FINAL DECISION
SA Power Networks determination 2015−16 to 2019−20

Attachment 6 − Capital expenditure

October 2015

AUSTRALIAN ENERGY REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: (03) 9290 1444
Fax: (03) 9290 1457

Email: AERInquiry@aer.gov.au

Note

This attachment forms part of the AER's final decision on SA Power Networks' 2015–20 distribution determination. It should be read with all other parts of the final decision.

The final decision includes the following documents:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Value of imputation credits

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

Attachment 7 – Operating expenditure

Attachment 8 – Corporate income tax

Attachment 9 – Efficiency benefit sharing scheme

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Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network distributor
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for electricity distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network distributor
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model

Shortened form	Extended form
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

6 Capital expenditure

Capital expenditure (capex) refers to the investment made in the network to provide standard control services. This investment mostly relates to assets with long lives (30–50 years is typical) and these costs are recovered over several regulatory periods. On an annual basis, however, the financing cost and depreciation associated with these assets are recovered (return of and on capital) as part of the building blocks that form SA Power Networks' total revenue requirement.[1]

This attachment sets out our final decision on SA Power Networks' total forecast capex. Further detailed analysis is in the following appendices:

- Appendix A - Assessment techniques
- Appendix B - Assessment of capex drivers
- Appendix C - Demand.

6.1 Final decision

We are not satisfied SA Power Networks' proposed total forecast capex of $2070.8 million ($2014–15) reasonably reflects the capex criteria. This is 23.7 per cent greater than the AER's allowance for the 2010–15 regulatory control period ($1673.7 million) and 30.8 per cent greater than actual capex for the 2010–15 period ($1583.7 million). We substituted our estimate of SA Power Networks' total forecast capex for the 2015–20 regulatory control period. We are satisfied that our substitute estimate of $1845.8 million ($2014–15) reasonably reflects the capex criteria. Table 6.1 outlines our final decision.

Table 6.1 Our final decision on SA Power Networks' total forecast capex ($2014–15 million)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
SA Power Networks' initial proposal	459.1	508.3	510.4	517.8	485.4	2481.0
AER preliminary decision	311.2	341.7	348.3	345.0	337.8	1684.0
SA Power Networks' revised proposal	409.1	444.4	423.6	411.7	382.0	2,070.8
AER final decision	376.5	380.5	364.7	358.8	365.4	1,845.8
Difference (final decision and revised proposal)	-32.7	-63.9	-58.9	-53.0	-16.6	-225.0
Percentage difference (%) (final decision and revised	-8.0	-14.4	-13.9	-12.9	-4.3	-10.9

[1] NER, cl. 6.4.3(a).

proposal)

Source: AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20: Attachment 6 - Capital expenditure*, April 2015, p. 8; SA Power Networks, *Revised regulatory proposal 2015–20*, July 2015, p. 183; AER analysis.

Note: Numbers may not add up due to rounding.

Note: The figures above do not include equity raising costs. For our assessment of equity raising costs, see attachment 3.

Table 6.2 summarises our findings and the reasons for our final decision.

These reasons include our responses to stakeholders' submissions on SA Power Networks' revised regulatory proposal. In the table we present our reasons by 'capex driver' (for example, augmentation, replacement, and connections). This reflects the way in which we tested SA Power Networks' total forecast capex. Our testing used techniques tailored to the different capex drivers, taking into account the best available evidence. Through our techniques, we found SA Power Networks' capex forecast across all categories was higher than an efficient level, inconsistent with the NER. We are not satisfied that SA Power Networks' proposed total forecast capex is consistent with the requirements of the NER.[2]

Our findings on the capex drivers are part of our broader analysis and should not be considered in isolation. Our final decision concerns SA Power Networks' total forecast capex for the 2015–20 period. We do not approve an amount of forecast expenditure for each capex driver. However we use our findings on the different capex drivers to arrive at an alternative estimate for total capex. We test this total estimate of capex against the requirements of the NER (see section 6.3 for a detailed discussion). We are satisfied that our estimate represents total forecast capex that reasonably reflects the capex criteria.

Table 6.2 Summary of AER reasons and findings[3]

Issue	Reasons and findings
Total capex forecast	SA Power Networks' proposed a total capex forecast of $2,070.8 million ($2014–15) in its revised proposal. We are not satisfied this forecast reflects the capex criteria. We are satisfied our substitute estimate of $1,845.8 million ($2014-15) reasonably reflects the capex criteria. Our substitute estimate is 10.9 per cent lower than SA Power Networks' revised proposal (and 25.7 per cent lower than SA Power Networks' initial proposal of $2,481.0 million ($2014–15). The reasons for this decision are summarised in this table and detailed in the remainder of this attachment.
Forecasting methodology, key assumptions and past capex performance	SA Power Networks' forecasting methodology predominately relies upon a bottom up approach. Top down constraints imposed by their governance process are insufficient for us to be able to conclude that the forecasts are prudent and efficient. Bottom up approaches have a tendency to overstate required expenditure as they do not

2 NER, cll. 6.5.7(c) and (d).

3 We have not allocated SA Power Networks' balancing item to the revised proposal figures in this table.

Issue	Reasons and findings
	adequately account for inter-relationships and synergies between projects or areas of work.
Augmentation capex	We do not accept SA Power Networks' forecast augex of $592.1 million ($2014–15) as a reasonable estimate for this category. We consider that $481.1 ($2014–15) million is a reasonable estimate for SA Power Networks to augment its network and satisfy the capex criteria. In coming to this view, we accept the majority of SA Power Networks revised augex forecast except that: • we are not satisfied that SA Power Networks' capex for bushfire mitigation and other safety augex reasonably reflects the prudent and efficient amount to maintain network safety and comply with its regulatory obligations • we are not satisfied that a proportion of SA Power Networks' proposed capex to invest in network reliability, network monitoring and network control is necessary to maintain network service levels over the 2015–20 regulatory control period.
Customer connections capex	We are satisfied SA Power Networks' forecast of connections capex reasonably reflects the capex criteria. We have therefore included an amount of $522.5 million ($2014–15)
Asset replacement capex (repex)	We do not accept SA Power Networks' forecast repex of $681.9 million ($2014–15) as a reasonable estimate for this category. We consider our alternative estimate of $655.1 million will allow SA Power Networks to meet the capex objectives and have included this amount in our alternative estimate. Our alternative estimate is 4 per cent lower than SA Power Networks' revised proposal. Our repex estimate is lower because we used updated data to inform our repex model. Also, because we consider SA Power Networks requires less funding than it forecast for pole top structures repex. We consider SA Power Networks' actual pole top repex from the 2015–20 period better reflects the capex criteria than SA Power Networks' forecast.
Non-network capex	We do not accept SA Power Networks' proposed non-network capex of $562.6 million ($2014–15). We have instead included in our alternative estimate of total capex $511.2 million ($2014–15) for non-network capex, a reduction of 9 per cent. We are satisfied SA Power Networks' forecast for non-network capex reflects the efficient costs of a prudent operator, except for information technology (IT) and buildings. In our view: • SA Power Networks' forecast non-network capex associated with the customer information system, RIN reporting, and tariffs and metering IT projects does not reflect the efficient costs required to meet the identified business needs • the major property project business cases do not satisfy us that the forecast capex for the Seaford and Nuriootpa depot projects is prudent and efficient or is required to achieve the capex objectives.
Capitalised overheads	We accept the majority of SA Power Networks' proposed capitalised overheads of $89.4 million ($2014–15) with a slight downward adjustment. We include in our substitute estimate of overall total capex an amount of $83.8 million ($2014–15) for capitalised overheads. We reduced SA Power Networks' capitalised overheads to reflect the reductions we made to their total capex forecast, particularly those components with overheads.
Real cost escalators	SA Power Networks accepted the AER's preliminary decision to apply zero per cent real cost escalation to materials for the 2015-20 regulatory control period. We are not satisfied SA Power Networks' proposed real labour cost escalators which form part of its total forecast capex reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2015–20 regulatory control period. We discuss our assessment of forecast our labour price growth for SA Power Networks in attachment 7. The difference between the impact of the real labour cost escalation proposed by SA Power Networks and that accepted by the AER in its capex decision is $30.2 million ($2014–15).

Issue	Reasons and findings
Adjustments and unaccounted for capex	SA Power Networks' revised RIN contained a balancing item of -$48.6 million ($2014-15). We have allocated this balancing item to driver categories for the purpose of our assessment.

Source: AER analysis.

We consider that overall our capex forecast addresses the revenue and pricing principles. In particular, we consider our overall capex forecast provides SA Power Networks a reasonable opportunity to recover at least the efficient costs it incurs in:

- providing direct control network services, and
- complying with its regulatory obligations and requirements.[4]

As set out in appendix B we are satisfied that our overall capex forecast is consistent with the NEO. We consider our decision promotes efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity.

We also consider that overall our capex forecast addresses the capital expenditure objectives.[5] In making our final decision, we specifically considered the impact our decision will have on the safety and reliability of SA Power Networks' network. We consider this capex forecast should be sufficient for a prudent and efficient service provider in SA Power Networks' circumstances to be able to maintain the safety, service quality, security and reliability of its network consistent with its current obligations.

6.2 SA Power Networks' revised proposal

SA Power Networks' revised proposal included a total forecast capex of $2070.8 million ($2014–15) for the 2015–20 regulatory control period.[6] This is 23 per cent higher than our preliminary decision and 16.5 per cent lower than SA Power Networks' initial regulatory proposal

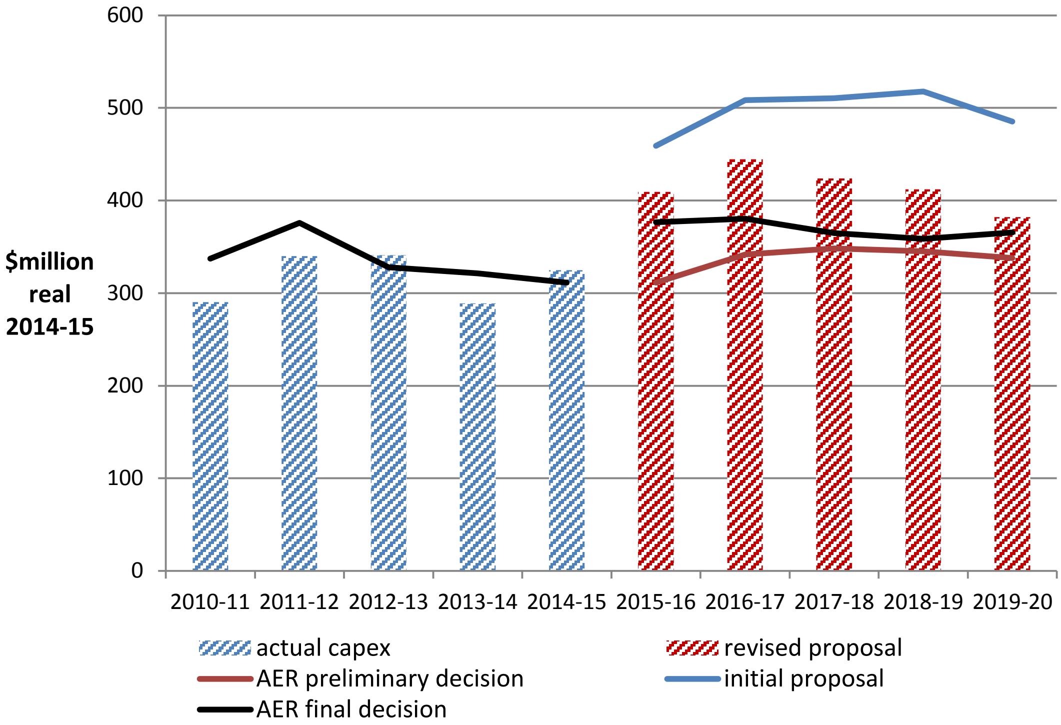
Figure 6.1 shows the difference between SA Power Networks' initial proposal, its revised proposal and our preliminary decision for the 2015–20 regulatory control period. Figure 6.1 also shows the actual capex SA Power Networks spent during the 2010–15 regulatory control period.

4 NEL, s. 7A.

5 NER, cl. 6.5.7(a).

6 This increases to $2,083.2 million ($2014–15) if we include equity raising costs of $12.4 million ($2014–15). See SA Power Networks, *Revised regulatory proposal 2015–20*, July 2015, p. 183.

Figure 6.1 SA Power Networks' total actual and forecast capex



Source: AER analysis.

SA Power Networks submitted its revised proposal was higher than our preliminary decision in the following key categories:[7]

- $91 million in replacement capital expenditure to reflect a different predictive modelling output and a higher pole top structure replacement rate
- $86 million in safety augmentation capital expenditure to enable implementation of its bushfire mitigation program and to deliver on customer concerns
- $144 million in capex to invest in the non-network category including IT systems, fleet and facilities.

6.3 AER's assessment approach

This section outlines our approach to capex assessments. It sets out the relevant legislative and rule requirements, and outlines our assessment techniques. It also explains how we derive an alternative estimate of total forecast capex against which we compare the distributor's total forecast capex. The information SA Power Networks provided in its revised proposal, including its response to our RIN, is a vital part of our assessment. We also took into account information that SA Power Networks provided in response to our information requests, and submissions from other stakeholders.

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7 SA Power Networks, *Revised regulatory proposal 2015–20*, July 2015, pp. 11–13.

Our assessment approach involves the following steps:

- Our starting point for building an alternative estimate is SA Power Networks' revised proposal.[8] We apply our various assessment techniques, both qualitative and quantitative, to assess the different elements of the distributor's proposal. This analysis informs our view on whether the distributor's proposal reasonably reflects the capex criteria in the NER at the total capex level.[9] It also provides us with an alternative forecast that we consider meets the criteria. In arriving at our alternative estimate, we weight the various techniques we used in our assessment. We give more weight to techniques we consider are more robust in the particular circumstances of the assessment.
- Having established our alternative estimate of the *total* forecast capex, we can test the distributor's total forecast capex. This includes comparing our alternative estimate total with the distributor's total forecast capex and what the reasons for any differences are. If there is a difference between the two, we may need to exercise our judgement as to what is a reasonable margin of difference.

If we are satisfied the distributor's proposal reasonably reflects the capex criteria in meeting the capex objectives, we will accept it. The capital expenditure objectives (capex objectives) referred to in the capex criteria, are to:[10]

- meet or manage the expected demand for standard control services over the period
- comply with all regulatory obligations or requirements associated with the provision of standard control services
- to the extent that there are no such obligations or requirements, maintain service quality, reliability and security of supply of standard control services and maintain the reliability and security of the distribution system
- maintain the safety of the distribution system through the supply of standard control services.

If we are not satisfied, the NER requires us to put in place a substitute estimate that we are satisfied reasonably reflects the capex criteria.[11] Where we have done this, our substitute estimate is based on our alternative estimate.

The capex criteria are:[12]

- the efficient costs of achieving the capital expenditure objectives

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8 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline,* November 2013, p. 7; see also AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, pp. 111 and 112.

9 NER, cl. 6.5.7(c).

10 NER, cl. 6.5.7(a).

11 NER, cl. 6.12.1(3)(ii).

12 NER, cl. 6.5.7(c).

- the costs that a prudent operator would require to achieve the capital expenditure objectives
- a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

The AEMC noted '[t]hese criteria broadly reflect the NEO [National Electricity Objective]'.[13] Importantly, we approve a total capex forecast and not particular categories, projects or programs in the capex forecast. Our review of particular categories or projects informs our assessment of the total capex forecast. The AEMC stated:[14]

> It should be noted here that what the AER approves in this context is expenditure allowances, not projects.

In deciding whether we are satisfied that SA Power Networks' total forecast capex reasonably reflects the capex criteria, we have regard to the capex factors.[15] Table 6-5 summarises how we took the capex factors into consideration.

In taking the capex factors into account, the AEMC noted:[16]

> …this does not mean that every factor will be relevant to every aspect of every regulatory determination the AER makes. The AER may decide that certain factors are not relevant in certain cases once it has considered them.

More broadly, we note that in exercising our discretion, we take into account the revenue and pricing principles set out in the NEL.[17] In particular, we take into account whether our overall capex forecast provides SA Power Networks a reasonable opportunity to recover at least the efficient costs it incurs in:

- providing direct control network services; and
- complying with its regulatory obligations and requirements.[18]

6.3.1 Expenditure Assessment Guideline

The rule changes the AEMC made in November 2012 required us to make and publish an Expenditure Forecast Assessment Guideline for electricity distribution (Guideline).[19]

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13 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 113.

14 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012*,* November 2012, p. vii.

15 NER, cl. 6.5.7(e).

16 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 115.

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

18 NEL, s. 7A.

19 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 114.

We released our Guideline in November 2013.[20] The Guideline sets out our proposed general approach to assessing capex (and opex) forecasts. The rule changes also require us to set out our approach to assessing capex in the relevant framework and approach paper. For SA Power Networks, our framework and approach paper stated that we would apply the Guideline, including the assessment techniques outlined in it.[21] We may depart from our Guideline approach and if we do so, we need to provide reasons. In this determination, we have not departed from the approach set out in our Guideline.

We note that RIN data form part of a distributor's regulatory proposal.[22] In our Guideline we stated we would "require all the data that facilitate the application of our assessment approach and assessment techniques". We also stated that the RIN we issue in advance of a distributor lodging its regulatory proposal would specify the exact information we require.[23] Our Guideline made clear our intention to rely upon RIN data during distribution determinations.

6.3.2 **Building an alternative estimate of total forecast capex**

The following section sets out the approach we apply to arrive at an alternative estimate of total forecast capex.

Our starting point for building an alternative estimate is SA Power Networks' revised proposal.[24] We review the proposed forecast methodology and the key assumptions that underlie SA Power Networks' forecast. We also consider its performance in the previous regulatory control period to inform our alternative estimate.

We then apply our specific assessment techniques to develop an estimate and assess the economic justifications that the distributor puts forward. Many of our techniques encompass the capex factors that we are required to take into account. Appendix A and appendix B contain further details on each of these techniques.

Some of these techniques focus on total capex; others focus on high level, standardised sub-categories of capex. Importantly, while we may consider certain projects and programs in forming a view on the total capex forecast, we do not determine which projects or programs the distributor should or should not undertake. This is consistent with the regulatory framework and the AEMC's statement that the AER does not approve specific projects. Rather, we approve an overall revenue

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

21 AER, *Final framework and approach for SA Power Networks: Regulatory control period commencing 1 July 2015*, April 2014, p. 72.

22 NER, cll. 6.8.2(c2) and (d).

23 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 25.

24 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline,* November 2013, p. 7; AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, pp. 111 and 112.

requirement that includes an assessment of what we find to be an efficient total capex forecast.[25]

We determine total revenue by reference to our analysis of the proposed capex and the various building blocks. Once we approve total revenue, the distributor is able to prioritise its capex program given its circumstances over the course of the regulatory control period. The distributor may need to undertake projects or programs it did not anticipate during the distribution determination. The distributor may also not require some of the projects or programs it proposed for the regulatory control period. We consider a prudent and efficient distributor would consider the changing environment throughout the regulatory control period in its decision-making.

As we explained in our Guideline:[26]

> Our assessment techniques may complement each other in terms of the information they provide. This holistic approach gives us the ability to use all of these techniques, and refine them over time. The extent to which we use each technique will vary depending on the expenditure proposal we are assessing, but we intend to consider the inter-connections between our assessment techniques when determining total capex … forecasts. We typically would not infer the findings of an assessment technique in isolation from other techniques.

In arriving at our estimate, we weight the various techniques we used in our assessment. We weight these techniques on a case by case basis using our judgement. Broadly, we give more weight to techniques we consider are more robust in the particular circumstances of the assessment. By relying on a number of techniques, we ensure we consider a wide variety of information and can take a holistic approach to assessing the distributor's capex forecast.

Where our techniques involve the use of a consultant, we consider their reports as one of the inputs to arriving at our final decision on overall capex. Our final decision clearly sets out the extent we accept our consultants' findings. Where we apply our consultants' findings, we do so only after carefully reviewing their analysis and conclusions, and evaluating these against outcomes of our other techniques and our examination of SA Power Networks' proposal.

We also take into account the various interrelationships between the total forecast capex and other components of a distributor's distribution determination. The other components that directly affect the total forecast capex include:

- forecast opex
- forecast demand

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[25] AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. vii.

[26] AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 12.

- the service target performance incentive scheme
- the capital expenditure sharing scheme
- real cost escalation
- contingent projects.

We discuss how these components impact the total forecast capex in Table 6.4.

Underlying our approach are two general assumptions:

- The capex criteria relating to a prudent operator and efficient costs are complementary. Prudent and efficient expenditure reflects the lowest long-term cost to consumers for the most appropriate investment or activity required to achieve the expenditure objectives.[27]
- Past expenditure was sufficient for the distributor to manage and operate its network in past periods, in a manner that achieved the capex objectives.[28]

6.3.3 Comparing the distributor's proposal with our alternative estimate

Having established our estimate of the total forecast capex, we can test the distributor's proposed total forecast capex. This includes comparing our alternative estimate of forecast total capex with the distributor's proposal. The distributor's forecast methodology and its key assumptions may explain any differences between our alternative estimate and its proposal.

As the AEMC foreshadowed, we may need to exercise our judgement in determining whether any 'margin of difference' is reasonable:[29]

> The AER could be expected to approach the assessment of a NSP's expenditure (capex or opex) forecast by determining its own forecast of expenditure based on the material before it. Presumably this will never match exactly the amount proposed by the NSP. However there will be a certain margin of difference between the AER's forecast and that of the NSP within which the AER could say that the NSP's forecast is reasonable. What the margin is in a particular case, and therefore what the AER will accept as reasonable, is a matter for the AER exercising its regulatory judgment.

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27 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 8 and 9. The Tribunal has previously endorsed this approach: see : Application by Ergon Energy Corporation Limited (Non-system property capital expenditure) (No 4) [2010] ACompT 12; Application by EnergyAustralia and Others [2009] ACompT 8; Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No 3) [2010] ACompT 11; Application by DBNGP (WA) Transmission Pty Ltd (No 3) [2012] ACompT 14; Application by Ausnet Services Distribution Pty Limited [2012] ACompT 1; Re: Application by ElectraNet Pty Limited (No 3) [2008] ACompT 3 ; Application by DBNGP (WA).

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

29 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 112.

As noted above, we draw on a range of techniques, as well as our assessment of elements that impact upon capex such as demand and real cost escalators.

Our decision on the total forecast capex does not strictly limit a distributor's actual spending. A distributor might spend more on capex than the total forecast capex amount specified in our decision in response to unanticipated expenditure needs.

The regulatory framework has a number of mechanisms to deal with such circumstances. Importantly, a distributor does not bear the full cost where unexpected events lead to an overspend of the approved capex forecast. Rather, the distributor bears 30 per cent of this cost if the expenditure is subsequently found to be prudent and efficient. Further, the pass through provisions provide a means for a distributor to pass on significant, unexpected capex to customers, where appropriate.[30] Similarly, a distributor may spend less than the capex forecast because they have been more efficient than expected. In this case the distributor will keep on average 30 per cent of this reduction over time.

We set our alternative estimate at the level where the distributor has a reasonable opportunity to recover efficient costs. The regulatory framework allows the distributor to respond to any unanticipated issues that arise during the regulatory control period. In the event that this leads to the approved total revenue underestimating the total capex required, the distributor should have sufficient flexibility to allow it to meet its safety and reliability obligations by reallocating its budget. Conversely, if there is an overestimation, the stronger incentives the AEMC put in place in 2012 should result in the distributor only spending what is efficient. As noted, the distributor and consumers share the benefits of the underspend and the costs of an overspend under the regulatory regime.

6.4 Reasons for final decision

We applied the assessment approach set out in section 6.3 to SA Power Networks. We are not satisfied SA Power Networks' total forecast capex reasonably reflects the capex criteria. We compared SA Power Networks' capex forecast to the alternative capex forecast we constructed using the approach and techniques outlined in appendices A and B. SA Power Networks' revised proposal is materially higher than ours. We are satisfied that our alternative estimate reasonably reflects the capex criteria.

Table 6.3 sets out the capex amounts by driver that we included in our alternative estimate of SA Power Networks' total forecast capex for the 2015–20 regulatory control period.

[30] NER, rule 6.6.

Table 6.3 Our assessment of required capex by capex driver 2015–20 ($2014–15 million)

Category	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Augmentation	96.0	109.2	104.4	93.6	77.9	481.1
Connections	96.3	99.7	102.2	108.8	115.7	522.5
Replacement	114.3	131.0	136.4	138.4	135.1	655.1
Non-Network	128.8	103.1	85.0	85.5	108.8	511.2
Capitalised overheads	16.4	16.1	16.6	17.1	17.6	83.8
Labour and materials escalation adjustment	-3.9	-6.9	-6.6	-6.5	-6.3	-30.2
Gross Capex (includes capital contributions)	447.8	452.1	438.1	436.9	448.7	2223.5
Capital Contributions	71.3	71.6	73.4	78.1	83.3	377.7
Net Capex (excluding capital contributions)	376.5	380.5	364.7	358.8	365.4	1845.8

Source: AER analysis.

Note: Numbers may not add up due to rounding.

We discuss our assessment of SA Power Networks' forecasting methodology, key assumptions and past capex performance in the sections below.

Our assessment of capex drivers is in appendices A and B. These set out the application of our assessment techniques to the capex drivers, and the weighting we gave to particular techniques. We used our reasoning in the appendices to form our alternative estimate.

6.4.1 Key assumptions

The NER requires SA Power Networks to include in its regulatory proposal the key assumptions that underlie its proposed forecast capex. SA Power Networks must also provide a certification by its Directors that those key assumptions are reasonable.[31]

SA Power Networks set out its key assumptions in its revised regulatory proposal.[32]

We assessed SA Power Networks' key assumptions in the appendices to this capex attachment.

[31] NER, cll. S6.1.1.1(2), (4) and (5).

[32] SA Power Networks, *Revised regulatory proposal: Attachment A.2: SAPN_RRP Director's certification & key expenditure assumptions*, 26 June 2015, p. 2.

6.4.2 **Forecasting methodology**

The NER requires SA Power Networks to inform us about the methodology it proposes to use to prepare its forecast capex allowance before it submitted its regulatory proposal.[33] SA Power Networks must include this information in its regulatory proposal.[34] SA Power Networks set out the main points of its forecasting methodology in its regulatory proposal.[35]

In our preliminary decision, we raised the following concerns regarding SA Power Networks' capex forecasting method:[36]

- SA Power Networks relied primarily on a bottom-up build and did not use a top down assessment of the overall capex forecast.
- SA Power Networks' underlying risk assessment for its capital projects and programs are excessively conservative.

SA Power Networks did not appear to address these concerns in its revised proposal. Hence, the concerns we raised in our preliminary decision also hold for this final decision and we did not depart from our preliminary decision in this regard.

The Energy Consumers Coalition of South Australia (ECCSA) submitted our preliminary decision identified proposed investments for which SA Power Networks did not provide 'rigorous justification'. ECCSA submitted this highlights that SA Power Networks management has not been rigorous in applying standard approaches to capex justification. ECCSA subsequently asked whether other areas of SA Power Networks' capex proposal may also lack such rigorous justification.[37]

Professionals Australia submitted:[38]

> The AER has repeatedly criticised the bottom-up approach used by the SA Power Networks in forecasting CAPEX requirements. However, this is based on an intimate knowledge of existing infrastructure, useful lifespans, expert engineering knowledge, and a detailed history of failures and replacement costs. The AER has chosen instead to run a more simplistic top-down approach, which fails to take into account the specific needs of networks.

We acknowledge bottom up approaches do indeed involve intimate knowledge of the network. As we discussed in our preliminary decision, however:[39]

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33 NER, cll. 6.8.1A and 11.60.3(c).

34 NER, cl. S6.1.1(2).

35 SA Power Networks, *Expenditure forecasting methodology: 2015 Reset project*, 25 November 2013.

36 AER, *Preliminary decision: SA Power Networks determination 2015−16 to 2019−20: Attachment 6: Capital expenditure*, April 2015, pp. 21–23.

37 Energy Consumers Coalition of South Australia, *SA electricity distribution revenue reset: The AER preliminary decision*, June 2015, p. 15.

38 Professionals Australia, *Response to the Australian Energy Regulator's preliminary determinations South Australia distribution businesses 2015–2020*, 2 July 2015, pp. 5–7.

> The drawback of deriving an estimate of capex by applying a bottom-up assessment is that of itself it does not provide sufficient evidence that the estimate is efficient. Bottom up approaches have a tendency to overstate required allowances as they do not adequately account for inter-relationships and synergies between projects or areas of work.

More importantly, we do not limit our capex assessment to top-down methods. We utilise a holistic assessment approach that include techniques such as predictive modelling and detailed technical reviews (see section 6.3 and appendix A).

6.4.3 **Interaction with the STPIS**

We consider our approved capital expenditure forecast is consistent with the setting of targets under the STPIS. In particular, we should not set the capex allowance such that it would lead to SA Power Networks systematically under- or over performing against its STPIS targets. We consider our approved capex forecast is sufficient to allow a prudent and efficient service provider in SA Power Networks' circumstances to maintain performance at the targets set under the STPIS. As such, it is appropriate to apply the STPIS as set out in attachment 11.

In making our final decision, we specifically considered the impact our decision will have on the safety and reliability of SA Power Networks' network.

In its submission, the Consumer Challenge Panel (CCP) noted the following explanation from the AEMC:[40]

> …operating and capital expenditure allowances for NSPs should be no more than the level considered necessary to comply with the relevant regulatory obligation or requirement, where these have been set by the body allocated to that role. Expenditure by NSPs to achieve standards above these levels should be unnecessary, as they are only required to deliver to the standards set. It would also amount to the AER substituting a regulatory obligation or requirement with its own views on the appropriate level of reliability, which would undermine the role of the standard setting body, and create uncertainty and duplication of roles.
>
> NSPs are still free to make incremental improvements over and above the regulatory requirements at their own discretion. Such additional expenditure will not generally be recoverable, through forecast capital and operating expenditure. However, DSNPs are also provided with annual financial incentives to improve reliability performance under the STPIS.

We consider our substitute estimate is sufficient for SA Power Networks to maintain the safety, service quality and reliability of its network consistent with its obligations.

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39 AER, *Preliminary decision: SA Power Networks determination 2015−16 to 2019−20: Attachment 6 − Capital expenditure*, April 2015, p. 22.

40 CCP, *Advice to the AER: AER's Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks' revised regulatory proposal*, August 2015 p. 27.

Our provision of a total capex forecast does not constrain a distributor’s actual spending—either as a cap or as a requirement that the forecast be spent on specific projects or activities. It is conceivable that a distributor might wish to spend particular capital expenditure differently or in excess of the total capex forecast in our decision. However, such additional expenditure is not included in our assessment of expenditure forecasts as it is not required to meet the capex objectives. We consider the STPIS is the appropriate mechanism to provide distributors with the incentive to improve reliability performance where such improvements reflect value to the energy customer.

Under our analysis of specific capex drivers, we explained how our analysis and certain assessment techniques factor in safety and reliability obligations and requirements.

In the preliminary decision, we did not approve $29.4 million in augex that SA Power Networks proposed to improve network reliability. We considered the STPIS regime is the more appropriate avenue to fund network improvement programs. We also asked SA Power Networks to provide additional information regarding these projects' interaction with the STPIS.[41] In its revised regulatory proposal, SA Power Networks maintained its proposal to include these network improvement programs. Section B.2 contains our assessment of these projects.

6.4.4 **SA Power Networks' capex performance**

We looked at a number of historical metrics of SA Power Networks' capex performance against other distributors in the NEM. We also compared SA Power Networks' capex forecast against historical trends. These metrics are largely based on outputs of the annual benchmarking report and other analysis using data the distributors provided for the annual benchmarking report. The report includes SA Power Networks' relative partial and multilateral total factor productivity (MTFP) performance, capex per customer and maximum demand, and SA Power Networks' historical capex trend.

The NER sets out that we must have regard to our annual benchmarking report.[42] This section shows how we have taken it into account. We consider this high level benchmarking at the overall capex level is suitable to gain an overall understanding of SA Power Networks' proposal in a broader context. However, in our capex assessment we have not relied on the high level benchmarking metrics set out below other than to gain a high level insight into SA Power Networks' proposal. We have not used this analysis deterministically in our capex assessment.

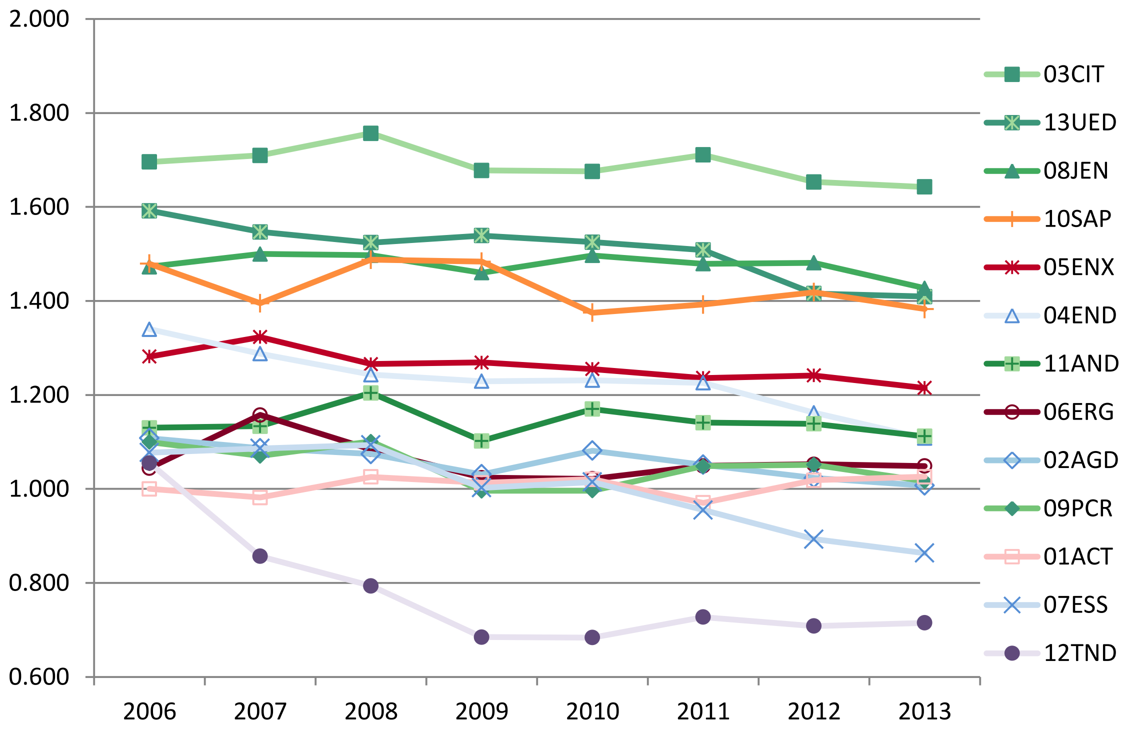
41 AER, *Preliminary decision: SA Power Networks determination 2015−16 to 2019−20: Attachment 6: Capital expenditure*, April 2015, p. 10.

42 NER, cl. 6.5.7(e).

Partial factor productivity of capital and multilateral total factor productivity

Figure 6.2 shows a measure of partial factor productivity of capital from our benchmarking report. This measure incorporated the productivity of transformers, overhead lines and underground cables. SA Power Networks performs relatively well on this measure, only falling behind some of the Victorian distributors.

