ISSUES PAPER

SA electricity distribution determination

SA Power Networks

2020 to 2025

March 2019

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: 1300 585 165
Email: AERInquiry@aer.gov.au

Invitation for submissions

A public forum on the proposal from SA Power Networks and our issues paper will be held on 4 April 2019 in Adelaide, as per our previous communication on 14 February. Interested parties who are yet to register, are invited to register their interest in attending the forum by emailing SAPN2020@aer.gov.au with their name, the business or agency they represent (if relevant) and contact details by 1 April 2019. Details regarding the forum are below:

Location: Stamford Plaza Adelaide, 150 North Terrace, ADELAIDE
Date: Thursday, 4 April 2019
Time: 9:00 am – 12:00 pm

Written submissions on SA Power Networks' proposal are invited by 16 May 2019.

We will consider and respond to all submissions received by that date in our draft determinations.

Submissions should be sent to: SAPN2020@aer.gov.au.

Alternatively, submissions can be sent to:

Warwick Anderson
General Manager, Networks Finance and Reporting
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

Submissions should be in Microsoft Word or another text readable document format.

We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process. Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information should:

(1) clearly identify the information that is the subject of the confidentiality claim

(2) provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential submissions will be placed on our website. For further information regarding our use and disclosure of information provided to us, see the *ACCC/AER Information Policy* (June 2014), which is available on our website.[1]

[1] https://www.aer.gov.au/publications/corporate-documents/accc-and-aer-information-policy-collection-and-disclosure-of-information.

Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
augex	augmentation capital expenditure
capex	capital expenditure
CCP/CCP14	Consumer Challenge Panel, sub-panel 14
CESS	Capital Expenditure Sharing Scheme
COAG	Council of Australian Governments
CPI	Consumer price index
DMIA/DMIAM	Demand Management Innovation Allowance/Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
EBSS	Efficiency Benefit Sharing Scheme
HID	high intensity discharge
ICT	information and communications technology
LED	light emitting diode
LIDAR	light detection and ranging
NEL	National Electricity Law
NEO	National electricity objective
NER	National Electricity Rules
NGL	National Gas Law
opex	operating expenditure
PTRM	Post tax revenue model
RAB	Regulatory asset base
repex	replacement capital expenditure
RIT-D	Regulatory Investment Test - Distribution
SA	South Australia
SAPN	SA Power Networks
STPIS	Service Target Performance Incentive Scheme
TNSP	Transmission network service provider
TSS	Tariff Structure Statement
WARL	weighted average remaining life

1 Introduction

The Australian Energy Regulator (AER) works to make all Australian energy consumers better off, now and in the future. We regulate electricity networks in all jurisdictions except Western Australia. Our work is guided by the National Electricity Objective (NEO) which promotes efficient investment in, and operation and use of, electricity services in the long term interests of consumers.[2] As part of this, we set the maximum revenues that networks are allowed to recover from consumers through their network tariffs (this is known as the 'revenue cap' form of control). The amount of these revenues is based on our assessment of efficient costs and a realistic expectation of forecast electricity demand. By only allowing efficient costs we regulate network tariffs so that consumers pay no more than necessary for the safe and reliable delivery of electricity.

Regulatory determinations usually occur every five years for each regulated business. We use an incentive approach where, once regulated revenues are set for a five year period, networks who keep actual costs below the regulatory forecast of costs retain part of the benefit. This benchmark incentive framework is a foundation of the AER's regulatory approach and promotes the delivery of the NEO. Service providers have an incentive to become more efficient over time, as they retain part of the financial benefit from improved efficiency. Consumers also benefit when efficient costs are revealed and a lower cost benchmark is set in subsequent regulatory periods.

On 31 January 2019, SA Power Networks submitted its revenue proposal for the five years commencing 1 July 2020. The AER has not yet formed a view on the proposals put to us by SA Power Networks. While we have commenced our review, we have not been able to consider all the materials and evidence that support the claims made by SA Power Networks. Further, we have not applied all our regulatory tools to test the robustness of the proposals.

A key part of our review is consultation with stakeholders. The purpose in publishing this paper, required under clause 6.9.3(b)(1), is to assist stakeholders by identifying those aspects of the proposals which, after our preliminary review, are likely to be relevant to our assessment of the proposal. Stakeholders can assist our process by providing their views on these aspects. Stakeholders should feel free to comment on any aspect of the regulatory proposals.

