25 RCP. The remaining programs will be deferred to the 2025-30 RCP. On this basis we accept the AER's Draft Decision of $7.6 million.

***Other programs***

We also accept the AER's Draft Decision for the bushfire, substation lighting and substation earth grid programs.

**Our revised forecast**

SA Power Networks revised forecast for the safety programs is $44.1 million as summarised in Table 5-41, $6.1 million higher than the AER substitute forecast of $38 million, reflecting the re-inclusion of the rural feeder protection program.

**Table 5-41: Revised forecast safety augex for the 2020-25 RCP (June 2020, $ million)**

| Safety | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| **Substation lighting** | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.6 |
| **Substation security and fencing** | 2.2 | 2.3 | 2.3 | 2.3 | 2.3 | 11.3 |
| **Substation earth grids** | 1.1 | 1.2 | 1.2 | 1.2 | 1.2 | 5.8 |
| **Rural feeder protection** | 1.0 | 1.3 | 1.3 | 1.3 | 1.0 | 6.1 |
| **CBD 33kV to 11kV conversion** | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 7.6 |
| **Network protection substation audits** | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 1.5 |
| **Bushfire mitigation** | 2.3 | 2.2 | 2.3 | 2.3 | 2.3 | 11.3 |
| **Total** | **8.6** | **8.9** | **9.0** | **9.0** | **8.7** | **44.1** |

**Supporting evidence**

Table 5-42 details the supporting evidence for the revised safety programs in our Revised Proposal.

**Table 5-42: Supporting evidence for the revised safety programs in our Revised Proposal**

| Document reference | Document name | Program it relates to |
|---|---|---|
| 5.19 | Rural feeder protection business case | Rural feeder protection |
| 5.19.1 | Rural feeder protection model | Rural feeder protection |

### 5.4.10 Environment

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

**What we originally proposed**

SA Power Networks originally proposed three programs totaling $9.7 million ($9.2 million excluding business overheads), to manage environmental related issues. These programs were:

- Environmental management ($1.0 million) - Long term program to replace aged or corroded oil filled distribution equipment, adjacent 'sensitive receptors being areas representing a high risk of potential or actual environmental harm through a pollution event, eg in lakes and rivers.
- Substation oil containment ($8.0 million) - Long term program to install oil containment systems in substation to comply with EPA requirements.
- Substation noise abatement ($0.8 million) - Long term program to install noise abatement measures to rectify targeted substation transformers that exceed EPA noise limits.

**The AER's Draft Decision and how we responded**

The AER accepted our forecast environmental related capex of $9.7 million for the 2020-25 RCP, as it considered we demonstrated the need and the efficient level of capex required to comply with a number of legislative and regulatory obligations. [61]

**Our revised forecast**

SA Power Networks revised forecast for the environment programs is $9.7 million, consistent with our Original Proposal and the AER's Draft Determination.

**Table 5-43: Revised forecast environment augex for the 2020-25 RCP (June 2020, $ million)**

| | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| **Environment** | 1.9 | 1.9 | 1.9 | 1.9 | 1.9 | 9.7 |

### 5.4.11 PLEC

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

**What we originally proposed**

SA Power Networks' originally proposed $55.2 million ($52.5 million excluding business overheads) to manage the PLEC program.

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

[61] *AER, Attachment 5, page 31.*

**The AER's Draft Decision and how we responded**

The AER accepted our forecast PLEC related capex, as it considered we demonstrated the need and the efficient level of capex required to comply with a number of legislative and regulatory obligations. [62] However, the AER revised real price escalations in its Draft Decision resulting in a PLEC allowance of $53.6 million for the 2020-25 RCP.

**Our revised forecast**

SA Power Networks revised forecast for the PLEC program is $54.3 million[63], consistent with our Original Proposal and the AER's Draft Determination.

**Table 5-44: Revised forecast PLEC augex for the 2020-25 RCP (June 2020, $ million)-**

| | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| **PLEC** | 10.7 | 10.7 | 10.8 | 11.0 | 11.0 | 54.3 |

## 5.5 Customer connections

Customer connection expenditure includes all expenditure required to connect or upgrade customers' connections to the distribution network. It is associated with additions, upgrades or alterations to meet increased loads from customer requests for new or additional supply connections.

### 5.5.1 Our revised connections forecast summary

Our revised net forecast for customer connections capex for the 2020-25 RCP is $261.7 million, $85.4 million higher than the AER's Draft Decision of $176.3 million and it is $48.5 million higher than our Original Proposal of $213.2 million.

The increase in the net customer connections forecast is due to two factors:

1. A reduction in the weighted average cost of capital (**WACC**), which increases the customers' incremental revenue rebate (**IRR**) and lowers the total forecast customer contributions, resulting in a higher net connections capex; and
2. The major projects forecast has increased due to the inclusion of new committed customer connection projects and a return to historic activity levels which is forecast in the next RCP and consistent with what has recently been evidenced.

The reasons for the higher customer connections forecast is discussed in greater detail below.

### 5.5.2 Customer connections profile

In the period 2014/15 to 2017/18 the connections activity was abnormally low due to the subdued economy. Customer connections economic activity is now returning to more historic 'normal' levels as evident in 2018/19.

SA Power Networks engaged BIS Oxford Economics (**BISOE**) to provide an updated connection forecast for our Revised Proposal (Supporting Document 5.12 – BIS Oxford Economics - Gross Customer Connections Expenditure Forecasts to 2025-26). In its report, BISOE noted the following:

> *Total customer connections expenditure recovered strongly over 2017/18 and 2018/19, rising 16% and 17% respectively to $80.9 million. The 2018/19 level is a return to more 'normal' levels of*

[62] *Ibid.*

[63] The minor reduction in dollars is due to overhead and escalation adjustments.

*customer connections expenditure, following four years of relatively weak levels. Total connections expenditure is forecast to decline -3.5% in 2019/20, with declines across the minor, URD and medium categories more than offsetting a 10% increase in major connections.*

*Total connections expenditure is forecast to then rise steadily (cumulatively 18.4%) over the subsequent three years to 2022/23, peaking at $92.5 million in 2022/23, driven by strengthening economic, building and infrastructure activity, with defence and other government projects key contributors. Thereafter, we expect connections expenditure to decline by a cumulative 11% over the three years to 2025/26 as building and construction activity fall back. The seven-year average to 2025/26 is predicted to be $84.3 million, compared with an average of $67 million over the previous five years to 2018/19.*[64]

Given the recent connections activity and the committed major projects in the coming years, we are confident the connections forecast is based on sound assumptions.

### 5.5.3 AER's Draft Decision for customer connections

The AER accepted our contributions forecast of $350.1 million as it was consistent with our historic levels of contributions. However, the AER did not accept our proposed forecast net connection capex of $213.2 million ($202.9 million excluding business overheads) as they were not satisfied the forecast reasonably reflected the capex criteria. The AER included $176.3 million ($166.7 million excluding business overheads) in its substitute estimate for connections.

The AER's primary concerns were that our economic modelling includes unsupported assumptions. In addition, EMCa identified material discrepancies between our reset RIN data and the supporting economic modelling.

### 5.5.4 How our revised customer connections expenditure forecast compares

Table 5-45 details our Original Proposal and our Revised Proposal customer connections forecast for the 2020-25 RCP, compared to the AER's Draft Decision.

**Table 5-45: SA Power Networks' Original and Revised Proposals customer connections forecast compared to the AER's Draft Decision (June 2020, $ million)**

| Connections category | Original Proposal | AER Draft Decision | Revised Proposal | Difference to Draft Decision $ |
|---|---|---|---|---|
| **Customer connections** | 563.2 | 523.4 | 623.8 | 100.4 |
| **Customer contributions** | (350.1) | (347.1) | (324.4) | 22.7 |
| **Customer net** | 213.2 | 176.3 | 299.4 | 123.1 |
| **Other contributions** | 0.0 | 0 | (37.8) | (37.8) |
| **Total net** | 213.2 | 176.3 | 261.7 | 85.4 |

**What we originally proposed**

Our Original Proposal connections capex forecast for the 2020-25 RCP was $213.2 million net. The gross connections forecast was $563.2 million (including gifted assets) and the contributions forecast was $350.1 million (including gifted assets).

[64] *BIS Oxford Economics, Gross customer connections expenditure forecasts to 2020/26, p.1*. Note the dollars quoted in the BISOE report are in 2017/18 dollars.

The customer connections expenditure is divided into four categories, being:

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

**The AER's Draft Decision and how we responded**

The AER sought advice from their consultant EMCa who expressed a number of key concerns with our connections forecast. EMCa's primary concerns summarised in the AER's Draft Decision were: [65]

- Our forecast for major customer connections was based solely on BISOE's top-down economic model. Direct access to BISOE's model was not provided and therefore EMCa could not assess the reasonableness of the forecast. EMCa were also unclear how the bottom-up forecast of major customer connections was used to support and verify the outcomes from the economic model.
- BISOE did not demonstrate its basis for forecasting 'Non-residential' to remain at approximately current levels throughout the 2020–25 regulatory control period. EMCa claimed other data sources appear to suggest that non-residential commencements may not remain at current levels.
- It observed an increase in 'Non-residential Commencements' and an increase in major customer connections capex, however it did not observe any relationship between 'Engineering Construction Work' and major customer connections capex.
- There were material data discrepancies between our reset RIN data and the Regulatory Proposal, which indicated gross connections forecasts up to $114 million higher than BISOE's figure.

In response to the AER's Draft Decision, SA Power Networks and BISOE met with the AER on 5 September 2019. The objective of the meeting was to provide a greater clarity on BISOE's forecasting methodology for major projects, explain how the connections activity in the 2014/15 to 2017/18 period was abnormally low and to explain the impact of WACC on contributions. At this meeting SA Power Networks' agreed to provide further information on these matters in our Revised Proposal.

SA Power Networks' response to the AER's Draft Decision includes:

- Explaining why it was incorrect and inconsistent for the AER to accept our contributions forecast but reduce the gross forecast on which the contributions forecast was based.
- Explaining the impact of the Pre-Tax Real WACC on customer contributions.
- Providing an updated gross connections expenditure forecast with additional justification and alignment to the Reset RIN data.

In August 2019 SA Power Networks formed a Connections Working Group, established to address stakeholder feedback about the customer connections process and resolve some concerns relating to ACS Connections Pricing. Since its establishment, this group has been working collaboratively to improve the connections process and the information available to customers.

When our Revised Proposal customer connections proposal was discussed with the SA Power Networks CCP and other stakeholders, they indicated that BISOE's updated forecast appeared optimistic and sought more

[65] *AER, Attachment 5, pp. 41-42.*

detailed information about the increased Revised Proposal forecast, which we have endeavored to provide. We will continue to work with all interested stakeholders, including the Connections Working Group, to address concerns and improve outcomes for customers. However, we retain the view that BISOE's forecasts remain a reasonable best estimate, and reflect a return to historic levels of connections activity, taking into account appropriate economic drivers which we describe further below.

***Customer contributions methodology***

In the AER's Draft Decision it reduced our customer gross connections forecast by 9%, however the AER did not make the corresponding 9% reduction to the customer contributions forecast. Lower gross connections expenditure results in a corresponding reduction in customer contributions.

The AER also stated it accepted our contributions forecast because it was consistent with our historical contributions. The customer connections expenditure cannot be extrapolated from historical actuals because there are many factors that influence the forecast. For example, the factors that can significantly affect connections expenditure include: the state economy, government initiatives, the allowed cost of capital and many other factors that will influence the net connections expenditure. These factors will differ significantly in 2020-25 from historical years.

***The impact of WACC on contributions***

SA Power Networks charges contributions in accordance with its Connections Policy which is fully compliant with the National Energy Customer Framework (**NECF**). The charging methodology provides for rebates to be deducted from the cost to connect.

The contribution amounts for a large portion of our forecast are a direct function of the regulatory WACC as required by the NECF and our (revised) Connection Policy 2020-25, which we understand will be accepted by the AER. Given the AER is proposing to reduce our Pre-Tax Real WACC from 4.27% in the current RCP to 2.63%[66] in the 2020-25 RCP, the contribution amount as a proportion of the gross connection expenditure must reduce, resulting in an increase in net connections expenditure as a proportion of gross[67].

***Unsupported assumptions in the BISOE connections forecast***

The AER raised concerns regarding the assumptions used in the BISOE forecasting methodology. Section 3 of the Supporting Document 5.12 – BIS Oxford Economics - Gross Customer Connections Expenditure Forecasts to 2025-26, sets out in detail the methodology and assumptions applied in the development of the connections forecast.

***Increase in net connections expenditure in our Revised Proposal***

On 27 November 2019, SA Power Networks presented our Revised Proposal to key stakeholders and the SA Power Networks CCP. During this meeting a number of stakeholders, including SACOSS, expressed concern over the significant increase in connections expenditure. We were asked to clearly explain the reasons behind this increase in our Revised Proposal.

The increase in gross connections is largely due to a downturn in the South Australian economy that suppressed connections activity over the first three years of the current RCP, but returned to more 'normal' levels in 2018/19. BISOE are forecasting this level of activity will continue into the 2020-25 RCP with a small

[66] Calculated value as of November 2019

[67] The Pre-Tax Real WACC affects the IRR calculation which in turn affects the customer contributions. Specifically, as the WACC decreases, rebates increase, customer contributions decrease and thus net connection expenditure increases.

increase driven by strengthening economic, building and infrastructure activity, with defence and other government projects being key contributors.

However, the connection contribution forecast only increases by 14% from our estimate for the current period. The reduction in contributions as a proportion of gross capex is due to the reduction in WACC (as noted above). This will reduce the contribution we will receive for medium and major connections (by approximately 10%). It also increases the asset rebates we will pay to real estate developers (by approximately 25%).

In summary, the reasons behind the higher connections forecast in our Revised Proposal, compared to our Original Proposal are two-fold:

(1) updated higher gross connections forecast; and
(2) updated lower contributions forecast due to the lower WACC.

SA Power Networks has produced Supporting Document 5.11 – Connections 2020-25 Response to AER's Draft Decision, in direct response to the AER's concerns. The connections overview document sets out our detailed response to the issues the AER and EMCa raised in the Draft Decision.

**Our revised forecast**

An updated gross connections expenditure forecast is provided in this Revised Proposal with adjustments to address key concerns raised on our Original Proposal by the AER, including alignment of the 2020-25 forecast to Reset RIN data, utilisation of 2018/19 actual expenditure and customer contributions and current forecast known projects, plus improved detail of both historical spend and forecast expenditure residuals reflecting the latest State economic activity.

We note the AER largely accepted our Connection Policy for 2020-25 subject to minor edits relating to embedded generation only, which have been addressed in our revised Attachment 16 – Connection Policy.