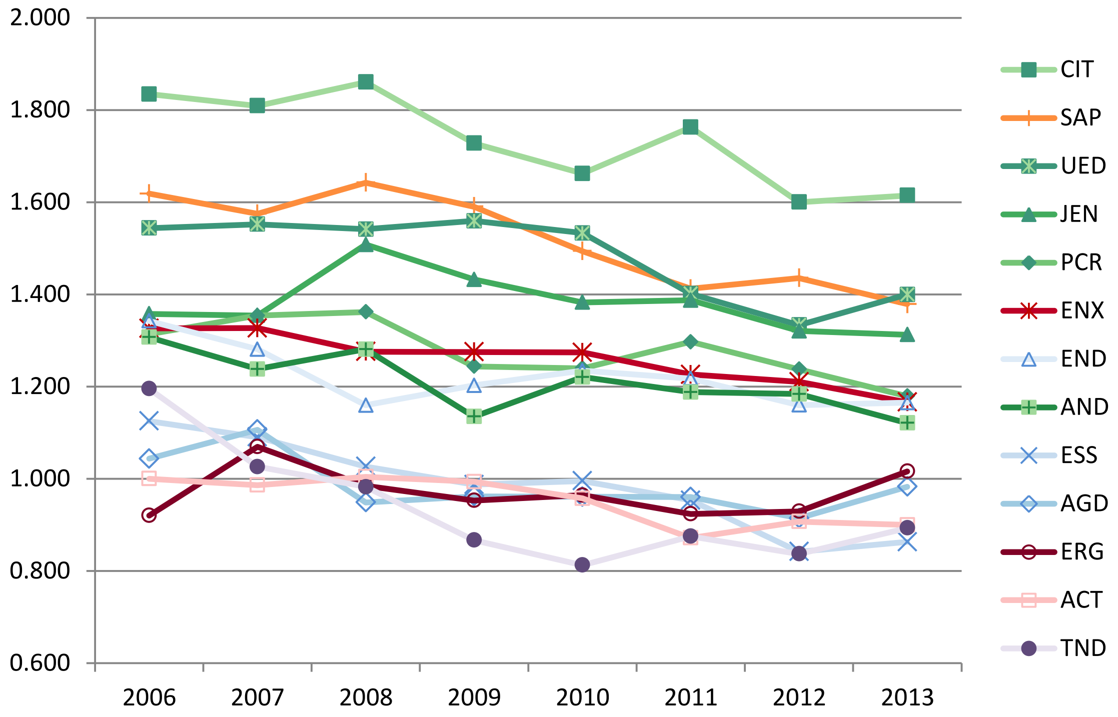
Figure 6.2 Partial factor productivity of capital (transformers, overhead and underground lines)



Source: AER, *Electricity distribution network service providers: Annual benchmarking report*, November 2014, p. 33.

Figure 6.3 shows that SA Power Networks ranks similarly on multilateral total factor productivity (MTFP). MTFP measures how efficient a business is in terms of its inputs (costs) and outputs (energy delivered, customer numbers, ratcheted maximum demand, reliability and circuit line length).

Figure 6.3 Multilateral total factor productivity



Source: AER, *Electricity distribution network service providers: Annual benchmarking report*, November 2014, p. 31.

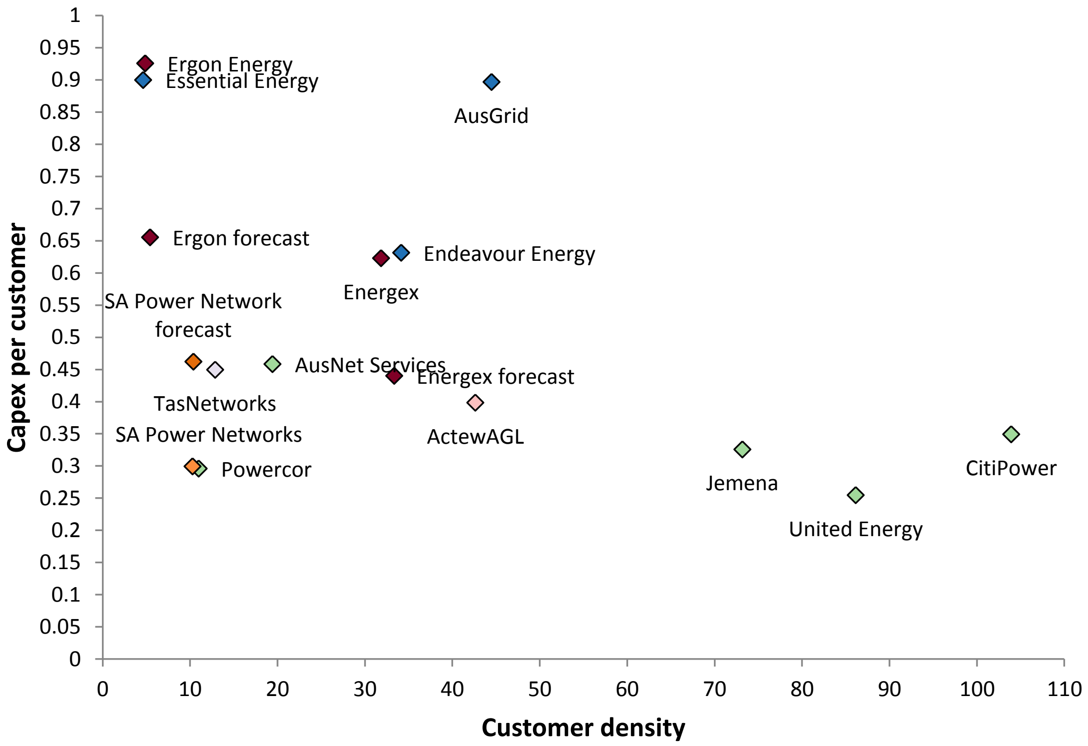
Relative capex efficiency metrics

Figure 6.4 and Figure 6.5 show capex per customer and per maximum demand, against customer density. Unless otherwise indicated as a forecast, the figures represent the five year average of each distributor's actual capex for the years 2008–12. We considered capex per customer as it reflects the amount consumers are charged for additional capital investments.

Figure 6.4 and Figure 6.5 show the SA Power Networks generally performed well in these metrics compared to other distributors in the NEM in the 2008–12 years. For completeness, we included Energex's and Ergon Energy's proposed capex for the 2015–20 regulatory control period in the figures. However, we do not use comparisons of SA Power Networks' total forecast capex with the total forecast capex of the Queensland distributors as inputs to our assessment. We consider it is appropriate to compare SA Power Networks' forecast only with actual capex. This is because actual capex is a 'revealed cost' and would have occurred under the incentives of a regulatory regime.

Figure 6.4 shows SA Power Networks performed well in the 2008–12 period when compared to its peers in terms of capex per customer. Based on the initial proposal, our preliminary decision stated SA Power Networks' capex per customer will be relatively high in the 2015–20 regulatory control period.[43] While the revised proposal yielded an improvement in the capex per customer metric in the 2015–20 regulatory control period, it is still materially higher than historical levels.

Figure 6.4 Capex per customer (000s, $2013–14), against customer density



Source: AER analysis.

Figure 6.5 shows SA Power Networks performed well in 2008–12 in terms of capex per maximum demand, similar to the capex per customer metric (Figure 6.4). Compared to its initial proposal, the revised proposal sees SA Power Networks improve its performance in the capex per customer metric in the 2015–20 regulatory control period. However, it is still significantly higher than historical levels.[44]

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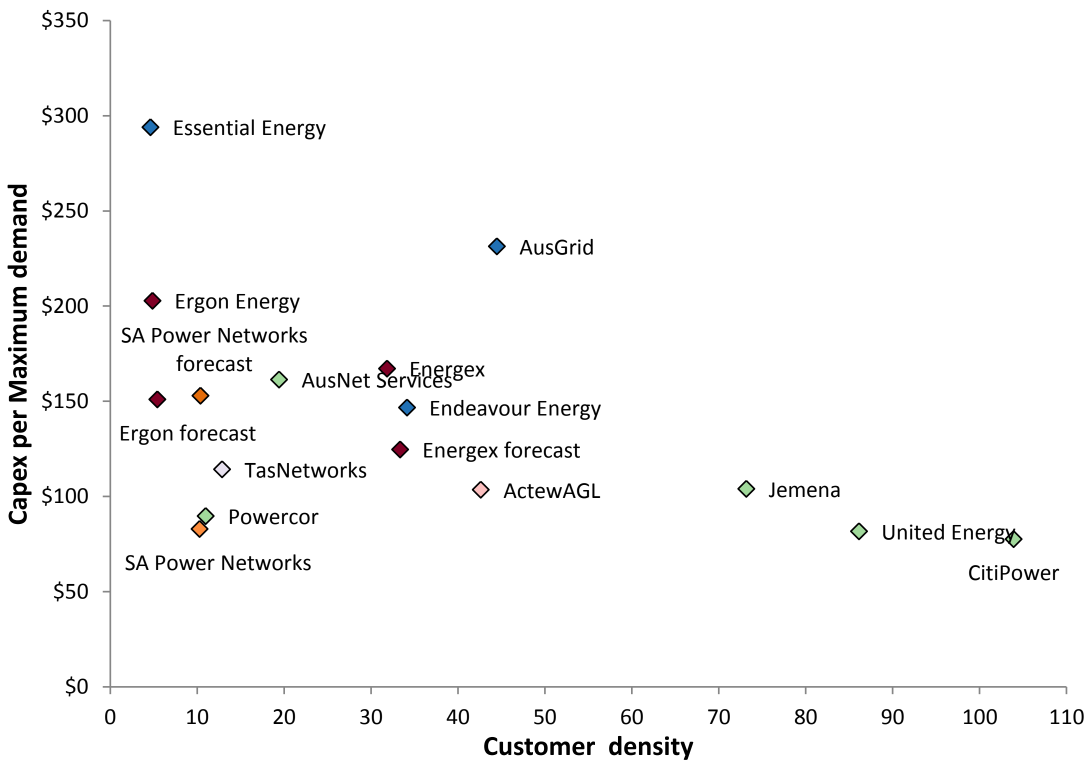
43 AER, *Preliminary decision: SA Power Networks determination 2015−16 to 2019−20: Attachment 6: Capital expenditure*, April 2015, p. 26–27.

44 AER, *Preliminary decision: SA Power Networks determination 2015−16 to 2019−20: Attachment 6: Capital expenditure*, April 2015, pp. 27–28.

Figure 6.5 Capex per maximum demand (000s, $2013–14) against customer density



Source: AER analysis.

The CCP acknowledged the relative efficiency of SA Power Networks' historical capex. However, the CCP raised concerns that the 'very significant' increases to capex in SA Power Networks' initial and revised proposals would lead to a deterioration of this relative efficiency.[45] The CCP does not consider such levels of investment are prudent because of factors such as:[46]

- lower demand
- poor load factors
- increasing spare capacity in the network.

The CCP stated a business facing such circumstances would not normally expand its capital base. Rather, it would preserve its capital and maximise the efficiency of its

45 CCP, *Presentation: Preliminary decision conference for SA Power Networks*, 13 May 2015, p. 7.

46 CCP, *Submission on AER's preliminary decision for SA Power Networks for 2015–20 and SA Power Networks' revised proposal*, August 2015, pp. 44–45; CCP, *Presentation: Preliminary decision conference for SA Power Networks*, 13 May 2015, p. 9.

current service operations. This is what we see in non-regulated businesses facing risks of declining demand and/or prices.[47]

Similarly, the Central Irrigation Trust (CIT) stated basic business principles should apply in a time of static or low demand. This would involve finding productivity improvements by reducing operating expenditure in real terms and minimising capital expenditure. The CIT stated it does not see these basic business principles in either SA Power Networks' regulatory proposal or our preliminary determination.[48]

Uniting Care, Yatco, Berri Estates and the D&F Ceracchi Family Trust made similar points in their submissions.[49]

The South Australia Financial Counsellors Association considered the expenditure allowances in our preliminary decision were too high given the decline in consumption. It considered it would be appropriate to further reduce these allowances, leading to greater price reductions for South Australian consumers.[50]

Appendix B details our assessment of SA Power Networks' capex categories. These assessments, along with the high level analysis in this section 6.4.4, were inputs into our final decision on SA Power Networks' total capex for the 2015–20 regulatory control period. We consider our assessment has taken into account the issues and concerns stakeholders raised in their submissions. Figure 6.1 shows our final decision capex forecast is about 10 per cent higher than SA Power Networks' actual capex in the 2010–15 regulatory control period. By comparison, SA Power Networks' revised proposal capex is 30.8 per cent higher than its actual capex for the 2010–15 period. SA Power Networks' initial capex proposal was around 50 per cent higher than its actual capex in the 2010–15 regulatory control period.

To arrive at our final decision, we considered the issues noted in these submissions, such as lower demand and spare capacity in the network. For example, we consider SA Power Networks' forecast of flat overall demand is reasonable because it reflects a realistic expectation of demand over the 2015-20 period (see Appendix C). Where SA Power Networks proposed augex in areas forecast to reach full capacity, we consider SA Power Networks, for the most part, provided the justification for such expenditure (see section B.2). Importantly, our assessment considered many other factors. While we consider SA Power Networks' demand-related augex was reasonable, we consider they did not justify augex related to bushfire mitigation and network reliability,

47 CCP, *Submission on AER's preliminary decision for SA Power Networks for 2015–20 and SA Power Networks' revised proposal*, August 2015, pp. 19, 44–45.

48 CIT, *Submission to SA Power Networks regulatory proposal (2015 – 2020)*, 19 June 2015, pp. 2 and 6.

49 Uniting Care, *Response to electricity distribution business revised regulatory proposals for 2015-20, from SA Power Networks, electricity distribution business, and AER preliminary determination*, July 2015, p. 20; D&F Ceracchi Family Trust, *Submission to SA Power Networks preliminary decision*, 22 June 2015; Berri Estates, *Submission: SA Power Networks regulatory proposal 2015-2020*, June 2014; Yatco, *Submission to SA Power Networks regulatory proposal (2015-2020)*, 3 July 2015.

50 South Australia Financial Counsellors Association, *Submission: AER's preliminary decision*, 3 July 2015, p. 1.

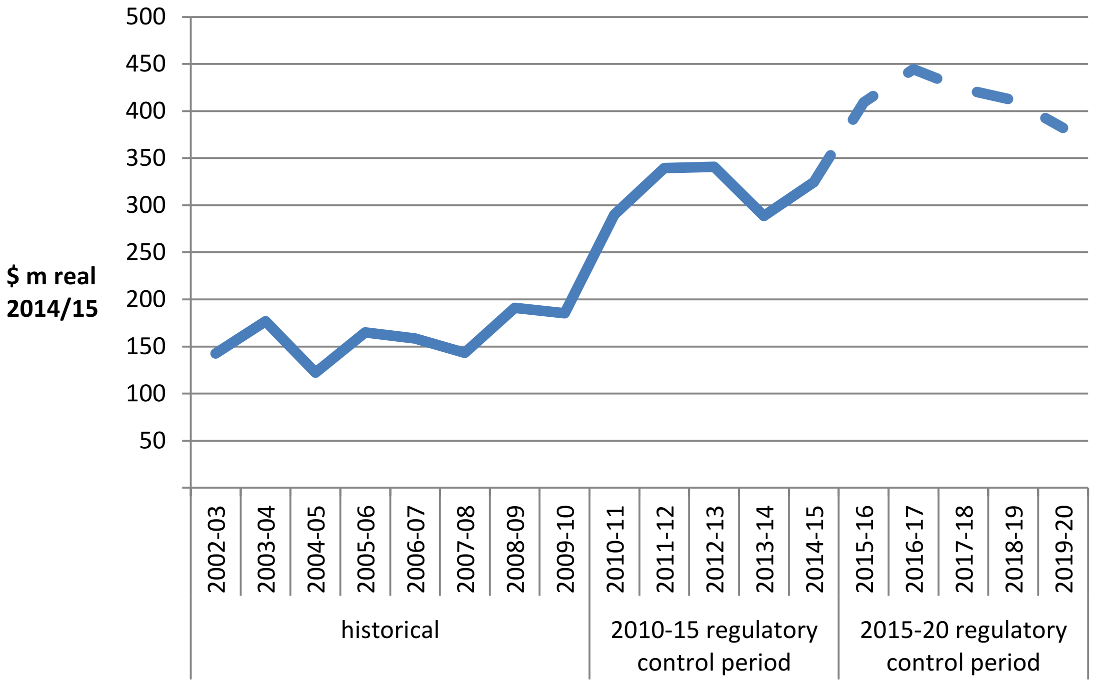
monitoring and control (see section B.2). We discuss these, and other issues relevant to SA Power Networks' capex proposal, in detail in appendix B.

SA Power Networks' historical capex trends

We compared SA Power Networks' capex proposal in the revised proposal for the 2015–20 regulatory control period against the long term historical trend.

Figure 6.6 shows actual historic capex and capex forecast from the revised proposal between 2002–03 and 2019–20. This figure shows SA Power Networks' capex forecast for the 2015–20 regulatory control period is substantially higher than historical levels (actual spend). However, it will not increase to the same degree as the capex forecast from SA Power Networks' initial proposal.[51] Our detailed assessment in appendix B examined whether the increase is reasonably reflective of the capex criteria.

Figure 6.6 Long term capex trend



Source: AER analysis.

[51] AER, *Preliminary decision: SA Power Networks determination 2015−16 to 2019−20: Attachment 6: Capital expenditure*, April 2015, p. 28.

6.4.5 Interrelationships

There are a number of interrelationships between SA Power Networks' total forecast capex for the 2015–20 regulatory control period and other components of its distribution determination (see Table 6.4). We considered these interrelationships in coming to our final decision on total forecast capex.

Table 6.4 Interrelationships between total forecast capex and other components

Other component	Interrelationships with total forecast capex
Total forecast opex	There are elements of SA Power Networks' total forecast opex that are specifically related to its total forecast capex. These include the forecast labour price growth that we included in our opex forecast in Attachment 7. This is because the price of labour affects both total forecast capex and total forecast opex. More generally, we note our total opex forecast will provide SA Power Networks with sufficient opex to maintain the reliability of its network. Although we do not approve opex on specific categories of opex such as maintenance, the total opex we approve will in part influence the repex SA Power Networks needs to spend during the 2015–20 period.
Forecast demand	Forecast demand is related to SA Power Networks' total forecast capex. Growth driven capex, which includes augex and customer connections capex, is typically triggered by a need to build or upgrade a network to address changes in demand or to comply with quality, reliability and security of supply requirements. Hence, the main driver of growth-related capex is maximum demand and its effect on network utilisation and reliability.
Capital Expenditure Sharing Scheme (CESS)	The CESS is related to SA Power Networks' total forecast capex. In particular, the effective application of the CESS is contingent on the approved total forecast capex being efficient, and that it reasonably reflects the capex criteria. As we noted in Table 6-5, this is because any efficiency gains or losses are measured against the approved total forecast capex. In addition, in future distribution determinations we will be required to undertake an ex post review of the efficiency and prudency of capex, with the option to exclude any inefficient capex in excess of the approved total forecast capex from SA Power Networks' regulatory asset base. In particular, the CESS will ensure that SA Power Networks bears at least 30 per cent of any overspend against the capex allowance. Similarly, if SA Power Networks can fulfil their objectives without spending the full capex allowance, it will be able to retain 30 per cent of the benefit of this. In addition, if an overspend is found to be inefficient through the ex post review, SA Power Networks risks having to bear the entire overspend.
Service Target Performance Incentive Scheme (STPIS)	The STPIS is interrelated to SA Power Networks' total forecast capex, in so far as it is important that it does not include any expenditure for the purposes of improving supply reliability during the 2015–20 period. This is because such expenditure should be offset by rewards provided through the application of the STPIS. Further, the forecast capex should be sufficient to allow SA Power Networks to maintain performance at the targets set under the STPIS. The capex allowance should not be set such that there is an expectation that it will lead to SA Power Networks systematically under or over performing against its targets. In section B.2, we discuss our consideration of interactions between the STPIS and specific capex items.
Contingent project	A contingent project is interrelated to SA Power Networks' total forecast capex. This is because an amount of expenditure that should be included as a contingent project should not be included as part of SA Power Networks' total forecast capex for the 2015–20 period. We did not identify any contingent projects for SA Power Networks for the 2015–20 period.

Source: AER analysis.

6.4.6 Consideration of the capex factors

As we discussed in section 6.3, we took the capex factors into consideration when assessing SA Power Networks' total capex forecast.[52] Table 6-5 summarises how we have taken into account the capex factors.

Where relevant, we also had regard to the capex factors in assessing the forecast capex associated with capex drivers such as repex, augex and so on (see appendix B).

Table 6-5 AER consideration of the capex factors

Capex factor	AER consideration
The most recent annual benchmarking report and benchmarking capex that would be incurred by an efficient distributor over the relevant regulatory control period	We had regard to our most recent benchmarking report in assessing SA Power Networks' proposed total forecast capex and in determining our alternative estimate for the 2015–20 regulatory control period. This can be seen in the metrics we used in our assessment of SA Power Networks' capex performance.
The actual and expected capex of SA Power Networks during any preceding regulatory control periods	We had regard to SA Power Networks' actual and expected capex during the 2010–15 and preceding regulatory control periods in assessing its proposed total forecast capex. This can be seen in our assessment of SA Power Networks' capex performance. It can also be seen in our assessment of the forecast capex associated with the capex drivers that underlie SA Power Networks' total forecast capex. For non-network related capex, we rely on trend analysis to arrive at an estimate that meets the capex criteria.
The extent to which the capex forecast includes expenditure to address concerns of electricity consumers as identified by SA Power Networks in the course of its engagement with electricity consumers	We had regard to the extent to which SA Power Networks' proposed total forecast capex includes expenditure to address consumer concerns that SA Power Networks identified. SA Power Networks undertook a consumer engagement program which included workshops, bilateral engagement with stakeholders and a willingness-to-pay survey. Section B details our consideration of SA Power Networks' customer engagement to address concerns associated with bushfire mitigation, safety and reliability augex proposals.
The relative prices of operating and capital inputs	We had regard to the relative prices of operating and capital inputs in assessing SA Power Networks' proposed real cost escalation factors. In particular, we have not accepted SA Power Networks' proposal to apply real cost escalation for labour.
The substitution possibilities between operating and capital expenditure	We had regard to the substitution possibilities between opex and capex. We considered whether there are more efficient and prudent trade-offs in investing more or less in capital in place of ongoing operations. See our discussion about the interrelationships between SA Power Networks' total forecast capex and total forecast opex in Table 6.4 above.
Whether the capex forecast is consistent with any incentive scheme or schemes that apply to SA	We have had regard to whether SA Power Networks' proposed total forecast capex is consistent with the CESS and the STPIS.

52 NER, cll. 6.5.7(c), (d) and (e).

Capex factor	AER consideration
Power Networks	See our discussion about the interrelationships between SA Power Networks' total forecast capex and the application of the CESS and the STPIS in Table 6.4 above.
The extent to which the capex forecast is referable to arrangements with a person other than the distributor that do not reflect arm's length terms	We had regard to whether any part of SA Power Networks' proposed total forecast capex or our alternative estimate is referable to arrangements that do not reflect arm's length terms. We did not identify any parts of SA Power Networks' proposed total forecast capex or our alternative estimate that is referable in this way.
Whether the capex forecast includes an amount relating to a project that should more appropriately be included as a contingent project	We had regard to whether any amount of SA Power Networks' proposed total forecast capex or our alternative estimate relates to a project that should more appropriately be included as a contingent project. We did not identify any such amounts that should more appropriately be included as a contingent project.
The extent to which SA Power Networks has considered and made provision for efficient and prudent non-network alternatives	We had regard to the extent to which SA Power Networks made provision for efficient and prudent non-network alternatives as part of our assessment. In particular, we considered this within our review of SA Power Networks' augex proposal.
Any other factor the AER considers relevant and which the AER has notified SA Power Networks in writing, prior to the submission of its revised regulatory proposal, is a capex factor	We did not identify any other capex factor that we consider relevant.

Source: AER analysis.

6.5 Allocation of balancing item

SA Power Networks' revised RIN contained a balancing item of –$48.6 million ($2014–15). We have allocated this balancing item to driver categories for the purpose of our assessment. Table 6.6 sets out our allocation of SA Power Networks' balancing item.

Table 6.6 Allocation of balancing item to driver ($2014–15 million)

Driver	Revised proposal	Revised proposal (after allocating balancing item)	Final decision
Augmentation	608.1	592.1	481.1
Connections	536.7	522.5	522.5
Replacement	700.4	681.9	655.1
Non-Network	562.6	562.6	511.2
Capitalised overheads	89.4	89.4	82.1
Escalation adjustment	0.0	0.0	-29.7
Balancing item	–48.6	0.0	0.0
TOTAL GROSS CAPEX	2,448.5	2,448.5	2,222.3
Capital contributions	377.7	377.7	377.7
TOTAL NET CAPEX	2,070.8	2,070.8	1,844.6

A Assessment techniques

This appendix describes the assessment approaches we applied in assessing SA Power Networks' total forecast capex. We used a variety of techniques to determine whether the SA Power Networks' total forecast capex reasonably reflects the capex criteria. Appendix B sets out in greater detail the extent to which we relied on each of the assessment techniques.

The assessment techniques that we apply in capex are necessarily different from those we apply in the assessment of opex. This is reflective of differences in the nature of the expenditure we are assessing. As such, we use some assessment techniques in our capex assessment that are not suitable for assessing opex and vice versa. We set this out in our expenditure assessment guideline, where we stated:[53]

> Past actual expenditure may not be an appropriate starting point for capex given it is largely non-recurrent or 'lumpy', and so past expenditures or work volumes may not be indicative of future volumes. For non-recurrent expenditure, we will attempt to normalise for work volumes and examine per unit costs (including through benchmarking across distributors) when forming a view on forecast unit costs.
>
> Other drivers of capex (such as replacement expenditure and connections works) may be recurrent. For such expenditure, we will attempt to identify trends in revealed volumes and costs as an indicator of forecast requirements.

Below we set out the assessment techniques we used to asses SA Power Networks' capex.

A.1 Economic benchmarking

Economic benchmarking is one of the key outputs of our annual benchmarking report. The NER requires us to consider the annual benchmarking report as it is one of the capex factors.[54] Economic benchmarking applies economic theory to measure the efficiency of a distributor's use of inputs to produce outputs, having regard to environmental factors.[55] It allows us to compare the performance of a distributor against its own past performance, and the performance of other distributors. Economic benchmarking helps us to assess whether a distributor's capex forecast represents efficient costs.[56] As the AEMC stated, 'benchmarking is a critical exercise in assessing the efficiency of a NSP'.[57]

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[53] AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p.8.

[54] NER, cl. 6.5.7(e)(4).

[55] AER, *Better regulation: Explanatory statement: Expenditure forecasting assessment guidelines,* November 2013.

[56] NER, cl. 6.5.7(c).

[57] AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 25.

A number of economic benchmarks from the annual benchmarking report are relevant to our assessment of capex. These include measures of total cost efficiency and overall capex efficiency. In general, these measures calculate a distributor's efficiency with consideration given to its inputs, outputs and its operating environment. We considered each distributor's operating environment in so far as there are factors outside of a distributor's control that affect its ability to convert inputs into outputs.[58] Once such exogenous factors are taken into account, we expect distributors to operate at similar levels of efficiency. One example of an exogenous factor we took into account is customer density. For more on how we derived these measures, see our annual benchmarking report.[59]

In addition to the measures in the annual benchmarking report, we considered how distributors performed on a number of overall capex metrics, including capex per customer, and capex per maximum demand. We calculated these economic benchmarks using actual data from the previous regulatory control period.

The results from economic benchmarking give an indication of the relative efficiency of each of the distributors, and how this has changed over time.

A.2 Trend analysis

We considered past trends in actual and forecast capex as this is one of the capex factors under the NER.[60]

Trend analysis involves comparing a distributor's forecast capex and work volumes against historical levels. Where forecast capex and volumes are materially different to historical levels, we seek to understand the reasons for these differences. In doing so, we consider the reasons the distributor provides in its proposal, as well as changes in the circumstances of the distributor.

In considering whether the total forecast capex reasonably reflects the capex criteria, we need to consider whether the forecast will allow the distributor to meet expected demand, and comply with relevant regulatory obligations.[61] Demand and regulatory obligations (specifically, service standards) are key drivers of capex. More onerous standards will increase capex, as will growth in maximum demand. Conversely, reduced service obligations or a decline in demand will likely cause a reduction in the amount of capex the distributor requires.

Maximum demand is a key driver of augmentation or demand driven expenditure. Augmentation often needs to occur prior to demand growth being realised. Hence, forecast rather than actual demand is relevant when a business is deciding the

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58 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p.113. Exogenous factors could include geographic factors, customer factors, network factors and jurisdictional factors.

59 AER, *Electricity distribution network service providers: Annual benchmarking report*, November 2014.

60 NER, cl. 6.5.7(e)(5).

61 NER, cl. 6.5.7(a)(3).

augmentation projects it will require in an upcoming regulatory control period. To the extent actual demand differs from forecast, however, a business should reassess the need for the projects. Growth in a business' network will also drive connections related capex. For these reasons it is important to consider how trends in capex (in particular, augex and connections) compare with trends in demand (and customer numbers).

For service standards, there is generally a lag between when capex is undertaken (or not) and when the service improves (or declines). This is important when considering the expected impact of an increase or decrease in capex on service levels. It is also relevant to consider when service standards have changed and how this has affected the distributor's capex requirements.

We looked at trends in capex across a range of levels including at the total capex level, and the category level (such as growth related capex, and repex) as relevant. We also compared these with trends in demand and changes in service standards over time.

A.3 Category analysis

Expenditure category analysis allows us to compare expenditure across NSPs, and over time, for various levels of capex. The comparisons we perform include:

- overall costs within each category of capex
- unit costs, across a range of activities
- volumes, across a range of activities
- asset lives, across a range of asset classes which we use in assessing repex.

Using standardised reporting templates, we collected data on augex, repex, connections, non-network capex, overheads and demand forecasts for all distributors in the NEM. The use of standardised category data allows us to make direct comparisons across distributors. Standardised category data also allows us to identify and scrutinise different operating and environmental factors that affect the amount and cost of works performed by distributors, and how these factors may change over time.

A.4 Predictive modelling

Predictive modelling uses statistical analysis to determine the expected efficient costs over the regulatory control period associated with the demand for electricity services for different categories of works. We have two predictive models:

- the repex model
- the augex model (used in a qualitative sense).

The use of the repex and augex models is directly relevant to assessing whether a distributor's capex forecast reasonably reflects the capex criteria.[62] The models draw

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62 NER, cl. 6.5.7(c).

on actual capex the distributor incurred during the preceding regulatory control period. This past capex is a factor that we must take into account.[63]

The repex model is a high-level probability based model that forecasts asset replacement capex (repex) for various asset categories based on their condition (using age as a proxy), and unit costs. If we consider a distributor's proposed repex does not conform to the capex criteria, we use the repex model (in combination with other techniques where appropriate) to generate a substitute forecast.

The augex model compares utilisation thresholds with forecasts of maximum demand to identify the parts of a network segment that may require augmentation.[64] The model then uses capacity factors to calculate required augmentation, and unit costs to derive an augex forecast for the distributor over a given period.[65] In this way, the augex model accounts for the main internal drivers of augex that may differ between distributors, namely peak demand growth and its impact on asset utilisation. We can use the augex model to identify general trends in asset utilisation over time as well as to identify outliers in a distributor's augex forecast.[66]

For our final decision we have relied on input data for the augex model to review forecast utilisation of individual zone substations to assess whether augmentation may be necessary to alleviate capacity constraints. We use this analysis both as a starting point for our further detailed evaluation, and as a cross-check on our overall augex estimate. We have not otherwise used the augex model in our assessment of SA Power Networks' augex forecast.

A.5 Engineering review

We drew on engineering and other technical expertise within the AER to assist with our review of SA Power Networks' capex proposals.[67] This involved reviewing SA Power Networks' processes, and specific projects and programs of work.

Appendix B discusses in detail our consideration of these reviews in our assessment of SA Power Networks' capex forecast.

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63 NER, cl. 6.5.7(e)(5).

64 Asset utilisation is the proportion of the asset's capability under use during peak demand conditions.

65 For more information, see: AER, *Guidance document: AER augmentation model handbook,* November 2013.

66 AER, *'Meeting summary – distributor replacement and augmentation capex', Workshop 4: Category analysis work-stream – Replacement and demand driven augmentation (Distribution),* 8 March 2013, p. 1.

67 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline*, November 2013, p. 86.

B Assessment of capex drivers

We present our detailed analysis of the sub-categories of SA Power Networks' forecast capex for the 2015–20 regulatory control period in this appendix. These sub-categories reflect the drivers of forecast capex over the 2015–20 period. These drivers are augmentation capex (augex), customer connections capex, replacement capex (repex), reliability improvement capex, capitalised overheads and non-network capex.

As we discuss in the capex attachment, we are not satisfied that SA Power Networks' total forecast capex reasonably reflects the capex criteria. In this appendix we set out further analysis in support of this view. This further analysis also explains the basis for our alternative estimate of SA Power Networks' total forecast capex that we are satisfied reasonably reflects the capex criteria. In coming to our views and our alternative estimate we applied the assessment techniques that we discuss in appendix A.

This appendix sets out our findings and views on each sub-category of capex. The structure of this appendix is:

- Section B.1: alternative estimate
- Section B.2: forecast augex
- Section B.3: forecast customer connections capex, including capital contributions
- Section B.4: forecast repex
- Section B.5: forecast bushfire safety capex
- Section B.6: forecast capitalised overheads
- Section B.7: forecast non-network capex.

In each of these sections, we examine sub-categories of capex which we include in our alternative estimate. For each such sub-category, we explain why we are satisfied the amount of capex that we include in our alternative estimate reasonably reflects the capex criteria.

B.1 Alternative estimate

Having examined SA Power Networks' proposal, we formed a view on our alternative estimate of the capex required to reasonably reflect the capex criteria. Our alternative estimate is based on our assessment techniques, explained in section 6.3 and appendix A. Our weighting of each of these techniques, and our response to SA Power Networks' submissions on the weighting that should be given to particular techniques, is set out under the capex drivers in this appendix B.

We are satisfied that our alternative estimate reasonably reflects the capex criteria.

B.2 Forecast augex

Our estimate of required augex for SA Power Networks for the 2015– 20 regulatory control period in this final decision is $481.1 million ($2014–15).

In our preliminary decision, we did not accept SA Power Networks initial proposed augex of $839.4 million ($2014–15) and instead included an amount of $463 million ($2014–15) in our alternative estimate. In coming to our view, we considered each augex component as proposed by SA Power Networks and formed a view on whether it reasonably reflected the capex criteria. As part of our analysis, we applied:

- trend analysis, comparing the proposed augex (and its components) with historic expenditure levels, taking into account changes in demand, network capacity, and security, safety and reliability obligations to assess whether the forecast is within a reasonable range to allow SA Power Networks to meet expected demand, and comply with relevant regulatory obligations[68]
- an engineering and economic review of major programs and projects proposed by SA Power Networks, drawing upon expert consultants (where relevant) and engineering and other technical expertise within the AER.

In its revised proposal, SA Power Networks proposed $592.1 million ($2014–15) in augex. As per its initial proposal, SA Power Networks' revised augex forecast was comprised of a number of different components, each of which has a different driver for augmentation. In its revised proposal, SA Power Networks responded to our preliminary decision on each augex component.

The primary differences between SA Power Networks’ original proposal and its revised proposal for forecast augex are:

- reduced augex for bushfire mitigation
- reduced augex for network monitoring, and
- removed augex for road safety.

In this final decision, we have considered each augex component as proposed by SA Power Networks and formed a view on whether it reasonably reflects the capex criteria. We have focused our analysis on the main differences between SA Power Networks’ revised proposal and our preliminary decision. We use the same assessment techniques as per our preliminary decision, including drawing upon engineering and other technical expertise within the AER.

Table B.1 sets out our final decision for each of SA Power Networks' proposed augex components (including a comparison to our preliminary decision and SA Power

68 We used the augex model to generate trends in asset utilisation, to assess SA Power Networks' need for demand-related network augmentation.

Networks’ revised augex). SA Power Networks' revised proposal and our detailed findings for each component are set out in detail in sections B.2.1 to B.2.5.