1.1 How can you get involved?

A public forum on the proposals will be held in Adelaide on 4 April 2019. As part of this review we're also seeking written submissions from stakeholders on SA Power Networks' proposal, its priorities for these reviews and its views on where our assessment should focus.

---

2 NEL, s. 7.

The decisions we make and the actions we take affect a wide range of individuals, businesses and organisations. Hearing from those affected by our work helps us make better decisions, provides greater transparency and predictability, and builds trust and confidence in the regulatory regime.

Throughout these reviews we will also have the benefit of advice from our Consumer Challenge Panel (CCP14).[3] The expert members of the CCP help us to make better regulatory decisions by providing input on issues of importance to consumers and bringing consumer perspectives to our processes.

The table below sets out the key milestones planned for these reviews:

Milestone	Date
SA Power Networks submitted its proposal	31 January 2019
AER issues paper published	28 March 2019
Public forum on SA Power Networks' proposal	4 April 2019
Submissions on AER's issues paper and SA Power Networks' proposal due	16 May 2019
AER draft decision to be published	September 2019
Public forum on draft decision	October 2019
SA Power Networks submits revised proposal	December 2019
Submissions on draft decision and revised proposal due	January 2020
AER final decision to be published	April 2020

Note: Timelines are subject to change.

3 Members of CCP14 are Mark Grenning, Mike Swanston and Louise Benjamin. Member biographies are available on our website: https://www.aer.gov.au/about-us/consumer-challenge-panel.

2 What SA Power Networks proposal means for SA customers?

SA Power Networks is the sole electricity distribution network service provider in South Australia (SA). SA Power Networks has proposed total revenue of $4.2 billion ($ nominal, smoothed) to be recovered from SA electricity customers over the five years from 1 July 2020 to 30 June 2025 as set out in Table 1. We set out proposed revenue in nominal dollar terms as these are the total revenues that SA Power Networks expect to recover from customers after taking into account forecast inflation over the next regulatory control period.

Table 1 Summary of proposed revenue ($nominal, smoothed)

($ million)	2020-21	2021-22	2022-23	2023-24	2024-25	Total 2020-25
SA Power Networks	802.3	822.1	842.4	863.2	884.5	4214.5

Source: SA Power Networks, *Regulatory Proposal Attachment 1.1 PTRM,* January 2019; AER, *Final decision PTRM for 2015-20 regulatory period*, as updated post final decision, expected smoothed revenue $nominal (revenue cap).

Table 2 shows the estimated impact that SA Power Networks' proposal would have on distribution network tariffs over the five years. These are also set out in nominal terms.

Table 2 Estimated distribution network tariff impact (per cent, nominal)

($ million)	2020-21	2021-22	2022-23	2023-24	2024-25	Average 2020-25
SA Power Networks	-6.0%	2.2%	2.2%	1.9%	1.6%	0.3%

Source: SA Power Networks, *RIN workbook 7*, January 2019.