SA Power Networks' revised forecast for the customer connections program is $261.7 million net, refer to Table 5-46.

**Table 5-46: Revised forecast customer connections expenditure for the 2020-25 RCP (June 2020, $ million)**

| Customer connections | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| **Connections (gross)** | 120.4 | 123.4 | 131.9 | 125.9 | 122.1 | **623.8** |
| **Contributions** | (62.9) | (63.8) | (68.9) | (65.3) | (63.4) | **(324.4)** |
| **Customer Net expenditure** | 57.5 | 59.6 | 63.0 | 60.6 | 58.7 | **299.4** |
| **Other contributions** | (7.5) | (7.5) | (7.5) | (7.6) | (7.6) | **(37.8)** |
| **Total net** | **50.0** | **52.1** | **55.4** | **53.0** | **51.1** | **261.7** |

The remaining other customer contributions, totaling $37.8 million ($ June, 2020), consist of:

- recovery of costs of assets damaged by third parties (ie recoverable works, $18.3 million); and
- contributions towards embedded generation assets ($19.5 million).

All of the above contribution forecasts are based on historical averages, however adjusted to take into account the lower WACC.

**Supporting evidence**

Table 5-47 details the supporting evidence for the customer connections program included in our Revised Proposal.

Table 5-47: Supporting evidence for the customer connections program included in our Revised Proposal

| Document reference | Document name | Program it relates to |
|---|---|---|
| 5.11 | Connections 2020-25 Response to the AER's Draft Decision | Customer connections |
| 5.11.1 | Connections forecast model | Customer connections |
| 5.12 | BISOE, Gross customer connections expenditure forecasts to 2025-26 | Customer connections |
| 5.13 | BISOE, Response to EMCa report | Customer connections |

## 5.6 Information technology

Information technology expenditure is associated with maintaining IT systems and delivering the capabilities required to enable SA Power Networks' operations and business. Our proposed investment will maintain our services and enable the delivery of better outcomes for our customers at a lower price through reliable, safe, secure and efficient technology capabilities.

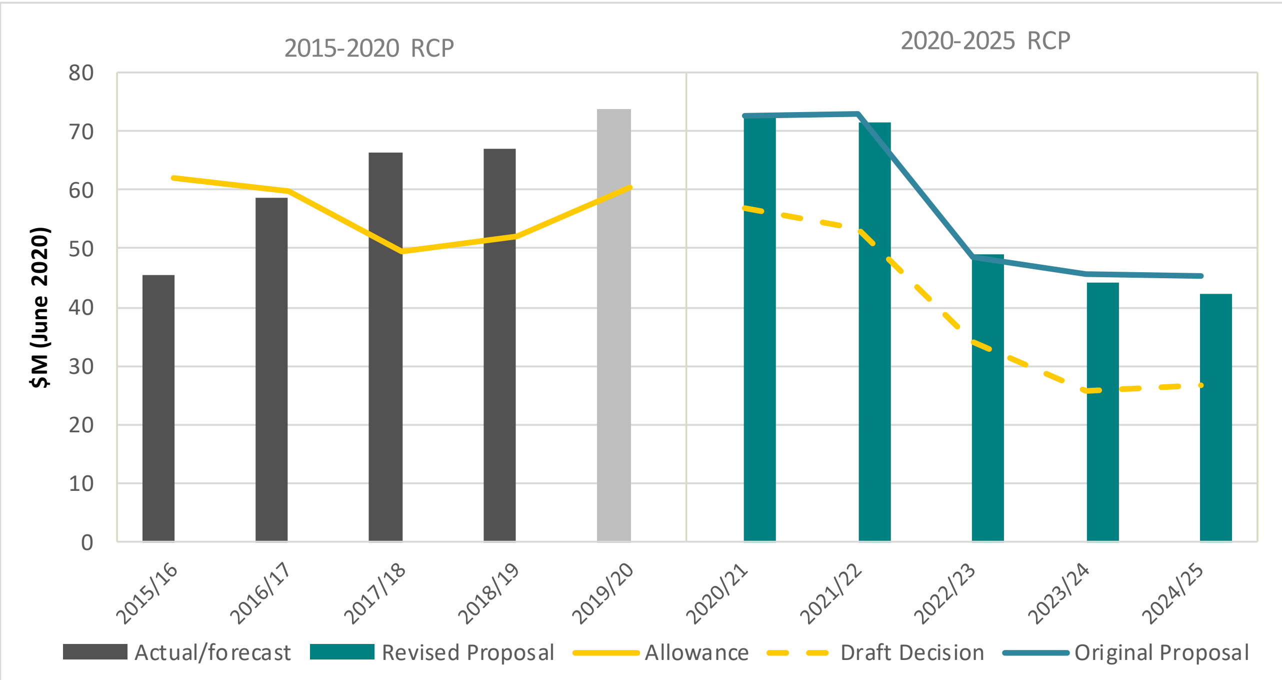
### 5.6.1 Our revised IT forecast summary

Our revised forecast for IT capex for the 2020-25 RCP is $279.4 million. This is $82.6 million higher than the AER's Draft Decision of $196.8, but $5.2 million lower than our Original Proposal and $27.2 million lower than we are forecasting to spend in the current RCP. Our revised forecast also enables $74.3 million more benefits than the AER Draft Decision – helping us to keep prices down in the long term.

### 5.6.2 IT profile

The overall IT capital forecast will trend strongly downward over the 2020-25 RCP. SA Power Networks is currently completing a large-scale replacement and consolidation program for our IT systems. Almost 80% of the IT capex forecast ($219.5 million) is focused on maintaining current levels of service and managing IT risk though replacement and updates to existing IT applications and infrastructure. This program was commenced in the 2015-20 RCP and the capex will reduce significantly as the program is completed (Figure 5-9). We expect to reduce to IT capital levels lower than that in 2015/16.

Figure 5-9: IT expenditure profile 2010-2025 (June 2020, $ million)



### 5.6.3 AER's Draft Decision for IT

The AER did not accept all of our proposed IT forecast of $284.6 million as they were not satisfied the forecast reasonably reflected the capex criteria. The AER included an amount of $196.8 in its Draft Decision for IT which is a 31% reduction compared to our Original Proposal. However, in making their determination the AER noted the following:[68]

- SA Power Networks IT governance and management frameworks are consistent with industry practice.
- The cost estimation methodology is appropriate.
- SA Power Networks had taken steps to assess the risk of delivery.
- Recurrent IT capex is 10.8% less than the current period and is a "reasonable forecast of the prudent costs".

The AER accepted our proposed expenditure for recurrent IT works but rejected four (of eight) non-recurrent IT programs that we proposed.

### 5.6.4 How our revised IT expenditure forecast compares

Table 5-48 details our Original Proposal and our Revised Proposal IT forecast for the 2020-25 RCP, compared to the AER's Draft Decision.

**Table 5-48: SA Power Networks' Original and Revised Proposals IT forecast and benefits compared to the AER's Draft Decision (June 2020, $ million)**

| IT | Original Proposal | AER Draft Decision | Revised Proposal | Difference to Draft Decision $ |
|---|---|---|---|---|
| **Total capital** | 284.6 | 196.8 | 279.4 | 82.6 |
| **Total benefits** | 102.9 | 27.8 | 102.0 | 74.3 |

In response to stakeholder and AER feedback we undertook a rigorous analysis of our forecast and the four business cases for non-recurrent IT programs that had not been accepted. We have decided not to seek funding for our worker fatigue program. However, we are proposing a new utilities cyber security maturity uplift program. Our revised IT forecast ($279.4 million) is marginally smaller ($5.2 million) than our original forecast ($284.6 million). Overall, the recommended options from our large business cases (ie. Assets and Work, SAP upgrade and ring-fencing programs) have still proven to be the long-term least cost options for customers, efficiently manage our risks and deliver the best benefits.

Our revised IT forecast enables benefits of $102.0 million which is over two and a half times (267.6%) the value of benefits under the AER Draft Decision ($27.8 million), and similar to the Original Proposal ($102.9 million). The majority of financial benefits from the IT Portfolio are from avoiding expected cost increases in the forecast network and IT expenditures, allowing us to efficiently keep customer prices down in the long term. Our Assets and Work program will embed and retain larger value benefits well beyond the 2020-25 RCP.

**What we originally proposed**

Our Original Proposal IT forecast for the 2020-25 RCP was $284.6 million and delivered $102.9 million of benefits in the same period, with more benefits accruing in subsequent RCPs.

We provided 13 detailed IT business cases (see Figure 5-10 below) to support our proposed investment. We were rigorous and thorough in the development of these business cases to ensure we were selecting the

[68] *AER, Attachment 5, page 19*

most prudent, efficient and NER compliant options available to us, understanding the impact and the benefits to customers.

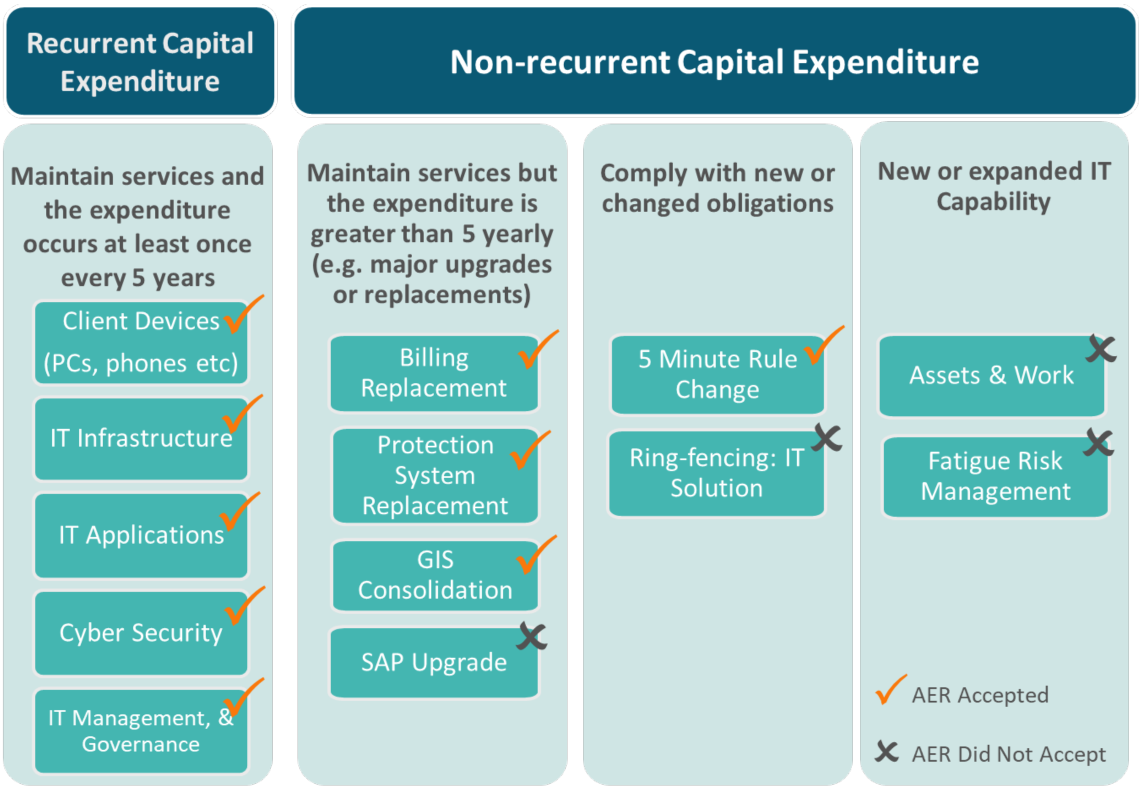
**The AER's Draft Decision**

The AER did not accept our proposed IT forecast of $284.6 million and instead included an amount of $196.8 million in its Draft Decision.

In its evaluation of the original IT proposal the AER acknowledged the significant customer and stakeholder feedback on the IT Investment, in particular, the need to thoroughly assess the quantity of the IT investment.

On 28 November 2019, the AER released a framework for the evaluation of regulatory IT capex proposals.[69] The framework lays out in detail the categories (ie recurrent and non-recurrent) and sub-categories of IT expenditure and how each category will be evaluated and expected to be justified by distributors. Our original and revised IT proposal and business cases are strongly aligned to this framework (Figure 5-10). In fact, the AER's framework was influenced by our approach as being a reasonable and practical means of giving effect to the expectations of the National Electricity Rules with respect to expenditure assessments and improving transparency with respect to expenditure proposals.

**Figure 5-10: Strong alignment of the IT business cases to the AER Expenditure Evaluation Categorisation and the AER Draft Decision Outcomes**




The AER Draft Decision accepted IT business cases worth $202.9 million but reduced this to $196.8 million on the basis of 'modelling adjustment' associated with its alternative modelling of labour escalations and revised inflation rates.

69 *https://www.aer.gov.au/communication/aer-publishes-guidance-on-non-network-ict-capital-expenditure-assessment-approach*

The AER accepted the need to maintain current levels of service and manage risk and allowed our proposed forecast Recurrent IT expenditure as a "reasonable forecast of the prudent costs".[70]

The AER also accepted four (of eight) Non-Recurrent business cases including Billing Replacement, GIS Consolidation, Protection System Replacement and 5 Minute Rule Change.

The AER Draft Decision did not accept four other business cases which proposed non-recurrent IT expenditure, on the basis that we had either not sufficiently established the need (Worker Safety: Fatigue Risk Management), not considered all potential options (SAP Upgrade; Ring-fencing Compliance) or overstated the expected benefits (Assets and Work Program). The AER Draft Decision also noted a concern with the deliverability of the IT portfolio given a perceived lack of allowance for time contingency to mitigate the risk of project overruns, which may result in SA Power Networks not being able to deliver all of the outcomes for the RCP.

**How we responded**

In response to the concerns from the AER, our stakeholders and customers, we have undertaken a significant analysis and revision process and:

- reviewed the need and the viability of the business cases that were not accepted by the AER;
- provided additional options (as appropriate), increased the rigour of financial analysis and tested the robustness of the benefits for those business cases we retained;
- responded to new and emerging cyber security related regulatory obligations by adding a new business case "Utilities Cyber Maturity Uplift Business Case"; and
- addressed the AER concerns regarding the deliverability of our IT portfolio, supported by an independent review by KPMG and provided in Supporting Document 5.28 – KPMG – Deliverability Review (confidential).