Table B.1 SA Power Networks' augex forecast components and AER preliminary decision ($2014–15 million, excluding overheads)

Component	Preliminary decision	Revised proposal capex	AER final decision	AER reasons
Demand and power quality	311.4	312.4	312.4	We include SA Power Networks’ proposed capex for demand and power quality augex in our alternative estimate. This is consistent with our preliminary decision. We respond to stakeholder submissions on this capex in section B.2.5.
Bushfire mitigation and road safety	21.1	103.4	21.3	We have not included SA Power Networks proposed capex for bushfire mitigation and other safety projects in our alternative estimate (except for its core safety program). This is because we are satisfied that SA Power Networks is currently complying and is expected to continue to meet its regulatory safety obligations over the 2015–20 period. SA Power Networks will not require additional capex for bushfire mitigation to maintain safety and meet its obligations. Our reasons are set out in section B.2.1 and appendix B.5.
Kangaroo Island undersea cable	45.2	45.6	45.6	We include SA Power Networks’ proposed capex for the Kangaroo Island undersea cable in our alternative estimate. This is consistent with our preliminary decision. We respond to stakeholder submissions on this capex in section B.2.5.
Reliability	27.0	56.4	43.6	We include SA Power Networks’ proposed capex to maintain network reliability and harden the network against severe weather events in our alternative estimate. However, we do not include the remaining capex to improve network reliability because it does not reflect the capex criteria. Our reasons are set out in section B.2.2.
Network control	0.0	25.3	9.1	We include SA Power Networks’ proposed capex to install SCADA in some of its rural substations in our alternative estimate. However, we do not include the remaining capex to install SCADA on network switches because it does not reflect the capex criteria. Our reasons are set out in section B.2.3.
Network monitoring	0.0	5.8	2.6	We include SA Power Networks’ proposed capex to install demand monitors in rural substations in our alternative estimate. However, we do not include SA Power Networks’ remaining capex for LV network monitoring because it is not reflect the capex criteria. Our reasons are set out in section B.2.4.
Environmental	14.9	14.9	14.9	We include SA Power Networks revised proposal for environmental capex in our alternative estimate. This is consistent with our preliminary decision.
Other — PLEC	44.3	44.5	44.5	We include SA Power Networks revised capex to underground power lines as part of the Power Line Environment Committee (PLEC) in our alternative estimate. This is consistent with our preliminary decision.

Component	Preliminary decision	Revised proposal capex	AER final decision	AER reasons
Total	463.6	592.1	481.1	

Source: AER analysis, SA Power Networks' reset RIN; SA Power Networks' response to AER SAPN 054 .

SA Power Networks slightly increased the proposed capex for its augex projects based on proposed changes in labour cost escalators between its original and revised proposals.[69] Our decision on SA Power Networks' labour cost escalators is considered separately.

Table sets out SA Power Networks' revised augex proposal and our final alternative estimate for each year of the 2015–20 regulatory control period.

Table B.2 AER's alternative estimate of augex ($2014–2015 million, excluding overheads)

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Revised proposal	121.9	138.6	132.2	118.1	98.2	609.1
AER alternative estimate	98.9	112.5	107.3	95.8	79.7	494.1
Difference	-18.9%	-18.9%	-18.9%	-18.9%	-18.9%	-18.9%

Source: AER analysis, SA Power Networks' reset RIN, SA Power Networks' response to AER SAPN 005.

Note: To reach our alternative estimate for each year we first calculated our total estimate for the 2015–20 period based on our assessment of the individual augex components within SA Power Networks' revised regulatory proposal. We then allocated our total alternative estimate across years based on SA Power Networks' allocations in the revised regulatory proposal. SA Power Networks' revised reset RIN contains a negative balancing item, part of which is related to augex. As set out in section 6.5 of Attachment 6, we have allocated this balancing item to driver categories for the purpose of our assessment. After accounting for this balancing item, our alternative estimate of augex is $481.1 million ($2014–15).

The remainder of this appendix sets out SA Power Networks' revised proposal and our final decision for:

- bushfire mitigation and other safety capex (section B.2.1 and appendix B.5)
- reliability augex (section B.2.2)
- network control augex (section B.2.3)
- network monitoring augex (section B.2.4)
- the remaining components of SA Power Networks augex proposal, which includes capex that we previously accepted in our preliminary decision (section B.2.5).

69 SA Power Networks' response to AER SAPN 054, p. 3.

B.2.1 Bushfire mitigation and other safety capex

SA Power Networks proposed $103.4 million for bushfire mitigation and other safety capex. This includes:

- $21.3 million for SA Power Networks 'core safety' program
- $82.2 million for bushfire-safety related capex.

In our preliminary decision we accepted SA Power Networks core safety program of $21.3 million ($2014–15). This safety program included substation fencing and security, substation earthing, substation lighting, and CBD fault level control.[70] SA Power Networks accepted our preliminary determination in relation to this program and has incorporated the core safety program in its revised proposal.[71] We have not changed our position in relation to the core safety program in this final decision.

SA Power Networks' proposed a combined $82.2 million for bushfire-safety related capex. This includes:

- $38.9 million for bushfire mitigation
- $25.6 million for a 'bushfire safer places' program
- $17.7 million for a 'back up protection' program.

Our detailed assessment of this capex is set out in appendix B.5. For the reasons set out in that appendix, we are not satisfied that this capex reasonably reflects the capex criteria.

Road safety

In our preliminary determination, we did not accept SA Power Network's proposed $74.2 million ($2014–15) to underground power lines at select traffic intersections and roads that are deemed as high risk for road safety. We considered the proposed program was not required to maintain the safety or reliability of SA Power Networks' distribution system and did not reasonably reflect the costs that a prudent operator, acting efficiently, would require to achieve the capex objectives.[72] This finding was supported by the CCP and the Energy Consumers Coalition of South Australia (ECCSA).[73]

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70 SA Power Networks, *Regulatory Proposal 2015-20*, 31 October 2014, p. 225.

71 SA Power Networks, *Revised Regulatory Proposal 2015–20*, April 2015, p.73.

72 AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, pp. 59–60.

73 Consumer Challenge Panel #2, *Advice to AER: AER's Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks' Revised Regulatory Proposal*, August 2015, pp. 67–68; Energy Consumers Coalition of South Australia, ECCSA response to AER preliminary decision, June 2015, p. 22.

SA Power Networks accepted our preliminary determination in relation to this program and did not incorporate the road safety program into its revised proposal.[74] Accordingly, we include no capex forecast for the original road safety program in our alternative estimate in this final decision.

B.2.2 Reliability capex

We include $43.6 million (excluding overheads) in our alternative estimate for reliability augex. We consider that this reflects the efficient amount for SA Power Networks to meet its reliability obligations and maintain reliability over the 2015–20 regulatory control period.

SA Power Networks' original proposal forecast $56.4 million in reliability augex. This included:[75]

- $27 million to maintain historical average levels of reliability performance as required under reliability targets set by the Essential Services Commission of South Australia (ESCoSA)
- $16.3 million to ‘harden the network’ to mitigate the impact of severe weather events by improving the durability of 78 powerlines that are susceptible to storms and lightning.
- $8.1 million to improve the performance of 24 high voltage feeders that consistently perform below SA Power Networks' reliability targets (i.e. worst performing feeders) during lightning and storms
- $2.3 million to improve network infrastructure to the Hawker and Elliston communities in response to customer concerns
- $2.7 million to conduct a trial of micro-grid to improve the reliability of SA Power Networks' worst performing feeder.

In our preliminary decision, we accepted that the proposed $27 million reasonably reflected an efficient amount to satisfy SA Power Networks' reliability targets set by ESCoSA to maintain network reliability over the 2015–20 period. This was because SA Power Networks’ reliability targets are based on average reliability experienced over the 2010–15 period and SA Power Networks’ proposed capex aligns with the historic amount it spent on maintaining reliability capex over the 2010–15 period.[76]

However we did not accept the additional capex to improve network reliability. This was for three primary reasons:[77]

- We were not satisfied based on the information provided by SA Power Networks that this capex would not otherwise be funded through the Service Target

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74 SA Power Networks, *Revised Regulatory Proposal 2015–20*, April 2015, p.74.
75 SA Power Networks, *Regulatory Proposal 2015-20*, 31 October 2014, pp. 218-219.
76 AER, *Preliminary decision SA Power Networks distribution determination*, Attachment 6, April 2015, pp. 74-76.
77 AER, *Preliminary decision SA Power Networks distribution determination*, Attachment 6, April 2015, pp. 76-82.

Performance Incentive Scheme (STPIS) over the 2015–20 period. This was because it was unclear whether SA Power Networks' modelling of the impact of the reliability improvement programs on STPIS took into the account the new definition of major event days (MEDs).

- We were not satisfied that the proposed capex was required to maintain network reliability.
- We were not satisfied that there was a positive cost-benefit from undertaking these programs in the 2015–20 period based on SA Power Networks' analysis.

Revised proposal

SA Power Networks' revised proposal includes $56.4 million in reliability augex. SA Power Networks did not accept our preliminary decision and continued to propose the reliability improvement programs.[78]

In its revised proposal, SA Power Networks provided additional cost-benefit analysis of the individual reliability improvement programs and analysis of the proposed impact on reliability.[79] We consider these analyses in our assessment below.

As set out in Table (which is taken from SA Power Networks revised proposal), overall network reliability is expected to improve from the four reliability programs in terms of both frequency and duration of outages as experienced by customers. However, when major events days (MEDs) are excluded, reliability is actually expected to decrease due to the hardening the network program.

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[78] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p.110.

[79] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, Attachments G6, G.7, G.8 and G.9

Table B.3 Proposed impact on reliability from SA Power Networks reliability improvement capex

Table 7.18: Combined reliability programs impact on SAIDI and SAIFI

Reliability improvement pa	Hardening the network	Low reliability feeders	Remote communities	Micro-grid	Total
Overall SAIDI (minutes)	16.89	0.94	0.35	0.12	**18.31**
Overall SAIFI (number)	0.074	0.003	0.001	0.001	**0.079**
Underlying SAIDI (excl MEDs) (minutes)	(1.48)	0.68	0.32	0.12	**(0.36)**
Underlying SAIFI (excl MEDs) (number)	0.004	0.003	0.001	0.001	**0.008**

Source: SA Power Networks revised regulatory proposal, p. 122.

This shows that SA Power Networks expects that the combined impact of these four reliability programs will decrease reliability (in terms of number of minutes off supply) when major event days are excluded from reliability calculations.[80] This is relevant because the reliability targets set under the STPIS exclude the impact of major event days (see attachment 11 for more detail about this scheme). Because of this, SA Power Networks submitted that the implementing these programs will likely lead to small penalties under the STPIS framework.[81]

Our preliminary decision stated it was unclear whether SA Power Networks had correctly accounted for the new method for calculating major event days under the STPIS (the standard IEEE exclusion method), as opposed to adopting the current Box-Cox methodology. In its revised proposal, SA Power Networks confirmed that its modelling of the reliability improvement programs is based on the standard IEEE method of calculating major event days.[82]

80 This is because the hardening the network program will improve reliability outcomes so that several major event days will no longer affect reliability performance; however reliability will not improve to the average.

81 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 122.

82 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 121.

SA Power Network submitted these reliability improvement programs were developed in response to its customer engagement program.[83] It submitted that:

> Our robust and representative customer engagement program identified that 88% of customers supported further protecting the network to harden against lightning and storms, with 91% of metropolitan and regional customers supporting further protecting the network. This demonstrates that our customers want further protection of the network.[84]

In its revised proposal, SA Power Networks submitted that we did not give sufficient weight to its customer engagement program in our preliminary decision.[85] SA Power Networks also submitted that we are required to have regard to these views of customers under the capex factors in the NER. In particular, it submitted that in assessing the expenditure required to comply with the capex objectives and criteria, we are required to have regard to:

> the extent to which the forecast includes expenditure to address the concerns of electricity consumers identified by the DNSP in the course of its engagement with electricity consumers.[86]

SA Power Networks stated that we must treat the consideration of customer concerns (and the extent to which forecast expenditure addresses them) as a central element of our decision.[87] SA Power Networks also submitted that we gave more weight to a number of submissions which were critical of its proposal, as opposed to the views of its customers. [88] We consider this below.

AER position

We consider an amount of $43.6 million (excluding overheads) reflects a prudent and efficient amount for SA Power Networks to satisfy the capex objectives in relation to reliability. We have included this amount in our alternative estimate. This is a reduction of about 22 per cent on SA Power Networks' revised proposal.

Under the NER, we must not accept SA Power Networks forecast capex unless we are satisfied that it reasonably reflects each of the capex criteria. The capex criteria are concerned with the efficient costs a prudent operator would require to achieve the capex objectives. The capex objectives state that SA Power Networks must include capex to comply with relevant reliability obligations associated with providing standard control services and, to the extent there are no such requirements in relation to reliability, maintain the reliability of the distribution system and supply of standard control services.[89]

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83 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 111.

84 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 116.

85 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 115.

86 NER, cl. 6.5.7(e)(5A).

87 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 115.

88 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 115.

89 NER, cl. 6.5.7(a).

We have considered whether SA Power Networks' proposed reliability capex reasonably reflects the capex criteria required to achieve the capex objective relating to reliability. Based on our assessment, our position is that:

- the proposed $27 million reflects the prudent and efficient amount for SA Power Networks to meet its reliability obligations set by ESCOSA
- the proposed $16.6 million to 'harden the network' reflects the prudent and efficient amount for SA Power Networks to maintain network reliability
- the remaining $13.3 million for reliability improvement programs do not reasonably reflect the capex criteria and are not required to maintain network reliability or satisfy regulatory obligations.

As such, we have included $43.6 million in our alternative estimate. This reflects SA Power Networks' proposed capex to meet ESCOSA obligations and to invest in hardening the network.

The Energy Consumers Coalition of South Australia (ECCSA) submitted that any improvement in reliability should be funded from STPIS rewards achieved by increasing reliability.[90] While we agree that reliability improvement programs should usually be funded through the STPIS, SA Power Networks' analysis suggested that it will unlikely receive STPIS rewards from investing in these programs.[91] We are satisfied that SA Power Networks has correctly modelled the impact of implementing the reliability improvement programs, and that it has used the new method for calculating the impact of the new definition of major event days. This means that SA Power Networks may not be able to rely on the STPIS to fund any of its reliability capex programs (including the hardening the network program).

The remainder of this section considers in more detail:

- SA Power Networks' proposed capex to comply with its regulatory obligations relating to reliability
- SA Power Networks' proposed capex to harden the network
- SA Power Networks' other augex for reliability improvement programs
- SA Power Networks' statements in its revised proposal about its customer engagement program relating to reliability augex.

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90 Energy Consumers Coalition of South Australia, submission to preliminary decision, pp. 8, 20.

91 As set out in Table , the impact of the hardening the network program is that SA Power Networks' reliability performance will likely decrease slightly when major event days are excluded. This is because the hardening the network program will mean that four major event days would no longer be classified as major event days, and therefore the reliability of the feeders can be considered under normal weather conditions. However, the reliability of these powerlines under weather conditions is forecast to be slightly less than the network average. See SA Power Networks, *response to AER SAPN020*, 9 February 2015, p. 2.

Capex to comply with relevant reliability obligations

SA Power Networks faces three regulatory obligations relating to reliability as set out in ESCOSA's service standards. It must:[92]

- use best endeavours to meet specified reliability targets during normal weather events (excluding major event days such as severe storms)
- monitor and report on reliability performance during major event days
- monitor and report on the reliability performance of the worst performing five per cent of feeders, and report on planned action to improve the reliability of each feeder.

As set out in our preliminary decision, we consider that SA Power Networks' proposed $27 million reflects a prudent and efficient amount to satisfy its obligation to meet reliability targets during normal weather events. This is for the reasons set out in the preliminary decision and summarised above.[93] We maintain this position and will include this amount of capex in our alternative estimate.

This is the only proposed reliability capex that we consider is required to comply with a regulatory obligation relating to reliability. SA Power Networks' proposal noted its obligations to monitor and report on network reliability performance during major event days and its worst performing feeders, suggesting that these obligations require it to incur capex over the 2015–20 period.[94]

While we accept that these obligations may equate to a regulatory obligation in relation to reliability (for the purposes of the capex objectives), compliance with these obligations does not require SA Power Networks to meet reliability performance outcomes or perform capital works to address poor performing feeders. Similarly, SA Power Networks is required to report on planned action to improve the reliability of its worst performing feeders. However this also does not require SA Power Networks to actually remediate these feeders and meet particular reliability outcomes.

This means that SA Power Networks' proposed capex to harden the network and improve worst performing feeders is not required to achieve the capex objectives to comply with relevant regulatory obligations. Because of this, we then look to whether these reliability capex programs are required to achieve the capex objective to maintain reliability. As set out below, we include SA Power Networks proposed hardening the network capex in our alternative estimate because we consider it reasonably reflects the efficient costs a prudent operator would require to comply with the capex objective to maintain reliability.

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92 ESCOSA, *SA Power Networks jurisdictional service standards for the 2015-2020 regulatory period*, October 2014.

93 AER, *Preliminary decision SA Power Networks distribution determination*, Attachment 6, April 2015, pp. 74-76.

94 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, pp. 111-112.

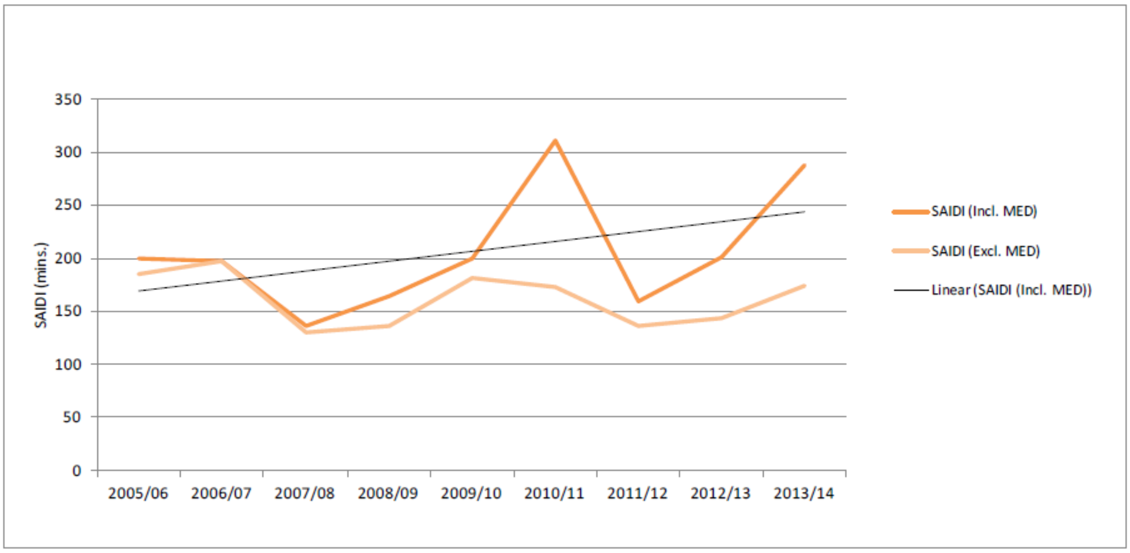
Capex for hardening the network

SA Power Networks proposed $16.6 million to 'harden the network' to keep more customers connected during major weather events. We are satisfied this forecast reasonably reflects the capex criteria because it:

- is reasonably required to maintain reliability on its network (as discussed in detail below), and
- reflects prudent and efficient costs because it is supported by appropriate cost-benefit analysis using the value of customer reliability (VCR).

Figure below (which is taken from the revised proposal) shows that SA Power Networks' overall reliability, including the impact of major weather events, decreased on average between 2005–06 and 2013–14 (shown by an increase in the duration of network outages as measured by SAIDI). SA Power Networks submitted that the cause of recent supply interruptions have been several major wind events and lightning events in 2010–11, 2012–13 and 2013–14.[95] The reliability impact of these events was significantly greater than SA Power Networks experienced during previous major weather events.

Figure B.1 SA Power Networks reliability between 2005–06 and 2013–14 (including and excluding major event days)



Source: SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, Attachment G.6.

SA Power Networks submitted that the Bureau of Meteorology predicts the trend in severe weather events is likely to continue due to observable trends in rising

95 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, Attachment G.6, pp. 6-7.

temperatures and increased thunderstorm and lighting activity.[96] SA Power Networks stated that it expects that overall reliability performance will continue to deteriorate unless the network's performance during severe weather events is addressed.[97]

The SA Government's submission on the regulatory proposal provided analysis from ESCoSA's annual reporting on network reliability performance which showed that the average number of interruptions caused by weather has remained relatively stable from 2000, with a spike in 2013–14.[98] It therefore questioned the need for an increase of expenditure for reliability against weather events by more than double from the previous regulatory period.[99]

It is difficult to determine whether the recent impacts of severe weather on reliability are isolated events or demonstrate an expected trend in reliability deterioration. However, it is clear that recent weather events (e.g. storms and lightning) are correlated with significant decreases in reliability. Taking into account the Bureau of Meteorology's predictions that the recent trends in severe weather events may continue, we accept that there is a risk that overall network reliability could deteriorate further over the 2015–20 period due to the impact of major weather events. We therefore consider that capex for hardening the network may reasonably be required to maintain overall network reliability over the 2015–20 period because, without this program, overall network reliability could deteriorate.[100]

SA Power Networks supported this reliability improvement program with cost-benefit analysis using estimates of VCR. SA Power Networks modelled the impact of this program based on the historic performance of its network during the 2010–14 period. SA Power Networks concludes that had the improvements been in place during the 2010–14 period, the benefits to customers (in terms of the cost of reliability using VCR) would exceed the cost of the program within two years.[101] This provides evidence that the cost of the program is efficient.

In addition, the results of SA Power Networks customer engagement program suggest that customers are supportive of hardening the network against lightning and storms.[102]

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[96] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, Attachment G.6, p. 8; Bureau of Meteorology, Climate extremes analysis for South Australian Power Networks operations, p. 5.

[97] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 111.

[98] SA Government submission to SA Power Networks' regulatory proposal, p. 7.

[99] SA Government submission to SA Power Networks' regulatory proposal, pp. 7-8.

[100] SA Power Networks also submitted that the Bureau of Meteorology's predictions for increases in severe weather events means that more fires will be started by SA Power Networks' network over 2015–20. On this basis, it proposed additional capex for bushfire mitigation. However, unlike our observations about the positive correlation between severe weather and reliability, we observe that the number of fire starts on SA Power Networks' network has actually decreased over the recent period, when a greater number of severe weather events occurred. We also conclude that SA Power Networks' currently satisfies it obligations relating to the safety of its network.

[101] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 116.

[102] For example, see SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, Attachment 6.5 (Deloitte SAPN Online Consumer Survey Report), pp. 7 and 31.

In particular, between 84 and 88 per cent of customers surveyed indicated support for SA Power Networks proposed initiative to harden the network.[103]

As set out further below, we are generally not satisfied that these customer views, on their own, provide support for the prudency and efficiency of this capex. However, we consider that, in combination, SA Power Networks' cost-benefit analysis and the customer engagement results demonstrate that the cost of the hardening the network program is also prudent and efficient. On this basis, we have included capex for hardening the network in our alternative estimate.

However, the Consumer Panel Challenge (CCP) questioned whether this capex is required:

> Clearly, there is much that SA Power Networks can be proud of in its ability to manage the challenges of weather related supply interruptions. However, this does not seem to be a basis for providing SA Power Networks with an additional allowance over and above the replacement and augmentation allowances approved by the AER in the preliminary determination.[104]
>
> …
>
> … nothing prevents SA Power Networks undertaking additional hardening of its network systems and, for instance, the increased replacement capex allowance provides funding for SA Power Networks to do so if it chooses to prioritise this activity. SA Power Networks' CE program suggests that consumers have a preference for this, however, it does not automatically mean that acting on that preference requires additional funding rather than simply prioritisation.[105]

We agree with the CCP that SA Power Networks should generally prioritise its capital works to most efficiently maintain network reliability. However, the drivers of asset replacement (e.g. asset condition) and demand-driven augmentation (e.g. network utilisation and forecast demand) capex are different from the hardening the network program, and should be considered on their own merits. In practice, if SA Power Networks is able to re-prioritise its allowed capex more efficiently, then these benefits will be shared with customers through the capital expenditure sharing scheme.

Capex for other reliability improvement programs

SA Power Networks proposed an additional $13.3 million to improve the reliability of rural feeders that experienced low reliability over 2010–15. This includes:

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[103] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, Attachment 6.5 (Deloitte SAPN Online Consumer Survey Report), p. 31.

[104] Ms Bev Hughson CCP2, *Advice to the AER: AER's Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks' Revised Regulatory Proposal*, August 2015, p. 76.

[105] Ms Bev Hughson CCP2, *Advice to the AER: AER's Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks' Revised Regulatory Proposal*, August 2015, p. 78.

- $8.1 million to improve the performance of 24 high voltage feeders that consistently perform below SA Power Networks' reliability targets (i.e. worst performing feeders) during lightning and storms
- $2.3 million to improve network infrastructure to the Hawker and Elliston communities
- $2.7 million to conduct a trial of micro-grid to improve the reliability of SA Power Networks' worst performing feeder.

For these programs, SA Power Networks proposed similar reliability solutions to the hardening the network program (except for the micro-grid trial).[106]

The capex for the other programs are not aimed at improving reliability during major weather events. Rather they are aimed at improving the reliability of specified feeders that have experienced lower than average reliability in the 2010–15 period. While SA Power Networks proposed to augment these feeders, SA Power Networks has not submitted that it will be unable to maintain overall network reliability without augmenting these feeders.

On this basis, we do not consider that the proposed capex for these programs is required to achieve the capex objective to maintain reliability of the network. This suggests that we should not include this capex in our alternative estimate. However, we have also considered whether the capex may reflect the capex criteria (in particular whether the proposed costs are prudent and efficient).

The CCP submitted that:

> The AER not accept SA Power Networks' proposed additional capex on low reliability distribution feeders (LRDF). There is no evidence that current expenditure allowances have been insufficient to progressively address LRDFs or have led to a sustained decline in performance; nor has there been a directive from ESCoSA to improve performance.[107]

SA Power Networks' revised proposal also provided cost-benefit analysis of these programs using VCR. SA Power Networks stated that:

- The cost-benefit analysis of the low reliability feeders capex is neutral. The present value of the capital investment required to implement the program exceeds the present value of the expected benefits by $0.1 million.[108]
- The cost-benefit analysis of the Hawker-Elliston capex is negative. The present value of the capital investment required to implement the program exceeds the present value of the expected benefits by $1.7 million.[109] SA Power Networks

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106 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 112.

107 Ms Bev Hughson CCP2, *Advice to the AER: AER's Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks' Revised Regulatory Proposal*, August 2015, p. 80.

108 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, pp. 117-118.

109 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 119.

stated that this is because of the small number of customers being targeted and the radial nature of their supply.[110]

- The cost-benefit analysis of the micro grid trial is negative. The present value of the capital investment required to implement the program exceeds the present value of the expected benefits by $1.7 million.[111] This is calculated based on assuming that projected STPIS benefit from the trial is a reasonable surrogate for the value to customers of the increased reliability.[112]

SA Power Networks submitted that, while these capex may not be supported by financial cost-benefit alone, it is unacceptable for customers in these areas to be disadvantaged by reliability levels below regional targets set by ESCOSA.[113] These capex programs are proposed primarily on the basis of SA Power Networks' customer engagement program and views of customers in regional areas. This is supported by submissions to the revised proposal from local regional areas:

- The Wakefield Regional Council submitted that it has four of the 24 worst performing feeders in South Australia and there are significant outages across these four lines. It submitted that outages make it extremely difficult for its rural community to undertake their business. The Council's submission sought commitment to ensure the community is not disadvantaged through a lack of focus on maintenance and upgrade. [114]
- The District Council of Elliston submitted that low reliability performance in the Elliston community disadvantages many of council's remote rural people who rely on receiving a supply of adequate and quality power via a feeder line from the Polda substation. The council submitted that a positive result to implement the SA Power Networks' project will see a great reduction of identified risks to the Elliston area especially during extreme weather events.[115]
- The Flinders Ranges Council submitted that it supported SA Power Networks' plans to upgrade the power lines supplying Hawker to better protect them against storms and other failures. It submitted that a key reason is that improved electricity reliability is critical for Hawker to maintain essential services, schools and hospitals that the local residents rely on, and drive tourism.[116]

We recognise that there is support for these capex programs from specific regional stakeholders and SA Power Networks' customer engagement program suggested that the majority of surveyed customers support protecting the network against severe weather. Having said that, the results of SA Power Networks' customer engagement program suggested that customers were only supportive of hardening the network

110 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 119.
111 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 121.
112 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 121.
113 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, pp. 118 and 119.
114 Wakefield Regional Council, *SA Power Networks Regulatory Proposal*, 24 July 2015, p. 1.
115 The district council of Elliston, *RE: SA Power Networks – Revised Regulatory Proposal*, 17 July 2015, pp. 1-2.
116 The Flinders Ranges Council , *Re: reliability of electricity in Hawker, South Australia*, 16 July 2015, pp. 1-2.

against lightning and storms.[117] It is not clear from SA Power Networks' survey results whether this support extend to more specific programs such as capex for low reliable feeders and remote communities.

More importantly, SA Power Networks' customers did not provide views on the proposed costs of these programs and their willingness-to-pay for improvements to specific regional areas. Unlike for its bushfire and road safety proposals, SA Power Networks did not conduct any willingness-to-pay survey and analysis for its specific reliability improvement proposals. This is supported by the submission from the South Australian Council of Social Service which states that:

> … SA Power Networks' WTP work was only narrowly focussed on bushfire and traffic blackspot issues rather than reliability issues per se. Thus it provides no real support for increased spending initiatives related to reliability. [118]

SA Power Networks own cost-benefit analysis showed that the cost of these measures can be quite prohibitive as they exceed the expected benefits. ESCoSA also noted that its reliability targets exclude major event days because it would be very difficult (and prohibitively expensive) to design an electricity distribution network to withstand all severe weather events.[119] While these additional reliability programs are not designed to address the impact of severe weather events, the actual augmentation SA Power Networks proposed for these feeders are similar to the hardening the network program.[120]

In relation to low reliability feeders, ESCoSA also submitted that remediation of feeders depends on the proposed cost of doing so:

> Remediation of low reliability distribution feeders is dependent, to a degree, on the extent of the benefit gained relative to the cost of the work. Understandably there will be situations where the costs far outweigh the benefits. There will continue to be parts of the network with lower reliability; however, SA Power Networks should ensure that reliability in these areas does not decline over time. To some extent, GSL payments serve to balance the impact of poor performance for the poorest served customers.[121]

The SA Government similarly submitted that we must have regard to the findings of SA Power Networks' consumer engagement within the context of the broader regulatory requirements. In regard to reliability, it stated that this framework includes the setting of network reliability standards by ESOCSA, the AER's STPIS and the Guaranteed Service Level Scheme (GSL). It further stated that a trade-off exists between electricity prices and reliability levels, and as the regulator responsible for the setting of reliability

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117 For example, see SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, Attachment 6.5 (Deloitte SAPN Online Consumer Survey Report), pp. 7 and 31.

118 South Australian Council of Social Service, submission to SA Power Networks' revised proposal, p.14.

119 ESCoSA, *Fact Sheet: SA Power Networks Jurisdictional Service Standards for the 2015–20 Regulatory Period, Implementation of Service Standard Targets*, October 2014, p. 3.

120 SA Power Networks, *Revised Regulatory Proposal 2015–20*, April 2015, p. 112.

121 ESCoSA, Performance of SA Power Networks, Report 2, 2013-14, p. 7.

standards, ESCOSA has determined the acceptable reliability levels in South Australia using an informed and transparent determination process.[122]

We consider that these views support our position that the proposed costs of these reliability improvements programs (excluding hardening the network) are not prudent and efficient. On this basis (and our previous conclusions that the capex is not required to comply with the capex objective to maintain reliability), we are not satisfied that the proposed $13.3 million capex reasonably reflects the capex criteria. For this reasons, we have not included the proposed $13.3 million capex for these programs in our alternative estimate.

Customer engagement program

This section provides responses to SA Power Networks' statements in its revised proposal about how our preliminary decision had regard to its customer engagement program.

In its revised proposal, SA Power Networks submitted that we did not give weight to its customer engagement program in our preliminary decision.[123] It also stated that we instead gave weight to a limited number of submissions to the regulatory proposal that were critical of the reliability capex proposals but which were unsubstantiated or were technically lacking.

SA Power Networks submitted that in assessing the expenditure required to comply with the NER capex objectives and criteria, we are required to have regard to:

> the extent to which the forecast includes expenditure to address the concerns of electricity consumers identified by the DNSP in the course of its engagement with electricity consumers[124]

Our preliminary decision to not accept the reliability improvement capex was based on the uncertainties about the application of the STPIS and the cost-benefit analysis. We have had regard to the views and concerns of customers (as contained in both SA Power Networks' customer engagement program and submissions to its regulatory proposals) in this final decision (as set out in the previous sections).

It is important to note that the test we apply is whether SA Power Networks' forecast capex reasonably reflects the capex criteria required to achieve the capex objectives. In deciding whether the capex reflects the capex criteria, we must have regard to, among other factors, the extent to which the distributor has included capex to address the concerns of electricity consumers, as identified in the course of its engagement with consumers. According to the relevant AEMC rule determination, this clause is intended to inform us about whether proposed capex is efficient:

122 The Government of South Australia, Minister for Mineral and Resources and Energy submission to SA Power Networks' revised proposal, p. 2.

123 SA Power Networks, *Revised Regulatory Proposal 2015–20*, April 2015, p. 115.

124 NER, cl. 6.5.7(e)(5A).

> What consumers want and are prepared to pay for, whether in terms of reliability or some other element, will assist in showing what is efficient. The more confident the AER can be that consumer's concerns have been taken into account, the more likely the AER could be satisfied that a proposal reflects efficient costs.[125]

Customer concerns can therefore inform us about whether the proposed costs of a project are efficient and reflect customers' willingness to pay for capital improvements. As set out above, where customer views show a consideration of the trade-offs between price and service outcomes, it will be more persuasive. However, the views of customers do not replace the capex objectives or the capex criteria themselves. For example, if we are not satisfied that proposed capex is required in order to achieve on or more of the capex objectives, even with strong consumer support we will not be satisfied that the proposed expenditure reasonably reflects the capex criteria.

In the overview of our final decision, we consider SA Power Networks overall customer engagement program and how it has been used to develop and support the regulatory proposal. We also discuss the ways in which customer views can give support to proposed expenditure within regulatory proposals.

B.2.3 Network control capex

SA Power Networks' revised proposal of $25.4 million ($2014–15) for network control capex is the same as its initial proposal. This comprises three projects to rollout Supervisory Control and Data Acquisition (SCADA) equipment:

- $9.1 million for SCADA to rural substations
- $7.9 million for SCADA to 33kV switches
- $8.4 million for SCADA to 11kV and 19 kV switches.

In our preliminary decision, we did not accept the proposed network control capex as we considered that it did not reasonably reflect the costs that a prudent operator, acting efficiently, would require to maintain service levels on the network. We considered that SA Power Networks did not provide sufficient evidence that proposed SCADA rollout is required in the 2015–20 regulatory control period to maintain service levels on the network and that there insufficient evidence that the capex satisfied a business case.[126] We made this decision based on our technical review of the three proposed programs. In its revised proposal, SA Power Networks provided additional information in support of the three capex projects.[127]

Under the NER, SA Power Networks must include in its proposal a total capex forecast that it considers is required in order to achieve the capex objectives. These include complying with all applicable regulatory requirements and obligations and, to the extent

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125 AEMC, *Economic Regulation of Network Service Providers, Final Rule Determination*, 29 November 2012, p. 101.

126 AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, p. 70.

127 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, Attachment G.10, p. 126.

that there are none, maintaining quality, reliability and security of supply. If this forecast capex is prudent and efficient, and is based on a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives, we must accept the forecast. However, if we are not satisfied that the total capex reasonably reflects these criteria, we must reject and substitute it with our own estimate. We have applied this same assessment framework to the network control capex component.