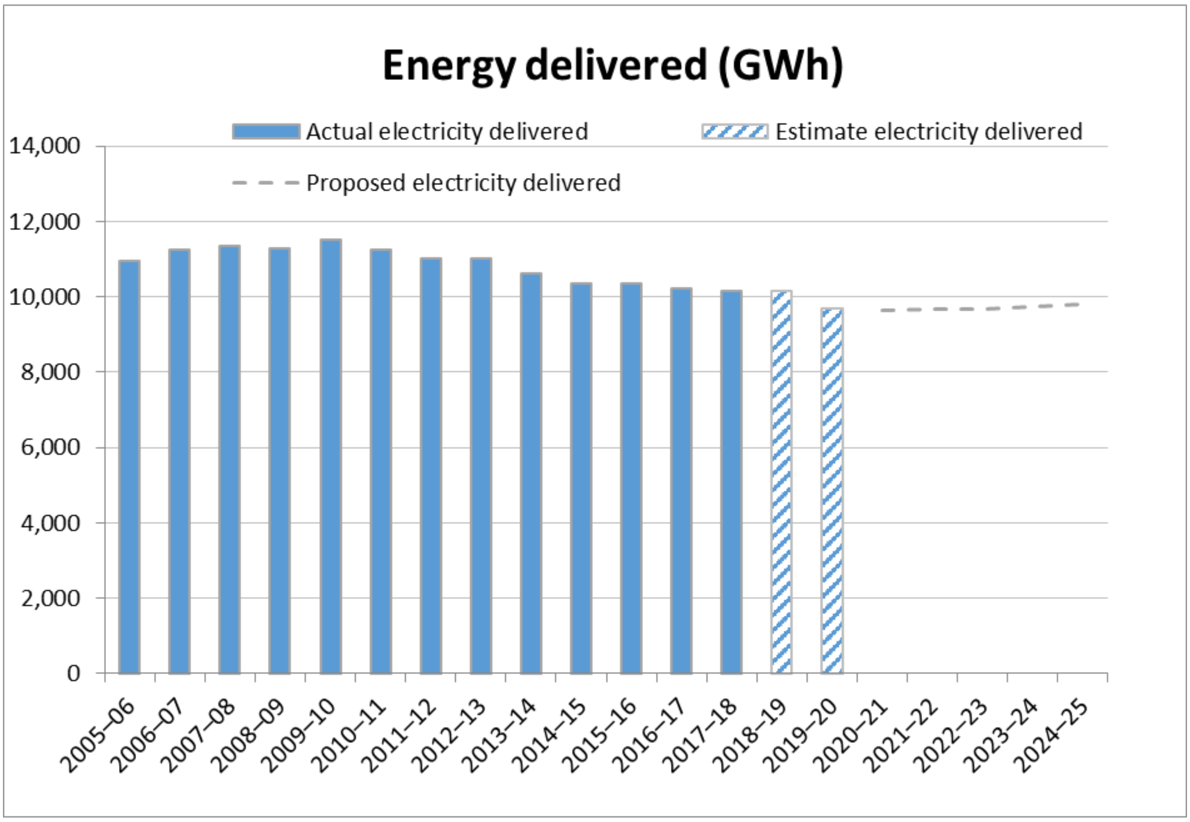
SA Power Networks estimates a reduction in the distribution network tariff cost component of around 6.0 per cent of a typical average residential electricity bill from 2019-20 to 2020-21.[4] This reduction in the first year of the next regulatory control period is largely driven by the revenue reduction which is generally referred to by the industry and us as the P0 adjustment. The P0 adjustment is expressed in real terms

[4] SA Power Networks, *Reset RIN Workbook 7* - Bill Impacts, January 2019. Assumes distribution costs make up 34 per cent of a typical residential customer's electricity bill and 32% of a typical small business customer's electricity bill (on a single rate tariff).

($2019-20). SA Power Networks proposes a P0 reduction of 2.8 per cent ($, 2019-20), and constant real revenues thereafter (X factor of 0 per cent), respectively.[5]

Under the revenue cap form of control that applies to SA Power Networks, any difference between forecast and actual energy delivered will impact distribution tariffs: if actual energy delivered is higher than forecast, tariffs will go down (and vice versa). Figure 1 shows the actual energy delivered during the 2015–20 regulatory control period and the forecast proposed by SA Power Networks for the next regulatory control period from 2020 to 2025.

Figure 1 Actual and forecast energy delivered



Source: SA Power Networks, *Economic benchmarking RINs*; SA Power Networks, *2020-25 reset RIN.*

The common categories of costs that are typically identified as making up retail electricity prices are wholesale costs (generation), network costs (transmission and distribution), environmental (green) scheme costs and retail costs and margins. The distribution network tariffs that will be set on the basis of our decisions on maximum revenue are only one component of retail energy bills. Holding all other bill components

5 The P0 adjustment measures the real change in smoothed revenue from 2019–20 to 2020–21. This is different to the change in indicative network tariff from 2019–20 to 2020–21 because the change in indicative network tariff takes into account the change in volumes as well as nominal revenue change. It should also be noted that the P0 adjustment is based on real 2019–20 dollar terms, while the change in indicative network tariff is based on a nominal value comparison which include the impact for annual inflation.

constant, Table 3 shows the impacts of the revenue SA Power Networks is seeking over the 2020–25 regulatory control period on the distribution network tariffs over that period. We provide these in both nominal and real dollars.