SA Power Networks hosted workshops on 21 October 2019 for ICT and on 25 October 2019 for repex and IT Assets and Work with customers and stakeholders (SA Power Networks CCP and our stakeholders) on our developing plans for our Revised Proposal. While broad concerns remain about the overall 'level' of IT investment, stakeholders acknowledged our alignment to the AER framework and our efforts to address specific AER feedback. Overall the feedback from these sessions was constructive and in particular stakeholders were supportive of the Assets and Work program in lieu of having higher repex in the 2020-25 RCP. Further information on stakeholders' feedback and how we have addressed it is included in Supporting Document 5.26 - IT Investment Plan Addendum (confidential).

Table 5-49 summarises the changes to the business cases. The detailed analysis in support of our Revised Proposal is set out in each of our December 2019 business case addendum documents, and our IT Investment Plan 2020-25 Addendum.

The changes to the IT capex forecast are:

- Reduced the capex request for the **Assets and Work Program** by $2.8 million but retained the recommended option from the original business case with some revisions. Initiatives which contributed lower levels of benefits were deferred into the 2025-30 RCP (subject to further evaluation in the lead-up to the 2025-30 RCP). Benefits for the Program are forecast at $56.5 million for the 2020-25 RCP, including $52.7 million of efficient repex deferral and which has been accounted for in the overall revised repex submission.
- Removed the **Worker Safety: Fatigue Risk Management Business Case** ($5.8 million). Safety is a very high priority for SA Power Networks and after a review of our capabilities we will seek opportunities to leverage ongoing initiatives to improve our management of worker fatigue risks.

[70] *AER, Attachment 5, page 19.*

- Added a **Utilities Cyber Maturity Uplift Business Case** ($5.6 million) to enable SA Power Networks to respond to the expected regulatory obligations for all utilities in the NEM to have strong minimum cybersecurity standards, starting in the 2020-25 RCP.

The recommended options and the capital requests for the **SAP Upgrade** and the **Ringfencing Compliance** have been retained as they were shown to be the most cost-efficient options available to us to manage the identified need, risks and issues. We explored and costed a number of additional options for these business cases:

- For the SAP Upgrade we explored multiple options to delay the upgrade post 2025. However, these proved to be more expensive and higher risk than the original recommended option to complete the key components of the SAP Upgrade by 2025.
- For Ringfencing compliance, we added more options for achieving compliance. Importantly the additional analysis identified significant additional cost avoidance benefits to customers of approximately $16 million over the RCP of the recommended IT solution for Ringfencing.

Additional reductions in the capital request compared to the Original Proposal are due to the revised labour escalation and inflation adjustments explained in Section 5.2.7 of this Attachment.

**Table 5-49: Revised IT Capital Proposal and Benefits compared to the Original IT Proposal and key actions taken in response to feedback**

| Business case | How we have responded to Stakeholder and AER Comments | Original Proposal capital forecast 2020-25 | Revised capital forecast 2020-25 | Capex Difference to Original Proposal | Revised Benefits 2020-25 |
|---|---|---|---|---|---|
| **AER Approved** | Accepted. | 202.9 | 201.1 | -1.8* | 27.8 |
| **Not Approved** | | | | | |
| Assets and Work Program | • Remodelled the financial benefits<br>• The repex benefits are now more clearly demonstrated in the repex forecasts. | 44.9 | 42.1 | -2.8 | 56.5 |
| SAP Upgrade | • Assessed other options to delay the upgrade | 26.9 | 26.7 | -0.3* | 1.6 |
| Ringfencing compliance: IT solution | • Considered other options.<br>• Provided analysis of the significant financial benefits to customers | 4 | 4 | 0 | 16.1 |
| Worker safety: Fatigue risk management | • Removed from the IT Revised Proposal | 5.8 | 0 | -5.8 | |
| **New – responding to emerging cyber security standards for utilities on the NEM** | | | | | |
| Utilities Cyber Maturity Uplift | NA | NA | 5.6 | +5.6 | |
| **Total IT investment** | | **284.6** | **279.4** | **-5.2** | **102.0** |

*Variations due to labour escalation and inflation adjustments. [71]

[71] The escalator adjustments are explained in Section 5.2.7 of this Attachment.

**Deliverability**

We are confident that we will be able to deliver this IT portfolio and ensure the benefits to our customers because we have:

- delivered a larger IT portfolio of work in the 2015-20 RCP, while effectively responding to a rapidly changing environment[72];
- effectively managed our portfolio risks – including allowed sufficient levels of change management and warranty period across the Portfolio;
- a mature IT Delivery capability with extensive use of Agile delivery methodologies to maximise value, minimise cost and effectively manage business change;
- tried and tested flexible IT workforce arrangements; and
- a mature Corporate Portfolio Management Office (CPMO) that uses lead rather than lag indicators of performance – hence dealing with issues before they impact on the project timelines or delivery.

In its independent report on the deliverability of the IT program (Supporting Document 5.28 – KPMG – Deliverability Review (confidential)), KPMG concluded that:

- "*SAPN has adopted a sound approach to planned portfolio delivery and has taken a prudent approach to scheduling the major projects within the portfolio*";
- *"The project pipeline is actively managed, balancing delivery of large, medium and small projects along with the resource profiles required to deliver them. A highly contingent IT workforce provides the flexibility to scale as required, whilst the incoming pipeline provides the mechanism to forecast and manage demand*"; and
- "*SAPN has repeatedly demonstrated their delivery capability within the 2015-2020 RCP, which is larger than the IT portfolio proposed for 2020-2025*".

**Summary**

The SA Power Networks revised IT forecast takes into account the feedback from our stakeholders, customers and the AER. We have undertaken significant additional analysis on our options, costs and risks. This work has shown that, by and large, our original recommended approaches did present the long-term least cost options for customers and deliver the best benefits.

Our IT investment will continue to enable the delivery of tangible benefits to customers in the 2020-25 RCP. Our investment will continue to facilitate a targeted customer-focused value-based approach to managing the risk of our network assets in a dynamic electricity environment. Our investment will continue to ensure our services remain reliable and secure through the completion of our significant planned IT replacement program. Our IT capex profile will reduce significantly over the 2020-25 RCP as the IT replacement program is completed.

**Our revised forecast**

SA Power Networks revised forecast for IT is $279.4 million, $82.6 million higher than the AER's substitute forecast of $196.8 million. However, our revised forecast delivers significantly more benefits ($74.3 million more) that the AER's substitute forecast and enables more benefits in the following RCPs.

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[72] Refer section 4 of the Original IT Investment Plan

**Table 5-50: Revised forecast IT expenditure for the 2020-25 RCP (June 2020, $ million)**

| IT | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| **Recurrent – Accepted** | 29.1 | 37.9 | 27.6 | 25.3 | 27.6 | 147.6 |
| **Non-Recurrent** | | | | | | - |
| **Non-Recurrent – Accepted** | 28.4 | 16.3 | 7.5 | 1.2 | 0.1 | 53.5 |
| **Asset and Work Program** | 7.1 | 10.3 | | 11.9 | 12.8 | 42.1 |
| **SAP Upgrade** | 5.0 | 3.9 | 11.5 | 4.5 | 1.8 | 26.7 |
| **Ringfencing Compliance** | 2.7 | 1.4 | | | | 4.0 |
| **Utilities Cyber Uplift** | - | 1.9 | 2.6 | 1.2 | - | 5.6 |
| **Total** | **72.3** | **71.6** | **49.1** | **44.2** | **42.2** | **279.4** |

**Supporting evidence**

Table 5-51 details the supporting evidence for the revised non-recurrent ICT programs included in our RRP.

**Table 5-51: Supporting evidence for the revised non-recurrent ICT programs included in our RRP**

| Document reference | Document name | Program it relates to |
|---|---|---|
| 5.26 | IT Investment Plan 2020-25 Addendum | Total IT program |
| 5.27 | Ring-fencing Compliance IT Solution Business Case Addendum | Ring-fencing Compliance program |
| 5.28 | Independent Review of the Deliverability of SAPN' Regulatory Resubmission for IT Expenditure | Total IT program |
| 5.29 | SAP Upgrade Business Case Addendum | SAP Upgrade |
| 5.30 | Utilities Cyber Maturity Uplift Business Case - Confidential | Utilities Cyber Maturity Uplift |
| 5.31 | Assets and Work Program Business Case Addendum | Asset and Work Repex forecast |

## 5.7 Operational Technology

Network operational technology capex is required to enable continuous day to day operation and monitoring of our distribution and telecommunications network.

### 5.7.1 Our revised OT forecast summary

Our revised forecast for OT capex for the 2020-25 RCP is $21.9million, $12.2 million higher than the AER's Draft Decision of $10 million and it is consistent with our Original Proposal.

### 5.7.2 AER's Draft Decision for OT

The AER did not accept our proposed OT forecast of $22.2 million as it was not satisfied the forecast reasonably reflected the capex criteria. The AER included an amount of $10.2 million in its Draft Decision for OT which was a 55% reduction compared to our Original Proposal.

### 5.7.3 How our revised OT expenditure forecast compares

Table 5-52 summarises our Original Proposal and our Revised Proposal OT forecast for the 2020-25 RCP, compared to the AER's Draft Decision.

**Table 5-52: SA Power Networks' Original and Revised Proposals OT forecast compared to the AER's Draft Decision (June 2020, $ million)**

| OT | Original Proposal | AER Draft Decision | Revised Proposal | Difference to Draft Decision $ |
|---|---|---|---|---|
| **TNC Management** | 2.8 | 2.8 | 2.7 | (0.1) |
| **UPAX/Business telephone network** | 2.2 | 2.2 | 2.1 | (0.1) |
| **OT security** | 5.0 | 5.0 | 4.9 | (0.1) |
| **ADMS** | 12.2 | 0.0 | 12.2 | 12.2 |
| **Total** | **22.2** | **10.2** | **21.9** | **11.9** |

**What we originally proposed**

Our Original Proposal OT forecast for the 2020-25 RCP was $22.2 million. The OT forecast comprised the following programs:

- Telecommunications Network Control (TNC) management ($2.8 million) - TNC manage the monitoring, control and restoration of the telecommunications networks across South Australia.
- UPAX/Business telephone network used by SA Power Networks ($2.2 million) - Maintenance of the SA Power Networks' voice network deployed throughout the State for operational telephony.
- OT security ($5 million) - Cyber program to segregate, monitor and protect the OT networks that support critical operational functions.
- Advanced Distribution Management System (ADMS) replacement ($12.2 million) – Replacement of ADMS hardware and software components that are obsolete and no longer supported by the vendor.

**The AER's Draft Decision and how we responded**

The AER did not accept our proposed OT forecast of $22.2 million as they were not satisfied the forecast reasonably reflected the capex criteria. [73] The AER included an amount of $10 million in its Draft Decision.

The AER asked SA Power Networks to provide a bottom-up forecast for the TNC Management, UPAX/Business telephone network and OT Security programs. The AER was satisfied that the forecasting methodology that was applied arrived at a prudent and efficient level of expenditure.

The AER did not accept our proposed expenditure for the ADMS hardware and software replacement as there was insufficient information to demonstrate the prudency and efficiency of this program. [74]

During the 2020-25 RCP, support for key components of our ADMS will be withdrawn by the product vendors. Good electricity industry practice dictates that to manage the risk of cyber security attacks on mission critical system such as ADMS, vendor support should be current and in place.
The ADMS requires three components to function:

(1) Hardware,
(2) an Operating System, and
(3) ADMS Software

[73] *AER, Attachment 5, page 84.*
[74] *AER, Attachment 5, page 85.*

From 2023, vendor support for the Operating System (Microsoft Windows 7 and Windows Server 2012) will cease. Testing[75] has identified that our current ADMS Software is not compatible with newer Operating Systems and therefore a change in Operating System necessitates an update to the ADMS Software.

The next refresh of the Hardware falls within the 2020-25 RCP. We have undertaken additional analysis that identifies aligning the update of all components in parallel delivers efficiencies and results in the lowest NPV of all feasible options considered.

Our preferred option for maintaining ADMS capabilities during the 2020-25 RCP is to update the operating systems to Windows 10 and Windows Server 2019 in 2022. The ADMS software will be updated from v3.6 to v3.8[76]. The next scheduled hardware refresh will be aligned with the ADMS software update.

We have developed a comprehensive business case (Supporting Document 5.32 - ADMS Business Case) that demonstrates the prudency and efficiency of the ADMS hardware and software replacement in the 2020-25 RCP. Our SA Power Networks CCP and stakeholders support this replacement program.

**Our revised forecast**

SA Power Networks revised forecast for OT is $21.9 million as detailed in Table 5-53 below.

**Table 5-53: Revised forecast OT expenditure for the 2020-25 RCP (June 2020, $ million)**

| OT | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| **Telecommunications** | 1.7 | 2.4 | 2.7 | 1.7 | 1.5 | 10.0 |
| **ADMS hardware** | 1.7 | - | - | 1.8 | 1.8 | 5.3 |
| **ADMS software** | 1.6 | - | - | 1.8 | 3.6 | 6.9 |
| **Total** | **4.9** | **2.4** | **2.7** | **5.1** | **6.7** | **21.9** |

**Supporting evidence**

Table 5-54 details the supporting evidence for the ADMS program included in our Revised Proposal.

**Table 5-54: Supporting evidence for the ADMS program included in our Revised Proposal**

| Document reference | Document name | Program it relates to |
|---|---|---|
| 5.32 | ADMS business case | ADMS software and hardware replacement |
| 5.32.1 | ADMS model | ADMS software and hardware replacement |

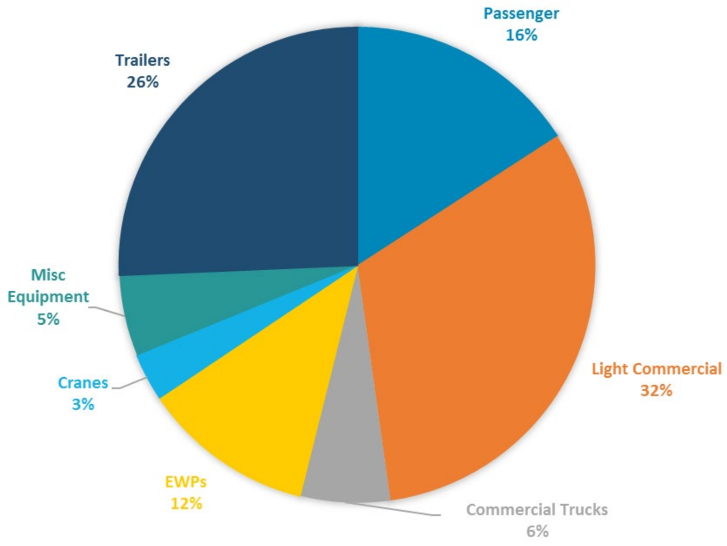
## 5.8 Fleet

We maintain a fleet of specialised vehicles that provide a safe and efficient work environment for our field crews. With over 89,000 kilometres of powerlines and a service area of 178,000 square kilometres, we require a fleet that supports the delivery of a safe and reliable service to our customers. Our fleet enables our field crews to access the network, to work at height and on live components, reducing customer power outages and restoring power quickly and safely.