We have included an amount of $9.1 million (excluding overheads) in our alternative estimate. This is because:

- The proposed $9.1 million capex for SCADA to rural substations reflects the prudent and efficient costs to maintain reliability.
- The remaining proposed network control capex of $16.3 million is not required to maintain reliability and power quality performance on the network. We have already provided a sufficient amount of capex in our alternative estimate to allow SA Power Networks to maintain network reliability and power quality in the absence of additional SCADA equipment.

The reasons for our decisions are set out below.

SCADA to 11kV, 19kV and 11kV switches

SA Power Networks proposed $16.3 million to rollout SCADA to its 11kV, 19 kV, and 33kV switches. SA Power Networks submitted that it has limited supervisory control and monitoring of its 33kV sub-transmission network.[128] It also submitted that the SCADA rollout to its network switches is necessary because a significant number of switching devices are not SCADA compliant.[129]

In our preliminary decision, we were not satisfied that the proposed expenditure was necessary to maintain network service levels, and considered that SA Power Networks had not quantified the customer benefits of this program.[130] On this basis, we did not include the proposed amount in our alternative estimate of SA Power Networks' capex.

SA Power networks' revised proposal for this capex was the same as its initial proposal. SA Power Networks revised proposal stated that "the primary purpose of SCADA is to facilitate control and monitoring of existing assets, ensuring efficient asset and load management to maintain reliability and security of the network."[131] SA Power Networks also submitted that the benefits of rollout SCADA to its switches include:

- greater security of supply for customers and enabling the provision of actual data for planning and reporting purposes

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128 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 126.

129 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 129.

130 AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, pp. 70-73.

131 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 128.

- reduced length of power outages for customers because it enables network control operators to be automatically notified of outages and begin the process of remediation immediately
- managing projected increases in 'two-way power flows' from solar PV generation.[132]

SA Power Networks' Asset Management Plan 2.1.02 (Network Security and Control) sets out some of the specific benefits from the proposed capex: [133]

- meeting customer service standards
- faster fault detection
- reduced visits onsite to change device settings
- deferred augmentation through enhanced information for planners
- bushfire benefits
- faster outage restoration from changing settings remotely
- real-time accurate data to maximise and optimise ADMS functionality.

As a general position, we do not dispute that there are benefits to network automation and control, in particular for major feeders and critical assets. From a technical perspective, SCADA allows distributors to remotely control switches that can only currently be manually controlled which usually improve network service levels or achieves specific cost reductions. However, all the benefits of this program as set out in SA Power Networks' regulatory proposal and its supporting documentation relate to specific improvements in reliability, security and power quality.

SA Power Networks has not demonstrated that the additional capex proposed for SCADA to switches is necessary in order for it to maintain network service levels over the 2015–20 period. Given that the relevant capex objectives relate to maintaining network service levels (e.g. reliability, security, quality), this suggests that the capex for SCADA to switches is not required to achieve the capex objectives. However, we have also considered whether the capex may reflect the capex criteria (in particular whether the capex is prudent and efficient).

For this capex to be prudent and efficient, we need to be satisfied that the customer benefits of this capex outweigh the costs, and that the benefits can be linked to specific service outcomes (e.g. reliability, security or quality improvements). In our preliminary decision, we stated that SA Power Networks did not provide any supporting business case for its proposed capex.[134] SA Power Networks' revised proposal stated that all the

[132] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, pp.128-129.

[133] SA Power Networks, AMP 2.1.02, p. 14 and 17.

[134] AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, pp. 70-71

necessary information was provided in its original proposal within the attachment Asset Management Plan 2.1.02 (Network Security and Control).[135]

We have considered Asset Management Plan 2.1.02 and do not consider it shows that the suggested benefits of the capex outweigh the costs. The benefits presented by SA Power Networks in its revised regulatory proposal and supporting document are qualitative in nature and are not linked to specific service outcomes. In particular, SA Power Networks has not provided information to demonstrate that there are positive cost benefit trade-offs from:

- reduced visits onsite to change device settings
- deferred augmentation through enhanced information for planners
- bushfire benefits
- faster outage restoration from changing settings remotely
- provide real-time accurate data to maximise ADMS functionality.

This makes it difficult for us to be satisfied that the costs of the proposed SCADA to 11kV, 19kV, and 33kV switches reasonably reflect the efficient costs a prudent operator would require to achieve the capex objectives.

Importantly, we have otherwise provided SA Power Networks with capex to maintain reliability and quality in accordance with its regulatory obligations:

- As set out in section B.2.2, we have provided SA Power Networks with a sufficient amount to maintain network reliability in accordance with SA Power Networks' regulatory obligations. This capex is commensurate with the level of actual capex SA Power Networks spent on maintaining network performance during the last regulatory control period.
- As set out in sections B.2.5 (demand and power quality) and section B.2.4, we have provided SA Power Networks with a sufficient amount to maintain network power quality in the context of projected increases in solar PV generation.

In our preliminary decision, we also stated that the rollout of SCADA across the network was not necessarily an industry standard except where it can be shown there is a positive benefit to customers.[136] SA Power Networks' revised proposal stated that there are some network service providers in Australia that have over 80 per cent SCADA coverage, whereas SA Power Networks' SCADA coverage is currently under 50 per cent.[137] It stated that this is a good indicator that SCADA is now industry standard.

135 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 130.

136 AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, pp. 70-71.

137 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 129.

We do not dispute that SCADA is an industry standard equipment in providing centralised control and monitoring of network assets. However, the rollout of additional SCADA for SA Power Networks must be considered in light of the proposed costs and whether it is required to achieve the capex objectives. For the reasons set out in this section, we are not satisfied that SA Power Networks has demonstrated that the proposed costs reflect the efficient costs that a prudent operator would require to achieve the capex objectives.

SCADA to rural substations

SA Power Networks proposed $9.1 million to expand SCADA to rural substations as part of a program to rollout SCADA to 75 of SA Power Networks' rural substations by 2025.[138] SA Power Networks revised proposal submitted that:

> Given the ageing population of our assets, installing SCADA in country substations is essential in order to maintain the current levels of reliability and customer service. Conceptually, as assets age there is a greater probability of failure and SCADA is essential to identifying these failures through remote alarm annunciation. Furthermore, the metering information from these substations is essential to ensure that there is sufficient distribution capacity to supply increases in demand in the long term.[139]

Unlike its proposal for SCADA to switches, SA Power Networks submitted that rolling out SCADA to rural substations may be required to maintain network reliability and service levels in rural areas of its network where its assets are aging. As we stated above, we consider that the benefits of SCADA lie in improvements to network service levels or specific cost reductions. In areas of the network where reliability levels may otherwise be deteriorating, SCADA equipment may help SA Power Networks more efficiently maintain reliability through identifying faults and outages.

We next consider whether the proposed capex reflects the efficient costs that a prudent operator would incur to maintain reliability. As part of this, we have assessed whether the proposed costs outweigh benefit the proposed to customers.

SA Power Networks supported its initial proposal with a business case prepared by consultant DNV-GL that considered there is a positive benefit to customers to rollout SCADA to rural substations over the next 10 years. In our preliminary decision, we stated that it is difficult to be satisfied that the proposed benefits outlined in the business case are accurate and therefore whether the overall cost-benefit is positive for consumers.[140] On this basis, we did not include the proposed capex in our alternative estimate of SA Power Networks' capex.

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[138] SA Power Networks proposed to target 75 substations in bushfire risk areas. This appears to be a reduction from the 203 rural substations proposed in the initial proposal. SA Power Networks submitted that the primary driver of this program is to maintain network service levels, and is not bushfire mitigation. See SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 131.

[139] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p.126.

[140] AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, pp. 71-73.

SA Power Networks revised its business case in light of our preliminary decision and a review by its consultant DGA Consulting (previously DNV-GL).[141] The main revisions to the business case are:

- updating the VCR estimate used to calculate the cost to consumers of unserved energy to the Australian Energy Market Operator's (AEMO) current VCR
- reduced the benefits from automation by taking a more conservative approach to the costs of manual control (e.g. number of visits per substation, travel time and crew size).[142]

After adjusting for these changes in input assumptions, this revised business case shows that the capex to rollout SCADA to rural substations still has a positive net present value. However, this positive business case is not as strong as it was in the initial proposal.

We are satisfied with SA Power Networks' revisions to this business case and consider that the input assumptions are now more realistic and reasonable. On this basis, we accept the conclusion that there are positive benefits to consumers from rolling SCADA out to the rural substations identified within SA Power Networks proposed program.

We note that the business case is largely predicated on the value of improved customer reliability. This means that this capex may otherwise be funded through the STPIS regime. SA Power Networks submitted that the benefits of this program will have no impact on its SAIDI reliability performance and therefore no impact on STPIS payments. This is primarily because SCADA will result in faster identification of faults, but SAIDI performance is only measured from the time faults are identified rather than from when the outage occurs. This will mean that SAIDI performance measures will likely be unchanged. We are satisfied with these reasons and consider that the STPIS regime will unlikely provide funding for this project.

Our final decision is to accept $9.1 million ($2014–15) for installing SCADA to rural substations as we are satisfied that it reasonably reflects the capex criteria. In particular, there is likely an economic business case for this expenditure and this expenditure will otherwise not be funded through the STPIS.

B.2.4 Network monitoring capex

SA Power Networks' revised proposal included $5.8 million ($2014–15) capex to install network monitors on its network, excluding overheads. This is comprised of:

- $3.2 million to establish a monitoring trial and to install monitors targeted areas with high solar PV penetration to manage power quality issues associated with solar PV. SA Power Networks' revised proposal also included an opex step change and IT capex for this project (see attachment 7 and appendix B.7.3).

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141 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, Attachment G.10a.

142 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 130.

- $2.6 million to install HV load monitors in rural substations that do not currently have modern monitoring and control equipment installed (e.g. SCADA), and will not have any monitoring systems installed as part of its network control upgrades (as discussed in network control above).

In its initial proposal, SAPN proposed $35.1 million capex for network monitoring.[143] SA Power Networks submitted that this capex was necessary to allow it to maintain supply voltage levels on its network in areas that have high solar PV connections.

We did not accept this capex in our preliminary decision. Evidence showed that SA Power Networks had effectively managed power quality over 2010–15 in the presence of significant uptakes in solar PV connections, and we provided sufficient capex to maintain this performance over 2015–20.[144] We did not consider that SA Power Networks provided sufficient evidence to demonstrate that it would not be able to maintain supply voltage without additional capex for monitoring.[145] We also stated that we did not consider that solar generation is expected to increase to the extent forecast by SA Power Networks. See our preliminary decision for more detail on our reasoning.

We do not accept SA Power Networks' proposed $3.2 million capex for network monitoring and we have not included any capex for network monitoring in our alternative estimate. As set out below, we remain of the view that SA Power Networks has not provided sufficient evidence that capex for network monitoring is required to maintain reliability and other service levels in the 2015–20 regulatory control period.[146]

However, we have included $2.6 million (excluding overheads) in our alternative estimate for our final decision. We consider that this reflects the efficient amount for SA Power Networks to install HV load monitors in its rural substations to provide data to comply with its regulatory reporting obligations.

Revised proposal for network monitoring

SA Power Networks accepted our preliminary decision that it has been effective in managing the significant uptake in solar PV over 2010–15.[147] SA Power Networks stated that, while its modelling (undertaken by consultant PSC) suggests it will be able to correct voltage issues using established practices, in many cases it will be unable to

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143 This was comprised of $19.7 million to install monitors in rural areas of it network and $15.4 million to install monitors in smart meters at customer premises.

144 AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, pp. 44-48.

145 AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, pp. 44-48.

146 SA Power Networks informed us that this $3.2 million mistakenly includes $1.72 million of non-network IT, which is also included in the non-network IT capex proposal. Our decision to exclude the $3.2 million from our alternative estimate means that we have removed the impact of any double-counting from the revised proposal. See SA Power Networks response to AER SAPN 057, pp. 1-2.

147 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 73.

undertake remedial work without the capability to detect issues as they emerge.[148] Because of this, its revised proposal maintained that some form of network monitoring is required to maintain supply voltage levels.

SA Power Networks submitted new information relating to preliminary findings of a recent trial of voltage monitoring on its low voltage network.[149] SA Power Networks stated:

> This data indicates that there were quite widespread irregularities in LV network voltage in the trial area over the 12-month trial period, with one in five premises with monitoring detecting at least one voltage excursion at some point during the year. Only a small fraction of the actual voltage issues were revealed in customer complaints, however, with fewer than one in every 1,000 residents in the trial area reporting a voltage problem over the course of the year.
>
> …
>
> Although customers may not themselves be aware of voltage issues, it is clearly in their interest for us to be able to detect these issues, as there can be detrimental consequences to customers when we fail to maintain voltage within the range required by regulation.
>
> Although our analysis of this data is preliminary at this time, the evidence from the trial supports our view that active monitoring of voltage in the LV network is required, and that neither continued reliance on customer complaints as our primary means to detect voltage excursions is no longer prudent nor in customers' best interests.[150]

SA Power Networks also observed that AEMO forecasts a continued increased in residential solar PV connections, and a significant increase in small commercial solar PV connections, compared to AEMO's 2014 forecasts for South Australia.[151] It stated that "this supports the need for SA Power Networks to be able to efficiently manage the impact of 'two-way power flows' from solar PV generation."[152]

SA Power Networks' revised proposal retained its network monitoring program, but instead proposed a 'staged approach' that will defer the majority of the capex to the 2020–25 regulatory control period. The capex proposed for the 2015–20 period will include a monitoring trial in the Unley Park area of South Australia and install monitors in targeted areas with high solar PV penetration.[153]

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148 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 135.

149 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, Attachment G.12a .

150 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, Attachment G.12a, pp. 8-9.

151 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 130; AEMO, *2015 National Electricity Forecasting Report*, June 2015, p. 54.

152 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 130.

153 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 136.

In coming to this view, SA Power Networks considered that it is consistent with the view we adopted in our preliminary decision:

> …it is more prudent to adopt a 'wait and see' approach which will allow SA Power Networks to consider the actual quantum and impact of additional solar panel installation on power quality problems, and its ability to manage these problems using existing industry standard approaches.[154]

SA Power Networks' also stated the additional $2.6 million for HV monitors in rural substations is required to record actual load data for the purposes of completing regulatory information notices (RINs).[155] It stated that its economic benchmarking and category analysis RINs require it to collect, store and manage certain data, including the requirements to provide 'actual' demand data from the 2014–15 period.[156] SA Power Networks submitted that installing load monitors will facilitate meeting these requirements.[157]

AER position

Network monitoring capex

We recognise that solar PV will likely continue to play a large role in the South Australian energy market and this will have implications for power quality. As parts of the network experience higher amounts of solar rooftop generation, this can lead to voltage fluctuations on the network (in particular voltage spikes) that may need to be addressed by SA Power Networks. We recognised this in our preliminary decision.

AEMO forecasts that solar PV generation in South Australia will grow by approximately 70 per cent over the 2015–20 period, which continues the growth seen over the 2010–15 period.[158] While this is lower than the amount forecast by SA Power Networks (it forecasts a doubling of solar connections by 2020), this will still likely increase the number of network zones that have more than 50 per cent of connected premises with PV by 2019–20.[159] AEMO and SA Power Networks' forecasts of solar generation remain the same from the initial proposal, which we considered in the preliminary decision.

As noted above, SA Power Networks stated that its consultants modelling suggested that it is possible to remediate supply voltage issues using existing techniques (that is, without monitoring). However, SA Power Networks submitted that network monitoring is required in the first instance to identify voltage fluctuations so that major issues can be addressed (e.g. non-compliant voltage levels). While it is not specifically stated, SA

154 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 136.

155 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 133.

156 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 132.

157 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 133.

158 AEMO's medium growth forecasts for solar PV are an increase from approximately 900 GWh to 1,500 GWh over the period from 2014–15 to 2019–20. See AEMO, *2015 National Electricity Forecasting Report*, June 2015, p. 53.

159 SA Power Networks submitted that 57 substations had more than 50 per cent of connected premises with PV in in May 2015. See SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, Attachment G.12a, p. 6.

Power Networks appeared to argue that its existing practices — receiving customer complaints, thoroughly investigating those complaints, and taking action as appropriate to resolve voltage issues — is no longer the most prudent and efficient practice to the management of power quality complaints.

This is not consistent with SA Power Networks' historical performance and approach over 2010–15. As we stated in our preliminary decision, SA Power Networks was able to effectively identify and remediate voltage issues over the 2010–15 period in the presence of a significant increase in high-voltage complaints and issues. This was without network monitoring on its network. While SA Power Networks relied mostly on customer complaints and inquiries (rather than data from monitoring devices), this did not prevent it from maintaining supply voltage levels across the network.

The new information provided by SA Power Networks (from its monitoring trial) confirmed that there have been voltage fluctuations across its network in the past twelve months. However, it is not clear that this evidence suggested these fluctuations are in excess of historical levels and that SA Power Networks are unable detect these voltage issues and undertake remedial action in the absence of monitoring. Historically, SA Power Networks received around 1100 supply quality complaints annually from a customer base of over 840,000 customers, or 0.13 per cent of customers.[160] The recent trial data shows that only 9 out of 12400 customers in the trial area reported a quality of supply complaint, or 0.7 per cent. This trial data does not provide strong evidence in support of a claim that voltage compliance issues are increasing above historical levels.

SA Power Networks have reduced the amount of capex from its initial proposal. This is because it has proposed to defer the majority of its monitoring program to the 2020–25 period, and adopt a further trial and an initial targeted program in the 2015–20 period. While we recognise this reduction in capex, SA Power Networks are still fundamentally proposing a large scale monitoring program over a longer period of time. As we set out through this section, we are not satisfied that this is required for SA Power Networks to achieve the capex objectives to maintain network quality or comply with its obligations to maintain voltage levels within regulated levels.

As discussed within section B.2.5 (demand and power quality), we have provided SA Power Networks with a capex forecast that will allow it to maintain supply voltage consistent with its historical performance. We consider that this is sufficient for SA Power Networks to maintain the quality of its network without additional capex for network monitoring.

Compliance with RIN requirements

SA Power Networks also proposed $2.6 million to install HV monitors (or load loggers) in rural substations that do not currently have modern monitoring and control

160 For historical data on customer complaints about power quality issues, see SA Power Networks' response to AER SAPN015, 21 January 2015.

equipment installed (e.g. SCADA), and will not have any monitoring systems installed as part of its network control upgrades (as discussed in section B.2.3). SA Power Networks submitted in its revised proposal that monitoring of rural substations without SCADA is required to record actual demand data to meet its RIN reporting requirements.

SA Power Networks original monitoring capex proposal included $1.1 million for load data monitoring in rural substations.[161] The revised proposal increased this capex to $2.6 million because it no longer proposed the more substantial network monitoring program over the 2015–20 period. This means that more data loggers are required.

In SA Power Networks' 'smarter network strategy' attachment, it summarised its existing approach to recording demand data in rural areas:

> Currently there is very little remote monitoring and control of the distribution network outside of urban areas. In order to quantify the loads on the network in these areas and improve overall network visibility, SA Power Networks currently has a rotational program to conduct temporary testing that meters all country non-SCADA substations, country feeders and a prioritised portion of the 19kV SWER system (90 per annum) in rural areas every three years for a few months at a time.[162]

The recording and reporting of actual load data for regulatory purposes is not a new requirement. SA Power Networks has also not submitted that it has had any issues of complying with its existing requirements to report actual demand data. However, it is clear from the above that SA Power Networks currently uses temporary and sporadic testing to quantify the loads in rural parts of its network and has limited visibility of its actual load in these areas.

The value of installing load loggers in rural substations (that are currently without more sophisticated equipment such as SCADA) is that it will allow SA Power Networks to provide more accurate and disaggregated demand data for its regulatory reporting requirements. We note that we have provided SA Power Networks with capex to install SCADA equipment in a large number of its rural substations (as discussed in network control). When combined with the addition of HV load loggers in remaining rural substations, this should provide significantly improve SA Power Networks' capacity to record actual load data in rural areas of its network.

SA Power Networks did not provide information to support the proposed costs of data loggers. However the costs are significantly less than the monitors SA Power Networks proposed in the original proposal, and less than full SCADA rollout across all of its rural substations. We are therefore satisfied that an investment of $2.6 million in data loggers is likely to be an efficient cost for SA Power Networks to record data for the purposes of its regulatory reporting requirements.

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[161] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 132

[162] SA Power Networks, *Regulatory Proposal 2015–20*, October 2015, Attachment 13.1, p. 31

B.2.5 Remaining augex components

This sections sets out our final decision on the following remaining components of SA Power Networks revised augex proposal:

- Demand and power quality capex
- Kangaroo Island undersea cable capex
- Environmental capex
- Power Line Environment Committee (PLEC) capex.

Demand and power quality

SA Power Networks' revised proposal included $312.4 million ($2014–15) capex to meet forecast demand growth and address power quality issues as a result of existing demand (e.g. voltage fluctuations). We have included this amount in our alternative estimate for this final decision.

We accepted this capex in our preliminary decision.[163] SA Power Networks' revised proposal for demand growth power quality augex is consistent with our preliminary decision. Accordingly, we are satisfied that SA Power Networks estimates are sufficient to allow it to:

- meet or manage the expected demand for standard control service over the 2015–20 period
- maintain the quality of supply of standard control services and the distribution system.

Our consideration of SA Power Networks' maximum demand forecasts is set out in Appendix C.

As discussed in section B.2.4, SA Power Networks originally proposed an additional $19.6 million to install monitors on its network to manage the impact of solar PV connections on network power quality (primarily high voltage fluctuations). We did not accept this capex because SA Power Networks had shown to be effective in managing power quality over 2010–15 in the presence of significant uptakes in solar PV connections.[164] Our alternative capex estimate provided SA Power Networks with a sufficient amount to manage power quality issues and maintain power quality levels consistent with its historical performance.

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[163] AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, pp. 40-46

[164] AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, pp. 44-48.

As an alternative to its originally proposed network monitoring capex, SA Power Networks have included $5.8 million in its revised proposal for network monitoring. We considered this additional capex in section B.2.4 above.

We received submissions from the Energy Consumers Coalition of SA (ECCSA) and the CCP that questioned the amount of capex we accepted to meet forecast demand growth. The CCP submitted:

> … it would appear that the AER has adopted an overly conservative position on demand growth related augmentation expenditure and one that does not adequately reflect the current increases in spare capacity and the previous investment in the upstream assets (distribution and zone substations and transformers). Given the spare capacity and uncertain forecasts for future demand, there is a real risk of continuing the trend towards overinvestment in network capacity.[165]

The CCP concluded that we should “revisit the capex allowance for forecast demand growth and capacity constraints to ensure that its allowance is consistent with the growing spare capacity on the network and the extent of SA Power Networks’ investment in upstream assets in 2010–15.”[166]

The ECCSA submitted that because of the flattening of demand forecasts over the 2015–20 period it expects that there will be no need for any augmentation capex for this period.[167] Whilst it accepts that there may well be localised demand growth, it submitted that this will be offset by falls in demand elsewhere in the SAPN network. It also noted that we reviewed three substations that SA Power Networks plans for augmentation:

> Based on the major works planned for these three substations, the AER considers that the entire SAPN forecast of $186m for demand driven augmentation is appropriate. The ECCSA considers that this outcome is inconsistent with the view that there is no regional growth expected to exceed historic peak demand levels and considers that the AER has overstated the need for demand driven capex.[168]

The demand-related augex we have included in our alternative estimate is 21 per cent less than the actual capex SA Power Networks incurred in the 2010–15 period, and significantly less than SA Power Networks’ capex allowance over this period. This is a direct result of the flattening of demand and investments made over this period. We considered that this was consistent with high-level indicators such as system demand and utilisation rates.

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165 Ms Bev Hughson CCP2, *Advice to the AER: AER's Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks' Revised Regulatory Proposal*, August 2015, p. 55.

166 Ms Bev Hughson CCP2, *Advice to the AER: AER's Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks' Revised Regulatory Proposal*, August 2015, p. 55.

167 Energy Consumers Coalition of South Australia, *AER SA Electricity Distribution Revenue Reset, The AER preliminary decision - A response*, 3 July 2015, p. 16.

168 Energy Consumers Coalition of South Australia, *AER SA Electricity Distribution Revenue Reset, The AER preliminary decision - A response*, 3 July 2015, p. 18.

While SA Power Networks overall network utilisation decreased over the period (indicating there is spare network capacity), there are areas of the network where network utilisation is forecast to increase and augmentation is required. This is evident in utilisation analysis in the preliminary determination which showed that SA Power Networks' forecasts that between 10 and 20 substations will experience utilisation at 90 to 100 per cent of capacity by 2020.[169] We examined three largest of these substations that SA Power Networks proposed to augment.[170] This was necessarily a sample of SA Power Networks projects rather than a comprehensive review of each project. However we consider that this sample provided evidence that SA Power Networks proposed augex was prudently directed at alleviating network capacity constraints.

SA Power Networks demand-related augex also included $0.56 million as part of its proposed 'flexible load strategy' which includes reprogramming up to 27,000 meters to address the hot water load price spikes observed in South Australia.[171]

We received a submission from AGL on this proposed capex:

> AGL is seeking confirmation from the AER, as the relevant regulatory authority for this regulated entity, as to the status of SA Power Networks proposed program of work in relation to the 27,000 customer sites. This includes advice from the AER as to whether this activity has been approved/funded by the AER as part of SA Power Networks current, or future, program of work. AGL considers that there is considerable merit in market participant's being made aware that regulated entities are to address specific issues where such issues have a negative market impact.[172]

SA Power Networks has confirmed that its revised proposal includes capex for this program within its demand-related augex.[173] Because we have accepted SA Power Networks proposed demand-related augex, SA Power Networks will receive funding for this project within its regulated revenue allowance.

Kangaroo Island cable

Our alternative estimate includes SA Power Networks' proposed $45.6 million ($2014–15) capex for SA Power Networks to install a second undersea cable to Kangaroo Island in 2015–20 period. In our preliminary decision, we accepted SA Power Networks proposed capex for this program and SA Power Networks included this in its revised proposal.[174]

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169 AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, p. 43.

170 AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, p. 44.

171 SA Power Networks, response to AER SAPN 063, p. 1.

172 AGL, *Letter to the AER on SA Solar off peak hot water*, 31 July 2015, p.1.

173 SA Power Networks, response to AER SAPN 063, p. 1.

174 AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, p. 63.

Our preliminary decision was supported by submissions from the SA Government and the Commissioner for Kangaroo Island.[175] However, the CCP submitted a number of concerns with our preliminary decision to accept the capex:[176]

- It is not clear what the overall costs of the project are given that SA Power Networks stated that it will need to upgrade the Kingscote power station on the island if the existing cable fails.
- "There are substantial risks involved in investing such a significant amount of money in this type of single project and given the rapid growth in renewable technologies. The project may crowd out the opportunity to develop alternative energy sources on the island even though this may well provide a more sustainable, lower risk alternative over the longer term."
- The CCP also raised a number of concerns with our modelling of the cost-benefit of SA Power Networks' capex proposal.

The ECCSA submitted that catastrophic failure of the existing Kangaroo Island under sea is extremely unlikely (based on the performance of the previous cable) and that any failure is more likely to be addressed by repair.[177] It stated that we should carry out another cost-benefit assessment assuming that the failures of the existing cable can be repaired rather than need replacement of the entire cable.[178]

Both ECCSA and the CCP submitted that the Kangaroo Island capex should be included as a contingent project rather than as ex-ante capex allowance.

In response to the CCP submission, we note that the costs we have included in our alternative estimate reflect SA Power Networks' proposed capex to install a second cable only. It does not include additional capex associated with a cable failure, such as upgrading the Kingscote power station and local diesel generation.[179] Having said that, our assessment of SA Power Networks' proposal was based on an economic cost-benefit analysis that considered the proposed cost of the undersea cable against the probability of cable failure and the likely costs to consumers. This specifically included assumptions about the time and cost to repair the existing cable if it fails, the cost to

[175] Commissioner for Kangaroo Island submission to preliminary decision, p. 1; SA Government submission to SA preliminary decision, p. 4.

[176] Ms Bev Hughson CCP2, *Advice to the AER: AER's Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks' Revised Regulatory Proposal*, August 2015, pp. 82-83.

[177] Energy Consumers Coalition of South Australia, *AER SA Electricity Distribution Revenue Reset, The AER preliminary decision - A response*, 3 July 2015, p. 20.

[178] Energy Consumers Coalition of South Australia, *AER SA Electricity Distribution Revenue Reset, The AER preliminary decision - A response*, 3 July 2015, p. 20.

[179] We separately consider SA Power Networks' proposed nominated cost pass through to recover the costs it would incur in maintaining power on Kangaroo Island and repairing the existing undersea cable in the event it were to fail. See Attachment 15, section 15.4.7.

maintain backup generation on the island, and the cost to consumers from a loss of energy supply (using the value of customer reliability).[180]

Our analysis suggests that the probability of a major failure of the existing cable was unlikely over the 2015–20 regulatory control period.[181] However, on the basis of our cost benefit analysis, the proposed capex to install a second undersea cable was less than the cost (in net present value terms) of SA Power Networks repairing the existing cable if it fails.[182] This suggested that it would be prudent to install a second undersea cable by 2018.

This analysis was consistent with the modelling performed by SA Power Networks and was peer reviewed by our independent consultants Energy Market Consulting Associates (EMCa).[183]

A key assumption in SA Power Networks proposal was that it would require two years to install a new cable due to the time required to order, produce, ship and install the cable. Information provided by SA Power Networks as part of our original assessment supported its case that the appropriate assumption for cable replacement is two years.[184] We asked SA Power Networks to further consider options to reduce this time by paying a deposit with a cable supplier to shorten the production lead time or pre-purchasing and storing the cable.

In relation to shortening the production time, SA Power Networks' submitted:

> SA Power Networks has contacted six cable suppliers in relation to this option and five of those six cable suppliers have advised us that a 'jump the production queue' option is not available. The reason for this is that this may ultimately cause delays to suppliers in producing other customer orders. Further, an option to prepay only applies if the cable date production window can be confirmed or fixed.
>
> For the single cable supplier that advised it may be possible to accept this option, that supplier has not yet actually made any commitment to being able to do so. In order to make such a commitment, that supplier still has to consider the opportunity cost related to other projects, the size of the order and the strategic importance of the project.[185]

In relation to pre-purchasing and storing the cable, SA Power Networks' submitted:

> Most of the cable suppliers we have consulted have confirmed the full length of the cable can be coiled. However, they have advised that it is costly and

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180 AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, pp. 63-68.

181 AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, p. 65.

182 AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, p. p. 64-65.

183 EMCa, *Peer review of AER analysis for Kangaroo Island – Network security second undersea cable*, 9 April 2015.

184 AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, p. 65.

185 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, pp. 75-76.

> inefficient to load the cable onto a ship, unload the cable off that ship for storage and then load the cable back onto a cable laying ship. Instead, those cable suppliers have recommended that manufactured submarine cables be loaded directly onto a cable laying ship. This will avoid the risk of damaging the cable during extra handling operations which require the utmost care and expertise.
>
> One cable supplier has also confirmed that it would be a very costly exercise to transport the cable and store a single long length of submarine cable. A more feasible option would be to transport the cable in 500 metre lengths on 32 drums. This would require many straight joints during the actual installation. However, that method is not recommended by that supplier or by SA Power Networks, as cable joints are a common mode of failure.[186]

While SA Power Networks has not modelled the impact of shortening the production queue (from the single supplier that may be able to do so), or pre-purchasing and storing the cable, SA Power Networks suggested that the cost of doing so may be inefficient. We have not adjusted our decision to accept the proposed capex in light of this information. However, SA Power Networks noted that a formal Regulatory Investment Test for Distribution (RIT-D) process will be undertaken prior to committing to the installation of a second undersea cable.[187] We encourage SA Power Networks to consider the costs of these options in more detail as part of its RIT-D process.

The RIT-D process will allow third party proponents to submit, among other things, non-network solutions for due consideration. This is supported by the submissions from the SA Government, the Commissioner for Kangaroo Island, and the CCP.[188] However, the CCP also submitted that if the project does not proceed at all, then South Australian consumers will still bear a proportion of costs as included in SA Power Networks' capex allowance.[189]

We consider that the risk of SA Power Networks not proceeding with a project to improve the security of supply to Kangaroo Island at all over the 2015–20 period is low. This is because SA Power Networks have proposed capex for this project in the past two regulatory periods, and there is strong support from the Kangaroo Island community and the South Australian government for additional security of supply to the island.[190] Having said that, in the event that SA Power Networks proceeds with an alternative and lower cost option discovered through its RIT-D consultation process these cost savings will be shared with consumers through the capital expenditure sharing scheme.

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186 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 76.

187 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 77.

188 Commissioner for Kangaroo Island submission to preliminary decision, p. 1; SA Government submission to preliminary decision, p. 4; Ms Bev Hughson CCP2, *Advice to the AER: AER's Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks' Revised Regulatory Proposal*, August 2015, p. 84.

189 Ms Bev Hughson CCP2, *Advice to the AER: AER's Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks' Revised Regulatory Proposal*, August 2015, pp. 84-85.

190 Commissioner for Kangaroo Island submission to preliminary decision; SA Government submission to preliminary decision

Environmental

Our alternative estimate includes SA Power Networks' proposed $14.9 million ($2014–15) capex for the environmental program for the 2015–20 period. In our preliminary decision, we accepted SA Power Networks proposed capex for this program and SA Power Networks' includes this in its revised proposal.[191]

The ECCSA submitted that:

> ECCSA notes that the AER has accepted the proposed remediation at the Mannum Town substation necessitated by leaking transformers. The ECCSA does not see why consumers should have to pay for remediation that has been caused by poor maintenance practices of SAPN (and its antecedents).[192]

We have provided SA Power Networks with capex to remediate the Mannum Town substation because we considered it reflected the prudent and efficient costs for SA Power Networks to comply with its environmental safety obligations. Irrespective of the reasons for existing oil leaks at this substation, we are satisfied that this capex reflects the capex criteria in the NER. To the extent that SA Power Networks does not comply with its environmental safety obligations (including maintenance of new and existing assets), this is a matter for the Environment Protection Authority.

Power Line Environment Committee

Our alternative estimate includes SA Power Networks' proposed $44.5 million ($2014–15) capex for the environmental program for the 2015–20 period. In our preliminary decision, we accepted SA Power Networks proposed capex for this program and SA Power Networks' includes this in its revised proposal.[193] Our preliminary decision sets out the full reasons for our acceptance of the forecasts proposed by SA Power Networks.

B.3 Forecast customer connections capex, including capital contributions

Connections capex is incurred by SA Power Networks to connect new customers to its network, and where necessary, augment the shared network to ensure there is sufficient capacity to meet the new demand.

New connection works can be undertaken by SA Power Networks or a third party. The new customer provides a contribution towards the cost of the new connection assets. This contribution can be monetary or in contributed assets. In calculating the customer

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191 AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, pp. 82-84.

192 Energy Consumers Coalition of South Australia, *AER SA Electricity Distribution Revenue Reset, The AER preliminary decision - A response*, 3 July 2015, p. 21.

193 AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, pp. 84-84.

contribution, SA Power Networks is required to take into account the forecast revenue anticipated from the new connection[194]. These contributions are subtracted from total gross capex and as such decrease the revenue that is recoverable from all network consumers. Customer contributions are sometimes referred to as capital contributions or capcons.

B.3.1 AER Position

We accept SA Power Network's revised proposal for net connections capex of $190.8 million ($2014–15). Similarly, we accept SA Power Networks' proposed forecast for customer contributions of $532.2 million ($2014–15).

Our preliminary decision accepted SA Power Networks' proposed connections forecast and customer contributions forecast. We accepted the forecast after considering trends relative to recent expenditure and our assessment that the forecast was consistent with expected construction activity in South Australia. Our preliminary decision set out our full reasons for accepting the SA Power Networks' forecasts.[195]

SA Power Networks in its revised proposal accepted the AER's preliminary determination for net connections capex. The revised proposal includes slight upward revisions to both gross expenditure and customer contributions. SA Power Networks noted this upwards revision to its customer contribution forecast reflects revisions to the augmentation charges included in SA Power Network's amended Connection Policy. See Attachment 18 of this decision for more details on our determination of SA Power Networks' Connection Policy.