Table 3 Indicative impact of SA Power Networks' proposed 2020–25 revenue on the distribution network tariffs

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	Total 2020-25
Residential customer							
Regulated tariff ($ nominal)	$547	$514	$526	$537	$548	$557	$2682
Annual change ($ nominal)		-$33	$11	$12	$10	$9	$9
Regulated tariff ($ real, June 2020)	$547	$502	$501	$499	$497	$493	$2492
Annual change ($ real, June 2020)		-$45	-$1	-$1	-$3	-$4	-$54
Small business customer							
Regulated tariff ($ nominal)	$1087	$1022	$1044	$1068	$1088	$1106	$5328
Annual change ($ nominal)		-$65	$23	$23	$21	$18	$19
Regulated tariff ($ real, June 2020)	$1087	$997	$995	$992	$987	$979	$4950
Annual change ($ real, June 2020)		-$90	-$3	-$2	-$5	-$8	-$108

Source: SA Power Networks, Reset RIN Workbook 7 - Bill Impacts, January 2019.

2.1 Stakeholder engagement

SA Power Networks sets out its customer engagement prior to lodging the regulatory proposal in detail in its proposal. These engagement processes and information are also available on its website: talkingpower.com.au. This engagement has been undertaken in four stages:

- February 2017— strategic research and early engagement
- August to December 2017 — in-depth engagement
- January to August 2018 —draft plan development and consultation on it from August to September 2018
- October 2018 to January 2019 — regulatory proposal development.

Our CCP 14 and staff also participated in some of these stakeholder engagement events. CCP 14 made two submissions to us after observing/participating in SA Power Networks engagement events. The first related to challenges facing SA Power

Networks due to the high penetration of embedded generation, and the second was on the draft plan. SA Power Networks also provided us with a submission in response to CCP 14's first submission. All these submissions are available on our website.[6] Based on its stakeholder engagement, SA Power Networks' identified that customers and stakeholders generally agreed that they value:

- Keeping prices down
- A safe and reliable network
- Transitioning to the new energy future.

As part of our assessment, we are particularly interested in hearing from stakeholders how well:

- the above value areas reflect stakeholder priorities for these determinations
- SA Power Networks has — in the proposal submitted to us for assessment— addressed matters put to SA Power Networks over the engagement period.

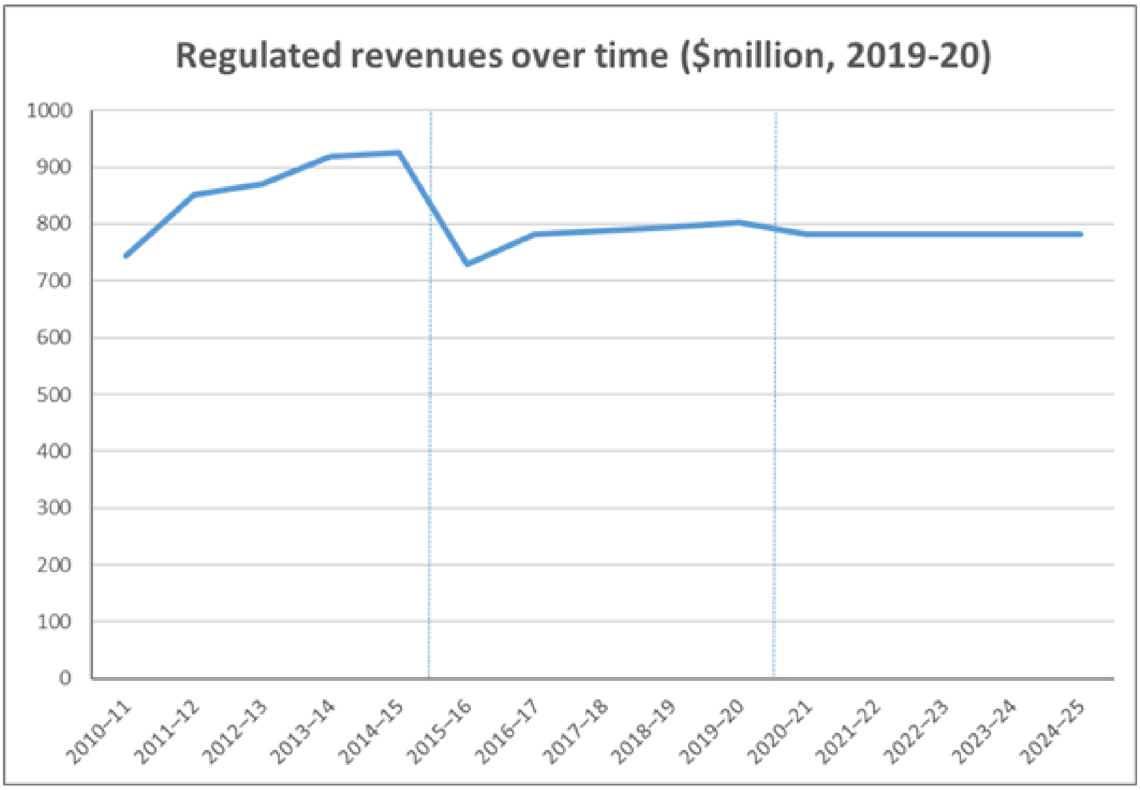
6 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2020-25/proposal.