Our fleet is comprised of Elevated Work Platforms (**EWPs**), Crane Borers, Heavy Commercial Trucks, Passenger and Light Commercial vehicles, as provided in Figure 5-11 below.

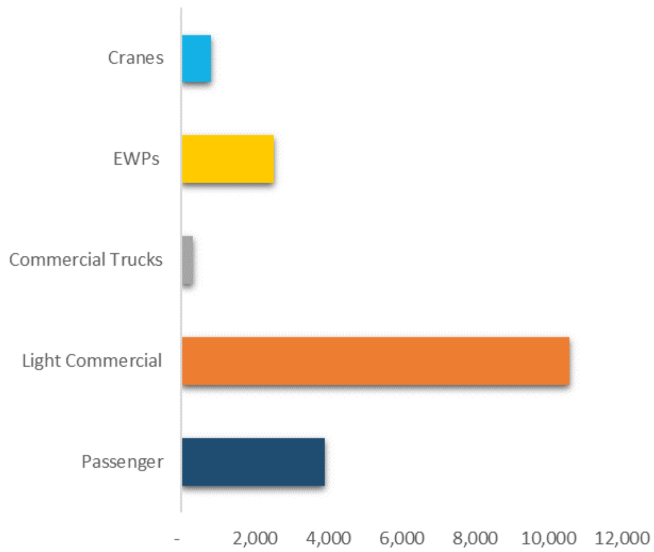
[75] Schneider tested the current ADMS version (3.6) on Windows 10 and Windows Server 2016 and found that it was not compatible.
[76] Schneider have advised v3.7 is not available.

**Figure 5-11: SA Power Networks fleet composition**




Fleet capex is incurred to replace vehicles based on age, use (eg kilometres travelled) and condition. Our fleet travels on average 18 million kilometres per year, with our light commercial fleet travelling the furthest, approximately 10.5 million kilometres. Further detail is provided in Figure 5-12 below. We do not track the kilometres travelled for trailers.

**Figure 5-12: Fleet distance travelled ('000 km's)**




### 5.8.1 Our revised fleet forecast summary

Our revised forecast for fleet capex for the 2020-25 RCP is $97.3 million, $17.4 million higher than the AER's Draft Decision of $79.9 million.

### 5.8.2 Fleet profile

SA Power Networks undertakes cyclical replacement of our fleet in accordance with our specified replacement criteria, as detailed in Table 5-55.

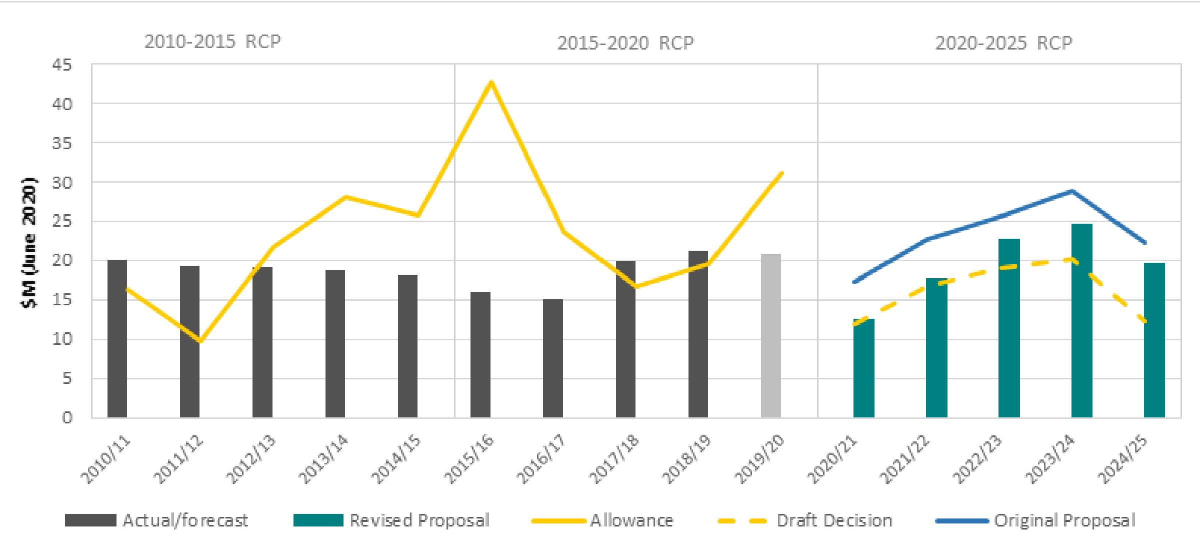
Table 5-55: Fleet replacement criteria

| Fleet category | Current replacement criteria | Proposed replacement criteria |
|---|---|---|
| Elevated working platform | 10 year replacement | 10 year replacement |
| Cranes | 10 year rebuild, 14 year replacement | 10 year rebuild, 14 year replacement |
| Heavy commercial vehicles | 15 year replacement | 15 year replacement |
| Trailers | 15 year replacement (previously 20 years) | 15 year replacement |
| Other specialist equipment | 20 year replacement | 20 year replacement |
| TEC vehicles | 3 year replacement / 90,000km | 3 year replacement / 90,000km |
| Passenger vehicles | 5 year replacement / 150,000km | 5 year replacement /150,000km |
| Light commercial vehicles | 5 year replacement / 150,000km | 5 year replacement /150,000km |

Given that the key fleet replacement criteria are based on age, this introduces a cyclic nature to the replacement of vehicles and results in some regulatory years having a higher number of replacements than others.

Our fleet expenditure profile over the 2010-25 period is provided in Figure 5-13 below.

Figure 5-13: Fleet expenditure profile 2010-2025 (June 2020, $ million)




Except for shortening trailer replacement cycles from 20 years to 15 years, SA Power Networks did not propose any changes to our vehicle replacement criteria in our Original Proposal for the 2020-25 RCP.

### 5.8.3 AER's Draft Decision for fleet

The AER did not accept our proposed fleet forecast of $116.6 million as it was not satisfied the forecast reasonably reflected the capex criteria.[77] The AER provided a substitute estimate of $79.9 million in its Draft Decision, based on adjustments to fleet service lives and unit rates, as well as an adjustment to, in the AER's opinion, better account for the proportion of vehicles used to deliver SCS.

### 5.8.4 How our revised fleet expenditure forecast compares

Table 5-56 summarises our Original Proposal and our Revised Proposal fleet forecast for the 2020-25 RCP, compared to the AER's Draft Decision.

[77] *AER, Attachment 5, page 73.*

**Table 5-56: SA Power Networks' Original and Revised Proposals fleet forecast compared to the AER's Draft Decision (June 2020, $ million)**

| Fleet | Original Proposal | AER Draft Decision | Revised Proposal | Difference to Draft Decision $ |
|---|---|---|---|---|
| **EWPs** | 37.7 | 21.5 | 31.2 | 9.7 |
| **Cranes** | 15.8 | 14.6 | 15.7 | 1.1 |
| **Commercial Trucks** | 9.9 | 9.1 | 9.8 | 0.7 |
| **Trailers** | 2.8 | 2.7 | 2.8 | 0.2 |
| **Passenger and Light Commercial** | 39.8 | 29.4 | 33.6 | 4.3 |
| **TEC** | 10.6 | 2.8 | 4.1 | 1.4 |
| **Total** | **116.6** | **79.9** | **97.3** | **17.4** |

**What we originally proposed**

SA Power Networks originally proposed $116.6 million to manage the cyclical replacement of our fleet. This forecast fleet capex was based on the cyclic replacement specified in our replacement criteria. We did not propose any vehicle additions in the 2020-25 RCP. Furthermore, with the exception of trailer replacement criteria moving from 20 years to 15 years, we did not alter any other fleet replacement criteria from the 2015-20 RCP.

Operational costs for fleet (fuel, registration, insurance, fleet management, maintenance, repair, etc) are directly attributed to work undertaken by way of a standard hourly vehicle rate in accordance with our AER approved cost allocation method (**CAM**).

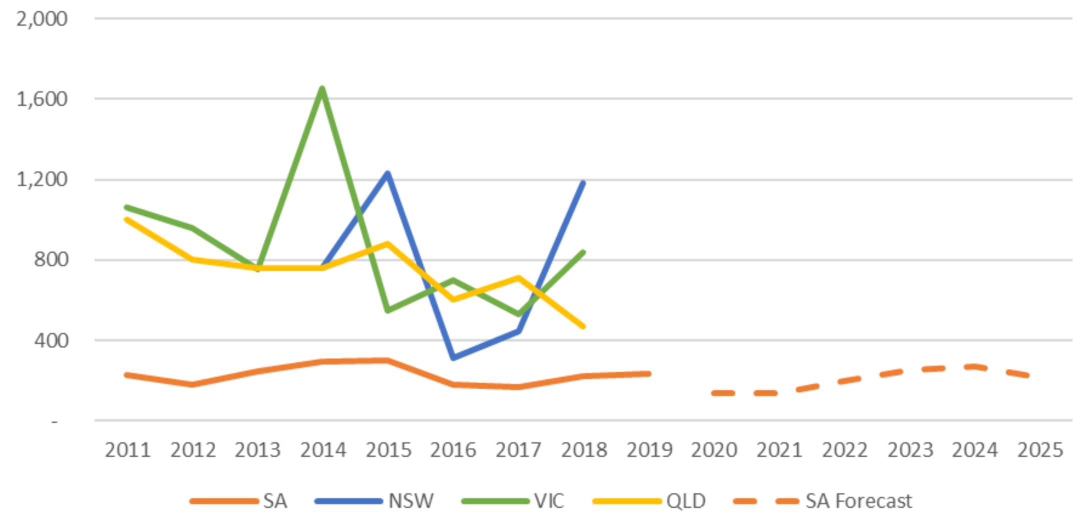
**The AER's Draft Decision and how we responded**

The AER did not accept our forecast fleet related capex for the 2020-25 RCP as they were not satisfied the forecast of $116.6 million reasonably reflected the capex criteria. The AER's substitute estimate of $79.9 million is 31% below our Original Proposal forecast, and 14% below our estimated expenditure over the 2015-20 RCP.

We note that, in its Draft Decision, the AER conducted analysis of SA Power Networks fleet expenditure on a per employee basis and compared this to other states, finding that SA Power Networks is currently among the most costly providers for fleet on a per employee basis. SA Power Networks does not support the findings of this analysis, which considers capex in isolation of other factors. The size of our distribution network is a significant contributor to the volume of fleet required, with the need to efficiently access urban and rural assets to maintain safety and reliability of the network for all customers.

To support our Revised Proposal, we have conducted analysis of our fleet capex on a circuit kilometre basis, which we consider a more reasonable measure of the volume fleet (refer to Figure 5-14 below). This analysis demonstrates that SA Power Networks fleet capex is the lowest on a state-by-state basis.

**Figure 5-14: Fleet capex per circuit kilometre by state (June 2020, $ million)[78]**




This capex profile is consistent with our 2019 capex benchmarking performance, which has SA Power Networks ranked as the second most efficient distributor in the NEM for capital multilateral partial factor productivity. From a top-down perspective, we find it difficult to understand how the AER can reasonably justify an expectation that SA Power Networks, as one of the most efficient distributors in the NEM, could manage its services with a fleet expenditure forecast that is significantly and materially below our actual expenditures over two RCPs.

In the sections below we have considered each of the elements of the AER's Draft Decision and provided our Revised Proposal response.

***EWP Life Extension and Service Life Alignment***

SA Power Networks' current EWP fleet ranges in size from 10m to 40m in working height to undertake work on the distribution network.

Our Original Proposal provided for the replacement of EWPs on a 10-year replacement cycle. This was consistent with the replacement cycle approved by the AER for the current 2015-20 RCP. Since 2012, we have undertaken a standardisation program on the design layout, build and commissioning on the most commonly used EWPs in the fleet (ie 14m units), with these units replaced on a 10-year cycle.

The main drivers for replacing EWPs at 10 years of age include:

- EWP utilisation, including travel and operating time;
- new safety features being incorporated in vehicles earlier;
- new environmental features being incorporated into vehicles earlier;
- eliminating the requirement of the units being off the road for up to three months during each rebuild; and
- eliminating the general dissatisfaction with crews over, and the loss of efficiency associated with, the age of the equipment, maintenance requirements and breakdowns.

Replacement of EWPs on a 10-year cycle has resulted in reduced lead times and cost in the construction phase of the units, and enhanced operational familiarisation, safety and efficiency.

In its Draft Decision, the AER rejected SA Power Networks 10-year replacement cycle for EWPs. The AER acknowledged that not all EWPs will necessarily pass inspection as suitable for life extension. In

[78] NSW/ACT category analysis RIN data was not available on the AER's website for 2010-2014.

determining the refurbishment rate, the AER applied a refurbishment rate derived from Energy Queensland of 45%.

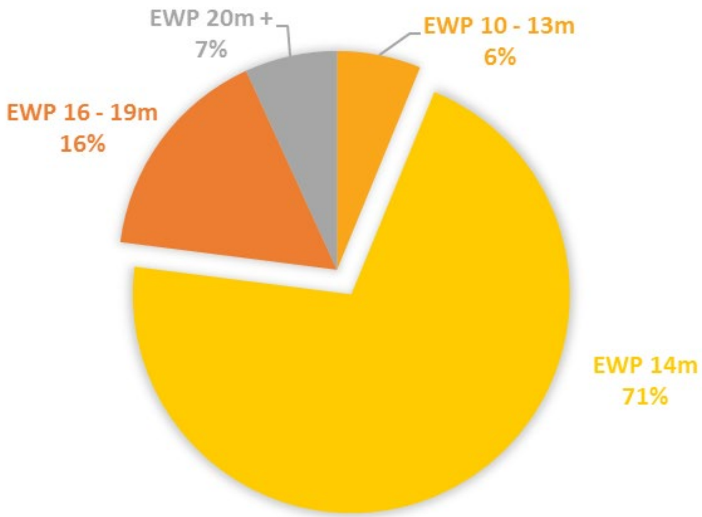
Energy Queensland's EWP refurbishment rate combines the state's refurbishment percentage achieved for EWPs 14m or greater with the number of smaller EWPs due for replacement over the same period. The AER also noted that Energex and Ergon Energy own a larger portion of EWPs smaller than 14m than is indicated by SA Power Networks' fleet model, indicating that this assumed EWP replacement rate would be conservative.