We are satisfied that the reduced augmentation charge rates will reduce the expenditure SA Power Networks is able to recover through customer contributions. With this in mind we have assessed SA Power Networks customer contribution forecast and accept SA Power Networks revised proposal.

B.4 Forecast repex

Repex is driven by a service provider's need to replace its assets. In the long run, a service provider's assets will no longer meet the requirements of the network and need to be replaced, refurbished or removed.[196] Replacement may occur when an asset fails, or a condition assessment may find it is likely to fail soon and replacement is the most economic option. It may also occur because jurisdictional safety regulations mean it can no longer be safely operated on the network, or because the risk of using the asset exceeds the benefit of continuing to operate it on the network.

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194 In South Australia , the National Energy Customer Framework (NECF) and chapter 5A of the NER specifies that AER approves a connection guideline for Ergon Energy which determines these customer connection charges

195 AER, SA Power Networks Preliminary Determination Attachment 6 – Capital expenditure p.6-86 – 6-89

196 Assets may also be replaced due to network augmentation. In these cases the primary reason for the asset expenditure is not the replacement of an asset that has reached the end of its economic life, but the need to deploy new assets to augment the network, predominantly in response to changing demand.

In general, the majority of network assets will remain in efficient use for far longer than a single five year regulatory period. As a consequence, a distributor will only need to replace a portion of its network assets in each regulatory control period. The majority of its assets will remain in commission beyond the end of the regulatory control period, and be replaced in subsequent regulatory periods.

Our assessment of repex seeks to establish the portion of SA Power Networks' assets that will likely require replacement over the 2015–20 regulatory control period, and the associated expenditure.

B.4.1 Position

We do not accept SA Power Networks' revised proposed repex of $700 million. We have instead included in our alternative estimate of overall total capex, an amount of $655 million ($2015–16) for repex, excluding overheads. This represents 94 per cent of SA Power Networks' revised proposal and 85 per cent of its initial proposal. It also represents 57 per cent more repex than SA Power Networks spent in the 2010–15 regulatory control period. We are satisfied that this amount reasonably reflects the capex criteria.

B.4.2 Revised proposal

SA Power Networks' revised proposal is $700 million, which is $72 million or 10 per cent lower than its initial proposal of $772 million. SA Power Networks submitted that it accepted that the AER's repex model is a good predictor of prudent future expenditure.[197] More generally SA Power Networks did not raise concerns with our assessment approach.

However SA Power Networks did not accept our preliminary decision on repex of $609 million for the following reasons:

- the years over which the repex model forecasted data[198]
- the repex for pole top structures does not reflect the upward trend in overall replacements.[199]

B.4.3 AER approach

In the preliminary decision, we applied several assessment techniques to assess SA Power Networks' forecast of repex against the capex criteria. These techniques were:

- analysis of SA Power Networks' long term total repex trends
- predictive modelling of repex based on SA Power Networks' assets in commission[200]

197 SA Power Networks, *Revised Regulatory Proposal 2015-2020*, July 2015, p. 67.

198 SA Power Networks, *Revised Regulatory Proposal 2015-2020*, July 2015, p. 67.

199 SA Power Networks, *Revised Regulatory Proposal 2015-2020*, July 2015, p. 68.

- technical review of SA Power Networks' approach to forecasting, costs, work practices and risk management
- consideration of various asset health indicators and comparative performance metrics.

In the preliminary decision, we did not accept SA Power Networks' proposed repex forecast of $772 million. We instead included in our alternative estimate an amount of $609 million. Our estimate was 21 per cent lower than SA Power Networks' initial proposal. However, our forecast would nonetheless have represented an increase of approximately 46 per cent over SA Power Networks' actual replacement expenditure in the 2010–15 regulatory control period. Our estimate reflected the outcomes of our predictive modelling and our view that SA Power Networks has not established that its asset risk will increase in the 2015–20 regulatory control period by the amount forecast by SA Power Networks. In particular:[201]

- we observed that SA Power Networks was proposing a significant increase in repex across the 2015–20 regulatory control period.
- we considered, based on our technical review of the material put forward by SA Power Networks, that there may be a level of conservatism and subjectivity embedded in SA Power Network's forecasting approaches. For example, some of SA Power Networks' options analysis appears limited, and consequence and criticality rankings had a degree of subjectivity.
- for the asset categories where we had regard to the repex model, we considered that a business as usual estimate, based on replacement volumes from the last five years and unit costs derived from SA Power Networks' recent forecast expenditure, was likely to reasonably reflect the capex criteria. On this basis, we included $487 million ($2014–15) in our alternative estimate of total forecast capex for these modelled categories. We had regard to the outcome and the findings of the technical review in considering whether it was appropriate to forecast repex on the basis of a business as usual estimate.
- based on a limited set of asset health indicators, we observed that asset health may have declined, but that the proposed amount provided for increased repex relative to the current regulatory control period.

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[200] We use predictive modelling to estimate how much repex SA Power Networks is expected to need in future, given how old its current assets are, and based on when it is likely to replace the assets. We modelled six asset groups using the repex model. These were poles, overhead conductors, underground cables, service lines, transformers and switchgear. To ensure comparability across different distributors, these asset groups have also been split into various asset sub categories. Pole top structures and SCADA were not modelled, along with specialised categories of capex defined by SA Power Networks that were not classified under the groups above. In total, the assets modelled represent 81 per cent of SA Power Networks' proposed repex.

[201] AER, *Preliminary decision SA Power Networks distribution determination - Attachment 6 - Capital expenditure*, April 2015, pp. 95–96, 103,105, 106, 108.

- for the unmodelled asset category defined as “other”, we considered that SA Power Networks' forecast repex of $39 million was likely to reflect the capex criteria, as it was not materially different from historical repex on these assets.
- for the unmodelled asset category for SCADA, network control and protection, we considered that SA Power Networks had not established the need to more than double its expenditure from the last period. In doing so, we reviewed SA Power Networks' supporting business cases and asset management plans. We were of the view that they relied on assumptions that were not sufficiently justified. Additionally, we considered that SA Power Networks did not make a satisfactory case for the investment, as its cost benefit analysis did not appear to support the investment. We considered that SA Power Networks' SCADA, network control and protection repex from last period of $31 million was likely to reasonably reflect the capex criteria.
- for the unmodelled asset category of pole top structures, we considered that SA Power Networks' had not justified an increase in pole top structures expenditure from the last period, particularly that it had it had not established a change in risk that would necessitate an increase. We considered that SA Power Networks' actual pole top repex from last period of $52 million was likely to reasonably reflect the capex criteria.

In the revised proposal, SA Power Networks raised an issue with our interpretation of the results of predictive modelling and our conclusions on pole top structures. SA Power Networks did not raise concerns in relation to other parts of our assessment or our overall assessment approach. This final decision is focussed on addressing these issues.

B.4.4 AER repex findings

We do not accept SA Power Networks’ revised proposal for the modelled repex categories. Instead, using updated data in the repex model, we are satisfied that the amount of $524 million for the modelled categories reasonably reflects the capex criteria.

We do not accept SA Power Networks’ revised proposal for pole stop structures repex of $72 million, and are instead satisfied that SA Power Networks' actual pole top repex from last period of $61 million reasonably reflects the capex criteria. SAPN accepted our preliminary decision for the remaining unmodelled categories of SCADA ($31 million) and “other” ($39 million).

In total, we are satisfied that $655 million for repex reasonably reflects the capex criteria and have included this amount in our alternative forecast for total capex.

The CCP noted that a forecast of over $700 million is 85 per cent greater than in actual repex in 2010–15. The CCP considered this was excessive when compared to the level of augex and increases in spare capacity that has occurred over the current period.[202] The Energy Consumers Coalition of South Australia questioned why we did not apply benchmark replacement lives to determine an alternative repex estimate.[203]

Business SA acknowledged that the benchmarking of SA Power Networks is required, but considered we should use judgement and rely on expert analysis where there may be micro level improvements despite the aggregated level of efficiency.[204]

The CCP noted in a presentation to the AER Board that the AER's repex allowance is very generous, provides ample scope for SA Power Networks to focus on aging assets and risk areas, and that we should consider an alternative replacement profile.[205] This suggests that we should consider whether the business as usual approach to repex is likely to result in an efficient level of repex, or whether a different profile is appropriate.

We are satisfied that the business as usual approach to repex will provide SA Power Networks with sufficient capex to manage the replacement of its assets and meet the capex objectives of maintaining safety, reliability and security of the distribution system. The business as usual approach takes into account the service provider's recent replacement practices, together with information on the age of its current stock of assets, to estimate the replacement volumes and expenditure the service provider business is likely to require if it maintains its current asset replacement practices over the next period. As noted in the Expenditure Forecast Assessment Guideline, we consider that its replacement practices in the last period were appropriate to allow the business to meet the capex objectives.[206] We consider that adoption of the business as usual estimate approach means these asset replacement practices will continue to allow the businesses to meet the capex objectives.[207]

That said, we have also considered whether the business's replacement practices from the last regulatory control period did more than maintain safety, reliability and security of the distribution system, such that applying the business as usual approach for asset replacement may result in replacement practices that provide for some expenditure that is not necessary to satisfy the capex objectives. In considering the efficiency of recent replacement practices, we have placed some weight on the ex-ante capex incentive framework under which the service providers' operate.

There are incentives embedded in the regulatory regime that encourage a service provider to spend capex efficiently (which may involve spending all of the allowance, less or more, in order to meet the capex objectives). A service provider is only funded in the regulatory control period to meet the capex allowance. The service provider

[202] Consumer Challenge Panel Sub Panel 2, *Advice to the AER, AER's Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks' Revised Regulatory Proposal*, August 2015, pp. 18–19.

[203] Energy Consumers Coalition of SA, *Submission on SA Power Networks' revised proposal*, July 2015, pp. 25–26.

[204] Business SA, *Submissions re SA Power Networks Determination 2015-2020*, 20 July 2015, pp. 3–4.

[205] Consumer Challenge Panel Sub Panel 2, *Presentation to AER Board*, 30 September 2015, Slide 22.

[206] AER, *Expenditure Forecast Assessment Guideline*, November 2013, p. 43.

[207] We also consider whether there are any new or removed obligations that may mean more or less than business as usual is required, such as whether there are new safety obligations likely to impact on repex.

keeps the funding cost obtained over the regulatory control period of any unspent capex for that period, and, conversely, bears the funding cost of any capital expenditure that exceeds the allowance. In this way, the service provider has an incentive to spend efficient capex, or close to the allowance set by the regulator, as it is essentially rewarded (penalised) for any underspend (overspend). This provides some assurance that a business reacting to these incentives will undertake efficient capex to meet the capex objectives. This means that to some extent we can rely on the ex-ante capex framework to encourage the service providers to engage in efficient and prudent replacement practices.

Going forward, this incentive will be supplemented by a Capital Expenditure Sharing Scheme, which will provide a constant incentive to spend efficient capex over the regulatory control period, as well as the ability to exclude capex overspends from the RAB as part of an ex-post review. These additional arrangements will provide us with greater confidence that the service provider's past replacement practices are likely to reflect efficient and prudent costs, such that service providers as usual asset replacement approach is likely to be consistent with the capex objectives.

Possible future rule changes may also extend the regulatory investment test for distribution (RIT-D) to repex. Such a change would make it incumbent upon the service provider to develop credible options for asset replacement, including considering whether the asset life could be extended or whether the asset could be retired rather than replaced.

Finally, the collection of a longer period of data on changes in the asset base as part of our category analysis RIN will provide us with further information into the service provider's asset replacement practices over a longer period of time. This will further inform our understanding of business as usual replacement practice to estimate repex. More time series data would also strengthen our ability to use benchmarked information (e.g. asset life inputs) in the repex model in the future, which is intended to drive further efficiency in replacement expenditure.

Predictive model outputs

In our preliminary decision, we used predictive modelling to estimate how much repex SA Power Networks is expected to need in the future, given how old its current assets are, and based on when it is likely to replace the assets.

In our preliminary decision we were satisfied that an amount of $487 million of repex was a reasonable estimate for the categories of repex that were subject to our predictive modelling.[208]

SA Power Networks did not challenge our conclusions from the repex model, though it raised a technical issue around the appropriate model outputs. [209] We used the model

[208] AER, *Preliminary Decision, SA Power Networks determination 2015−16 to 2019−20, Attachment 6 − Capital expenditure*, April 2015, p. 90.

outputs from years one to five of the repex model in making our preliminary decision. SA Power Networks submitted that years two to six were appropriate. Using those outputs would result in a model outcome of $539 million, $52 million higher than our preliminary decision of $487 million.

SA Power Networks' asset age profile in the category analysis RIN reported the installation date of its assets as at the end of the financial year 2013–14. This was one year before the commencement of the 2014–15 regulatory period. We used this age profile as an input in the repex model. The model was then calibrated using volumes and historical unit costs for the five years ending 30 June 2015. SA Power Networks' submitted that the one year gap between the end of the age profile and the beginning of the 2015–20 regulatory period should be acknowledged by skipping the first year output from the repex model, and using the outputs from year two to six.

In response to SA Power Networks' submission, and in order to test whether our position in the preliminary decision was appropriate, we sought to obtain the most up-to-date data on the age composition of SA Power Networks' assets. We issued an information request, seeking SA Power Networks' asset age profile as at the end of the financial year 2014–15. SA Power Networks provided us with an updated age profile in response to this request.

We used this data in a further modelling process. Holding our other assumptions from the draft decision (namely, the use of historical unit costs) resulted in a forecast of $524 million, $37 million higher than predicted at the draft decision for the modelled repex categories. We consider this amount, based on more up-to-date data, more accurately reflects SA Power Networks' likely business as usual repex than the repex model based on older data (which was the basis for our preliminary decision and the forecast included in SA Power Networks' revised proposal). Consequently, the final decision includes an amount that reflects the outputs of this revised repex model.

Pole top structures

SA Power Networks submitted in its revised proposal that the AER's rationale for arriving at its alternative forecast for the 'pole top structures' asset group was incorrect as the forecast did not reflect the AER's findings in other areas of our replacement forecast.[210] It considered that an amount of $72 million, approximately $11 million higher than its historical repex on this asset group, was necessary to meet the capex criteria.

To date we have not considered replacement of pole top structures as suitable to include in the repex model because of their relationship to pole replacement. That is, when a pole is replaced, it usually includes the structure, such that it is difficult to predict the number of structures that will be replaced independent of the pole category. Where we are unable to directly use predictive modelling for pole top structures we

209 SA Power Networks, *Revised Regulatory Proposal 2015-2020*, July 2015, p. 67.

210 SA Power Networks, *Revised Regulatory Proposal 2015-2020*, July 2015, p. 68.

have placed more weight on analysis of historical repex, trends, and information provided by the service provider.

We consider that the replacement of network assets is likely to be relatively recurrent between periods. We recognise there will be period-on-period changes to repex requirements that reflect the lumpiness of the installation of assets in the past. Using predictive tools such as the repex model allows us to take this lumpiness into account in our assessment. For repex categories we do not consider suitable for modelling, historical expenditure is our best high level indicator of the prudency and efficiency of the proposed expenditure. Where past expenditure has been sufficient to achieve the capex criteria it can be a good indicator of whether forecast repex reasonably reflects the capex criteria. This is due to the predictable and recurrent nature of repex.[211]

For unmodelled asset categories we consider that if the forecast expenditure for the next period is similar or lower than the expenditure in the last period, the service provider's forecast is likely to reasonably reflect the capex criteria. If forecast repex exceeds historical expenditure, we would expect the service provider to sufficiently justify the increase.

SA Power Networks noted that pole top structures are high volume, low cost assets associated with its overhead network, similar to many of the assets we assessed through the repex model. SA Power Networks further submitted that, the majority of pole top assets were installed at the same time as the poles and conductors and are subject to the same service and environmental conditions. It noted that the repex model forecasts the need for a significant increase in the asset groups assessed through the model.

We consider that the driver of pole top structure replacement is not the same as the driver of pole replacement. The increase in SA Power Networks' pole replacement is due to it identifying more faults during inspections of the pole base, not in the pole top structure. We consider that a defect that may necessitate the replacement of a pole top structure are different to the types of defect driving changes in pole replacement, which predominantly occur at the base of the pole. We therefore consider that an increase in pole replacements is not likely to also lead to a proportional increase in pole top structure replacements, so as to necessitate an increase in repex for pole top structures.

Consequently, we do not consider there is sufficient justification for an increase in pole top structure repex in the 2015–20 regulatory control period. We consider SA Power Networks' actual pole top repex from last period of $61 million reasonably reflects the capex criteria, and we have included this amount in our alternative estimate of total forecast capex.

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211 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 7–9.

B.5 Forecast bushfire safety capex

In its revised proposal SA Power Networks set out $103.5 million ($2014–15) in addition to business-as-usual capex for bushfire mitigation and other safety measures. This reflects a reduction of $109.1 million ($2014–15) from the additional expenditure SA Power Networks included in its initial proposal. The revised proposal includes:

- $38.9 million for bushfire mitigation
- $25.6 million for its 'bushfire safer places' program
- $17.7 million for its 'back up protection' program.
- $21.3 million for SA Power Networks' 'core safety' program

In our preliminary decision, we accepted SA Power Networks' proposed $21.3 million ($2014–15) core safety program. We maintain this view in our final decision. However, we do not accept the expenditures related to proposed additional programs included in SA Power Networks' revised proposal. In coming to this view, we have assessed SA Power Networks new bushfire mitigation, bushfire safer places and backup protection programs outlined above. Based on our assessment, we find that the proposed capex does not reasonably reflect each of the capex criteria. Our alternative estimate of $21.3 million for safety capex remains.

Our assessment of SA Power Networks' revised bushfire mitigation, bushfire safer places and backup protection programs are contained in the sections below.

Bushfire mitigation program

In its revised proposal, SA Power Networks has proposed a $38.9 million ($2014–15, excluding overheads) bushfire mitigation program. The revised bushfire mitigation program focuses on the following three key programs:

- replacement of manual 33kV, 19kV and 11kV reclosers with fast operating SCADA controlled units ($18.1 million, including overheads)
- replacement of rod air gaps and current limiting arc horns with modern surge arresters ($12.4 million, including overheads)
- reconstructing metered mains ($10.1 million, including overheads).

SA Power Networks originally proposed $212.5 million for its bushfire mitigation program. The $173.6 million reduction in proposed capex is attributable to SA Power Networks reducing the scope of work for some projects, and removing some projects from the original bushfire mitigation program umbrella. In the revised proposal it now proposed the Bushfire Safer Places (BSPs) and back-up protection programs separately from the bushfire mitigation program.

We are not satisfied that the additional capex for the proposed bushfire mitigation program is efficient additional capex that a prudent operator would require to maintain the reliability and safety of the network, or to comply with regulatory obligations or requirements. As such, we do not accept SA Power Networks' capex proposal to spend $38.9 million on its bushfire mitigation program. We find that SA Power Networks' revised regulatory proposal, and our alternative estimate, already factor in a sufficient level of capex related to its business-as-usual bushfire risk management.

As we noted in the preliminary decision, the evidence before us indicates that SA Power Networks is meeting its existing obligations, and historically, its bushfire risk management has been effective.[212] The Office of the Technical Regulator has confirmed that SA Power Networks currently satisfies existing regulations and standards relating to managing bushfires.[213]

We have assessed SA Power Networks' revised bushfire mitigation program in two steps:

1. We assessed SA Power Networks' compliance with its safety related obligations, and its ability to manage bushfire risk;
2. We assessed the prudency and efficiency of the three projects within the proposed bushfire mitigation program, including SCADA reclosers, surge arrestors and metered mains.

In undertaking these technical reviews, we have drawn on engineering and other technical expertise within the AER.

In summary we consider that:

- The information before us does not satisfy us that section 60 of the SA Electricity Industry Act requires SA Power Networks to incur bushfire mitigation capex, in addition to capex that it may be required to incur in order to comply with other, more specific requirements under the SA Electricity Industry Act.
- contrary to SA Power Networks' assertion, the information before us does not demonstrate that the practices now adopted by Victorian networks are required to be adopted in order for a prudent South Australian network operator to achieve the capex objectives. SA Power Networks' bushfire risk and network construction is different from its Victorian counterparts.
- SA Power Networks is in a position to manage an increase in bushfire risk if it eventuates, given its legislated power to cut off the power to specific parts of the network in high bushfire risk situations.
- SA Power Networks has improved its fire start performance to date with business-as-usual expenditure, in compliance with its obligation under the NER to maintain the safety of the distribution system.[214]

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212 SA Power Networks, *SA Power Networks: Bushfire Mitigation Programs Business Case*, October 2014, p. 13.

213 File note of conversation with a representative from the Office of the Technical Regulator, 24 February 2015.

214 NER, cl. 6.5.7(a)(4).

- SA Power Networks has maintained its compliance with its obligations under the Work Health and Safety Act, and there is no indication that the Act will be amended to increase SA Power Networks' obligations.
- contrary to SA Power Networks assertions that a cost/benefit analysis for the bushfire mitigation program is not feasible, it could have provided a cost benefit analysis based on the 'As Low As Reasonably Practical' risk mitigation principle.
- while we accept that SA Power Networks proposed SCADA reclosers program may mitigate fire start risks, we have provided funding for the replacement of aging reclosers in our repex allowance.
- the proposed surge arrestors program is not efficient capex that a prudent network operator would need to make to achieve the capex objectives. Further, SA Power Networks has been given additional repex that addresses increased asset replacement needs.
- the proposed metered mains project is not efficient capex that a prudent network operator would incur .

As such, we are not satisfied that SA Power Networks' proposed capex for the revised bushfire mitigation program reasonably reflects the capex criteria. Each of these reasons is discussed further below.

SA Power Networks' regulatory obligations and requirements

In its initial proposal, SA Power Networks submitted that it has a duty to take *reasonable steps* to ensure that the distribution system is safe and safely operated [emphasis added].[215] It also submitted that it has a duty to maintain and operate the distribution system in accordance with good electricity industry practice.[216] It considered these duties require it to have regard to objectively determined standards of safety, which will change over time; therefore it continually monitors industry developments and learnings to ensure that it is discharging its evolving duties. Consequently, SA Power Networks proposed its bushfire mitigation program in response to the recommendations of Victorian Bushfire Royal Commission (VBRC) and the resulting Powerline Bushfire Safety Taskforce (PBST). SA Power Networks states that it must adopt good electricity industry practice in bushfire risk management to comply with its regulatory obligations.[217]

In the preliminary decision, we acknowledged SA Power Networks' initiatives to date in reviewing its current practices and procedures for bushfire risk management following the release of the recommendations of the VBRC and the strategies proposed by the PBST.[218] However we noted that there had not been a change to its regulatory

215 Section 60(1) of the Electricity Act.

216 NER, cl. 5.2.1(a); SA Power Networks, SA Power Networks: Bushfire Mitigation Programs Business Case, October 2014, p. 5.

217 SA Power Networks, *SA Power Networks: Bushfire Mitigation Programs Business Case*, October 2014, p. 5.

218 AER, *SAPN preliminary decision: Attachment 6 capital expenditure*, April 2015, p. 49.

obligations and safety standards related to bushfire risk that would justify additional expenditure.[219] We also noted that the evidence before us indicated that it was compliant with its existing obligations.[220]

In its revised proposal, SA Power Networks submitted the forecast capex for its revised bushfire mitigation program is required to achieve compliance with all applicable regulatory obligations and requirements.[221] It reiterates its obligation under section 60(1) of the Electricity Act requires it to take reasonable steps to ensure that its distribution network is safe and safely operated, which requires it to have regard to objectively determined standards of safety.[222] SA Power Networks considered its obligation requires it to have regard to (amongst other things):[223]

- the findings of the VBRC and the PBST concerning the ignition risks associated with the operation of certain types of distribution network assets in bushfire risk areas, and the steps which can and should be taken to minimise those ignition risks
- 'good electricity industry practice' (as defined in Chapter 10 of the NER)
- improvements in knowledge and technology and authoritative expert opinion.

SA Power Networks submitted that specific findings of the VBRC and PBST need to be considered in its circumstances:[224]

> In our view, it is clear that the findings of the VBRC and the PBST in relation to the ignition risks associated with manual reclosers and aged and poorly maintained low voltage power lines and other assets, would (to the extent that those findings are relevant to the SA Power Networks distribution system and circumstances) inform the meaning of *'reasonable steps'* and *'good electricity industry practice'* under the South Australian regulatory obligations and requirements.

SA Power Networks also submitted it must undertake the bushfire mitigation program to comply with its obligations under the *Work Health and Safety Act 2012* (SA) (WHS Act).[225]

In summary, we consider that the information before us does not demonstrate:

- that the current capex and opex allowances are insufficient to provide for appropriate levels of replacement and maintenance of its assets, such that additional capex would be required for a prudent and efficient operator in SA Power Networks' position to meet its regulatory obligations or maintain network safety

219 AER, *SAPN preliminary decision: Attachment 6 capital expenditure*, April 2015, p. 50.
220 AER, *SAPN preliminary decision: Attachment 6 capital expenditure*, April 2015, p. 53.
221 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 80.
222 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 81.
223 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 82.
224 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 82.
225 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 82.

- that the recommendations of the VBRC and PBST are required to be adopted in addition to South Australian regulatory obligations, or how those recommendations would operate in parallel with existing South Australian bushfire specific regulatory obligations
- that the recommendations of the VBRC and PBST are directly applicable to SA Power Networks' operating environment and network characteristics.

We also consider that obligations under the WHS Act would not require a prudent and efficient operator to incur additional capex under the proposed bushfire mitigation program.

We discuss these positions below.

SA Power Networks' jurisdictional obligations relevant to bushfire mitigation

Section 60(1) of the Electricity Act is a general safety obligation, which we consider must be considered against the context of other, more specific provisions of the Electricity Act.

In their submissions, the Consumer Challenge Panel (CCP) and the SA Minister for Minerals and Energy (the Minister) highlighted that operational standards for bushfire mitigation are specified by the legislation and regulations in South Australia. The South Australian Government introduced legislation initially in response to the Ash Wednesday bushfires in 1983 and updated it in subsequent decades.[226]

Specific bushfire mitigation obligations and powers imposed under the Electricity Act include:

- Section 22(f), which requires the electricity entity to maintain insurance against any liability for causing a bushfire.
- Section 23, which relates to licences authorising the operation of the distribution network. It requires a distributor to hold a licence to operate a distribution network. In order to obtain a licence, the distributor must, among other things, prepare and periodically revise a safety, reliability, maintenance and technical management plan (SRMTMP), which must be approved by the licensing authority. It must comply with the plan and its compliance with the plan must be audited.
- Section 53, which allows the electricity entity, without incurring any liability, to cut off the supply of electricity to any region, area, land or place if it is, in the entity's opinion, necessary to do so to avert danger to person or property.
- Part 5, which are obligations in relation to vegetation management. It requires an electricity entity to take reasonable steps to keep vegetation clear of the powerlines

[226] Consumer Challenge Panel #2, *Advice to AER: AER's Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks' Revised Regulatory Proposal*, August 2015, p. 61; Government of South Australia, *Submission to the Australian Energy Regulator on the SA Networks' Regulatory Proposal 2015-20*, 30 January 2015, p. 5.

under the entity's control, in accordance with the principles of vegetation clearance. The principles of vegetation clearance stipulate clearance requirements around overhead powerlines in bushfire risk areas.[227]

On the information before us, we do not consider that SA Power Network' current bushfire mitigation practices or expenditures are inadequate to meet its obligations under Section 60(1) of the Electricity Act. Specifically, on the information before us, we are not satisfied that SA Power Networks':

- current bushfire mitigation practices do not meet its obligations under the terms and conditions of its bushfire insurance.
- current bushfire mitigation practices do not comply with its Bushfire Risk Management Manual, which forms part of its SRMTMP.
- current vegetation management practices are not sufficient to meet its obligations with respect to bushfire mitigation.
- current opex and capex levels are insufficient to meet its regulatory and safety obligations.

Rather, the evidence before us indicates that SA Power Networks is meeting its existing regulatory and safety obligations.[228]

As we have noted, the Office of the Technical Regulator in South Australia has advised that SA Power Networks is meeting its current bushfire obligations. It is open for the technical regulator to review the material provided by SA Power Networks and their consultant Jacobs and determine whether formal changes to South Australian requirements are necessary. We would consider expenditure required to meet any new obligations either as part of the next reset process or as part of a cost pass through application from SA Power Networks.

Good electricity industry practice

SA Power Networks submitted that under clause 5.2.1(a) of the NER, it is required to adopt additional bushfire mitigation measures in accordance with good electricity industry practice.

We do not accept that the clause 5.2.1(a) good electricity industry practice obligation is a regulatory obligation or requirement that imposes any augmentation capex obligation on a network operator. Clause 5.2.1(a) relevantly requires that:

> All *Registered Participants* must maintain and operate … all equipment that is part of their facilities in accordance with … *good electricity industry practice* and applicable *Australian standards*.

227 Electricity (Principles of Vegetation Clearance) Regulations 2010 (SA), Schedule 1, Section 4.

228 AER, *SAPN preliminary decision: Attachment 6 capital expenditure*, July 2015, p. 53.

That obligation specifies the standard to which a network operator must maintain and operate the equipment that is part of its distribution network facilities. It does not impose any obligation on a network operator to augment its existing facilities: at most, cl 5.2.1(a) might be seen to impliedly require a network operator to replace its existing equipment in the event that the equipment can no longer be maintained in accordance with good electricity industry practice or applicable standards.

In any event, good electricity industry practice is a contextual, rather than an absolute or "one size fits all", standard. Good electricity industry practice is defined in the NER as:

> The exercise of that degree of skill, diligence, prudence and foresight that reasonably would be expected from a significant proportion of operators of facilities forming part of the power system for the generation, transmission or supply of electricity <u>under conditions comparable to those applicable to the relevant facility consistent with applicable regulatory instruments, reliability, safety and environmental protection.</u> The determination of comparable conditions is to take into account factors such as the relative size, duty, age and technological status of the relevant facility and the applicable regulatory instruments. [emphasis added]

Good electricity industry practice needs to be considered in the context of the environment the electricity service provider operates in. It does not follow that bushfire mitigation practices recently adopted in Victoria automatically constitute 'good electricity industry practice' in the South Australian context.

A particular aspect of such practices is that actions to address asset related performance risk should reflect the conditions applicable to the relevant network. In the case of SA Power Networks' proposed bushfire mitigation program, we consider that the relevant circumstances are:

- the jurisdictional requirements in South Australia
- the level of risk and accepted practices for managing that risk
- the specific nature of the assets involved (including their design and operation)
- the specific bushfire environment in which the assets are operating in South Australia.

As we discuss below, Victoria has a different bushfire environment, including an inherently higher bushfire risk than South Australia. Additionally, the network design, jurisdictional requirements and accepted practice for managing bushfire risk differ between these two jurisdictions. For example, SA Power Networks has the authority to cut off power in high bushfire risk situations whereas the Victorian distributors do not have that measure available to them.

On the basis of the information before us, we do not consider that the recommendations of the VBRC qualify as 'good electricity industry practice' in the South Australian context. We have discussed the SA Power Networks' specific jurisdictional regulations above. Below we discuss the differences in bushfire risk, network construction, and SA Power Networks' ability to manage bushfire risk with its provision to turn off power.

Difference in bushfire risk levels

The evidence before us, including historical fire starts, Victorian Government reports and bushfire mapping, indicates that the bushfire risk is lower in South Australia than it is in Victoria.

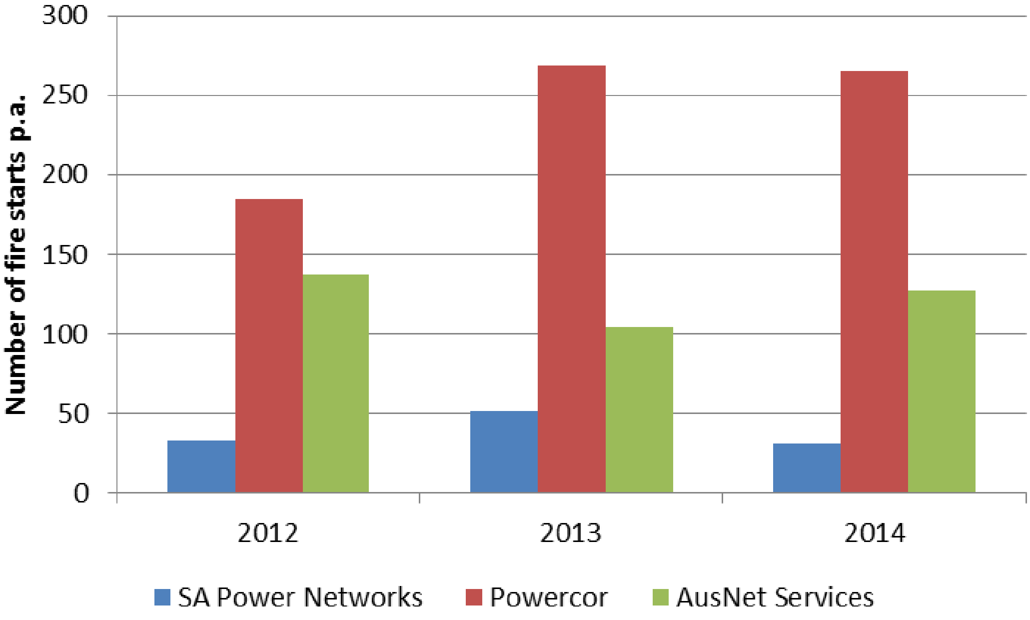
Our analysis of SA Power Networks' annual fire starts in bushfire risk areas shows that its fire starts are lower than the recorded annual number of fire starts on Powercor's and AusNet Services' respective networks. SA Power Networks has acknowledged that its fire starts are lower than in Victoria, noting that its current fire start performance is better than the Victorian fire start statistics reported in the PBST report.[229] However, it considered a comparison to these fire start statistics is not reasonable as the PBST statistics are based on data for 2008 and 2009, and the statistics do not allow for improvements that will eventuate from the increase in expenditure in Victoria to implement bushfire risk mitigation measures.[230] Figure B.2 shows SA Power Networks' annual bushfire starts between 2012 and 2014 in high bushfire risk areas, and the respective figures of Victorian distributors Powercor and AusNet Services in the same period.[231] The period 2012–2014 corresponds with an increase in bushfire mitigation expenditure on Victoria's network.

229 SA Power Networks, Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence, July 2015, p. 9.

230 SA Power Networks, Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence, July 2015, pp. 9–10.

231 The Victorian distributions, including Powercor and AusNet Services, have been required to report their annual fire starts from 2012 under the Victorian F-factor scheme, which is administered by the AER.

Figure B.2 SAPN, Powercor and AusNet Services annual fire starts 2012–14, in high bushfire risk areas



Source: AER analysis, SA Power Networks, Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence, p. 8, CitiPower/Powercor, Fire start report under clause 5 of F-Factor scheme, March 2013, p. 6, March 2014, p. 6, March 2015, p. 7; AusNet Services, Fire start report under clause 5 of F-Factor scheme, March 2013, p. 3, March 2014, p.3, March 2015, p. 3.

Note: Source data was not obtained for SA Power Networks' fire starts, figures here have been estimated from Figure B.6 below.

As can be seen in Figure , SA Power Networks' annual fire starts are considerably lower than either Powercor's or AusNet Services' in recent years. This shows that even with increased expenditure on bushfire mitigation in Victoria, SA Power Networks continues to outperform its Victorian peers. While Figure might be interpreted as demonstrating that SA Power Networks' lower fire starts are in part due its better management practices, the evidence we address below indicates that SA Power Networks faces a lower bushfire risk than its Victorian counterparts.

Victoria is one of the most fire-prone areas in the world, with a history of catastrophic bushfires.[232] It explains that Victoria's high bushfire risk is the consequence of a combination of factors including:[233]

- large areas of highly flammable dry eucalypt forest
- expanses of highly flammable grassland

232 Emergency Management Victoria, *State bushfire plan 2014*, October 2014, p. 1; Victorian Government Department of Sustainability and Environment, *Living with fire: Victoria's bushfire strategy*, June 2008, p. 1.