3 What's driving the change in revenue over time

In this chapter we discuss revenue changes in real dollars ($2019–20). This allows for comparisons after taking inflation impacts into account.

SA Power Networks' proposal would allow it to recover $3,914.7 million ($2019–20, smoothed) from customers over the 2020–25 regulatory control period. This is a 0.4 per cent real increase from our last decision for the 2015–20 regulatory period. Figure 2 shows the AER's approved regulated revenue in the past two regulatory periods from 2010–11 to 2019–20 ($2019–20, smoothed) compared to the forecast revenue proposed by SA Power Networks for the 2020–25 regulatory control period.

Figure 2 SA Power Networks' regulated revenue over time ($million, 2019–20)



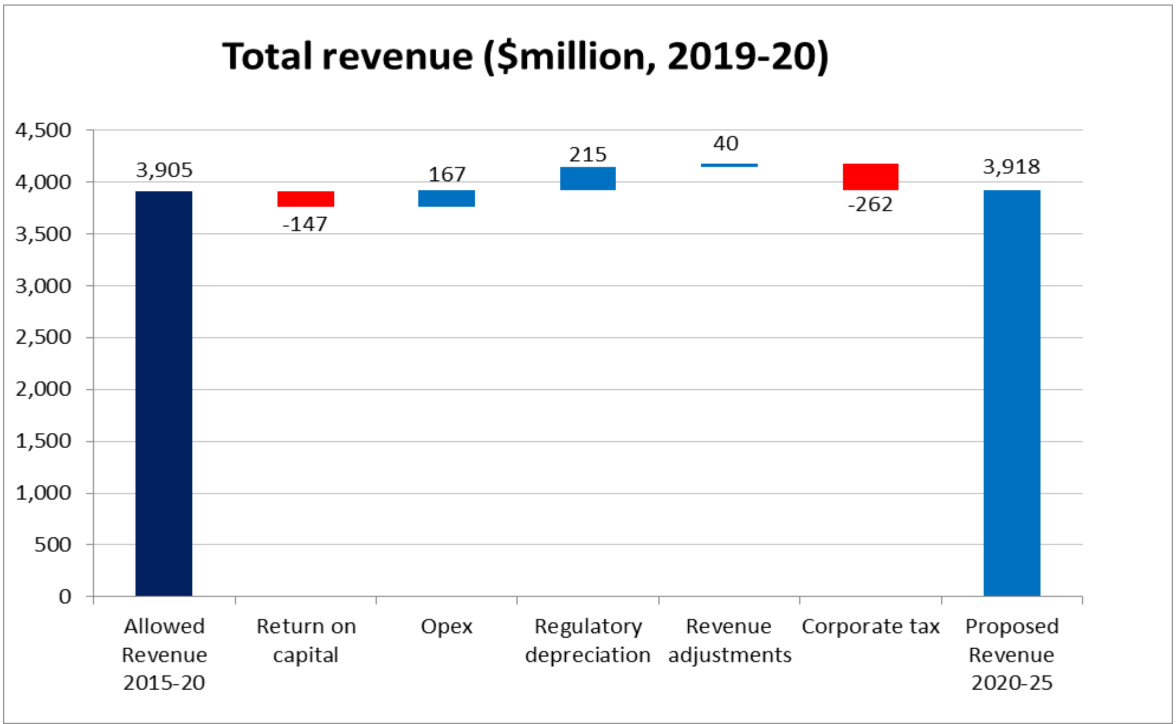
Source: AER analysis; AER, *Final decision PTRM for 2010-15 and 2015-20 regulatory periods*, as updated post final decision; SA Power Networks, *Regulatory Proposal PTRM 2020-25 regulatory period*. Total revenue for 2020-25 is $3915 million (2019-20).