SA Power Networks does not accept the AER's Draft Decision to extend the life of 45% of EWPs to 15 years. We do not accept the application of Energy Queensland's EWP refurbishment rate to SA Power Networks. We note that this refurbishment rate was an assumed rate calculated by the AER, and that this number has not been validated by Energy Queensland. Applying this rate to SA Power Networks also assumes that the configuration of our EWP fleet is consistent with Energy Queensland's fleet.

We have approximately 160 EWPs in our fleet, where the fleet is configured to support the timely delivery of services for our customers across South Australia. Most of our distribution network requires the use of insulated EWPs that have a basket floor height ranging between 12.5m and 13.6m. This basket height is determined based on the working height for a field worker to be able to safely and ergonomically access SA Power Networks elevated assets.

For SA Power Networks, our 14m EWPs are the backbone of our fleet, with approximately 70% of our EWPs 14m (as detailed in Figure 5-15 below).

**Figure 5-15: EWP fleet composition**

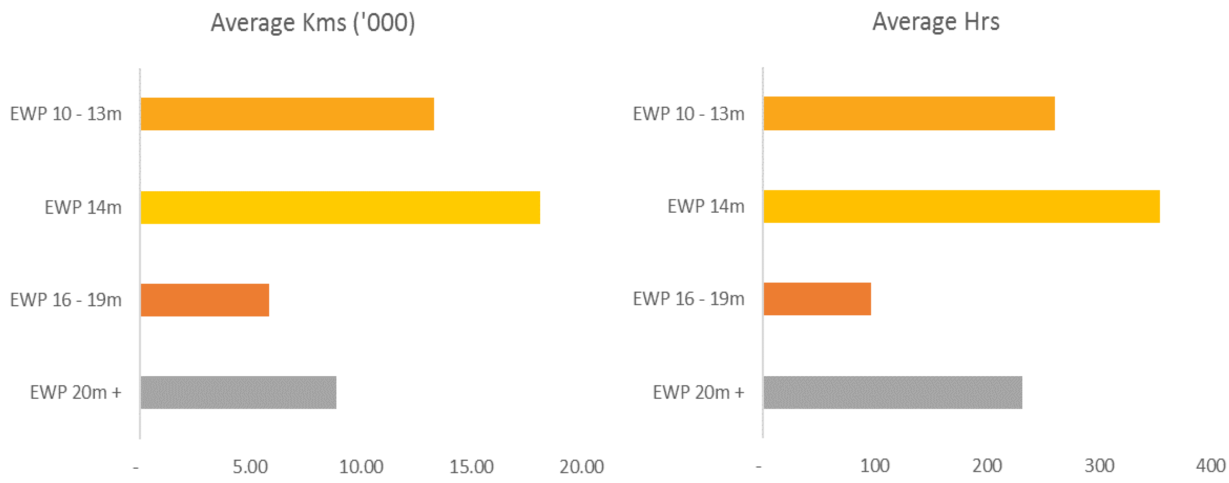



There are two predominant types of EWPs that constitute our 14m range of EWPs. The GMJ unit, has a basket floor height of 12.6m, and offers the traditional two boom style of operating. The Altec TA45S, has basket floor height of 13.6m, and offers a more versatile working arrangement with the use of the short lower boom and the extendable top boom allowing operators to position themselves between the increasing amount of network assets associated with overhead electricity infrastructure.

These two different configurations are often shared and swapped between crews and depot locations dependent on the work requirements and vehicle availability and are considered as equivalent models from competing manufacturers within a standardized 14m EWP range.

As detailed in Figure 5-16 below, our 14m EWPs travel on average 18,000 kms per year, which is more than twice the distance of larger EWPs. These EWPs also have a much higher utilisation rate on a per unit basis than other EWPs in our fleet, with the 14m EWPs in operation for approximately 350 hours per year (this excludes time travelling to and from the work site).

**Figure 5-16: EWP Kms travelled and utilisation**




Following feedback from the AER, we updated our NPV analysis for our 14m EWPs, removing the 're-trucking' costs (refer to Supporting Document 5.20.1 – Fleet Capex – 14m EWP NPV Analysis (Confidential)). This NPV has been completed considering a 10, 15, and 20-year replacement cycle. The 10-year NPV provides a marginal benefit over the longer life replacement options. This is consistent with the AER's assessment, noting that life extension tended to prove more viable for larger EWPs.[79]

While SA Power Networks does not support extending the life of EWPs, in consideration of the AER's Draft Decision, our Revised Proposal applies a 15-year life for EWPs that are greater than 14m in height. We will inspect and refurbish these EWPs at 10 years. This inspection data will assist us in better understanding the condition rating of our EWPs and inform the development of our replacement criteria for our 2025-30 Regulatory Proposal.

Our Revised Proposal provides for the continued replacement of EWPs that are 14m in height or less on a 10-year cycle. This provides the least cost option for our customers based on the outcomes of our NPV analysis, while also delivering non-tangible benefits such as improved safety and environmental features.

***Unit Rate Adjustments***

SA Power Networks Original Proposal provided for the cyclical replacement of our fleet over the 2020-25 RCP, with vehicles replaced in accordance with our specified replacement criteria (as detailed in Table 5-56 above). In forecasting the required replacement fleet capex, SA Power Networks used supplier quotes to derive an average replacement unit cost.

In its Draft Decision, the AER substituted SA Power Networks forecast unit rates with historical purchase rates (adjusted by CPI) for all passenger and light commercial vehicles (including TEC vehicles), matching on vehicle model and body type. This unit rate adjustment resulted in a reduction in fleet capex of $8.1m[80].

SA Power Networks has reviewed the unit rate adjustments proposed by the AER in its Draft Decision. We note that the AER's unit rates were derived using SA Power Networks 2015-19 acquisition data, which was provided in response to an AER information request. We accept the AER's use of our historical purchase

[79] *AER, Attachment 5, page 77, footnote 206.*

[80] We note that in some cases, the AER did not substitute a replacement unit rate in the Draft Decision fleet model. This appears to relate to an error in the substitution process the AER used in its Draft Decision. This resulted in understating the capex by approximately $0.5m.

data (adjusted by CPI) to set the replacement unit rate for fleet, however we do not accept the unit rates adopted by the AER in its Draft Decision.

We note that the AER adopted the average historical purchase price based on the vehicle make and model. SA Power Networks preference is to use the average purchase prices based on the following prescribed vehicle classifications, as provided in Table 5-57 below.

**Table 5-57: Passenger and Light Commercial vehicle classifications – Revised Proposal**

| Vehicle Category | Description |
|---|---|
| Passenger | Sedan, hatchback, small SUV |
| Passenger Wagon | Station wagons, large SUV |
| Light Commercial 4x2 – Light | 4x2 utility |
| Light Commercial 4x2 – Heavy | 4x2 cab chassis with a service type body |
| Light Commercial 4x4 – Light | 4x4 utility |
| Light Commercial 4x4 – Medium | 4x4 cab chassis with a service type body, less than 3.5 T |
| Light Commercial 4x4 – Heavy | 4x4 cab chassis with a service type body, above 3.5 T |
| Commercial Vans – Small | Commercial van less than 3.5T |
| Commercial Vans – Large | Commercial van greater than 3.5T |

To determine the unit rate, SA Power Networks has taken an average of the 5 year historical purchase price data in each vehicle category. Some adjustments were required to allow for part purchases across RCPs and where body swaps are undertaken, eg transfer of pod canopy from replacement vehicle to the new vehicle.

Applying an average unit rate by the broader vehicle classification criteria provides SA Power Networks the flexibility to replace vehicles with an alternate vehicle within the same category. Our selection of vehicles in each vehicle classification is based on a number of factors associated with providing a fit for purpose vehicle, including:

- Geographical requirements (eg metro, rural and remote areas).
- Business requirements (eg powerline worker, substation, field operations and administration).
- Legal requirements (including vehicle weights of gross vehicle mass (**GVM**), front and rear axle requirements).
- Managing risks through vehicles selection to reduce exposure to warranty, recall issues and maintain safety.
- Maintaining market forces and ensuring our pricing remains competitive.

In some instances, we may need to replace vehicles within one category with vehicles from another category, for example replacing medium light commercial vehicles with a heavy vehicle to meet the business requirements. These replacements are predominantly driven by the need to ensure the vehicle has an appropriate carrying capacity, including an ability to carry additional equipment to meet changing business needs. Our field crews in regional depots are multi-skilled and will undertake a wide variety of tasks daily, often requiring different tools and equipment for each job. Our fleet needs to support our field workers by ensuring that the crew have access to the necessary equipment to be able to perform their work efficiently, thereby minimising the need for travel to and from the depot to change equipment between jobs.

To address this requirement, SA Power Networks is progressively moving from medium commercial vehicles to large commercial vehicles where there is a defined need. The benefits of changing crews from medium commercial vehicles to large commercial vehicles, include:

- an increase in payload of up to 700kgs overall;
- additional 60kg front axle payload allows for more commissioning options to be fitted without being at risk of breaching axle limits (eg bullbars, winches and ladder racks);

- increased towing capacity, with large commercial vehicles able to tow the larger trailers due to the Gross Combination Mass (**GCM**) of the vehicle, the individual axle limit and the mass of the towing vehicle. The larger vehicles are preferred for towing trailers as the larger engines manage with the increased load and the heavier mass of the tow vehicle means the trailer is sturdier and safer as a combination on the road in terms of trailer sway control; and
- avoidance of additional maintenance and repair costs for medium commercial vehicles, with our fleet of medium commercial vehicles in regional areas primarily operating close to the axle limits and GVM virtually all the time.

Our Revised Proposal contains updated unit prices for Passenger and Light Commercial vehicles, TEC vehicles, and EWPs based on 5-year historical purchase prices. This is reflected in our updated Fleet Model, as provided in Supporting Document 5.20 - Fleet Model 2020-25 (confidential).

***Senior Staff Vehicle Adjustments***

Our Original Proposal provided for the cyclical replacement of TEC vehicles for senior staff in accordance with our fleet replacement criteria, with TEC vehicles replaced every 3 years (or 90,000 km's). In forecasting the required replacement fleet capex, SA Power Networks' used supplier quotes to derive an average replacement unit cost.

In its Draft Decision, the AER adjusted TEC capex by 20% to account for private use, assumed a 5-year service life, applied a unit rate by 'body type' from the passenger and light commercial vehicle category and retained a zero vehicle growth assumption. This reduced fleet capex by $7.5m.

Our Revised Proposal adopts a 5-year service life for TEC vehicles, consistent with the passenger and light commercial vehicle category. We do not accept the AER's amendments to account for the private use component of TEC vehicles, because we already factor the private use component of TEC vehicles into employee salaries, through an employee vehicle contribution.

The employee vehicle contribution incorporates the private use component of the operational maintenance costs associated with the vehicle (including fuel, registration, insurance and fleet management) as well as financing and depreciation costs. This vehicle contribution amount is deducted from the employee's salary, with the net salary allocated to our financial accounts in accordance with the AER approved CAM. In addition to the employee's net salary, a fleet transfer cost is charged against the employees cost centre. The fleet transfer cost covers the operational management costs associated with the vehicle only, it does not include any financing or depreciation costs. As a result, the costs allocated to the employee cost centre are reduced by the employee's contribution towards the financing and depreciation costs of the vehicle, effectively reducing the costs being allocated to SCS. This contribution effectively off-sets the RAB return associated with the private use component of these vehicles. Reducing capex by the private use component of TEC vehicles would mean SA Power Networks is not able to recover our efficient costs without adjusting our accounting treatment for senior staff salaries.

As provided in the unit rate adjustment section above, we do not accept the unit rates adopted by the AER in its Draft Decision. Our Revised Proposal contains updated unit prices for TEC vehicles, based on the revised unit rates for passenger and light commercial vehicles. These unit rates are based on 5-year historical purchase prices. This is reflected in our updated Fleet Model, as provided in Supporting Document 5.20 - Fleet Model 2020-25 (confidential).

***Standard Control Services Adjustment***

In our Original Proposal, we proposed acquisition of new and replacement vehicles centred on the primary use of vehicles. That proposal was based on these vehicles being required to undertake SA Power Networks' core distribution role, which is to deliver SCS. Where possible, vehicle utilisation is maximised by delivering other services, eg ACS. This aligns with the shared asset principles in the NER[81], which encourage such use, and reduce the operational cost of vehicles to regulated customers.

In its Draft Decision, the AER applied the proportion of total fleet expenditure allocated to SCS (around 90% on average) to reduce SA Power Networks' fleet capex allowance by approximately $8 million. The AER referenced SA Power Networks' submitted Reset RIN data, noting that the total fleet expenditure allocated as regulatory expenditure varied across vehicle type, with a range of between 87% and 94%.[82]

This is an estimate based on the actual fleet allocation for the 2017/18 regulatory year (as reported in the CA RIN) and highlights that the vehicles are predominantly used to deliver SCS. The average fleet allocation to all regulated activities (ie SCS, ACS, NDS) was close to 96% in 2017/18. It should be clarified that the data in the Reset RIN (and annual CA RINs) refers only to vehicles acquired for the primary purpose of delivering regulated services, in accordance with the AER's definitions.[83]

The AER accepted SA Power Networks shared asset revenue reduction of $6.3 million in its Draft Decision. This included $0.9 million from the use of regulated vehicles to deliver unregulated services in the 2020-25 RCP.

We do not accept the AER's Draft Decision to reduce SA Power Networks' fleet capex by $8 million for the SCS percentages applied in our Reset RIN data. In our Revised Proposal, we have included the total cost of acquisition of new and replacement fleet. We have not adjusted for the proportional use of vehicles for SCS only.

By applying this proportional percentage to fleet capex, the AER is allocating the use of vehicles to service categories at the time of acquisition. This does not accord with the shared asset principle of encouraging the use of regulated assets to provide other services where that use is efficient and does not prejudice the provision of regulated services.[84] A proportional use of fleet assets across service categories cannot be undertaken for a specific vehicle at the time of acquisition.

Applying a proportional use of vehicles is less likely to encourage the use of regulated vehicles to deliver other services and will create inefficiencies. Vehicles are more likely to be acquired to deliver specific services, which will reduce fleet flexibility and ultimately increase costs to all customers. This is particularly relevant in regional areas where a fleet will be maintained to meet emergency conditions.

All operational costs for fleet (ie fuel, registration, insurance, fleet management, maintenance and repair) are directly attributed to work undertaken by way of a standard hourly vehicle rate in accordance with our AER approved CAM. As such, SCS do not bear any operational costs associated with vehicles used to deliver other services. By encouraging greater use, vehicle utilisation is improved resulting in the recovery of more fixed operational costs (eg registration, insurance, fleet management) against other services thereby reducing the cost of SCS services to regulated customers.