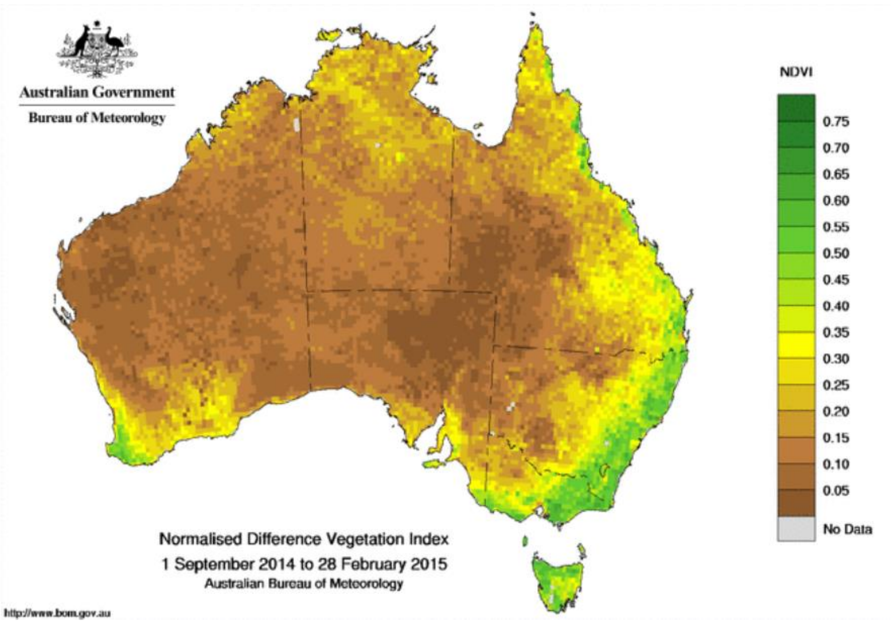
233 Emergency Management Victoria, *State bushfire plan 2014*, October 2014, p. 2.

- a climatic pattern of mild, moist winters followed by hot dry summers
- protracted droughts
- agricultural practices where fire is used routinely
- an increasing population density in bushfire-prone areas, such as in the rural-urban fringe.

On the basis of the information before us, we consider that conditions across SA Power Networks' network and operating environment do not present the same combination and intensity of those risk factors as the Victorian rural networks face. This is one reason why we are not satisfied the recommendations of the VBRC and PBST automatically constitute 'good electricity industry practice' in the South Australian context.

Noting Victoria's bushfire risk from flammable eucalypt forests, we have considered the density of vegetation in South Australia relative to Victoria, as increased vegetation density will contribute to the spread of major bushfires. We observe from figure B.3 below that Eastern Victoria has a notably higher vegetation density than the majority of the area that SA Power Networks' electricity network covers (the southern and south-eastern parts of the South Australia).

Figure B.3 Normalised Difference Vegetation Index: 6 Month Average September 2014 to 28 February 2015



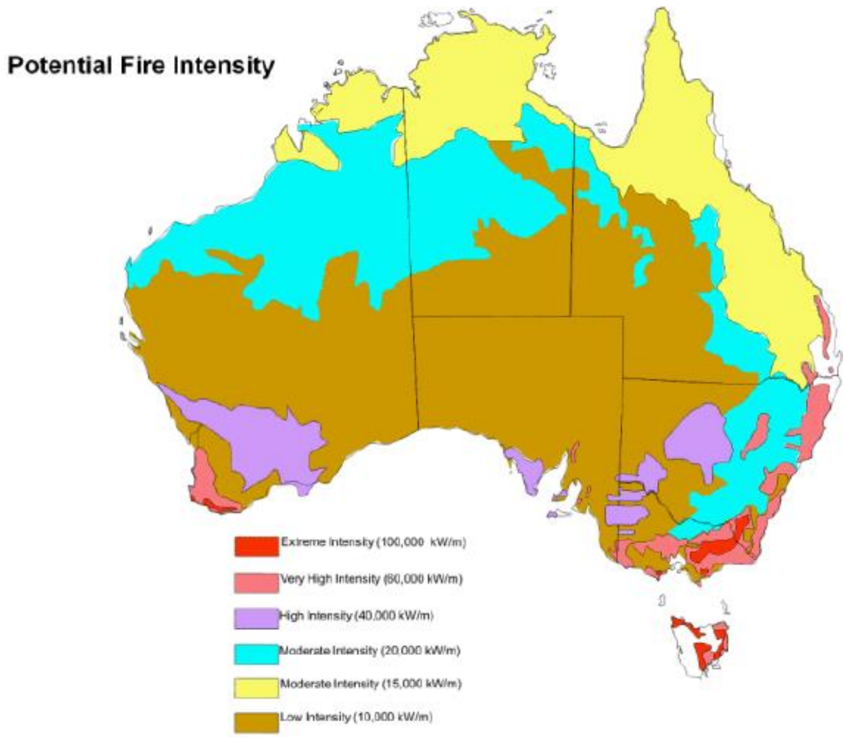
Source: Bureau of Meteorology.[234]

[234] Bureau of Meteorology, Six-monthly NDVI Average for Australia, available at http://www.bom.gov.au/jsp/awap/ndvi/index.jsp [last accessed 1 March 2015].

While vegetation density in western Victoria is more comparable to the vegetation density covering SA Power Networks' network area, we observe that only a small area of South Australia is covered by high-density vegetation. The coverage of high-density vegetation is predominantly observed at the southernmost tip of South Australia, an area that is smaller than the area of high density vegetation in south-western Victoria. We therefore consider that SA Power Networks faces a lower bushfire risk from eucalypt forests than its Victorian counterparts.

Additionally, we have obtained evidence of bushfire risk mapping referenced by other distributors, as shown in Figure and figure B.5 below.[235] It shows that the total area of South Australia classified as high or very-high bushfire risk is smaller than the respective bushfire risk areas in Victoria. Moreover, part of eastern Victoria is classified as extreme risk. We also note that there is a close relationship between the high to extreme bushfire potential zones in Figure and Figure B.5 and the areas of high vegetation density shown in Figure .

Figure B.4 Map of potential fire intensity



Source: Dr Kevin Tolhurst.[236]

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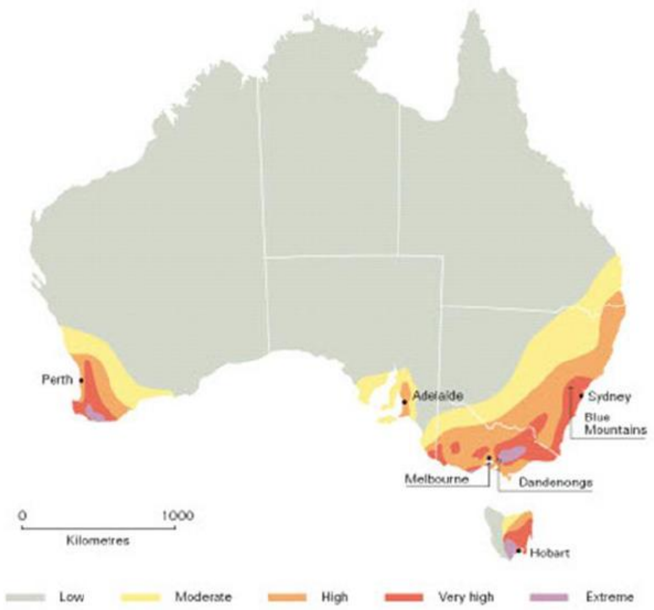
[235] Essential Energy, Revised Proposal: Attachment 7.10, 20 January 2015, p. 15; AusNet Services, *Energy Insights: Network safety and bushfire mitigation*, 2014, p. 4.

[236] Essential Energy, Revised Proposal: Attachment 7.10, 20 January 2015, p. 16.

Figure B.5 Map of bushfire potential zones in Australia



Source: Johnson, R. W., Blong R. J. and Ryan C.J., 1995.[237]

We consider that the evidence of fire starts and fire risk observed in Figure through Figure indicate that the bushfire risk environment in South Australia is materially lower than in Victoria.

Given time available, we have not provided figures B.2 to B.5 to SA Power Networks in advance of this final decision. However, in our preliminary decision, we noted that while the Jacobs report relied on by SA Power Networks submitted that some of the PBST initiatives may now be considered as good industry practice, it had offered no information to reasonably demonstrate that, in SA Power Networks' circumstances, it would be prudent to adopt these practices.[238] We expressed the view that the Jacobs report did not sufficiently support that its recommended package of works is required to comply with its current or expected future safety obligations related to bushfire risk. In response to our preliminary decision, we note that SA Power Networks did not provide sufficient evidence that demonstrates that bushfire risk levels in South Australia are comparable to bushfire risk levels on the Victorian rural networks. As such, we do not consider there is sufficient evidence before us to satisfy us that SA Power Networks is required to adopt the recommendations of the VBRC and PBST.

[237] Johnson, R. W., Blong R. J. and Ryan C.J. 1995. Natural Hazards Potential Map of the Circum-Pacific Region: Southwest Quadrant, 1995, pp. 51–52.

[238] AER, *SAPN preliminary decision: Attachment 6 capital expenditure*, April 2015, pp. 52–53.

Differences in network construction

As discussed above, 'good electricity industry practice' is influenced by the specific nature of the assets involved (including their design). We note that there are differences in the network construction between SA Power Networks' network and electricity distribution networks in Victoria. As SA Power Networks' consultant Jacobs explained, there are construction standards in South Australia that assist in reducing bushfire starts. These standards include:[239]

- Concrete and steel poles (Stobie poles) – Stobie poles are of consistent mechanical strength, are not combustible and are not prone to termite attack. This results in longer life and a lower likelihood of failure in high winds.
- Steel cross arms – Unlike wooden cross arms, steel cross arms are not combustible and do not catch fire during events such as flashovers or lightning surges.
- A common multiple earthed neutral (CMEN) arrangement that provides a low impedance path for fault current back to the source zone substation. CMEN, coupled with steel cross arms and steel poles, provides low impedance for earth fault currents resulting in generally fast protection operation and clearance.

These construction standards are widely used in South Australia and are not found, or are much less common, in Victoria. As shown in Table , the rural Victorian distributors AusNet Services and Powercor do not use stobie poles on their respective networks, rather they predominantly use wooden poles, which are susceptible to burning.

Table B.4 Proportion of SA Power Networks', AusNet Services' and Powercor's pole population by pole type

Pole type	SA Power Networks	AusNet Services	Powercor
Stobie poles	100%		
Wooden poles		54.6%	74.3%
Concrete poles		30.6%	24.6%
Steel poles		14.8%	0.2%

Source: AER analysis, SA Power Networks 2013-14 category analysis RIN, AusNet Services 2014 category analysis RIN, Powercor 2014 category analysis RIN.

Note: Numbers may not add to 100 percent due to rounding.

SA Power Networks noted that these differences in network construction are part of the reason its historical fire starts are better than the historical Victorian fire start

[239] Jacobs, *Recommended Bushfire Risk Reduction Strategies for SA Power Networks*, Final Report, October 2014, p. 5.

performance.[240] Although SA Power Networks considered that these measures are insufficient to mitigate its bushfire risk to acceptable levels,[241] it has not demonstrated that the advantages of its network construction have been accounted for in its proposal. This further supports our conclusion that SA Power Networks' proposed bushfire mitigation program does not reflect the capex criteria.

The Work, Health and Safety Act

We do not consider that SA Power Networks' current obligations under the WHS Act justify the additional expenditure sought through its bushfire mitigation program.

In its revised proposal SA Power Networks submitted that its activities are governed by the WHS Act. It therefore owes a non-delegable duty to ensure, so far as reasonably practicable, that its workplace is without risk to the health and safety of any person.[242] SA Power Networks says that it must therefore consider what can be done to remedy any risk to health and safety, and then consider whether it is reasonably practicable to take the identified action.

The Energy Users Association of Australia (EUAA) submitted that, to its knowledge, the WHS Act has not been amended recently and does not contain any new obligations in relation to SA Power Networks management of risk.[243] We agree with the EUAA. On the information before us, we do not consider that SA Power Networks is currently unable to meet its obligations under the WHS Act or that its obligations have changed such that additional capex is required to meet them.

SA Power Networks' ability to continue managing bushfire risk

As we noted above, the evidence before us indicates that SA Power Networks is meeting its obligations under the Electricity Act. SA Power Networks has explained that it has a comprehensive and mature Bushfire Risk Management System (BRMS). This system has been in place since the early 1980s after investigations into the impacts of the 1983 Ash Wednesday fires in South Australia, and has been progressively improved since.[244]

In this section, we explain that we do not consider SA Power Networks has provided sufficient evidence that demonstrates its fire start risk has increased. We have also considered SA Power Networks' ability to manage a potential increase in fire start risk. Evidence before us indicates that SA Power Networks would be able to manage an increase in fire start risk should it eventuate, given its legislated power to cut off power

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240 SA Power Networks, *Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence*, July 2015, p. 9.

241 SA Power Networks, *Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence*, July 2015, pp. 9–10.

242 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, pp. 83–84.

243 Energy Users Association of Australia, *Submission to AER draft determination and SA Power Networks' revised revenue proposal for the 2015 to 2020 regulatory period*, July 2015, p.9.

244 SA Power Networks, *SA Power Networks: Bushfire Mitigation Programs Business Case*, October 2014, p. 13.

in high bushfire risk situations. The evidence also indicates that SA Power Networks has improved its fire start performance to date; this satisfies the capex objective of maintaining the safety of the distribution system. We are therefore not satisfied that the additional proposed expenditure meets the capex criteria.

In its original proposal, SA Power Networks provided Bureau of Meteorology (BOM) and CSIRO reports analysing climatic trends in South Australia.245 The climate trends showed that extreme hot temperatures were expected to increase in South Australia over the next 5 to 10 years. While we noted in our preliminary decision that the BOM and CSIRO analyses forecast increasing fire danger days in summer, we considered that SA Power Networks did not provide analysis correlating that increase to an increase in the likelihood of a bushfire ignition from an electricity asset.[246]

In its revised proposal, SA Power Networks considered its bushfire risk is increasing because:[247]

- BOM and CSIRO data shows the number of extreme fire danger days per year is increasing
- it is accepted that the percentage of fires caused by electrical assets rises above the long-term average on extreme fire danger days.

As such, SA Power Networks submitted that if the proportion of fires caused by electricity assets remains the same on any given high bushfire risk day, then an increase in the number of high bushfire risk days will lead to more fires caused by electricity assets.[248]

SA Power Networks provided additional evidence of bushfire risk in its revised proposal. In summary it shows:[249]

- its assets do cause fires, an average of 49 per year in bushfire risk areas
- most of these fire starts occur between November and February each year
- the specific assets that cause fires, for example, it appears that its 33kV assets are most prone to start fires.

We accept that electricity assets do cause fires; however, we do not consider this additional evidence indicates that SA Power Networks is likely to cause more fires if the frequency of high bushfire risk days were to increase. SA Power Networks has extrapolated from the forecast increase in extreme fire danger days to predict an increased frequency of fire starts caused by electrical assets, but has not provided

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245 CSIRO and Bureau of Meteorology, *State of the Climate 2014*, 2014; Bureau of Meteorology (BOM), *Climate extremes analysis for South Australian Power Network operations*, 2014.

246 AER, *SAPN preliminary decision: Attachment 6 capital expenditure*, April 2015, p. 51.

247 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 85.

248 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 85.

249 SA Power Networks, *Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence*, July 2015, pp. 7–12.

sufficient evidence to support this extrapolation. As such, we do not consider that SA Power Networks has provided sufficient evidence that demonstrates its fire start risk has increased.

SA Power Networks has the ability to mitigate against the risk of fire starts on extreme fire danger days by cutting off the power. Further, the evidence before us indicates that SA Power Networks has improved its fire-start performance over recent years, during a period of time when bushfire risk has also been increasing. We discuss this evidence below.

SA Power Networks' ability to turn off the power

As explained by the SA Minister, and as we noted in the preliminary decision, SA Power Networks has been empowered through legislation to disconnect specific areas of the distribution network in extreme conditions to minimise the potential for a catastrophic bushfire.[250] SA Power Networks explained that cutting power to high-risk areas reduces the chances of a bushfire starting, particularly if a tree branch, vegetation or flying debris comes into contact with a powerline as a result of strong winds.[251] We consider that because SA Power Networks is empowered to cut off the power on extreme fire danger days, it does not necessarily follow that the frequency of asset-caused fires will increase correspondingly with the forecast increase in the frequency of extreme fire danger days. We are therefore not satisfied that the proposed incremental capex meets the capex criteria.

SA Power Networks considered it would not be taking reasonable steps if it relied on this power to mitigate bushfire risk, when the adoption of other practices could reduce that risk.[252] In particular, it is concerned that turning off the power will impose additional risks on the community.[253]

As we note above, SA Power Networks considered that the 'reasonable steps' obligation requires it to have regard to 'good electricity industry practice'. We have explained that 'good electricity industry practice' needs to be considered in the context of the regulatory and network environment the electricity service provider operates in. Although the PBST and the Victorian Government did not share the view that it is appropriate to provide the Victorian distribution networks with the ability to cut off the power, the South Australian Government has determined that it is an appropriate risk mitigation measure for SA Power Networks to have and to use in the South Australian context.

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[250] Electricity Act, section 53 (1) and (2); The Government of South Australia, *Minister for Mineral and Resources and Energy Submission to Regulatory Proposal*, 30 January 2015, p. 5.

[251] SA Power Networks, *Factsheet: Bushfires and your electrical safety*, September 2012, p. 1.

[252] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 89.

[253] SA Power Networks, Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence, July 2015, p. 19.

Following the 1983 Ash Wednesday bushfires, the South Australian Government passed legislation enabling electricity distributors to cut off the power to specific areas in extreme conditions. As SA Power Networks explained, it has an agreed set of criteria and procedures for using its power, which has been discussed with the Country Fire Service and the South Australian Government.[254]

Regarding the additional risks to the community of turning off the power, we note that SA Power Networks has communicated to its customers that they should be prepared and have plans in place to cope with a power outage. It also advises the media and advertises regularly during the warmer months.[255] We consider SA Power Networks has taken appropriate steps to ensure that community risks are minimised in the event of a power outage.

SA Power Networks states that although its authority to cut off the power does reduce bushfire risk, the fire reduction is localised, and does not prevent fires starting in other bushfire risk areas.[256] As noted above we accept that electricity assets will cause fire starts; the provision to cut off the power to specific areas allows SA Power Networks to mitigate against starting fires in those areas facing the most acute bushfire risk.

SA Power Networks' fire start performance

Evidence provided by SA Power Networks shows that it has improved its fire-start performance to date using business-as-usual expenditure, and has done so during a period of increasing bushfire risk. The evidence further supports the view that SA Power Networks does not require additional expenditure to meet the capex criteria.

As noted above, SA Power Networks provided evidence of its annual fire starts in bushfire risk areas. Figure shows SA Power Networks' annual fire starts between 2008 and 2014.

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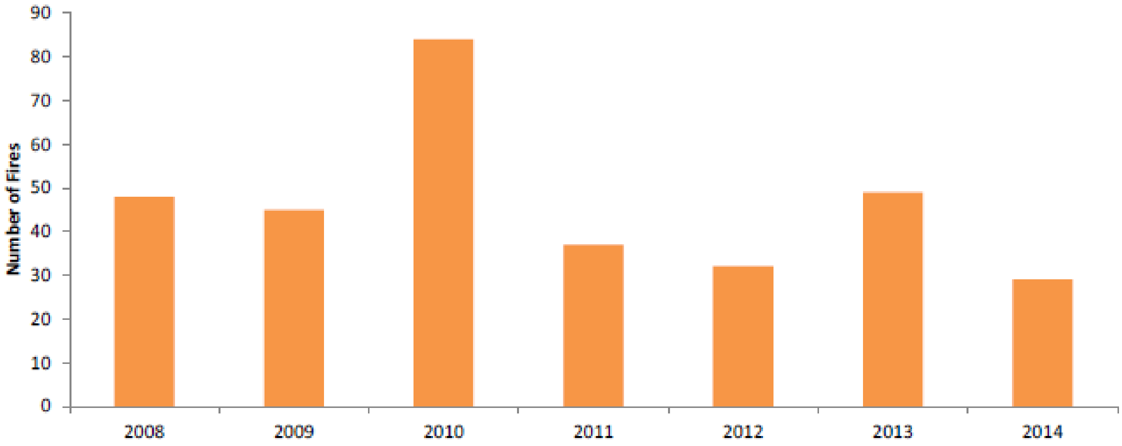
[254] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 88.

[255] SA Power Networks, *Factsheet: Bushfires and your electrical safety*, September 2012, p. 1.

[256] SA Power Networks, *Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence*, July 2015, p. 9.

Figure B.6 Annual trend of number of fire starts from electricity assets in the period 2008–14, in bushfire risk areas



Source: SA Power Networks, Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence, p. 8.

As SA Power Networks has noted, over the period 2008–2014, its assets have started an average of 49 fires per year in bushfire risk areas.[257] However, we consider that Figure shows a decreasing trend in fire starts per year between 2008 and 2014, which suggests that SA Power Networks is at least achieving the capex objective of maintaining the safety of the distribution system.[258] We accept that one would reasonably expect some variation in the number of fire starts year on year, as reflected in the increases experienced in 2010 and 2013. However, we consider that the data provided by SA Power Networks shows a clear improvement in performance over the 2008 to 2014 period.

We note this overall decrease in annual fire starts has occurred during a period when the number of fire danger days increased. BoM concluded in its analysis that the number of fire danger days in summer has increased between 1.7 and 2.5 times since 2000 in South Australia's high bushfire risk areas.[259]

This evidence, in addition to evidence of SA Power Networks' fire-start performance relative to Victorian distributors (Figure), indicates that SA Power Networks is managing its current fire start risk appropriately.

[257] SA Power Networks, *Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence*, July 2015, p. 8.

[258] NER, cl. 6.5.7(a)(4).

[259] Bureau of Meteorology (BoM), *Climate extremes analysis for South Australian Power Network operations*, 2014, p. 4.

Cost/benefit analysis

In the preliminary decision we noted that SA Power Networks' business case to support the bushfire mitigation program did not properly identify and measure the costs and the benefits of the program as is typically required in a cost benefit analysis.[260] In its revised proposal, SA Power Networks submitted that analysing the costs and benefits of any bushfire mitigation program is not appropriate.[261] It considered that in complying with safety laws:[262]

> …the role of cost/benefit analysis is not to determine whether the benefits of the proposed expenditure would outweigh the costs, but rather whether that cost is grossly disproportionate to the risk in question.

SA Power Networks submitted that works undertaken to address health and safety are as a general rule not capable of being fully justified by reference to a cost/benefit analysis. It considers this is because the chief benefits of such expenditure are typically the avoidance of death and serious injury.[263]

SA Power Networks has cited the As Low As Reasonably Practical (ALARP) risk mitigation principle. Our view is that is that if SA Power Networks considered an analysis based on ALARP is more appropriate than a standard cost/benefit analysis, then it should have provided us with an ALARP based cost/benefit analysis. In doing so, it could have indicated to us what it considered a reasonable cost/benefit threshold to be. As we explain in the explanatory statement to our expenditure forecast assessment guideline, where investments are intended to meet regulatory obligations (as SA Power Networks considered is the case in this instance) we do not expect the investments to necessarily be net benefit positive.[264] Where investment costs outweigh the benefits, the cost benefit analysis should show the chosen option is the least negative from a net benefit perspective. In the ALARP case, this would involve demonstrating that the cost involved in reducing the risk any further would be grossly disproportionate to the benefit gained from further risk reduction. As such we are not satisfied that the proposed allowance reflects the efficient costs that a prudent operator would require to maintain the safety and security of the distribution system to meet its regulatory obligations and requirements.

We recognise that SA Power Networks has a legitimate need to mitigate the risk of serious consequences occurring. It is essential to the complex regulatory framework for managing risk that a service provider properly evaluate risks, including both the probability of occurrence and consequence of the event, and make appropriate judgements about what can, as far as reasonably practicable, be done.

260 AER, *SAPN preliminary decision: Attachment 6 capital expenditure*, April 2015, p. 54.

261 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 90.

262 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 91.

263 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 91.

264 AER, *Explanatory Statement: Expenditure Forecasting Assessment Guidelines*, November 2013, pp. 126–127.

SA Power Networks has provided evidence that it has considered the cost of each project and the probability of reductions in fire start events.[265] Additionally, in its original proposal, SA Power Networks submitted a report by Willis, which details the estimated Maximum Probable Loss (MPL) from a bushfire event that Willis derived from its South Australian modelling.[266] Recognising that SA Power Networks has estimated the probability of fire start occurrences, and Willis estimated the financial consequences of bushfire events, it seems logical that SA Power Networks would have the information to undertake a cost/benefit analysis.

However, SA Power Networks not provided such an analysis; it has not drawn a quantitative link between the cost of the bushfire mitigation program, and the benefit (the estimated reduction in fire starts and the financial impact of those avoided fire starts). We are therefore not satisfied that SA Power Networks has demonstrated that the costs of its proposed bushfire mitigation program reasonably reflect the efficient costs that a prudent operator would require to maintain the safety and security of the distribution system.

Project proposals within the bushfire mitigation program

In the sections above we have considered SA Power Networks' compliance with its regulatory obligations and its ability to manage the existing and potential risks. As explained, we consider that SA Power Networks' proposed additional expenditure does not reasonably reflect the capex criteria.

However, as an additional step, we have also considered whether the three projects that form its revised bushfire mitigation program reasonably reflect the capex criteria at an individual project level. These proposed projects include SCADA reclosers, surge arrestors and metered mains. We consider these projects below.

SCADA reclosers

SA Power Networks proposed $18.1 million ($2014–15) to target and replace aging 33kV, 19kV and 11kV manual reclosers in bushfire risk areas with SCADA[267] controlled units.[268]

We recognise that the installation of SCADA reclosers may mitigate fire start risks, however we consider the replacement of aging reclosers funded through augex does not reasonably reflect the capex criteria. We have provided funding for the replacement of aging reclosers in our repex allowance, and expect that SA Power Networks will prioritise its repex program in accordance with its risk management framework.

[265] SA Power Networks, *Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence*, July 2015, pp. 13–20.

[266] Willis Risk Services, SA Power Networks Limited Bushfire Modelling: Attachment 11.3a, December 2013.

[267] Supervisory control and data acquisition

[268] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, pp. 95–97.

SA Power Networks cites the VBRC report, which found that in the case of a permanent fault, the reclosers operation can substantially increase the risk of a fire, because the recloser will repeatedly restore high-voltage electricity to the conductor. SA Power Networks noted it faces the same risks as it has many manual reclosers in service, as was the case in Victoria.[269]

SA Power Networks also highlights that the operation of SCADA reclosers will allow it to better target its authority to switch off supply during high bushfire risk conditions, reducing the number of customers affected by an outage. This submission was noted by the CCP, who submitted that we should reconsider the merits of the recloser replacement with SCADA reclosers, whether as replacement or augmentation.[270]

We consider the proposed SCADA reclosers program, as an augex program, does not reasonably reflect the capex criteria because we provide a repex allowance to fund replacement of aging reclosers. In other words, we consider that the efficient approach of a prudent operator would be to replace those aging reclosers as provided for through the repex allowance. We note that SA Power Networks is proposing to replace reclosers that are around 40 to 50 years old as augex.[271] The age of SA Power Networks' reclosers is captured in the asset age profiles of our repex modelling. As the repex modelling forms the basis of our repex estimate, the cost of like-for-like replacement of reclosers is provided for in the repex allowance. This allowance will allow SA Power Networks to maintain the safety level of its reclosers. We do not accept SA Power Networks' position that its proposed bushfire mitigation expenditure would not be classified as repex because it is being incurred to comply with its regulatory obligations.[272] As we discuss above, the evidence before us indicates that SA Power Networks is compliant with its regulatory obligations with its current expenditure levels.

We note that we do not regulate cost, only revenues. It is for SA Power Networks to balance its expenditure to meet its requirements in accordance with its risk profile. As the CCP noted, we have provided SA Power Networks with an increased repex allowance relative to historical levels; it can therefore prioritise replacement expenditure in high bushfire risk areas if it considered that to be a prudent risk-management approach.[273]

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269 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 95.

270 Consumer Challenge Panel #2, *Advice to AER: AER's Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks' Revised Regulatory Proposal*, August 2015, p. 64.

271 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 95.

272 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 89.

273 Consumer Challenge Panel #2, *Advice to AER: AER's Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks' Revised Regulatory Proposal*, August 2015, pp. 64–65.

Surge arrestors

SA Power Networks propose $12.4 million ($2014–15) to replace Rod Air Gaps (RAGs) and Current Limiting Arcing Horns (CLAHs) with modern surge arrestors.[274] It says it is currently good practice for distributors to use surge protectors for their power line overvoltage protection.[275]

We do not consider that the proposed investment program reasonably reflects the capex criteria. Additionally, as explained in appendix B.4, we note that SA Power Networks has been given additional business-as-usual repex that addresses increased asset replacement needs.

SA Power Networks states that RAGs and CLAHs are a legacy technology to protect its equipment from the effects of overvoltages. It submitted that RAGs and CLAHs have failed when these devices are bridged by animals or birds and lightning strikes, and this has resulted in the animals and birds falling to the ground and starting fires.[276] It says its practice is now to use surge arrestors to protect its equipment, which is a more expensive but more reliable form of surge protection.

SA Power Networks states that there are no specific obligations in other states to replace older surge arrestors that may be a fire hazard.[277] It considered that regardless of there being no specific obligation, the VBRC was critical of distributors and safety regulators for not adequately planning the retirement of older technologies that were shown to be a fire start hazard in bushfire risk areas.

On the information before us, we do not consider that the additional expenditure for surge arrestors is required for SA Power Networks to satisfy its obligation to take reasonable steps to ensure infrastructure safety under section 60(1). While surge arrestors are primarily intended as overvoltage protection (e.g. from lightning strikes), we do not consider that the expenditure is justified given SA Power Networks' network construction. In its report, Jacobs states that stobie poles and steel cross arms do not catch fire during lightning surges.[278] Further we consider that, in its submissions to us, SA Power Networks has not adequately reconciled the disadvantages of RAG's and CLAH's with the advantages of its unique network construction (stobie poles, steel cross arms, etc.).

SA Power Networks states that an average of four fires per year is caused by fauna contact with RAGs and CLAHs.[279] We recognise that RAGs and CLAHs are more

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[274] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, pp. 97–98.

[275] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 97.

[276] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 97.

[277] SA Power Networks, *Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence*, July 2015, p. 6.

[278] Jacobs, *Recommended Bushfire Risk Reduction Strategies for SA Power Networks*, Final Report, October 2014, p. 5.

[279] SA Power Networks, *Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence*, July 2015, p. 11.

prone to fauna contact incidents compared to surge arrestors, however it is also the case that fauna contact incidents do occur with surge arrestors. Most surge arrestors are also able to be bridged by fauna unless additional insulation is applied and consequently while it is likely that surge arrestors will reduce the frequency of fauna contact, they will not eliminate these incidents. SA Power Networks seem to acknowledge this point in Table 5 of Attachment G.2,[280] when it states that for $10 million spent on surge arrestors the expected reduction in events is 28.2 fewer fires per 30 years, or a reduction of just under one event per year. This reduction would mean approximately three (instead of four) fire starts will occur per year caused by fauna contact with surge arrestors.

SA Power Networks has not explained why expenditure of $12.4 million for a reduction of approximately one fire start per year is prudent and efficient, and required in the context of its ability to manage bushfire risks to date.

We note that SA Power Networks points to the statement in the Jacobs Report which identifies that it did not have a program to replace its older pole-mounted surge arrestors with modern equivalents.[281] However, we also note that while a dedicated program to replace RAGs and CLAHs with modern equivalents may not have historically existed, replacement of legacy devices has been occurring on an as–required basis.[282] Consequently repex already includes an amount that reflects historic replacement of RAGs and CLAHs that have maintained SA Power Networks surge arrestor population. In addition, we have approved a higher repex allowance for the 2015–20 period, relative to SA Power Networks' current repex allowance. This increased allowance will allow SA Power Networks to further add to the level of forward asset replacement.

Metered mains

'Metered mains' refers to the electricity infrastructure between a customer's meter and switchboard, in cases where there is a distance between the two.[283] SA Power Networks submitted that uncertainty over the ownership of and responsibility for these assets has resulted in the lack of maintenance of assets, which has resulted in fire risks. It also submitted that much of the 'metered mains' infrastructure did not meet its standards at the time of construction, or if it did, it no longer meets its current standards.[284]

[280] SA Power Networks, *Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence*, July 2015, p. 18.

[281] SA Power Networks, *Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence*, July 2015, p. 6.

[282] Jacobs, *Recommended Bushfire Risk Reduction Strategies for SA Power Networks*, Final Report, October 2014, p. 23.

[283] The metered mains were originally installed to aid the efficient reading of meters by co-locating all meters for properties in rural areas close to or adjacent to a road.

[284] SA Power Networks, *Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence*, July 2015, p. 6.

SA Power Networks propose $10.1 million ($2014–15) to upgrade or replace metered mains to ensure that they meet the required standards and to clarify with individual property owners who will be responsible for the maintenance of the asset going forward.[285]

We are not satisfied the proposed metered mains project is prudent and efficient and therefore, we do not consider the proposed expenditure meets the capex criteria.

SA Power Networks explains that prior to the privatisation of ETSA Utilities, there were various agreements between it and councils for the transfer of electricity undertakings:[286]

> These agreements contained broad and general descriptions of the (then) councils' electricity distribution system, with no apparent distinction of metered mains and its demarcation of ownership (and relevant responsibilities and obligations) between the distribution network and the customer - consequently a number of these assets have either not been inspected and/or maintained.

In addition to its general obligations under section 60(1) of the Electricity Act, the NER and the WHS Act (which we discuss above), SA Power Networks submitted that concerns over liability for damages is part of the rationale for the metered mains project.[287] It submitted that if one of the metered mains fail leading to a significant fire or public injury event, it is likely that any person who suffers a loss due to that failure will seek to recover that loss from SA Power Networks. It considered it will be liable for losses even if the exact ownership of the metered main is unclear (for example, the person may seek to argue that SA Power Networks has a duty of care in relation to electrical assets that are connected to, and are immediately adjacent to, SA Power Networks' distribution system).[288]

We note that SA Power Networks has an obligation under section 22(f) of the Electricity Act, which requires it to maintain insurance against any liability for causing a bushfire. We have confirmed with SA Power Networks that its current insurance covers it against liabilities relating to fires which are started by metered mains, subject to certain terms and conditions.[289] We therefore consider that any additional capex is not justified, noting that the information before us indicates that SA Power Networks is presently compliant with its regulatory obligations.

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285 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, pp. 98–99.

286 SA Power Networks, *Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence*, July 2015, p. 6.

287 SA Power Networks, *Revised Proposal Attachment G.4 SAPN metered mains – supporting evidence, July 2015*, p. 3.

288 SA Power Networks*, Revised Proposal Attachment G.4 SAPN metered mains – supporting evidence, July 2015*, p. 3.

289 SA Power Networks response to information request AER SAPN 060_Bushfire mitigation program, p. 2 (confidential).

SA Power Networks states that it is difficult to see empirical evidence of metered mains causing fires in its historical fire start data, and says that as far as it is aware, no reported incidents have occurred.[290] However, it considered this finding should be taken with caution as incidents may have been small and therefore not have been reported to it. SA Power Networks considered the absence of evidence is not sufficient to say the risk does not exist. It adds that mitigating fire risk associated with metered mains needs to be seen largely in isolation from the other proposed projects, as there will typically be no devices to operate (i.e. no reclosers) should a fault occur on those low voltage lines with metered mains.[291]

In the absence of any such empirical evidence, we do not consider that the capex proposed for SA Power Networks' metered mains program reasonably reflects the capex criteria.