Relative to the 2015-20 regulatory control period, forecast revenue for the return on capital and corporate tax components are significantly lower in the 2020-25 period. This reduction is largely driven by a decline in the allowed rate of return and changes to the corporate income tax allowance as a result of our recently concluded reviews of the rate of return and regulatory tax approach. These are discussed in 3.1.1 and 3.1.2 below.

Whilst capex is forecast to decline in real terms over the 2020-25 regulatory control period, the value of the RAB is projected to increase by around 2 per cent in real terms by the end of the 2020–25 period. Alongside this decrease in capex, opex is forecast to increase by 17.3 per cent compared to the current regulatory control period. A major contributor to the increase in forecast opex are proposed step changes. This includes changes to the treatment of expenditure on cable and conductor minor repairs, from capex to opex (opex/capex trade-off). SA Power Networks' proposed expenditures associated with alleviating network issues as a result of the continuing growth in distributed energy resources (DER) also has an impact on the amount of revenue required in the 2020-25 regulatory control period.

Figure 3 Changes in building blocks: SA Power Networks' allowed revenue 2015–20 to forecast revenue 2020–25 ($million, 2019/20 – unsmoothed)Figure 3 highlights changes in SA Power Networks' proposal at the building block level to illustrate what is driving its proposed increase in revenue from 2015–20 to 2020–25. The individual drivers of proposed revenue are discussed in more detail in section 4.

Figure 3 Changes in building blocks: SA Power Networks' allowed revenue 2015–20 to forecast revenue 2020–25 ($million, 2019/20 – unsmoothed)



Source: AER analysis; AER, *Final decision PTRM for 2015-20 regulatory period*, as updated post final decision; SA Power Networks, *Regulatory Proposal PTRM 2020-25 regulatory period*.

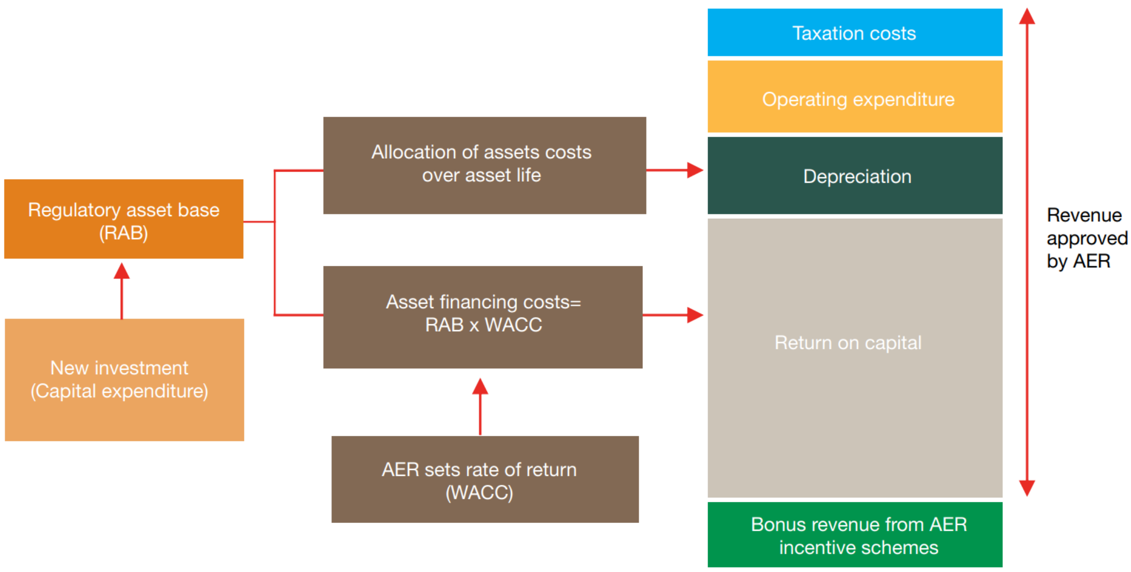
3.1 How we determine forecast revenue

SA Power Networks proposed total revenue reflects its forecast of the efficient cost of providing its distribution network services over the 2020–25 regulatory control period.