Further, the AER's Draft decision would result in new classes of ACS assets being established to recognise the proportional use of fleet assets across ACS. This would have implications on proposed ACS pricing, as currently SA Power Networks only recovers operational fleet costs in its ACS pricing. An ACS RAB would need to be established and fixed and quoted service prices amended to recover a return of and on these assets. This would create a further level of complexity for both SA Power Networks and the AER.

The AER's Draft Decision would also impact SA Power Network's shared asset revenue reduction. Applying the proportional use of assets across services at the time of acquisition of a vehicle would prevent it from

[81] *NER, clause 6.4.4.*

[82] *AER, Attachment 5, page 5-79.*

[83] *AER, AER Final Category Analysis RIN for distribution network service providers, March 2014, page 58.*

[84] *NER, clause 6.4.4(c)(1).*

becoming a shared asset. The $6.3 million shared asset revenue adjustment applied in the AER's Draft Decision includes $0.9 million for the use of regulated vehicles. This shared asset benefit would decrease as new and replacement vehicles are acquired and allocated directly to SCS or otherwise based on their intended principal use. The shared asset unregulated revenue adjustment is based on an estimate and there is no facility to amend this during the RCP.

Additionally, the proportional use of vehicles would need to be monitored to ensure that the correct proportions had been applied. This would add further unwarranted complexity in managing asset bases and in calculating our shared asset revenue adjustment.

In accordance with shared asset principles, SA Power Networks' proposal for the purposes of our Revised Proposal is to apply the total cost of the acquisition of new and replacement fleet against SCS capex. Operational fleet costs will continue to be directly attributed to work undertaken by way of a standard hourly vehicle rate in accordance with our AER approved CAM.

**Our revised forecast**

SA Power Networks' revised forecast for the fleet is $97.3 million, $17.4 million higher than the AER Draft Decision of $79.9 million.

**Table 5-58: Revised forecast fleet capex for the 2020-25 RCP (June 2020, $ million)**

| Fleet | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| **EWPs** | 3.8 | 3.1 | 4.9 | 11.1 | 8.3 | **31.2** |
| **Cranes** | 2.4 | 6.0 | 2.7 | 1.4 | 3.2 | **15.7** |
| **Commercial Trucks** | 1.0 | 1.8 | 2.9 | 2.7 | 1.4 | **9.8** |
| **Trailers** | 0.2 | 0.2 | 0.5 | 0.8 | 1.1 | **2.8** |
| **Miscellaneous** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | **0.0** |
| **Passenger and Light Commercial** | 5.3 | 6.4 | 9.9 | 7.9 | 4.2 | **33.6** |
| **TEC** | 0.0 | 0.2 | 1.8 | 0.7 | 1.4 | **4.1** |
| | **12.6** | **17.8** | **22.8** | **24.6** | **19.6** | **97.3** |

**Supporting evidence**

Table 5-59 details the supporting evidence for the fleet forecast included in our Revised Proposal.

**Table 5-59: Supporting evidence for fleet included in our Revised Proposal**

| Document reference | Document name | Program it relates to |
|---|---|---|
| 5.20 | Fleet model 2020-25 | Fleet |
| 5.20.1 | Fleet capex – 14m EWP NPV Analysis | EWP Replacement |

## 5.9 Property

We own and lease a range of properties across the State to support our regulated activities, including a mix of office and depot accommodation. Property capex relates to the acquisition, maintenance, refurbishment and disposal of our commercial, industrial and metropolitan and country depots.

### 5.9.1 Our revised property forecast summary

Our revised forecast for property related capex for the 2020-25 RCP is $50.7 million, $10.8 million lower than our Original Proposal forecast of $61.5 million and it is $1.6 million lower than our forecast expenditure in the current 2015-20 RCP.

### 5.9.2 Property profile

Our property portfolio includes 49 sites, of which approximately 58% were established more than 50 years ago. The capex forecast is required to address various needs at 39 of these properties. These needs are largely due to the advanced age of the facilities at these properties and primarily relate to:

- the poor condition of some facilities and engineering systems; and
- inadequate systems, layout, and design for the current operations.

Figure 5-17 sets out our property actual and forecast property expenditure over the 2010-25 period.

**Figure 5-17: Property expenditure profile 2010-2025 (June 2020, $ million)**

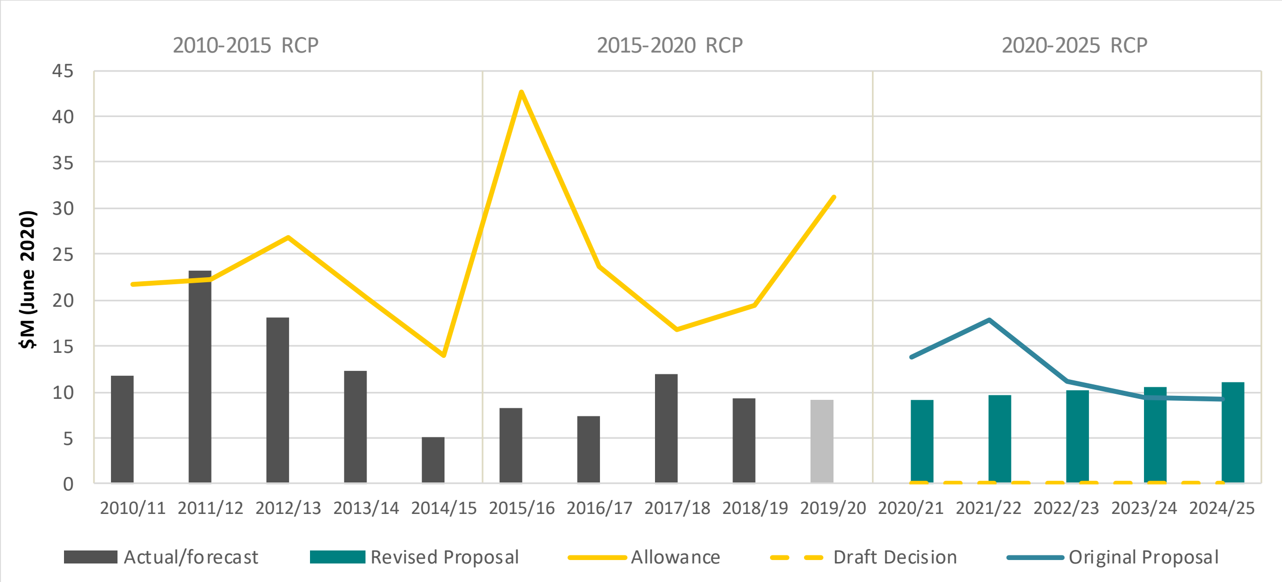
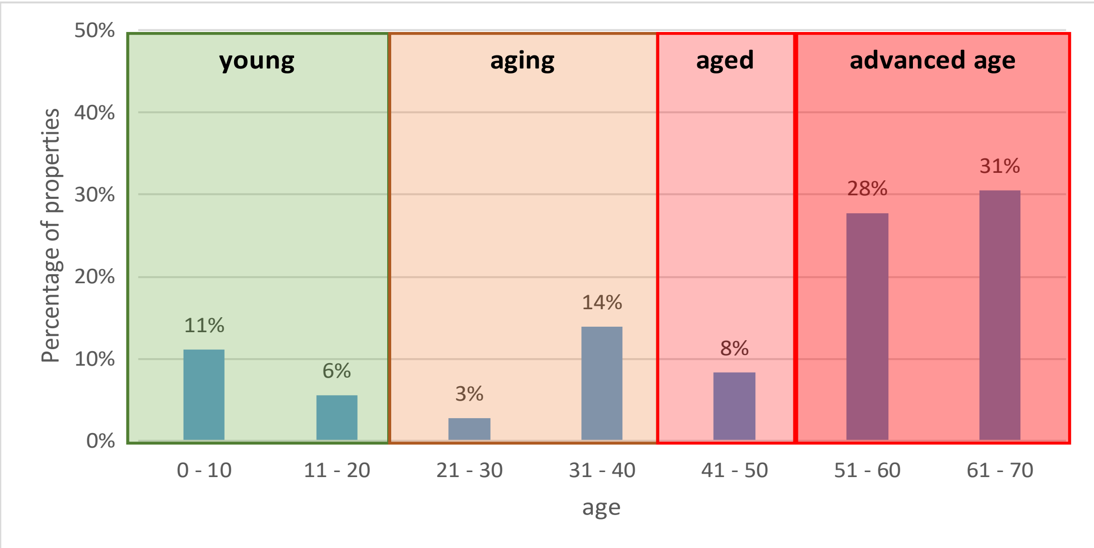



Figure 5-18 shows we have a very large portion of our properties (67%) that were established more than 40 years ago and would be expected to be nearing the end of their useful life (without major refurbishment). Of these, 59% were established more than 50 years ago, with 31% established more than 60 years ago.

**Figure 5-18: Property establishment age profile**




The oldest sites include Angle Park North (68 years), Marleston North (68 years) and Clare (53 years), which are three properties with major projects proposed for the 2020 to 2025 period. Angle Park North and Marleston North are both industrial sites and Clare is one of our regional depots.

The ageing of properties and our overall property portfolio generally increases reactive repair costs, with larger refurbishment works being capitalised.

Our depots and industrial properties also have large external pavement areas, which are subject to extensive vehicle and forklift traffic, and pedestrian movements. These pavement areas are in very poor condition which increases safety risks.

The poor condition and sub-optimal design of individual facilities (buildings and pavements), also affect the efficient operation of the properties, increases operational risks and can affect customer supply reliability by negatively impacting field crew response times to network faults.

As can be seen in Figure 5-19 from one of our top-down analysis, we are one of the lowest spending distributors on property over the last 10 years. We are not forecasting the need for an increase above historical levels in the 2020-25 RCP. Our revised forecast is below our estimated capex for the current regulatory period and it is 11% lower than our average per annum amount for the last 10 years[85].

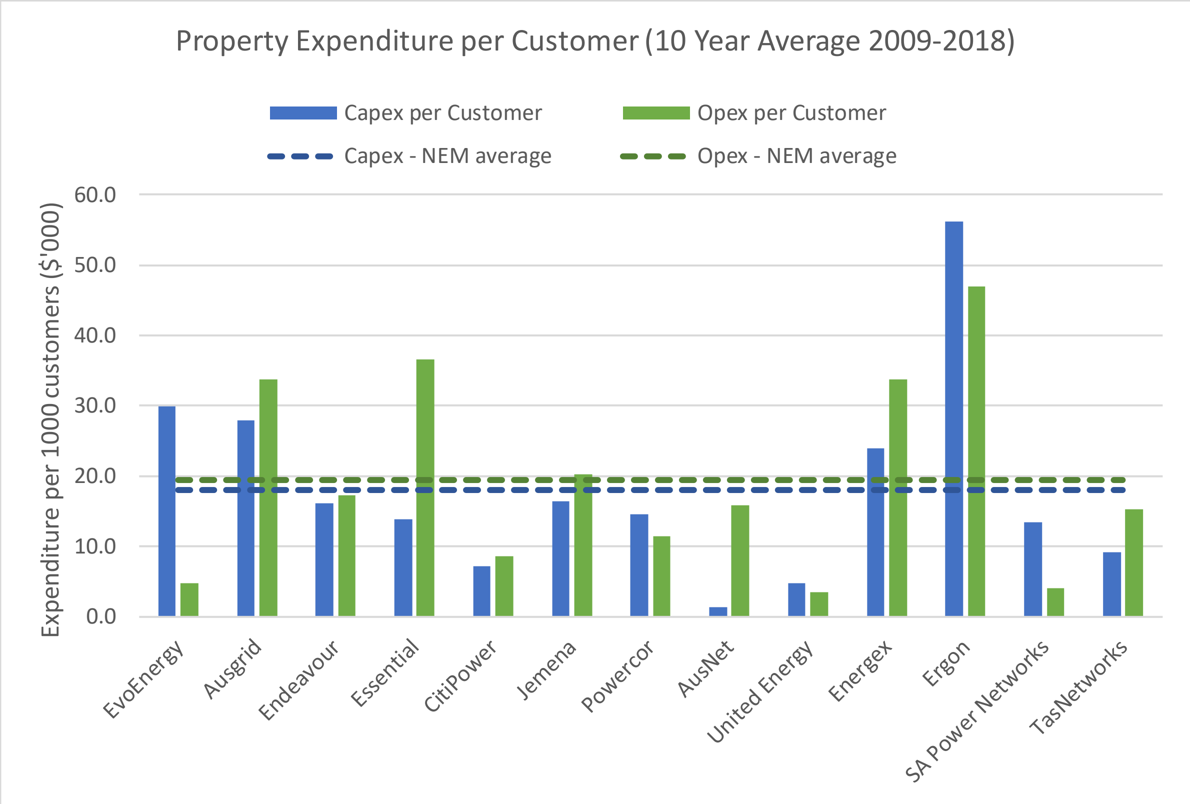
The above suggest that we could be considered a frontier business with regard to our recent levels of property expenditure, and in summary, suggests that:

- our recent past spend on our properties is most likely efficient, at least relative to other NEM DNSPs, and there is no evidence of gold-plating, including early replacement;
- assuming some of the other DNSPs lease a higher proportion of their properties, there is no clear indication that such leasing arrangements are resulting in lower overall costs, compared to our approach to manage our properties; and
- given the age profile of our properties, it is less likely we can achieve significant reductions from recent historical levels (ie there are likely far fewer opportunities for us to reduce costs compared to many other DNSPs).

Therefore, given we are in an early stage of a property replacement cycle, it is reasonable to expect that the efficient costs to maintain the performance of our properties as they age further would require an increase in expenditure in future regulatory periods from historical levels (ie costs in accordance with NER capex and opex criteria are unlikely to be reducing from average historical levels).

[85] On a real June 2020 basis as reported in our category analysis RIN.

**Figure 5-19: Average property opex and capex per customer metrics**




### 5.9.3 AER's Draft Decision for property

The AER did not accept our proposed forecast property capex of $61.5 million as they were not satisfied the forecast reasonably reflected the capex criteria. The AER did not include any allowance for property capex in its substitute estimate.

### 5.9.4 How our revised property expenditure forecast compares

Table 5-60 details our Original Proposal and our Revised Proposal property forecast for the 2020-25 RCP, compared to the AER's Draft Decision.

**Table 5-60: SA Power Networks' Original and Revised Proposals property forecast compared to the AER's Draft Decision (June 2020, $ million)**

| | Original Proposal | AER Draft Decision | Revised Proposal | Difference to Draft Decision $ |
|---|---|---|---|---|
| **Property** | 61.5 | 0.0 | 50.7 | 50.7 |

**What we originally proposed**

SA Power Networks originally proposed $61.5 million ($58.5 million excluding business overheads).