We also note that SA Power Networks has not provided evidence that it has taken any substantial steps to consult with the respective property owners to resolve uncertainty over ownership of these assets. Efforts to resolve uncertainty over ownership may have improved asset maintenance and reduced its potential obligation to fund repairs. Although SA Power Networks does discuss cost sharing the metered mains program with property owners (an option it rejects)[292], we consider SA Power Networks should have shown it consulted with property owners to clarify ownership uncertainties before proposing its capex program. We consider that clarifying ownership uncertainties is a more prudent and efficient approach than proposing additional capex in respect of assets that SA Power Networks may not own.

In circumstances where the landowner has responsibility over metered mains, we recognise that SA Power Networks still has a duty regarding the safety of these mains. If, in the normal course of its business it is aware that the condition of the metered mains is unsafe, then SA Power Networks has a duty to act to have the unsafe situation addressed. However, it does not follow that SA Power Networks is under a duty itself to bear the cost of rectifying the safety problem. Rather, it must at least take action to advise the owner of those mains that they are unsafe and that any safety issues must be rectified. SA Power Networks' service and installation rules state:[293]

> Should an installation not satisfy the requirements of these Rules, connection of electricity supply may be delayed or withheld, <u>and installations with supply may be disconnected until such time as the non-compliance/s has been rectified.</u> [emphasis added]

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290 SA Power Networks, *Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence*, July 2015, p. 12.

291 SA Power Networks, *Revised Proposal Attachment G.2 SAPN bushfire mitigation – supporting evidence*, July 2015, p. 12.

292 SA Power Networks, *Revised Proposal Attachment G.4 SAPN metered mains – supporting evidence, July 2015*, pp. 9, 13-14.

293 SA Power Networks Service and Installation Rules – 2014, Section 2, Clause 2.11.

This principle of the right to disconnect unsafe installations is common across all jurisdictions. It is further reinforced in the definition of the role of SA Power Networks' service and installation rules.[294]

Moreover, where a customers' installation is unsafe, Section 62 of the Electricity Act empowers the Technical Regulator to disconnect or repair the installation, and recover the cost of repair as a debt due to the Crown. As such, there are specific provisions that SA Power Networks can seek to enforce in order to ensure that metered mains are restored to a safe condition.

This indicates that SA Power Networks has the ability to disconnect unsafe installations until rectified as a means to mitigate damage. We therefore consider that the capex for the proposed metered mains program does not reasonably reflect the capex criteria. Further, insofar as metered mains are customer-owned, we consider the cost of rectifying metered mains is more appropriately borne by the individual customer rather than spread across the entire customer base and capitalised in the regulatory asset base.

Bushfire Safer Places

SA Power Networks proposed $25.6 million ($2014–15) to reinforce the supply of electricity (undergrounding) to 12 Country Fire Service (CFS) designated BSPs[295]. The primary driver behind the undergrounding of supplies to BSPs is to maintain electricity supply to these precincts for as long as possible during bushfire events.[296]

In our preliminary decision, we did not accept SA Power Networks' proposed $128.6 million ($2014–15) capex for the undergrounding work proposed as part of the bushfire safety program. We considered that the business case and WTP survey and its findings did not demonstrate that the bushfire mitigation program is a prudent and efficient investment.[297] SA Power Networks originally proposed to underground 135km of power lines in high bushfire risk areas, including the undergrounding of supplies to BSPs.

In its revised proposal, SA Power Networks reduced the scope of the project and removed it from the 'bushfire mitigation' umbrella because the driver of the project is community safety, not bushfire mitigation.[298] It justifies the expenditure on the undergrounding project from the level of support evident from its Customer Engagement Program (CEP).[299] SA Power Networks considered that our decision to reject its CEP is fundamentally erroneous. It considered the CEP demonstrated that its

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294 SA Power Networks Service and Installation Rules – 2014, Section 1, Clause 1.1.2.

295 Following the Back Saturday bushfires, the Country Fire Service launched the Bushfire Safer Places initiative, where certain settlements and precincts are designated places of relative safety in extreme fire conditions.

296 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 104.

297 AER, *SAPN preliminary decision: Attachment 6 capital expenditure*, April 2015, p. 54.

298 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p.105.

299 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, pp.103–105.

customers value safety very highly and expect it to undertake additional steps to ensure ongoing community safety in high bushfire risk areas.[300]

We consider that SA Power Networks has not demonstrated that the proposed capex for the revised BSPs program reasonably reflects the efficient costs a prudent operator would require to achieve one or more of the capex objectives. We also remain unsatisfied with the consultation process that SA Power Networks' provided in support of the BSPs program.[301] As also set out below, we accept that under the PLEC criteria, funding for BSPs projects are unlikely to be supported solely on safety grounds.

Prudency and efficiency of the Bushfire Safer Places program

We consider that the proposed capex for the BSPs program is not efficient capex that would be incurred by a prudent operator, because SA Power Networks has not demonstrated that there is an existing issue of network safety that needs to be resolved. It has not identified any specific regulatory requirement that requires it to provide underground power to the CFS-designated BSPs. Rather, it states that the program is based on concerns raised by its customers about community safety in bush fire risk areas.

Further, SA Power Networks has not demonstrated that the capex associated with the BSPs program is efficient because it did not provide an options analysis, showing that it considered the costs of other options aside from undergrounding. We noted the concerns of stakeholders in the preliminary decision, which questioned whether more cost effective options were considered by SA Power Networks.[302] SA Power Networks is proposing to underground the area of 12 Bushfire Safer Precincts, which costs approximately $2.23m per site (i.e. $26.8m for 12 sites).[303] We cannot properly assess the efficiency of the expenditures associated with the undergrounding program without reference to an evaluation of other options that have been considered. SA Power Networks briefly mentions that it considered local generation, but considered it is likely that installation of sufficient size local generation would be a costly alternative to undergrounding.[304] It also considered microgrid technology, but is of the view that microgrids are not proven technically or commercially ready. However, SA Power Networks provided no evidence that show it has evaluated the costs, benefits and risks of implementing each of these proposed options.

Stakeholder engagement

SA Power Networks' CEP lends support to the BSPs program and we have had regard to this information. We recognise that 83 per cent of participants in SA Power Networks' Stage 1 CEP workshop considered that ensuring a continuous supply of

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[300] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p.103.

[301] AER, *SAPN preliminary decision: Attachment 6 capital expenditure*, April 2015, pp. 56–57.

[302] AER, *SAPN preliminary decision: Attachment 6 capital expenditure*, April 2015, p. 52.

[303] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p.105.

[304] SA Power Networks, *SA Power Networks: Bushfire Mitigation Programs Business Case*, October 2014, pp. 12–13.

electricity to BSPs was an essential activity to be undertaken.[305] However, we also note stakeholders expressed concerns with the WTP survey that SA Power Networks used to support the proposed capex on the BSPs program. For example, the EUAA, SACOSS and the CCP considered that the WTP survey respondents were not presented with complete information regarding the additional cost impacts and the proposed benefits.[306] SA Power Networks considered that we should place little or no weight on those submissions regarding its CEP as they are unsubstantiated, largely anecdotal in nature and few in number.[307] As we discuss in Overview section 6, we have regard to all stakeholder views. We also expect the conclusions SA Power Networks has drawn from its CEP would be reflected in stakeholder submissions representing the views of South Australian residential and business users.

As outlined in our preliminary decision, we commissioned Oakley Greenwood to conduct a review of SA Power Networks' study.[308] It found the decision made by customers did not reflect informed choices given the limited information provided to customers about the benefits of each of the options.[309] In response to this finding, SA Power Networks and The NTF Group acknowledged that the safety benefits were not quantified. They stated this was because SA Power Networks could not draw objective, verifiable links between the initiatives and the outcomes that could be achieved.[310]

In response to SA Power Networks' revised proposal, SACOSS highlighted that while it might not be possible to link a cost to an outcome, this demonstrates weakness of the WTP methodology and tends to support the view that the findings are not robust.[311] We also reengaged Oakley Greenwood for the final decision, who noted that:[312]

> …asking customers to make choices where they are not as informed as possible, runs the risk of informing pricing decisions that may not be popular once the consequences are better understood.

We agree with SACOSS and Oakley Greenwood that if SA Power Networks is not able to quantify and communicate the safety benefits when undertaking its WTP research, the findings are less likely to reflect customers' views as to their willingness to pay.

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305 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p.103.

306 Energy Users Association of Australia, *Submission to AER draft determination and SA Power Networks' revised revenue proposal for the 2015 to 2020 regulatory period*, July 2015, p.6; SACOSS, *SACOSS Submission to the Australian Energy Regulator on SA Power Networks' Revised Regulatory Proposal 2015-20*, July 2015, p. 9; Consumer Challenge Panel #2, *Advice to AER: AER's Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks' Revised Regulatory Proposal*, August 2015, p. 63.

307 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, pp. 28, 30, 34.

308 Oakley Greenwood, *Peer review of the willingness to pay research submitted by SA* Power Networks, April 2015.

309 Oakley Greenwood, *Peer review of the willingness to pay research submitted by SA* Power Networks, April 2015, p.6.

310 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 33; SA Power Networks, Revised Proposal Attachment C.7 SAPN_The NTF Group report on Oakley Greenwood peer review, July 2015, pp. 5–6.

311 SACOSS, *SACOSS Submission to the Australian Energy Regulator on SA Power Networks' Revised Regulatory Proposal 2015-20*, July 2015, p. 9.

312 Oakley Greenwood, *Response to comments on the peer review of WTP research submitted by SA Power Networks*, September 2015, p. 4.

Further, the WTP survey was only aimed at measuring the willingness to pay of South Australian residential consumers.[313] It did not assess whether non-residential consumers would be willing to pay for increased vegetation management expenditure. Tariffs levied on non-residential customers provide approximately 50 per cent of SA Power Networks revenue.[314] Therefore the survey is not representative of SA Power Networks' entire customer base. We note that Business SA and the EUAA both expressed concern about the reliance SA Power Networks has placed on its WTP survey.[315]

Consultation with the South Australian State Bushfire Coordination Committee

The SA Minister for Minerals and Energy submitted that SA Power Networks is a member of the South Australian State Bushfire Coordination Committee (the Committee), which has responsibility for all aspects of bushfire management in South Australia.[316] The Minister considered any proposals for bushfire management should be taken to the Committee to ensure that SA Power Networks is not undertaking expenditure unnecessarily.[317]

We asked SA Power Networks whether it had taken any steps it had taken to consult with the Committee on its BSPs program. It said it did not specifically consult with the Committee concerning its proposed BSPs project, but noted that it did not have an explicit requirement to consult.[318] While we accept that SA Power Networks may not be required to consult with the Committee on the BSPs project, we agree with the Minister's submission that SA Power Networks should ensure it is not undertaking expenditure unnecessarily. In addition to providing an options analysis, we consider a prudent measure would have been to consult on the BSPs program with the Committee and obtain substantive feedback in support of the project.

Funding BSPs through the Power Line Environment Committee project

In the preliminary decision, we noted that SA Power Networks could alternatively obtain funds for the BSPs program through the PLEC program.[319] SA Power Networks sought advice from ESCoSA on the issue, ESCoSA provided the following:[320]

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313 The NTF Group, *Report on AER Discussion of Willingness to Pay Research*, July 2015, p. 5.

314 SA Power Networks, Economic Benchmarking RIN 2013-14, Template 3.1.

315 Business SA, *Submission on preliminary decision*, p, 2; EUAA, *Submission on initial proposal*, pp. 16-17.

316 The Government of South Australia, *Minister for Mineral and Resources and Energy Submission to Revised Proposal*, 4 August 2015, p. 4.

317 The Government of South Australia, *Minister for Mineral and Resources and Energy Submission to Revised Proposal*, 4 August 2015, p. 4.

318 SA Power Networks response to information request AER SAPN 060_Bushfire mitigation program, p. 1 (confidential).

319 AER, *SAPN preliminary decision: Attachment 6 capital expenditure*, April 2015, p. 50.

320 SAPN email correspondence with ESCoSA; SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p.104.

> Bushfire-safe areas, as submitted by SA Power Networks in its regulatory reset proposal, could certainly be proposed to PLEC by SA Power Networks but they would need to be financially supported by the council(s) involved and would also need to have met the PLEC criteria, i.e. to be worthy of PLEC funding. Given the nature of projects that are currently under consideration, SA Power Networks' proposed bushfire-safe areas may not rate as highly in terms of aesthetic benefits.

SA Power Networks explains that the primary driver of the BSPs program is to maintain electricity to bushfire safer precincts during bushfire events, and undergrounding would be along subsidiary roads, offering minimal aesthetic benefits. We note that ESCoSA has not rejected the possibility of funding bushfire-safe areas through PLEC. While the primary purpose of the PLEC fund is aesthetic undergrounding, the charter does also make reference to safety considerations.[321] We accept that under the PLEC criteria, funding for BSPs projects are unlikely to be supported solely on safety grounds. While there is potential for SA Power Networks to work with local councils to pursue projects that would realise safety benefits in addition to aesthetic benefits, this was not a material consideration in our final decision.

Back-up protection

SA Power Networks is proposing $17.7 million ($2014–15) to address sections of the network in country locations where the back-up protection does not currently comply with its regulatory obligations and requirements.[322] Under this proposal, SA Power Networks will install electronic reclosers to 11kV and 19kV feeders, and reconfigure existing manual reclosers to provide back-up protection.[323]

In the preliminary decision we did not accept SA Power Networks' bushfire mitigation program, which included the back-up protection program, however we did not comment on the back-up protection program specifically.

In its revised proposal, SA Power Networks has removed the back-up protection program from the umbrella of the bushfire mitigation program. It considered that whilst the back-up program is aligned with bushfire mitigation, the driver of this program is primarily to achieve compliance with its regulatory obligations and requirements related to back-up protection, not bushfire mitigation.[324] SA Power Networks also claim that it is experiencing an increase in the failure of protection devices in rural areas.[325]

We are not satisfied the proposed capex for the back-up protection program reasonably reflects the capex criteria, because SA Power Networks has not

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321 Power Line Environment Committee, Project Guidelines: Issue 6, January 2013.

322 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p.106.

323 SA Power Networks, *Revised Proposal Attachment G.5 SAPN_protection compliance_backup protection*, July 2015, pp. 11–12.

324 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p.109.

325 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p.107; SA Power Networks, *Revised Proposal Attachment G.5 SAPN_protection compliance_backup protection*, July 2015, p. 10.

demonstrated that its rural distribution feeders could cause system instability. Additionally, SA Power Networks has not provided evidence of a change in its regulatory obligation with regard to the back-up protection program. Rather, SA Power Networks appears to be in compliance with its current safety obligations.

SA Power Networks submitted the forecast expenditure is required to satisfy its regulatory obligations under subclause S5.1.9(c) and (f) of the NER and network directive NDJ1,[326] and to maintain the safety of the distribution system.

We consider S5.1.9(c) and (f) of the NER relate to protection systems required to maintain the stability of the network in the event of a fault and to protect upstream assets in the event that the primary protection system fails. The assets that SA Power Networks are referring to in its revised proposal are rural distribution feeders. We have undertaken a technical review of the project, which has drawn on internal engineering and technical expertise. We consider that in general, faults on rural distribution feeders are of relatively low fault levels, compared to faults on other parts of the network. Faults on these elements (i.e. rural feeders) would not be capable of causing system instability, and SA Power Networks has provided no evidence to show that these feeders could cause system instability. We therefore consider that clause S5.1.9(c) does not apply, because outages on rural feeders would not impact the larger system.

Similarly we consider that clause (f) does not apply as this clause relates to avoiding damage to upstream assets where the primary protection fails to operate. Specifically this clause requires that the fault clearance times associated with a backup protection system (i.e. a protection system that protects a facility e.g. a substation), are such that the fault current would not damage other parts of the network. In the context of rural distribution feeders it would be expected that protection within the substation immediately upstream would meet this requirement. Additionally, the fault ratings of substation equipment would accommodate the relevant fault currents. SA Power Networks has not demonstrated that its protection arrangements on rural feeders would cause damage to upstream assets in the event of primary protection failure. We therefore do not consider that additional capex for such back-up protection reasonably reflects efficient capex that would be incurred by a prudent operator.

SA Power Networks says that when NDJ1 came into effect in 2013, it undertook a detailed assessment of its protection systems at that time, which found a significant portion of the rural network did not comply.[327] In response to those findings, it commenced remediating the back-up protection on its rural network using a risk based prioritisation in 2014. We sought further information from SA Power Networks and confirmed that NDJ1 is not a new or more burdensome obligation (relative to the

[326] NDJ1 is an internal asset management document developed by SA Power Networks and referenced in its SRMTMP which addresses certain safety and technical matters. SA Power Networks is required, under the conditions of its Distribution Licence and Section 25 of the Electricity Act, to comply with its ESCoSA approved SRMTMP.

[327] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p.107.

previous directive) that it must comply with.[328] We also found that the principles in NDJ1 are very general and it is unclear how they apply to the specific situation described by SA Power Networks. As NDJ1 is not a new obligation and the evidence before us indicates that SA Power Networks remains in compliance with its safety obligations, we do not consider that an additional allowance for this driver reasonably reflects the capex criteria.

SA Power Networks reiterates that under the WHS Act that there is a presumption in favour of safety ahead of cost, and standard cost-benefit analysis is inappropriate. As discussed above, on the information available to us, we do not consider that SA Power Networks' obligations under the WHS Act have changed, nor that it is unable to meet its WHS obligations.

With regard to SA Power Networks' claim of an increase in the failure of protection devices; it appears that a total of 46 reclosers have failed in a period of 18 months between August 2013 and January 2015, in a population of approximately 1532 reclosers.[329] This equates to a failure rate of two per cent, and accords with an expected life of approximately 50 years. Consequently the reported failure rate appears to align with that expected in such an asset population.

In this decision we allowed a significant increase in repex relative to SA Power Networks' actual repex over the 2010–15 regulatory period. This increase in repex is based on our analysis and consideration of actual replacement history of a wide range of network assets including protection systems and related assets. Consequently, our repex estimate includes sufficient allowance for a significant increase in asset replacements over the 2015–20 regulatory control period, including failing protective devices. We consider the allowance is sufficient for SA Power Networks to manage the expected failure rates in its assets.

We also agree with SACOSS that SA Power Networks did not present any clear evidence that the solution embodied in the back-up protection program was the only or most efficient solution to the challenges of short circuit faults on the single-wire earth return (SWER) network.[330] SA Power Networks only provided minimal information to show it had considered an option to replace all reclosers on SWERs with electronic reclosers, and estimated a cost of $52.2 million ($2014–15).[331]

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328 SA Power Networks response to information request AER SAPN 061 – reclosers and back-up protection program, p. 2.

329 SA Power Networks, *Revised Proposal Attachment G.5 SAPN_protection compliance_backup protection*, July 2015, p. 10.

330 SACOSS, *SACOSS Submission to the Australian Energy Regulator on SA Power Networks' Revised Regulatory Proposal 2015-20*, July 2015, p. 14.

331 SA Power Networks, *Revised Proposal Attachment G.5 SAPN_protection compliance_backup protection*, July 2015, p. 14.

Core safety program

In our preliminary decision we accepted SA Power Networks core safety program of $21.3 million ($2014–15). This safety program included substation fencing and security, substation earthing, substation lighting, and CBD fault level control.[332]

SA Power Networks accepted our preliminary decision in relation to this program and has incorporated the core safety program in its revised proposal.[333] In its submission on this issue, the CCP noted that the expenditure is in line with previous "core" expenditure on safety.[334] No other submissions were received on the core safety program. We maintain our position from the preliminary decision in relation to the core safety program in this decision.

B.6 Forecast capitalised overheads

Capitalised overheads are costs associated with capital works that have been capitalised in accordance with SA Power Networks' capitalisation policy. They are generally costs shared across different assets and cost centres.

B.6.1 Position

We do not accept SA Power Networks' proposed capitalised overheads. We have instead included in our alternative estimate of overall total capex an amount of $83.8 million ($2014–15) for capitalised overheads. This is 6.3 per cent lower than SA Power Network's proposal of $89.4 million. We are satisfied that this amount reasonably reflects the capex criteria.

B.6.2 Our assessment

We consider that reductions in SA Power Networks' forecast expenditure should see some reduction in the size of SA Power Networks' total overheads. Our assessment of SA Power Networks proposed direct capex demonstrates that a prudent and efficient distributor would not undertake the full range of direct expenditure contained in SA Power Networks' proposal. It follows that we would expect some reduction in the size of SA Power Networks' capitalised overheads. We do accept that some of these costs are relatively fixed in the short term and so are not correlated to the size of the expenditure program. However, we maintain that a portion of the overheads should vary in relation to the size of the expenditure.

We have also considered the relationship between opex and capex, specifically whether it is necessary to account for the way the CAM allocates overheads between

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332 SA Power Networks, *Regulatory Proposal 2015-20*, 31 October 2014, p. 225.

333 SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p.73.

334 Consumer Challenge Panel #2, *Advice to AER: AER's Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks' Revised Regulatory Proposal*, August 2015, p. 60.

capex and opex in making this decision. We considered this was not necessary in order to satisfy the capex criteria. This is because:

- Our opex assessment sets the efficient level of opex inclusive of overheads and so has accounted for the efficient level of overheads required to deliver the opex program by applying techniques which utilise the best available data and information for opex.
- The starting point of our capitalised overheads assessment is SA Power Networks' proposal, which is based on its CAM. As such, SA Power Networks' forecast application of the CAM underlies our estimate. We have only reduced the capitalised overheads to account for the reduced scale of SA Power Networks' approved capex based on assessment techniques best suited to each of the capex drivers. In doing so we have accounted for there being a fixed proportion of capitalised overheads.

Our adjustments to SA Power Networks' overheads use the approach from our preliminary decision (which used information that SA Power Networks provided). We consider that a 1 per cent reduction in SA Power Networks' forecast capex should result in a 0.67 per cent reduction in SA Power Networks' capitalised overheads.[335] We reduced SA Power Networks' direct capex (that attract overheads) by nine per cent. We therefore consider a reduction of 6.3 per cent in capitalised overheads reasonably reflect the capex criteria.

B.7 Forecast non–network capex

The non-network capex category for SA Power Networks includes expenditure on information technology (IT), communications, motor vehicles, buildings and property, and tools and equipment. SA Power Networks' revised proposal includes forecast non-network capex of $562.6 million ($2014–15). This is a reduction of $100.7 million from SA Power Networks' initial proposal of $663.3 million,[336] but an increase of $145.2 million from our preliminary decision for non-network capex of $417.4 million.[337]

B.7.1 Position

We do not accept SA Power Networks’ revised proposal for non-network capex. We have instead included an amount of $511.2 million ($2014–15) for forecast non-network capex. As discussed below, we are not satisfied that SA Power Networks' forecast non-network IT capex or buildings and property capex reasonably reflects the

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[335] AER, *Preliminary decision: SA Power Networks determination 2015−16 to 2019−20: Attachment 6 − Capital expenditure*, April 2015, pp. 108–109.

[336] SA Power Networks, *Revised regulatory proposal*, 3 July 2015, pp. 140-141 and SA Power Networks, *21.11b - SEM-Capex Model 2015 V17.2*, Reconciliation tab. This includes non-network communications capex but excludes the negative adjustment to capitalised superannuation contributions.

[337] AER, *Preliminary Decision, SA Power Networks determination 2015−16 to 2019−20 Attachment 6 − Capital expenditure*, April 2015, p. 6-110.

efficient costs that a prudent operator, with a realistic expectation of the demand forecast and costs inputs, would require to achieve the capex objectives.

In coming to this view, we have found that:

- SA Power Networks' forecast non-network IT capex associated with the customer information system, RIN reporting, and tariffs and metering IT capex projects does not reflect the efficient costs required to meet the identified business needs. We consider that forecast capex of $264.9 million ($2014–15) reasonably reflects a prudent and efficient level of IT capex for the 2015–20 regulatory control period
- SA Power Networks' major property project business cases do not provide evidence that satisfies us that the forecast capex for the Seaford and Nuriootpa depot projects is prudent and efficient or is required to achieve the capex objectives. We maintain our draft decision that forecast buildings capex of $71.8 million ($2014–15), reflecting SA Power Networks' historical capex in the 2010–15 regulatory control period, will allow SA Power Networks to continue to invest in prudent construction, refurbishment, and maintenance projects as required.
- We are satisfied that SA Power Networks' revised forecast capex for the motor vehicles, communications and other non-network capex categories is likely to reflect the efficient costs of a prudent operator.

B.7.2 Revised proposal

In its revised proposal, SA Power Networks did not agree with our preliminary decision to reduce forecast capex for non-network IT, motor vehicles, or buildings and property. SA Power Networks' revised proposal for non-network capex:

- included forecast IT capex of $299.7 million ($2014–15), a reduction of $54.0 million from its initial proposal, reflecting a reduction in scope and reprioritisation of the non-recurrent IT capex program[338]
- included forecast motor vehicles capex of $122.9 million ($2014–15), a reduction of $23.1 million from its initial proposal, reflecting reductions in new and replacement fleet capex and vehicle weight compliance expenditure[339]
- included forecast buildings capex of $88.5 million ($2014–15), a reduction of $18.9 million from its initial proposal, reflecting our preliminary decision but with the addition of two specific building projects at Seaford and Nuriootpa[340]
- clarified the inclusion of three specific communications projects with total capex of $15.9 million as part of the non-network capex forecast[341]

[338] SA Power Networks, *Revised regulatory proposal*, 3 July 2015, pp. 140 and 152.

[339] SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 140.

[340] SA Power Networks, *Revised regulatory proposal*, 3 July 2015, pp. 140 and 174.

[341] SA Power Networks, *Revised regulatory proposal*, 3 July 2015, pp. 140 and 162-168.

- included forecast non-network capex of $2.6 million ($2014–15) associated with the implementation of cost reflective network tariffs.[342] This expenditure relates to the AEMC's final determination on the distribution network pricing arrangements rule change made in November 2014, and was not included in SA Power Networks' initial non-network capex forecast.

These aspects of SA Power Networks' revised proposal are discussed in turn below.

B.7.3 Information technology capex

Across our preliminary and final decisions, we have assessed SA Power Networks' IT capex using trend analysis and individual project review. In our trend analysis, we compared the proposed expenditure to historic expenditure, and sought to understand the reasons for material differences in forecast expenditure. In doing so, we considered the underlying drivers of expenditure, including the investment lifecycle stage the business is in and its particular IT needs. Where we have decided to review individual projects or programs, we have examined any business cases and other supporting documentation, and had regard to expert advice from our consultant Nous Group, to assess whether the expenditure reasonably reflects the capex criteria.

In our preliminary decision on SA Power Networks' forecast non-network IT capex, we were not satisfied that the proposed portfolio of IT projects was deliverable within the 2015–20 regulatory control period, or that the proposed capex reflected the efficient costs required to meet the identified need. We concluded that:[343]

- the proposed non-recurrent IT capex program was a large scale, complex and interdependent program of works impacting broadly across core IT systems and business processes
- there was a significant level of risk associated with SA Power Networks' ability to deliver the proposed non-recurrent IT capex program, including risks that:
    - the program may be delayed or costs increase
    - necessary resources may be difficult to obtain and utilise efficiently in a timely way
    - identified benefits may not be realised
    - business and process changes may prove difficult or take longer to implement
- a prudent operator would undertake such a significant and complex portfolio of work over a longer timeframe to reduce delivery and resourcing risk
- the business cases supporting the proposed non-recurrent IT capex projects did not provide an economic justification for the forecast capex. Typically, individual

[342] SA Power Networks, *Revised regulatory proposal*, 3 July 2015, pp. 140 and 179.

[343] AER, *Preliminary Decision, SA Power Networks determination 2015−16 to 2019−20 Attachment 6 − Capital expenditure*, April 2015, pp. 6-114 to 6-123.

projects provide few tangible benefits relative to forecast costs, and were not economically justified

- most projects are wholly or partially discretionary in nature and are not required to maintain service levels
- a prudent operator would not proceed with some of the proposed non-recurrent IT capex projects in the 2015–20 regulatory control period, or would pursue alternative options to meet the identified need.

We concluded that non-network IT capex of $213.6 million ($2014–15) reasonably reflects SA Power Networks' required capex for this category in the 2015–20 regulatory control period.

In our preliminary decision, our estimate of required non-recurrent IT capex was based on the average level of investment delivered by SA Power Networks across the 2013–14 and 2014–15 years. In determining our alternative estimate of non-network IT capex, we did not seek to determine which of the 24 proposed non-recurrent IT capex projects SA Power Networks should pursue in the 2015–20 regulatory control period. Rather, we sought to estimate a level of capex that would be deliverable in the 2015–20 regulatory control period consistently with the capex criteria.[344]

Following our preliminary decision, but prior to receiving SA Power Networks' revised proposal, we sought advice from Nous Group to provide a more detailed assessment of the justification for individual IT capex projects.[345] In making this final decision, we have had regard to the advice provided by Nous Group and SA Power Networks' response to that advice, noting that some aspects of the IT projects considered by Nous Group were subsequently amended by SA Power Networks in its revised proposal.[346]

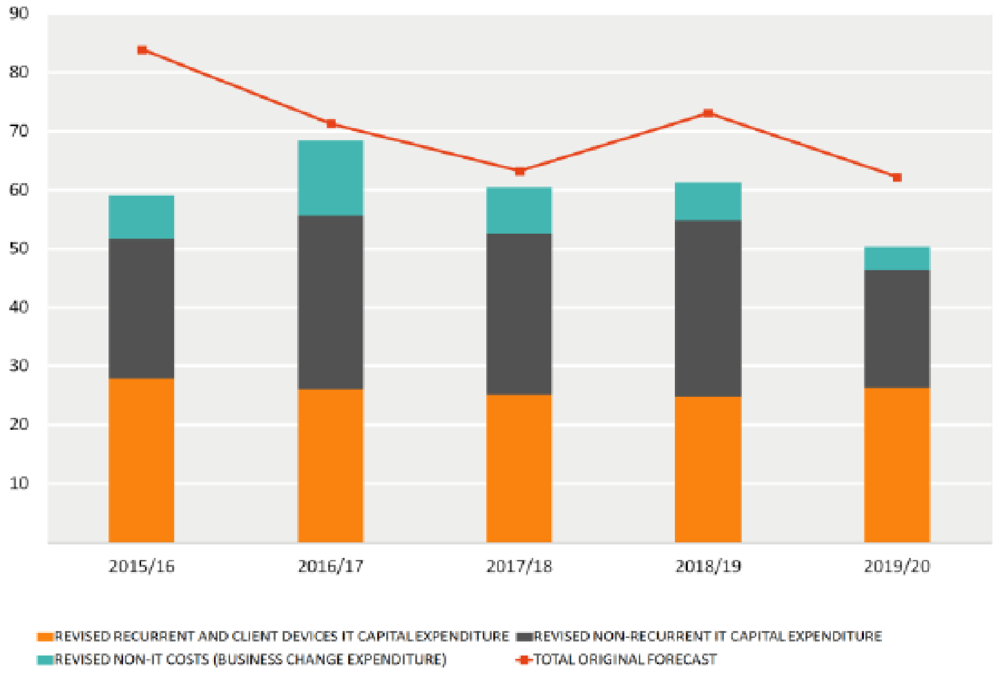
SA Power Networks' revised proposal for non-network IT capex of $299.7 million is a reduction of 16 per cent from its initial proposal. A comparison of SA Power Networks' initial and revised proposals for IT capex is shown in Figure.

[344] AER, *Preliminary Decision, SA Power Networks determination 2015−16 to 2019−20 Attachment 6 − Capital expenditure*, April 2015, p. 6-122.

[345] Nous Group, *SA Power Networks' ICT Expenditure 2015-20*, 9 July 2015.

[346] We provided Nous Group's report to SA Power Networks for consideration and response as part of: AER, *Information request AER SAPN 050*, 17 July 2015.

Figure B.7 Comparison of SA Power Networks' initial and revised non-network IT capital expenditure proposals ($ million, 2014–15)



Source: SA Power Networks, *Revised proposal*, July 2015, p. 154.

In its revised proposal, SA Power Networks accepted our decision on recurrent IT capex, but rejected our conclusions regarding the deliverability of the proposed non-recurrent IT capex program, and our assertion of the discretionary nature and lack of justification for some projects. SA Power Networks sought to address the concerns set out in our preliminary decision through a revised non-recurrent IT capex program. SA Power Networks' revised non-network IT capex proposal:[347]

- extends the program delivery timeframe over ten years rather than five
- defers lower priority projects both within and beyond the 2015–20 regulatory control period
- reduces the scope of some projects for the 2015–20 regulatory control period
- represents a reduction in forecast non-recurrent IT capex from its initial proposal of 26 per cent.

The Consumer Challenge Panel submitted that SA Power Networks had made important modifications to its IT plan, and considered that the revised proposal for IT capex provided a more reasonable roadmap to introducing the necessary

[347] SA Power Networks, *Revised regulatory proposal*, 3 July 2015, pp. 152-159.

enhancements to SA Power Networks' IT systems and processes.[348] Nonetheless, both the Consumer Challenge Panel and SACOSS requested that we further review SA Power Networks' revised IT proposal to ensure it is prudent, efficient and deliverable.[349] The EUAA submitted that our preliminary decision should be upheld, and specifically queried the need for IT capex related to the competition in metering rule change and RIN reporting requirements.[350] These projects are discussed below.

In our view, SA Power Networks' revised non-recurrent IT capex forecast alleviates many of the concerns raised in our preliminary decision regarding the deliverability of the forecast capex program and the justification for some individual projects. SA Power Networks has reduced the total number of non-recurrent IT projects in the 2015–20 regulatory control period from 24 to 14. SA Power Networks has also reduced the scope of some remaining projects. The revised proposal presents a smaller scale program, prioritised towards projects which reduce risk and deliver strategic objectives.[351]

We compared SA Power Networks' revised IT capex proposal to the recommendations made by Nous Group in reviewing SA Power Networks' initial IT capex proposal. Nous Group recommended a reduction in the total number of non-recurrent IT projects in the 2015–20 regulatory control period from 24 to 17. Nous Group also identified reductions in the scope of some of projects, and attempted to identify dependencies between projects to ensure the total program reflected a logically consistent sequence of work. Nous Group recommended a reduction of 28 per cent to SA Power Networks' initial IT capex proposal.[352] This is more than the reduction of 16 per cent made by SA Power Networks in its revised proposal, but less than the 40 per cent reduction we made in our preliminary decision.

As stated above, both SA Power Networks' revised proposal and Nous Group's review identified reductions in the number, scope and cost of required IT projects compared to SA Power Networks' initial proposal. However, the approach taken to individual projects varies. For example, SA Power Networks' revised proposal includes some minor projects excluded by Nous Group, but excludes other projects which Nous Group included in its recommended capex program.[353] We have not attempted to reconcile all differences between the non-recurrent IT programs specified by SA Power Networks and Nous Group. In part, the two programs are likely to reflect legitimate

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348 Ms Bev Hughson CCP2, *Advice on AER's preliminary decision and revised proposal from SA Power Networks*, August 2015, p. 92.

349 Ms Bev Hughson CCP2, *Advice on AER's preliminary decision and revised proposal from SA Power Networks*, August 2015, pp. 92-93; and SACOSS, *Submission to Australian Energy Regulator on SA Power Networks 2015 – 2020 AER Preliminary Decision*, 1 July 2015, p. 15.

350 Energy Users Association of Australia, *Submission to AER preliminary decision and SA Power Networks' revised proposal*, 24 July 2015, pp. 9-10.

351 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, pp. 154-156.

352 Nous Group, *SA Power Networks' ICT Expenditure 2015-20*, 9 July 2015, pp. 76-77.

353 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, pp. 160-161 and Nous Group, *SA Power Networks' ICT Expenditure 2015-20*, 9 July 2015, p. 77.

differences in opinion on the relative priority of projects and the nature of project interdependencies.

In making this final decision, we have taken SA Power Networks' revised proposal as the starting point for our assessment. We have then considered whether the advice from Nous Group on specific major projects is relevant and justifies an adjustment to SA Power Networks' revised estimate of project costs. The key projects where Nous Group's recommendations differ from SA Power Networks' revised proposal are discussed below.