We proposed to undertake major refurbishment works to eight properties as follows:

- Angle Park North
- Clare
- Gumeracha
- Keswick
- Marleston North
- St Marys

- Seaford
- Yorketown

In addition to the major property refurbishments, we proposed other minor works identified by a review undertaken by specialist quantity surveyors.

**The AER's Draft Decision and how we responded**

The AER did not accept our proposed forecast property capex of $61.5 million as they were not satisfied the forecast reasonably reflected the capex criteria. The AER did not include any allowance for property capex in its substitute estimate. The AER were of the view that SA Power Networks had not provided a sufficient demonstration of need, rigorous options analysis and cost benefit assessment to support the proposed expenditure.

To address these concerns, we have revised our property forecasting methodology and classified property works into[86]:

- **Major project sites** – comprising the sites where major refurbishment of property pavements and associated external works and buildings are necessary; and
- **Minor project sites** – comprising the balance of sites requiring ongoing minor refurbishment and upgrades.

The major works at four of the major property sites (Angle Park, Marleston North, St Marys and Clare) have been assessed and new business cases supporting the proposed works at these sites have been developed and submitted with this Revised Proposal[87]. We have also undertaken cost-benefit analysis of a range of options at these sites, including continuing with the business-as-usual approach, to ensure that the preferred option included in our forecast provides the greatest net benefit.

The minor project site forecast was based on a bottom-up forecast identified and developed from an independent quantity survey (and submitted with our Original Proposal).

We have undertaken further top-down analysis, including property benchmarking and historical capex trending to validate that our revised forecast is reasonable and reasonably reflect the NER capex criteria.

As a result of our revised approach we have also removed the following works (which were included in our original forecast):

- Seaford depot establishment (deferred to post 2025).
- Gumeracha depot refurbishment (now considering the closure of this depot).
- Some minor works items in our original cost build-up.
- Some items now being addressed in the current period (during 2019 and/or 2020).
- The 10% contingency component.

The various needs impose costs and risk on our business, in addition to increased reactive repair costs. These predominantly relate to safety risk and operational costs and risk. For the four sites noted above, we have quantified these costs and risk in performing our cost-benefit analysis. This analysis can be found in the corresponding business cases and models referenced in Table 5-62 below.

When the SA Power Networks CCP and other stakeholders viewed the Marleston North site, they were strongly supportive of investment in that site and others like it to improve conditions and address immediate safety and environmental concerns. They considered the AER's Draft Decision of $0 property

[86] This classification should align with the classification used in our Original Proposal and used by the AER in its draft Decision.

[87] The other major project site in our forecast is our main corporate office at Keswick. The forecast for this site is for a continuation of the existing major refurbishment program of this building, for which a major portion of the works is being undertaken in this current regulatory period.

allowance was unrealistic and encouraged SA Power Networks to improve our justification for property expenditure.

Supporting Document 5.21 - 2020-25 Property Capex Forecast Regulatory Justification, contains further information explaining how we developed the property forecast for our Revised Proposal.

**Our revised forecast**

SA Power Networks revised forecast for the property programs is $50.7 million.

**Table 5-61: Revised forecast property expenditure for the 2020-25 RCP (June 2020, $ million)**

| Property | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| **Property** | 9.2 | 9.7 | 10.1 | 10.6 | 11.0 | 50.7 |

**Supporting evidence**
Table 5-62 details the supporting evidence for the property program included in our Revised Proposal.

**Table 5-62: Supporting evidence for the property program included in our Revised Proposal**

| Document reference | Document name | Program it relates to |
|---|---|---|
| 5.21 | Property justification | Total property |
| 5.21.1 | Property justification model | Total property |
| 5.22 | Angle Park North business case | Property - Angle Park North |
| 5.22.1 | Angle Park North models | Property - Angle Park North |
| 5.23 | Marleston North business case | Property - Marleston North |
| 5.23.1 | Marleston North model | Property - Marleston North |
| 5.24 | St Marys business case | Property - St Marys |
| 5.24.1 | St Marys model | Property - St Marys |
| 5.25 | Clare business case | Property - Clare |
| 5.25.1 | Clare models | Property - Clare |

## 5.10 Other

### 5.10.1 Plant and tools

Plant and tools expenditure capex relates to the replacement or purchase of additional tools and equipment necessary to manage and undertake works on our distribution network.

**Our revised** plant and tools forecast summary
Our revised forecast for plant and tools capex for the 2020-25 RCP is $20.7 million, which is consistent with our Original Proposal.

**AER's Draft Decision for** plant and tools
The AER accepted our proposed plant and tools forecast of $20.7 million as they were satisfied the forecast reasonably reflected the capex criteria.[88]

[88] *AER, Attachment 5, page 83.*

**Our revised forecast**
SA Power Networks accepts the AER's Draft Decision to accept our plant and tool forecast. Our revised forecast for plant and tools is therefore $20.7 million.

**Table 5-63: Revised forecast plant and tools expenditure for the 2020-25 RCP (June 2020, $ million)**

| | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| **Plant and tools** | 5.3 | 4.5 | 3.7 | 3.4 | 3.9 | 20.7 |

### 5.10.2 Superannuation

Superannuation capex relates to a regulatory adjustment required to correctly account for the capital allocation of the superannuation contributions that we are required to make to the Electricity Industry Superannuation Scheme (**EISS**) and other superannuation schemes in the 2020-25 RCP. These costs are incorporated within our labour costs.

**Our revised superannuation** forecast summary
Our revised forecast for superannuation capex for the 2020-25 RCP is a negative adjustment of $33.6 million, which is $3.8 million more than the proposal adjustment in our Original Proposal of -$37.4 million.

The negative adjustment of $33.6 million is based on the regulatory adjustment for superannuation in the 2018/19 regulatory year.

**AER's Draft Decision for superannuation**
The AER accepted our proposed superannuation accounting adjustment. [89]

**Our revised forecast**
SA Power Networks accepts the AER's Draft Decision to accept our proposed adjustment. Our revised forecast for superannuation is therefore negative -$33.6 million.

**Table 5-64: Revised forecast superannuation expenditure for the 2020-25 RCP (June 2020, $ million)**

| | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| **Superannuation** | (6.6) | (6.6) | (6.7) | (6.8) | (6.8) | (33.6) |

## 5.11 Proposed contingent capex

### 5.11.1 Overview

This section of the Attachment:
(a) sets out SA Power Networks' response to the AER's Draft Decision concerning the proposed contingent project set out in our Original Proposal; and
(b) provides additional details and information in relation to, and in support of, that proposed contingent project.

### 5.11.2 Original Proposal

Pursuant to clause 6.6A.1 of the NER, SA Power Networks included proposed contingent capex in its Original Proposal which SA Power Networks considered was reasonably required for the purpose of undertaking a proposed contingent project (described as the 'Electricity System Security' project[90]) (the nature of which is discussed further below).

[89] *AER, Attachment 5, page 88.*
[90] SA Power Networks, Original Proposal, Attachment 5, section 5.17.

After submission of our Original Proposal, and following dialogue with the AER on the matter, we submitted amended trigger events for that contingent project to better address the requirements of clauses 6.6A.1(c)(3) and 6.6A.1(c)(5) of the NER.

### 5.11.3 AER's Draft Decision

In its Draft Decision, the AER indicated it was satisfied that our (amended) proposed trigger events for the contingent project were reasonable[91].

However, the AER rejected the contingent project because it determined that:[92][93]

- SA Power Networks did not provide sufficient information to support the contingent project;
- SA Power Networks did not demonstrate that the project was reasonably required to meet the capex objectives;
- SA Power Networks did not provide sufficient details in relation to the nature of the regulatory obligation to which the contingent project would be responding;
- the contingent project capex was not prudent and efficient as it did not meet the capex criteria; and
- as SA Power Networks had not considered alternatives or provided an options analysis or a cost benefit analysis, the contingent project capex was not efficient.

In addition, the AER noted that the proposed contingent capex could, instead, be dealt with by a cost pass through event.[94]

We have responded below to the AER's Draft Decision in relation to each of these matters.

### 5.11.4 SA Power Networks' response to the AER's Draft Decision

***Contingent project – further information in support***

As explained in our Original Proposal:

- under clause 4.3.1 of the NER, AEMO is responsible for maintaining power system security, which involves (amongst other things) having emergency frequency control schemes (**EFCS**) for restoring the power system to a satisfactory operating state, and significantly reducing risks of outages and disruptions, following certain events;
- clause 4.3.2(h) of the NER requires AEMO to develop and update load shedding procedures and schedules specifying the EFCSs for each participating jurisdiction, including South Australia;[95]
- to assist AEMO in meeting and carrying out these obligations and responsibilities, clause 4.3.4 of the NER requires a Network Service Provider (**NSP**) to cooperate with AEMO in relation to the design, procurement, commissioning, maintenance, monitoring, testing, modification and reporting in respect of, an EFCS applying to that NSP's distribution system;
- AEMO has put in place various EFCSs and associated load shedding procedures for South Australia which, in South Australia, includes an under-frequency load shedding (**UFLS**) scheme;
- the UFLS scheme ensures that the distribution system can automatically disconnect predetermined blocks of load if power system frequency falls below specified thresholds, thereby arresting the decay of system frequency and preventing a catastrophic collapse of the system;

[91] AER, Draft Decision, Attachment 5, Appendix F, page 101.
[92] AER, Draft Decision, Attachment 5, page 16.
[93] AER, Draft Decision, Attachment 5, Appendix F.
[94] AER, Draft Decision, Attachment 5, Appendix F, page 102.
[95] We inadvertently referred to clause 4.3.2(b) of the NER in our Original Proposal. The intended reference was clause 4.3.2(h) of the NER.

- as early as 2023, the level of distributed energy resources (**DER**) in South Australia will render the existing UFLS scheme ineffective;
- accordingly, prior to submitting our Original Proposal, AEMO had meetings with SA Power Networks and ElectraNet to discuss both the impending problem and the nature of the actions that would likely be required to be undertaken by AEMO, ElectraNet and SA Power Networks to address the issue; and
- as a result of those meetings, our Original Proposal set out proposed contingent capex for undertaking certain actions or projects in order to implement expected changes to the UFLS scheme and/or to implement additional measures expected to be required of SA Power Networks to help to maintain security of supply during the 2020-25 RCP given the increasing levels of DER (ie the 'Electricity System Security' proposed contingent project).

SA Power Networks recognises that, in its Original Proposal, it was unable to provide definitive details about the 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. Similarly, we had limited opportunity to engage with our customers and stakeholders on this issue.

However, since submitting our Original Proposal, further details and information have become available from further meetings and dialogue with AEMO. In particular, AEMO has undertaken a great deal of further assessment and analysis of the impacts of DER on UFLS in South Australia. For example, AEMO has:

- analysed the impacts in South Australia of DER on UFLS (as one of the EFCSs activated in the event that a large power system disturbance causes an extreme frequency change which is beyond the capability of frequency control ancillary services);
- considered how and why increasing levels of generation from DER undermine the successful operation of the UFLS scheme by reducing the net load available for shedding at a feeder level, because when a feeder is 'in reverse' (i.e. is feeding energy back into the grid), tripping that feeder worsens an under-frequency disturbance, rather than assists to correct it; and
- determined that tripping feeders that are operating in reverse flows could mean that the UFLS could potentially act to escalate a frequency disturbance into a system black event.

As a result, AEMO has identified specific operational challenges, begun to quantify when they may occur, and begun to determine potential mitigation measures in South Australia, including certain actions that it considers will need to be taken by SA Power Networks during the 2020-2025 RCP.

We indicated in our Original Proposal that we anticipated AEMO would require us to implement at least two changes, namely the redesign and rebuild and of the existing UFLS scheme and establishing the capability to shed DER.[96] (As noted below, we now anticipate a third change.)

In our Original Proposal, we indicated that the redesign and rebuild of the existing UFLS scheme would involve replacing and/or recommissioning 625 existing under-frequency protection relays with units that support load flow determination and the ability to selectively enable under-frequency operation. After further analysis, we now consider that we will need to replace and/or recommission some 572 existing under-frequency protection relays. Two options have been considered to implement the required functionality. Option 1 utilises existing protection relays wherever possible, and option 2 upgrades all relays to the modern standard. Option 1 requires less expenditure, however it provides limited functionality and slower speed of operation compared to option 2. AEMO's eventual specifications will determine whether option 1 is feasible. An assumption has been made for the purposes of this contingent project submission that high speed operation for dynamic arming is not required and therefore option 1 will be acceptable.

As a result of further dialogue with AEMO, we now anticipate that we will be required to implement a third change in addition to the two raised in our Original Proposal, namely the expansion of the scope of the

[96] SA Power Networks, Original Proposal, Attachment 5, section 5.17.2.2.

existing UFLS scheme.  The proposed capital expenditure for our proposed contingent project assumes that as a result of the modelled impact of the increasing levels of DER connected to SA Power Networks' distribution network and the resulting changes to the requirements for the UFLS scheme, we will be required to expand the scope of the existing UFLS scheme to new locations in order to comply with the applicable regulatory obligations and requirements relating to the UFLS scheme. The expansion of the UFLS scheme will require the installation or recommissioning of 181 under-frequency protection relays, and will include the ability for enabling/disabling based on load flow direction as below.

It is evident from our discussions with AEMO that the actions by SA Power Networks will be required from early in the 2020-25 RCP.  For example:

- implementing new SCADA feed for aggregate load on UFLS (likely in second half of 2020);
- implementing arrangements to monitor UFLS feeder flows and trigger relay replacement when feeders cross threshold values for reverse flows (likely in second half of 2020); and
- implementing new design of UFLS scheme after its re-design by AEMO (likely in second half of 2021).

***Proposed contingent capex***

The proposed contingent capex associated with our proposed contingent project is estimated to be $40.1 million (option 1) or $79.2 million (option 2) (June2020$). This includes $0.5 million for the establishment of the capability to shed DER in addition to the costs for the expansion, redesign and rebuild of the UFLS scheme. This reflects the efficient costs of an efficient and prudent operator in carrying out the proposed contingent project and clearly exceeds the materiality threshold in clause 6.6A.1(b)(2)(iii) of the NER as set out in Table 5-65.