Customer Information System (CIS) and Customer Relationship Management (CRM)

The CIS/CRM replacement is the largest single project in SA Power Networks' non-recurrent IT program. SA Power Networks' revised proposal includes forecast capex of $63.6 million for the CIS/CRM replacement project, an increase of $9.3 million from its initial proposal.[354]

The Consumer Challenge Panel requested that we consider whether SA Power Networks' costs associated with the CIS/CRM replacement project are efficient, noting that the Victorian DNSPs CitiPower and Powercor have also proposed to update these systems, including moving to a cloud-based CRM.[355]

Nous Group reviewed SA Power Networks' initial proposal for the CIS/CRM replacement project. Nous Group agreed with SA Power Networks that the CIS/CRM replacement project is necessary as SA Power Networks' existing billing and customer related systems are at 'end of life' and technically obsolete. However, Nous Group recommended that SA Power Networks pursue the 'cloud hosting' option rather than the 'on premise' option as the most efficient option to deliver the project. Nous Group also queried the level of contingency included in the forecast costs, and recommended the project be deferred by one year.[356]

We provided Nous Group's report to SA Power Networks for comment.[357] SA Power Networks submitted that the CIS/CRM project could not be deferred by one year as recommended by Nous Group. SA Power Networks stated that the project must be completed within the 2015–20 regulatory control period in order to:[358]

- meet new obligations arising within the period related to the Power of Choice rule changes

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354 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 160 and SA Power Networks, *Regulatory proposal*, October 2014, p. 236. Excludes business change costs.

355 Ms Bev Hughson CCP2, *Advice on AER's preliminary decision and revised proposal from SA Power Networks*, August 2015, pp. 92-93.

356 Nous Group, *SA Power Networks' ICT Expenditure 2015-20*, 9 July 2015, pp. 16-19 and p. 76.

357 AER, *Information request AER SAPN 050*, 17 July 2015.

358 SA Power Networks, *Response to information request AER SAPN 050*, 5 August 2015, pp. 1-2 and SA Power Networks, *Response to information request AER SAPN 057*, 17 August 2015, p. 4.

- allow for an adequate transition period prior to cessation of the support contract for the CIS legacy system.

SA Power Networks did not disagree with Nous Group's recommendation of the cloud hosting option, but noted that this option required a higher level of opex than the on premise option.[359]

In regard to the timing of the CIS/CRM project, we accept SA Power Networks' submission that the CIS/CRM replacement project should not be deferred as recommended by Nous Group. In our view, the timing of this project is driven by the need to replace existing systems before existing vendor support expires. This includes the need for an adequate transition period prior to cessation of the existing vendor support contract.

In regard to the potential hosting options for the CIS/CRM replacement project, we find that Nous Group's recommendation that SA Power Networks pursue the cloud hosting option is persuasive. This option was not selected by SA Power Networks due to the perceived risk of utilising cloud based solutions for critical business functions. However, this option is the most economically efficient (highest NPV) option identified by SA Power Networks, with the lowest total project cost.[360] It is not clear that the on premise hosting option provides any additional benefit in terms of information security or risk avoidance that would justify additional project costs. As advised by Nous Group, there are well established industry outsourcing and cloud processes that can minimise risk, especially in customer management solutions.[361]

Further, SA Power Networks' options analysis identified the on premise option as preferred over the cloud option 'until further work is conducted as part of an implementation project'.[362] This suggests that SA Power Networks may in fact adopt the cloud hosting approach, following further examination of all implementation options. In these circumstances, we do not consider that providing for the higher cost 'on premise' solution in SA Power Networks' total ex ante capex forecast is in the interests of consumers. We are satisfied that the cloud hosting option for the CIS/CRM replacement project is likely to reflect the efficient costs of a prudent operator.

The Consumer Challenge Panel sought to confirm whether the opex efficiencies associated with this project had been reflected in SA Power Networks' regulatory proposal, and that the new systems would have the flexibility to cope with future changes in tariff design and competitive metering arrangements.[363] SA Power Networks identified $2.9 million in total cost recovery, reduction or avoidance benefits

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359 SA Power Networks, *Response to information request AER SAPN 050*, 5 August 2015, p. 2.

360 SA Power Networks, *Attachment 20.37b: Deloitte CIS and CRM Business Case - SAPN Review and Summary*, October 2014, p. 20.

361 Nous Group, *SA Power Networks' ICT Expenditure 2015-20*, 9 July 2015, p. 17.

362 SA Power Networks, *Attachment 20.37b: Deloitte CIS and CRM Business Case - SAPN Review and Summary*, October 2014, p. 21.

363 Ms Bev Hughson CCP2, *Advice on AER's preliminary decision and revised proposal from SA Power Networks*, August 2015, pp. 94-96.

for this project in the 2015–20 regulatory control period, and a further $5.1 million in quantifiable benefits in the 2020–25 regulatory control period. SA Power Networks submitted that, while the project provides some quantifiable benefits, the primary purpose of the project is to maintain service rather than add new capability. We are satisfied that SA Power Networks has offset the benefits identified against forecast capex and opex in the 2015–20 regulatory control period.[364] We have also confirmed that SA Power Networks has considered the need for the new systems to have the flexibility to cope with current and potential changes in the market. SA Power Networks has described the new systems as not simply a 'like for like' replacement but rather:[365]

> a new technical foundation capability in order for it to comply with its regulatory obligations and interact with more complex business and market environments.

SA Power Networks' business case for the CIS/CRM replacement project (cloud hosting option) identifies total capex for this project in the 2015–20 regulatory control period of $37.5 million (unescalated, $2013–14). SA Power Networks advised that it had deferred the start of the project to avoid rework of customer data requirements arising from the AEMC's competition in metering rule change.[366] As such, capex planned for 2014-15 has been deferred into the 2015–20 regulatory control period. Our estimate of the total capex required for this project in the 2015–20 regulatory control period is therefore $42.3 million (unescalated, $2013–14).[367] We will make allowance for it in our estimate of non-network IT capex.

RIN Reporting project

SA Power Networks' revised proposal included $14.8 million for the RIN reporting project, essentially unchanged from its initial proposal. The majority of the proposed capex relates to business change costs of $10.8 million.[368]

Nous Group found that the proposed investment was reasonable in principle, but that SA Power Networks' forecast business change costs appeared significantly overstated and the basis for them is not clear. Nous Group considered that a more realistic estimate of resourcing requirements would be based on intensive activity in the first year, with a reducing requirement in subsequent years as implementation progresses and data quality improves. Nous Group recommended a reduction of $5.7 million ($2013–14) to the project resourcing requirement (business change costs).[369]

The AER's RIN reporting obligations apply to all network service providers in the NEM. However, SA Power Networks is one of only a small number of service providers to identify significant compliance costs in their capex or opex forecasts. CitiPower,

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364 SA Power Networks, *Attachment G.24 IT Benefits*, 3 July 2015, pp. 8-13.

365 SA Power Networks, *Attachment G.21 CISOV CRM Opex Step Change*, 3 July 2015, p. 4.

366 SA Power Networks, *Response to information request AER SAPN 057,* 17 August 2015, p. 3.

367 Excludes business change costs.

368 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 160.

369 Nous Group, *SA Power Networks' ICT Expenditure 2015-20*, 9 July 2015, pp. 48-52.

Powercor and United Energy have also proposed IT capex for compliance with the RIN reporting obligations. In contrast, AusNet Services, Jemena, Ausgrid, Endeavour Energy, Essential Energy, ActewAGL, Energex and Ergon Energy have either not proposed any IT capex for this or only proposed very small amounts.

We use the data that is provided in response to our category analysis and benchmarking RINs to improve our regulation of the network businesses. For example, the information is used to conduct trend analysis and benchmarking, to better inform our assessment of forecast expenditure. This has benefits for consumers through assisting the AER in coming to a view on whether forecast expenditure is efficient, and for all stakeholders in providing increased transparency and consistency in regulatory processes. In establishing the RIN reporting obligations, we acknowledged that there may be some upfront costs to businesses in order to comply with the new data requirements. We sought to minimise the scope and cost of data requirements so that the benefits of data collection outweigh the costs of collecting the data. However, we note that the businesses were not able to provide information on the costs of complying with the RIN when invited to do so during the consultation on the category analysis RINs.[370]

We recognise that each business is starting from a different position regarding its existing systems and data availability. SA Power Networks submitted that it will need to fundamentally change existing data recording and collection structures in order to comply with the RIN reporting requirements, involving changes to many core systems and business processes.[371] Nonetheless, we would not expect a prudent operator to require the full extent of additional investment identified by SA Power Networks. We have not seen requests for significant expenditure from businesses in New South Wales and Queensland, or from Jemena and AusNet Services in Victoria. We expect that a prudent and efficient operator would already likely collect much of the data required by the RIN reporting obligations in order to facilitate the efficient operation and management of its network. Given the above concerns, we are not satisfied that SA Power Networks' full proposed expenditure for the RIN reporting project is necessarily warranted.

In our view, the project resourcing costs identified by Nous Group are likely to reflect a more reasonable estimate of the business change costs required to implement this project. This level of resourcing would still provide a significant support team to complete the project, but is more reflective of the reduction in resourcing likely to be required as implementation progresses and data quality improves. This is consistent with the view we expressed when determining the RIN reporting requirements that the network businesses would incur a large portion of compliance costs upfront. Costs

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370 AER, *Better Regulation: Explanatory Statement: Final regulatory information notices to collect information for category analysis*, March 2014, pp. 1-2, 8. AER, *Better Regulation: Explanatory Statement: Regulatory information notices to collect information for economic benchmarking*, November 2013, p. 9.

371 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 150.

should be lower in the medium to long term as compliance with the data requirements becomes routine.[372]

The RIN reporting IT capex project has interdependencies with a large number of other IT projects proposed for the 2015–20 regulatory control period. SA Power Networks has also identified that, in the absence of the RIN reporting IT capex, an additional opex step change of $10.2 million would be required to meet the RIN reporting obligations.[373] On that basis, we consider that making some allowance for the RIN reporting project, with a reduced capex requirement as recommended by Nous Group, is likely to be in the long term interests of consumers. We make an allowance of $8.6 million ($2014–15) for this project in our estimate of non-network IT capex, consistent with Nous Group's recommended level of resourcing for this project.

Enterprise asset management project

SA Power Networks' revised proposal included $31.0 million ($2014–15) for the enterprise asset management project. This is a slight reduction of $0.4 million from SA Power Networks' initial proposal.[374]

Nous Group found that although SA Power Networks' asset management processes could be more efficient, the business case was not convincing in demonstrating the case for action. However, Nous Group recognised that the enterprise asset management project was an upstream dependency of other projects and an enabler of services in other areas. Nous Group recommended that core components of the project relating to loading asset data and enabling processes to manage data be included in the IT capex forecast. The core components identified by Nous Group amount to 89 per cent of the total project costs.[375]

SA Power Networks submitted that this project is the backbone to the collection and reporting of actual asset data needed for asset management and regulatory compliance purposes. SA Power Networks considered that it must maintain the full proposed expenditure, including business change costs, in order to achieve the benefits provided by the project.[376] In our view, the project costs proposed by SA Power Networks and estimated by Nous Group are not materially different. Given the slight reduction in proposed capex for this project from SA Power Networks' initial proposal, and that Nous Group recommended that 89 per cent of the initial proposal costs be accepted, the difference between Nous Group's recommended capex and SA Power Networks' revised proposal for this project is minor.

372 AER, *Better Regulation: Explanatory Statement: Expenditure Forecast Assessment Guideline*, November 2013, p. 14.

373 SA Power Networks, *Attachment G.19 SAPN_IT RIN Reporting Business Case*, 3 July 2015, pp. 25-35.

374 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 160.

375 Nous Group, *SA Power Networks' ICT Expenditure 2015-20*, 9 July 2015, pp. 28-32 and 76-77.

376 SA Power Networks, *Response to information request AER SAPN 050*, 5 August 2015, p. 2.

In our view, the economic justification for this project is relatively strong, when costs and benefits beyond the 2015–20 regulatory control period are considered. This project provides the single largest source of cost reduction and cost avoidance benefits of SA Power Networks' proposed non-recurrent IT projects. Total project benefits exceed project costs over the ten year period from 2015–25.[377]

On this basis, we accept that SA Power Networks' revised proposal capex for the enterprise asset management project reflects a reasonable estimate of the efficient costs of a prudent operator. We make an allowance for it in our estimate of non-network IT capex.

Tariffs and metering

In its revised proposal, SA Power Networks proposed $11.1 million for the tariffs and metering project, a significant reduction from its initial proposal of $27.0 million. SA Power Networks revised the scope of the project following publication of the AEMC's draft 'Competition in Metering' rule change in March 2015. The revised proposal includes capex associated with the Competition in Metering rule change, as well as a small component related to low voltage network monitoring, but excludes costs related to the implementation of cost reflective network tariffs.[378]

Nous Group reviewed SA Power Networks' initial forecast capex for the tariffs and metering project, and found that a base level of capability driven by future changes in metering, tariff design and distributed generation was likely to be prudent. However, Nous Group concluded that the higher level options relating to new network control and monitoring functions were discretionary and not justified for inclusion in the capex forecast. Nous Group recommended a reduction of 61 per cent to the forecast tariffs and metering IT capex, which aligns with the overall reduction made by SA Power Networks in its revised proposal. This recommendation was based on Nous Group's view that it would be prudent for SA Power Networks to prepare for future tariff structures and contestable metering.[379]

However, in making this final decision, we must consider the regulatory obligations and requirements in place at the time the decision is made. The AEMC's final decision on the Competition in Metering rule change has not yet been made. SA Power Networks submitted that it has sufficient confidence in the outcome of the rule change process to estimate the impact. SA Power Networks also noted that we would be able to take account of the final rule when making this final decision.[380] However, since SA Power Networks submitted its revised proposal, the AEMC has extended the timeframe for

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377 SA Power Networks, *Attachment G.24 IT Benefits*, 3 July 2015, p. 8.

378 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 160; SA Power Networks, *Attachment H.8 Competition in Metering Rule Change*, 3 July 2015, p. 10; SA Power Networks, *Attachment H.7 Distribution Network Pricing Rules*, 3 July 2015, p. 12; and SA Power Networks, *Response to information request AER SAPN 057*, 5 August 2015, p. 4.

379 Nous Group, *SA Power Networks' ICT Expenditure 2015-20*, 9 July 2015, pp. 19-21.

380 SA Power Networks, *Attachment H.8 Competition in Metering Rule Change*, 3 July 2015, pp. 5-6.

publication of the final rule determination on the Competition in Metering rule change.[381] The AEMC stated that it was considering complex issues around the details of implementing a competitive framework for metering, and flagged potential material changes to the draft rule.[382] In these circumstances, we consider that uncertainty remains around the nature of the Competition in Metering rule change and the details of its implementation.

We note that the Victorian DNSPs have recognised this uncertainty in their regulatory proposals (submitted in April 2015) in relation to the cost impact of the forthcoming rule change. AusNet Services, Jemena, CitiPower and Powercor all proposed to recover costs related to the Competition in Metering rule change through the cost pass through arrangements of the NER rather than through the ex-ante capex allowance. This is because the exact nature of the future regulatory obligations and the scope, timing and cost of system changes required to accommodate them remained uncertain, even after the draft rule change determination was published in March 2015.

In assessing SA Power Networks' forecast capex, we must be satisfied that the capex reasonably reflects the capex criteria and is required to achieve the capex objectives of the NER.

We are not satisfied that SA Power Networks' forecast IT capex relating to the Competition in Metering rule change reasonably reflects the capex criteria at this time. Given the uncertainty that exists around the nature of the applicable regulatory obligation, the possible system changes required, and the quantum of costs which may be incurred, it is not clear that SA Power Networks' forecasts reflect the efficient costs of a prudent operator or a realistic expectation of the cost inputs required to achieve the capex objectives.[383] Further, where a rule change process has commenced, but has not yet concluded, the relevant regulatory obligation is not yet applicable. We do not consider that possible capex associated with a future rule change meets the capex objective as being required to meet an applicable regulatory obligation or requirement. While we acknowledge that service providers may incur some costs to deliver new functionalities arising from future rule changes, the nature and quantum of these costs is not yet clear. On this basis, we have excluded forecast IT capex related to the Competition in Metering rule change from our estimate of total capex for this final decision. However, once these aspects are clear, it may be possible for SA Power Networks to apply to pass through costs associated with the rule change.

A small component ($1.7 million) of the tariffs and metering project capex proposed by SA Power Networks relates to its low voltage network monitoring program.[384] As

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381 AEMC, *Media release: Extension of time for final determination on metering and related services rule change*, 2 July 2015.

382 AEMC, *Media release: Extension of time for final determination on metering and related services rule change*, 2 July 2015; and AEMC, *Media release: Competition in metering rule change - upcoming consultation*, 3 September 2015.

383 NER, cl. 6.5.7(c).

384 SA Power Networks, *Response to information request AER SAPN 057*, 5 August 2015, p. 4.

discussed in our decision on SA Power Networks' forecast augmentation capex in section B.2 of this decision, we do not accept that the proposed capex for the low voltage monitoring program reflects the efficient costs of a prudent operator. We have therefore excluded this component of the forecast tariffs and metering project capex from our estimate of total capex.

Conclusion

For the reasons set out above, we are not satisfied that SA Power Networks' non-network IT capex forecast reasonably reflects the efficient costs that a prudent operator would require to achieve the capex objectives.[385] Our alternative estimate of forecast IT capex is $264.9 million ($2014–15). This is a reduction of $34.8 million or 12 per cent from SA Power Networks' forecast capex, but an increase of $51.3 million or 24 per cent from our preliminary decision. This estimate accounts for the adjustments made to forecast capex for the CIS/CRM, RIN reporting, and tariffs and metering IT projects set out above. We will make allowance for it in our estimate of total capex for the 2015–20 regulatory control period.

B.7.4 Buildings and property capex

In our preliminary decision, we found that SA Power Networks' forecast buildings and property capex of $111.6 million reflected historically high levels of expenditure from 2016–17 onwards. In relation to SA Power Networks' buildings and property capex, we concluded that:[386]

- SA Power Networks had not provided evidence of a systematic and transparent optimisation process that might justify the prudence and efficiency of the buildings and property capex forecast
- the business cases submitted by SA Power Networks did not address key factors typically evident in documentation used to justify the prudence and efficiency of a proposed capex project
- based on the information available, we were not satisfied that either the process used by SA Power Networks to forecast its buildings and property capex or the business cases submitted provide evidence that the forecast capex is prudent and efficient or is required to achieve the capex objectives
- forecast capex of $71.8 million ($2014–15), in line with SA Power Networks' actual and expected buildings and property capex for the 2010–15 regulatory control period, reasonably reflected the efficient costs that a prudent operator would require to meet the capex objectives.

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385 NER, cl. 6.5.7(c).

386 AER, *Preliminary decision - SA Power Networks distribution determination - Attachment 6 - Capital expenditure*, April 2015, pp. 6-123 to 6-127.

SA Power Networks' revised proposal for non-network buildings and property capex adopted our preliminary decision as a 'base program forecast', but proposed specific additional capex of $16.7 million for new depots at Seaford and Nuriootpa. SA Power Networks submitted that these two projects are required to accommodate increasing numbers of trade skilled workers delivering power line related construction and maintenance functions in the 2015-20 regulatory control period.[387]

The depot projects at Nuriootpa and Seaford were included as two of the eight major projects in SA Power Networks' initial proposal for non-network buildings and property capex. In our preliminary decision, we concluded that the major project business cases did not address key factors which we consider would typically be evident in documentation used to justify the prudence and efficiency of a proposed capex project. While the business cases provided a description of proposed works, costs and delivery timeframes, they typically did not provide:[388]

- a detailed description of the need for investment, with supporting evidence as to forecast staff numbers and work volumes, designed and actual occupancy levels, contamination and remediation costs, the nature of asset obsolescence, or other specific site condition, compliance, capacity or service demand issues
- evidence that a suitable range of alternative options, including a 'do nothing' option, has been considered[389]
- evidence of a formal risk assessment or analysis performed as part of the need identification or options analysis process
- evidence that tangible and intangible benefits have been identified and quantified for all options considered
- a comparison of costs and benefits for each option considered
- evidence of a positive net present value (NPV), or that the highest NPV option has been selected such that the preferred option is economically justified
- evidence to justify the inclusion of any contingency amount.

Based on the information available in making our preliminary decision, we were not satisfied that the business cases submitted by SA Power Networks provided evidence that the forecast capex is prudent and efficient or is required to achieve the capex objectives.[390]

In its revised regulatory proposal, SA Power Networks did not address our conclusions on the sufficiency of its non-network property business cases. SA Power Networks has

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387 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 174.

388 AER, *Preliminary decision - SA Power Networks distribution determination - Attachment 6 - Capital expenditure*, April 2015, p. 6-125.

389 The Nuriootpa business case (*Attachment 21.50g - Business Case Nuriootpa*) is the only business case which formally considers a 'do-nothing' option of minimal maintenance and refurbishment.

390 AER, *Preliminary decision - SA Power Networks distribution determination - Attachment 6 - Capital expenditure*, April 2015, p. 6-126.

not provided any additional information in support of these projects beyond the documentation already assessed in reaching our preliminary decision. We therefore have no basis to depart from the conclusion set out in our preliminary decision that SA Power Networks' major property project business cases do not provide evidence that the forecast capex is prudent and efficient or is required to achieve the capex objectives. This applies equally to the Seaford and Nuriootpa projects as for the other six major projects which SA Power Networks has not specifically included in its revised regulatory proposal.

In its revised proposal, SA Power Networks described the AER's preliminary decision on forecast buildings and property capex as a 'base program forecast'.[391] This is incorrect. As stated in our preliminary decision, this forecast was based on SA Power Networks' actual and expected buildings and property capex in the 2010–15 regulatory control period. SA Power Networks described its expenditure during this period in the following terms:[392]

> Significant investment has been made during the current period … highlighted by the construction of a new depot at Holden Hill and a range of other major refurbishment projects.

In our view, SA Power Networks' buildings and property program in the 2010–15 regulatory control period was not simply a base level program which allowed only for the maintenance of existing sites and capacities. The program included the construction of a new depot at Holden Hill, as well as other major refurbishment projects. In this period, SA Power Networks' non-network property portfolio accommodated an increase in SA Power Networks' total employee numbers from 1,833 in 2010 to 2,169 in 2013.[393] In our view, and as stated in our preliminary decision, an estimate of non-network property capex which reflects SA Power Networks' historical capex in the 2010–15 regulatory control period will allow SA Power Networks to continue to invest in a range of prudent construction, refurbishment, and maintenance projects as required. For example, we consider that this amount is sufficient for SA Power Networks to undertake the Seaford and Nuriootpa projects should it choose to do so, as well as a mix of other major, moderate and minor projects as determined by SA Power Networks.

As stated in our preliminary decision, in making this decision we have not sought to determine which specific non-network buildings and property capex projects SA Power Networks should pursue in the 2015–20 regulatory control period. It is open to SA Power Networks to prioritise particular needs, such as the Seaford and Nuriootpa depot projects, within the overall non-network buildings and property capex program. Rather, we have sought to estimate a prudent and efficient level of capex that is deliverable in the 2015–20 regulatory control period.

[391] SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 174.
[392] SA Power Networks, *Regulatory proposal*, October 2014, p. 240.
[393] SA Power Networks, *2013 Annual Report*, p. 19.

In line with our preliminary decision, we remain satisfied that forecast capex of $71.8 million ($2014–15), a reduction of $16.7 million ($2014–15) or 19 per cent from SA Power Networks' revised forecast of $88.5 million, reasonably reflects the efficient costs that a prudent operator, with a realistic expectation of demand forecast and cost inputs, would require to achieve the capex objectives.[394] We will make an allowance for it in our estimate of total capex for the 2015–20 regulatory control period.

B.7.5 Fleet capex

In its revised proposal, SA Power Networks proposed capex of $122.9 million ($2014–15) for standard control service fleet assets in the 2015–20 regulatory control period.[395] This is $23.1 million ($2014–15) or 15.8 per cent less than SA Power Networks' proposed standard control service fleet vehicle capex in its initial proposal.[396] SA Power Networks owns and operates a range of fleet assets to enable delivery of its network program of work, including passenger and light commercial vehicles, heavy vehicles such as line trucks, Elevating Work Platforms (EWPs), cranes, forklifts, trailers and associated plant and equipment. SA Power Networks also stated that the majority of its fleet is owned and that its core operational activities include the management, acquisition, maintenance, replacement and disposal of fleet assets.[397]

In our preliminary decision, we considered that an alternative forecast fleet capex of $103.2 million ($2014–15) reasonably reflected the efficient costs that a prudent operator would require to meet the capex criteria.[398] Our key reasons for reducing SA Power Networks' proposed fleet capex were:[399]

- Fleet replacement – a reduction of $10.6 million to SA Power Networks' proposed fleet replacement capex of $113.8 million. We did not accept SA Power Networks' proposed change in the replacement period for passenger and light commercial vehicles from five to four years because:
    - SA Power Networks' NPV analysis showed that it costs more to replace passenger and light commercial vehicles at four years compared to the current rate of five years
    - SA Power Networks' justification that these additional costs would be more than offset by gains in technological and safety advances in the motor industry and the improvement in operational flexibility were not substantiated

[394] NER, cll. 6.5.7(c)(1) and 6.5.7(c)(2).

[395] SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 140.

[396] SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 140.

[397] SA Power Networks, *Revenue Proposal, SA Power Networks - 20.26 PUBLIC - Strategic Fleet Plan 2015-2020*, October 2015, p. 4.

[398] AER, *Preliminary decision - SA Power Networks distribution determination - Attachment 6 - Capital expenditure*, April 2015, p. 6-135.

[399] AER, *Preliminary decision - SA Power Networks distribution determination - Attachment 6 - Capital expenditure*, April 2015, pp. 6-132-135.

- SA Power Networks' reported comparison of vehicle replacement criteria shows that a number of other Australian electricity distributors have passenger and light commercial vehicle replacement criteria similar to SA Power Networks' current criteria.

- New fleet expenditure – we did not accept SA Power Networks' proposal of $26.7 million. We considered that as our estimate of SA Power Networks' capex requirements for the 2015-20 regulatory control period is in line with SA Power Networks' actual expenditure during the 2010-2015 regulatory control period, expenditure on new fleet assets associated with forecast employee growth to deliver SA Power Networks' proposed network program was not justified.
- Safety initiatives – we did not accept SA Power Network's proposal of $6.6 million. Whilst we considered that there may be some merit in these proposed safety initiatives, SA Power Networks did not provide persuasive justification that its proposed In Vehicle Management System (IVMS) expenditure is necessary to meet new legislative and WH&S obligations. Also, in relation to SA Power Networks' proposed vehicle weighing system, we considered there had been no material changes to the compliance requirements with respect to the weight that its vehicles are required to operate.

In its revised proposal, SA Power Networks accepted our alternative fleet replacement program forecast of $103.2 million and noted that this reduction reflects the change to a five year replacement criteria for passenger and light commercial vehicles. SA Power Networks also stated that it submitted a different profile to the AER which aligns with the actual timing of its fleet replacement program.[400]

SA Power Networks did not accept our decision to exclude new fleet capex. SA Power Networks stated that additional fleet is required to support the delivery of its forecast network program of work. SAPN proposed new fleet capex of $16.7 million, which is a reduction of $8.9 million or 35 per cent from its initial proposal of $25.6 million. SA Power Networks stated that its revised work programs are heavily skewed to more labour intensive power line asset replacement and refurbishment works. This work is to be undertaken by Power Line Trade Skilled Workers (TSWs) through a combination of internal and externally outsourced resources. SA Power Networks estimate that based on its revised program of work there will be an increase of approximately 150 TSWs required to deliver the power line related construction and maintenance functions. SA Power Networks have determined that the most prudent and efficient approach is to recruit an additional 75 TSWs over the 2015-20 regulatory control period and outsource the balance. SA Power Networks stated that given a progressive increase in TSWs over the 2015–20 regulatory control period, it will need to invest in additional heavy and light vehicles.[401]

400 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 170.

401 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 170.

SA Power Networks did not accept our decision to not allow expenditure to support the further roll out of its IVMS safety program. SA Power Networks submitted that these systems are being adopted as standard practice in many industries with similar work place risks to those faced by SA Power Networks workers and contractors. This is to ensure (so far as is reasonably practicable) that workplaces are without risk to the health and safety of any person when travelling in vehicles as required by the *Work, Health and Safety Act 2012 (SA)* (WHS Act) and the *Electricity Act 1996 (SA)* by:

- managing and monitoring the safety and welfare of its mobile employees working alone in remote or risky areas; and
- measuring driver safety and behaviour and vehicle treatment.

SA Power Networks stated that the duty under the WHS Act is an objectively determined standard which will change over time as the accepted standard of what is 'reasonable' changes. SA Power Networks submitted that its workplace safety has improved over time as new safety measures are adopted and implemented. SA Power Networks also submitted that the introduction of the IVMS over the last 12 months has reduced the severity of significant incidents even though the number of vehicle incidents has remained relatively stable over this period.[402]

SA Power Networks stated that although it does not agree with our assessment of its proposed weight compliance capex of $3.6 million, it nevertheless accepts our preliminary decision and did not resubmit this expenditure.[403]

We have reviewed SA Power Networks' revised proposal and consider that SA Power Networks' forecast standard control fleet capex of $122.9 million ($2014–15) reasonably reflects the efficient costs that a prudent operator would require to meet the capex criteria.[404] In coming to this view, we acknowledge that SA Power Networks has responded to the issues raised by us in our preliminary decision with revised forecasts and additional justification in some areas. In particular, SA Power Networks has:

- accepted our decision with respect to replacement fleet capex
- accepted our decision not to allow $3.6 million for its weight compliance program.

We have assessed SA Power Networks' revised new fleet capex based on our review of the additional new fleet required to support the delivery of SA Power Networks' proposed network capex program of work, in particular the resource requirements for its power line asset replacement and refurbishment works. We consider that SA Power Networks has substantially justified its proposed replacement works and therefore consider SA Power Networks' forecast new fleet capex of $16.7 million to be reasonable.

402 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 171.

403 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 143.

404 NER, cl. 6.5.7(c)(1).

We consider that SA Power Networks' proposed IVMS fleet capex of $3 million is justified on the basis of this technology's ability to monitor SA Power Networks' employees driving behaviour, and its increasingly widespread adoption throughout industry.

B.7.6 Communications capex

In our preliminary decision for non-network capex, we noted that SA Power Networks had forecast communications expenditure to reduce substantially in the 2015–20 regulatory control period. On that basis, we did not pursue a detailed specific review of this category of forecast non-network capex.[405]

In its revised proposal, SA Power Networks submitted that in modelling our preliminary decision, we incorrectly allocated the proposed non-network communications capex across the augmentation and replacement categories. As a result of this error, adjustments subsequently made to the augmentation and replacement capex forecasts had the effect of excluding the non-networks communications capex from our preliminary determination estimate of total capex.[406]

SA Power Networks' revised proposal includes forecast non-network communications capex of $15.9 million ($2014–15). This is a reduction from its initial $25.5 million proposal of 38 per cent.[407] SA Power Networks has reduced the forecast capex for each of the three proposed communications projects as follows:

- Networks Operations Centre – project capex reduced from $11.1 million to $8.1 million to reflect removal of elements related to low voltage network monitoring using smart meters, which we did not accept in the preliminary decision[408]
- Telecommunications Network Operations Centre – project capex reduced from $9.0 million to $5.8 million to reflect only essential capex following removal of the related opex step change[409]
- Government Radio Network – project capex reduced from $5.4 million to $2.0 million due to the incorrect allocation of costs between capex and opex.[410]

As noted in our preliminary decision, SA Power Networks' forecast non-network communications capex is low compared to historical levels of expenditure in this category. SA Power Networks has further reduced its initial proposal for non-network communications capex to include only core components, consistent with changes in other aspects of its revised regulatory proposal. On this basis, we are satisfied that SA Power Networks' forecast non-network communications capex is likely to reflect a

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405 AER, *Preliminary decision - SA Power Networks distribution determination - Attachment 6 - Capital expenditure*, April 2015, p. 6-112.

406 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, pp. 141-142.

407 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 140.

408 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, pp. 162-164.

409 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, pp. 165-166.

410 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, pp. 167-168.

reasonable estimate of the efficient costs that a prudent operator would require for this capex category to achieve the capex objectives. We will make an allowance for it in our estimate of total capex for the 2015–20 regulatory control period.

B.7.7 Other non-network capex - distribution network pricing rule change

SA Power Networks' revised proposal includes non-network capex of $2.6 million ($2014–15) relating to the introduction of cost reflective tariffs. SA Power Networks' obligation to introduce new cost reflective tariffs arises from the AEMC's final determination on the distribution network pricing rule change made in November 2014.[411]

As discussed in attachment 7 of this decision, we have accepted SA Power Networks' proposed opex step change relating to the introduction of cost reflective network tariffs. We will therefore also allow for the associated capex for the implementation of cost reflective tariffs in our estimate of total capex which reasonably reflects the capex criteria.

[411] SA Power Networks, *Revised regulatory proposal*, 3 July 2015, pp. 176-177.

C Maximum demand forecasts

Maximum demand forecasts are fundamental to forecasting a service provider's capex and opex, and to our assessment of that forecast expenditure.[412] SA Power Networks uses demand forecasts in conjunction with network planning to determine the amount and timing of such expenditure. For capex, expected growth in demand is an important factor driving network augmentation expenditure and connections expenditure (growth capex).

We are satisfied the system demand forecast in SA Power Networks' revised regulatory proposal for the 2015–20 period reasonably reflects a realistic expectation of demand. We acknowledge that demand forecasting is not a precise science and that SA Power Networks' forecasts will inevitably contain errors. However, the evidence presented to us supports our conclusion.

In our preliminary decision, we accepted that SA Power Networks maximum demand forecasts reflected a realistic expectation of demand over the 2015–20 regulatory control period. This was because the forecast aligned with AEMO's independent connection point demand forecasts for SA Power Networks and was consistent with the flattening of demand over the 2010–15 period.[413]

Subsequent to the preliminary decision, AEMO released its 2015 national electricity forecast report which contains updated maximum demand forecasts for South Australia. AEMO's revised forecasts for the 2015–20 regulatory control period are consistent with its previous forecasts, although it forecasts higher growth over the longer term.[414]

SA Power Networks has not changed its maximum demand forecasts in its revised proposal. SA Power Networks submitted that it updated its demand forecast using recent actual demand from the 2014–15 summer, but because the summer was generally mild its forecast is unchanged from its 2014 forecast. [415] It also compared its spatial demand forecasts with AEMO's 2015 forecasts contained in the 2015 national electricity forecast report and found that the forecasts are aligned.[416]

The CCP submitted that SA Power Networks' maximum demand may reduce over the 2015–20 period due to the introduction of demand tariffs on residential and small business customers, and the impact of solar PV and energy efficiency in new

[412] In this attachment, 'demand' refers to summer maximum, or peak, demand (megawatts, MW) unless otherwise indicated.

[413] AER, *Preliminary Decision SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital Expenditure*, April 2015, p. 138.

[414] AEMO, *2015 National Electricity Forecasting Report*, June 2015 p. 59.

[415] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 55.

[416] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 55.

estates.[417] Because of this it submitted that our preliminary decision adopted an overly conservative position on demand and growth related augmentation expenditure.

We agree with the CCP and consider that factors such as energy efficiency and solar PV will likely dampen any demand growth over the 2015–20 period. The demand forecasting methodology adopted by both SA Power Networks and AEMO takes into account forecast trends in solar PV and energy efficiency, and this is likely a major driver of forecast flat demand growth over the period. In the absence of other information, we consider that the alignment of SA Power Networks demand forecast with AEMO's independent forecasts suggests that SA Power Networks forecasts reflects a realistic expectation of demand over the 2015–20 period. The impact of demand tariffs is less clear. First, this will depend on the availability of metering technology on a sufficient scale. Second, the timing of the introduction of these tariffs is likely to be late in the regulatory period.

417 CCP, *Submission to SA Power Networks' revised proposal*, p. 54.