**Table 5-65: Proposed contingent capex for the 2020-25 RCP**

| Forecast Project Cost (Option 1) | Forecast Project Cost (Option 2) | 5% of the proposed ARR for the 2020/21 regulatory year | Materiality Threshold |
|---|---|---|---|
| **$40.1 million** | **$79.2 mission** | $39.2 million | Exceeded |

SA Power Networks has used a bottom up approach to develop the proposed contingent capex associated with the contingent project. We will refine the forecast cost estimate once we receive further details from AEMO concerning the scope of the required response to the AEMO requirements and the likely timing for the commencement and completion of the proposed contingent project and provide the updated information to the AER.

A detailed project scope and cost estimate will be undertaken before any amendment to the distribution determination for the 2020-25 RCP is sought from the AER following the occurrence of the specified trigger event. This reflects the intended purpose of the contingent project regime and the required process under the contingent project regime. The contingent project regime was established to provide a structured mechanism whereby the occurrence of the relevant trigger event would lead to the undertaking of a RIT-D and the identification of the preferred option for meeting the identified need associated with the occurrence of the relevant trigger. In this way, the AER is able to review the identified need and preferred option and assess the forecast capex for the preferred option by reference to the usual checks and balances applying to the assessment of forecast capex during the distribution determination process.

***Contingent project – capex objectives***

In its Draft Decision, the AER stated that we had not demonstrated that the proposed contingent project capex was reasonably required to meet the capex objectives[97].

[97] AER, Draft Decision, Attachment 5, page 16.

Clause S6.1.3(14)(iv) of the NER requires us to provide information that reasonably demonstrates that the undertaking of the proposed contingent project is reasonably required in order to achieve one or more of the capex objectives.

One of the capex objectives is compliance with regulatory obligations or requirements associated with the provision of standard control services. This is discussed below.

***Contingent project – nature of regulatory obligation***

In our Original Proposal, we were unable to be certain about the precise nature of any expected change in regulatory obligations or requirements because AEMO had not provided details of the anticipated change. That remains the case, with AEMO not yet having provided that level of specific detail.

However, we understand that a number of potential regulatory changes are being considered by AEMO and the extent of those changes will be determined after completion of further power system studies and consultation with relevant stakeholders.

In some cases, there will be no change in the existing regulatory mechanisms. Rather, SA Power Networks will be required to modify its distribution system to meet the applicable regulatory obligations and requirements taking into account the outcome from the AEMO power system studies and the identified changes to the characteristics of the distribution system, and the broader power system, resulting from the increasing level of DER connections to the low voltage distribution network.

We expect that AEMO will soon initiate consultations with stakeholders concerning the options for addressing this emerging and critical issue.

As noted above, following dialogue with the AER after lodgement of our Original Proposal, we amended the drafting of the trigger events for the proposed contingent project to refer to:

> *'SA Power Networks receives a formal notification from AEMO requiring SA Power Networks to implement:*
> *(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 its Draft Decision, the AER stated that the updated trigger events proposed by SA Power Networks were reasonable[98]. And yet the AER then went on to state that:

> *'Although we recognise that the issues raised by SA Power Networks may require changes to the UFLS scheme, the obligation is not certain. SA Power Networks' expected changes in the UFLS may not necessarily reflect actual changes to its regulatory obligations. … Therefore the obligation is not certain.'[99]*

We are confused by these seemingly inconsistent statements by the AER. Nevertheless, we submit that the latter observation by the AER is not correct in the light of the level of detail that AEMO has raised in its discussions and meetings with us (albeit the precise nature of any required changes have not yet been identified by AEMO).

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[98] AER, Draft Decision, Attachment 5, page 101.
[99] AER, Draft Decision, Attachment 5, page 102.

Clause 6.6A.1(c)(5) of the NER requires the AER, in 'determining whether a trigger event in relation to a proposed contingent project is appropriate for the purposes of subparagraph (b)(4)' to 'have regard to the need for a trigger event … to be an event or condition, the occurrence of which is probable during the regulatory control period'. Clearly, given our interactions with AEMO, the occurrence of the event we have set out as the trigger is most certainly 'probable'.

We have proposed below some minor additions to the trigger events which were approved by the AER in its Draft Decision to reflect our better understanding of the outcomes from the AEMO studies and reviews. We have explained these changes in more detail in the following paragraphs.

Returning however to the nature of the change in SA Power Networks' regulatory obligations or requirements, we note that the AER has accepted other NSPs' proposed contingent projects without identification of the specific regulatory obligations that were to change. For example, in its regulatory proposal for its 2019-2023 RCP, ElectraNet proposed, and the AER accepted, a 'Main Grid System Strength Support' contingent project, the first trigger for which was:

> *'Confirmation by AEMO of the existence of a Network Support and Control Ancillary Services (NSCAS) gap relating to system strength, <u>or other requirement for ElectraNet to address a system strength requirement</u>, in the South Australian region'* [emphasis added]

The (amended) trigger event proposed by SA Power Network for the 'Electricity System Security' project is clearly analogous with this wording and approach.

In any event, we request that the AER communicates with AEMO to satisfy itself as to:

- the matters we have outlined above in relation to the proposed contingent project; and
- AEMO's intentions regarding the nature of the particular mechanism that it intends to employ to implement the required changes to the UFLS scheme.

***Contingent project – capex criteria***

In its Draft Decision, the AER stated that the proposed contingent project capex was not prudent and efficient as it did not meet the capex criteria[100].

Although this is a factor referred to in clause 6.6A.1 of the NER, that clause requires the assessment to be made 'in the context of the proposed contingent project'. The 'context' is that there is not yet sufficient clarity as to the precise nature and level of capex required, as further detail is still forthcoming from AEMO. But that is, of course, not uncommon when it comes to the AER assessing proposed contingent projects; in fact, that is why there are typically other triggers associated with contingent projects.

Moreover, the substantive assessment of whether a contingent project meets the capex criteria, is required by clause 6.6A.2(f)(2) of the NER to be undertaken once the NSP considers that the trigger events for a contingent project have occurred and then applies to the AER to amend its revenue determination.

***Contingent project – no options analysis or cost benefit analysis***

In its Draft Decision, the AER concluded that the proposed contingent capex was not efficient because SA Power Networks had not undertaken any options analysis or cost benefit analysis[101].

However, SA Power Networks submits that such analyses:

- are neither required for, nor relevant to, the AER's assessment under clause 6.6A.1 of the NER as to whether a proposed contingent project should be approved; and

[100] AER, Draft Decision, Attachment 5, page 101.
[101] AER, Draft Decision, Attachment 5, page 102.

- cannot realistically be undertaken in any event until such time as there is absolute clarity from AEMO as to the precise details of the UFLS actions required of SA Power Networks.

The time to carry out options analysis, and cost benefit analysis, is when the RIT-D (or other equivalent economic evaluation) is carried out. That is why SA Power Networks included the second trigger for the proposed contingent project, namely:

> *'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.'*

And this is entirely consistent with the approach accepted by the AER in recent decisions. For example, as noted above, in its regulatory proposal for its 2019-2023 RCP, ElectraNet proposed, and the AER accepted, a 'Main Grid System Strength Support' contingent project. The second trigger for that project was:

> *'Successful completion of the RIT-T (or equivalent economic evaluation) including an assessment of credible options showing a transmission investment is justified.'*

The wording of the second trigger proposed by SA Power Network for the 'Electricity System Security' project is almost identical to the ElectraNet wording.

***Contingent project – pass through event as an alternative***

We indicated in our Original Proposal that the proposed contingent capex associated with the proposed contingent project was estimated to be $79.2 million (June 2020$).

In its Draft Decision, the AER noted that as:

*'…the driver of this contingent project is an expected change in regulatory obligation, adjustments can be made to a building block determination for a cost pass through due to a regulatory change event. The materiality threshold for a pass through event is one per cent of annual revenue for that year. As the proposed capex meets the contingent project threshold of $30 million or five per cent of the value of the first year annual revenue requirement, the costs proposed by SA Power Networks would also meet the threshold for a cost pass through event.'*[102]

When we submitted our Original Proposal, one per cent of our proposed annual revenue requirement would have been in the vicinity of 7 to 8 million dollars. The observations of the AER in its Draft Decision above appear to indicate that, as our proposed contingent capex was greater than that one per cent amount, the materiality threshold for a pass through event would be satisfied.

Although we would welcome that outcome, and although it is consistent with SA Power Networks' (and other DNSPs[103]) position on how the cost pass through materiality threshold in the NER[104] should be interpreted, it seems to be at odds with how that threshold has in fact historically been interpreted by the AER, namely that the term 'costs' in the definition of 'materially' is to be taken to mean the building block revenue components resulting from the application of the capex and opex in the PTRM.

We would therefore welcome the AER clarifying its position on this important matter in its Final Decision in relation to our Revised Proposal.

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[102] AER, Draft Decision, Attachment 5, page 102.
[103] For example, see AusGrid, Cost pass through application – April 2015 storms, August 2015, page 13.
[104] NER, Chapter 10: Glossary, definition of 'materially'.

In addition, and as noted above, some of the changes to our UFLS scheme which AEMO has indicated in discussions could be required to be made, may not be linked to changes to our regulatory obligations and requirements. Rather, the steps we are required to take to comply with our existing regulatory obligations and requirements relating to the UFLS scheme will change as a result of:

- the outcomes from the AEMO studies and stakeholder consultations; and
- the identified changes to the manner in which our distribution system operates in response to the increasing levels of DER being connected to the electricity distribution network.

This is not dissimilar to the position which applies when increasing levels of demand in parts of our distribution system lead to the need to augment that distribution system in order to meet our regulatory obligations and requirements. In this case, increasing levels of connection of DER to our distribution network is (according to the AEMO power system studies) resulting in our existing UFLS scheme ceasing to be fit for the purpose of responding to significant underfrequency events threatening power system security.

***Contingent project – trigger events***

As noted above, the AER indicated in its Draft Decision that it was satisfied that our proposed trigger events for the contingent project were reasonable. However, subsequent discussions with AEMO have clarified that some of the required changes to our existing UFLS scheme may not require changes to our existing regulatory obligations and requirements. Rather, changes to the parameters and requirements for the UFLS scheme may be linked to AEMO exercising its existing power system security responsibilities and SA Power Networks being required to make changes to its UFLS scheme in order to meeting the new parameters and requirements.

We have therefore suggested the following minor addition to the trigger events that were approved by the AER in its Draft Decision (marked up for ease of reference):

> *'SA Power Networks receives a ~~formal~~ notification from AEMO <u>which requires</u> ~~requiring~~ SA Power Networks to implement <u>any of the following options in order to comply with its applicable regulatory obligations or requirements</u>:*
>
> *(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 addition, given the range of potential responses from SA Power Networks that have been raised by AEMO in our discussions with them, we propose the addition of the following new sub-paragraph to the trigger events that were approved by the AER in its Draft Decision, to be numbered as '(iv)' (with the existing sub-paragraph (iv) to be renumbered as '(v)' :

> '*(iv) any other specific components or elements of the distribution network; or'*

### 5.11.5 Revised Proposal

We have addressed above the reasons set out in the Draft Decision by the AER for rejecting the proposed contingent project.

Accordingly, given that the current trigger events appear to be acceptable to the AER, and given that the proposed additions to those trigger events simply reflect our better understanding concerning the likely outcomes from AEMO's studies and review, we propose the 'Electricity System Security' project as a proposed contingent project for the 2020-25 RCP. Our customers and stakeholders supported the inclusion of the contingent project to address AEMO's supply security concerns but encouraged us to look at the most efficient solution.

For completeness, we set out the trigger events below (with the changes noted above marked up for clarity):

- *SA Power Networks receives a ~~formal~~ notification from AEMO which requires ~~requiring~~ 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.*
- *SA Power Networks Board commitment to proceed with the project subject to the AER amending the distribution determination for the 2020-25 RCP pursuant to the NER.*

# Shortened Forms

| | |
|---|---|
| **ABA** | *Adelaide Business Area* |
| **ABS** | *Australian Bureau of Statistics* |
| **ACS** | *Alternative Control Services* |
| **ADMS** | *advanced distribution management system* |
| **AEMO** | *Australian Energy Market Operator* |
| **AER** | *Australian Energy Regulator* |
| **AIS** | *air insulated switchgear* |
| **Attachment 5** | *AER, Draft Decision for SA Power Networks Distribution Determination 2020-2025, Attachment 5: Capital expenditure* |
| **augex** | *augmentation expenditure* |
| **BAU** | *Business as Usual* |
| **BISOE** | *BIS Oxford Economics* |
| **CAM** | *Cost Allocation Method* |
| **capex** | *capital expenditure* |
| **CBD** | *Central Business District* |
| **CBRM** | *condition-based risk management* |
| **CCP** | *SA Power Networks' Consumer Consultation Panel* |
| **DER** | *Distributed Energy Resources* |
| **CPI** | *consumer price index* |
| **DAE** | *Deloitte Access Economics* |
| **Draft Decision** | *AER, Draft Decision—SA Power Networks Distribution Determination 2020 to 2025* |
| **EFCS** | *emergency frequency control schemes* |
| **EPA** | *Environmental Protection Authority* |
| **EGWWS** | *Electricity, Gas, Water and Waste Services* |
| **EISS** | *Electricity Industry Superannuation Scheme* |
| **EMCa** | *Energy Market Consulting associates* |
| **ETC** | *Electricity Transmission Code* |
| **EWP** | *elevated work platform* |
| **GCM** | *Gross Combination Mass* |
| **GVM** | *gross vehicle mass* |
| **ICT** | *Information, Communications and Technology* |
| **IRR** | *incremental revenue rebate* |
| **IT** | *information technology* |
| **LV** | *Low Voltage* |
| **NECF** | *National Energy Customer Framework* |
| **NEM** | *National Energy Market* |

| | |
|---|---|
| **NEO** | *National Electricity Objective* |
| **NER** | *National Electricity Rules* |
| **NPV** | *net present value* |
| **NSP** | *Network Service Provider* |
| **Original Proposal** | *Regulatory Proposal for the 2020-25 RCP* |
| **OT** | *operational technology* |
| **PILC** | *Paper Insulated Lead Covered* |
| **PLEC** | *Power Line Environmental Committee* |
| **PTRM** | *post tax revenue model* |
| **QoS** | *Quality of supply* |
| **RCP** | *Regulatory Control Period* |
| **repex** | *replacement expenditure* |
| **Revised Proposal** | *SA Power Networks 2020-25 Revised Regulatory Proposal* |
| **RIN** | *Regulatory Information Notice* |
| **SAIDI** | *system average interruption duration index* |
| **SAIFI** | *system average interruption frequency index* |
| **SCADA** | *supervisory control and data acquisition* |
| **SCS** | *Standard Control Services* |
| **$SF_6$** | *sulphur hexafluoride gas* |
| **WACC** | *weighted average cost of capital* |
| **WPI** | *Wage Price Indices* |