This revenue proposal, and our assessment of it under the National Electricity Law and Rules (NEL and NER), are based on a 'building block' approach (see Figure 4) which looks at five cost components:

- a return on the RAB (or return on capital, to compensate investors for the opportunity cost of funds invested in this business)
- depreciation of the RAB (or return of capital, to return the initial investment to investors over time)
- forecast opex – the operating, maintenance and other non-capital expenses, incurred in the provision of network services
- revenue increments or decrements resulting from the application of incentive schemes such as the opex Efficiency Benefit Sharing Scheme (EBSS), Capital Expenditure Sharing Scheme (CESS) and Demand Management Innovation Allowance (DMIA)
- the estimated cost of corporate income tax.

Figure 4 The building block approach for determining total revenue



Source: AER

We use an incentive approach where, once regulated revenues are set for a five year period, networks who keep actual costs below the regulatory forecast of costs retain part of the benefit. This benchmark incentive framework is a foundation of the AER's regulatory approach and promotes the delivery of the national electricity objective (NEO) and national gas objective (NGO). Service providers have an incentive to become more efficient over time, as they retain part of the financial benefit from improved efficiency. Consumers also benefit when efficient costs are revealed and a lower cost benchmark is set in subsequent regulatory periods.

Our assessment breaks these costs down further. For example:

- Capex—the capital costs and expenditure incurred in the provision of network services—mostly relates to assets with long lives, the costs of which are recovered over several regulatory control periods. The forecast capex approved in our decisions directly affects the size of the capital base and therefore the revenue generated from the return on capital and depreciation building blocks. All else being equal, higher forecast capex will lead to a higher RAB and higher return on capital and regulatory depreciation allowances.
- The RAB accounts for the value of regulated assets over time. To set revenue for a new regulatory control period, we take the opening RAB value from the end of the last period and roll it forward year-by-year by indexing it for inflation, adding new capex, and subtracting depreciation and other possible factors (for example, disposals or customer contributions).[7] This gives us a closing value of the RAB at the end of each year of the regulatory control period. The value of the RAB is used to determine:
    - the return on capital building block, which is the product of the RAB and our approved rate of return (see section 3.1.1)
    - regulatory depreciation (or the return of capital).

There are two aspects of our approach to forecast revenue that were recently reviewed. The outcomes of these reviews are discussed in sections 3.1.1 and 3.1.2 below.

3.1.1 Rate of return

The return (the 'return on capital') each business is to receive on its RAB continues to be a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the RAB.

The allowed rate of return is a forecast of the cost of funds a network business requires to attract investment in the network.

We estimate the rate of return by combining the returns of the two sources of funds for investment: equity and debt. The return on equity is the return shareholders of the business will require for them to continue to invest. The return on debt is the interest rate the network business pays when it borrows money to invest.

We will apply the 2018 rate of return instrument (the instrument) published by us and the values therein to calculate SA Power Network's rate of return.[8] The instrument was

---

[7] The term 'rolled forward' means the process of carrying over the value of the RAB from one regulatory year to the next.

[8] AER, *Rate of return instrument*, 17 December 2018; AER, *Rate of return instrument explanatory statement*, December 2018. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-guideline-2018/final-decision.

developed after extensive consultation and is binding following legislative amendments passed by the South Australian Parliament in December 2018.[9]

SA Power Networks submitted that its proposal is consistent with the instrument and the key values of its proposal are set out in Table 4 below.[10]

Table 4 Key rate of return values

	SAPN proposal	2018 Instrument
Return on equity	6.1% (indicative)	Risk free rate + 3.66%
Risk free rate	2.44% (indicative)	Based on criteria in the instrument
Market risk premium	6.1%	6.1%
Equity beta	0.6	0.6
Equity risk premium (equity beta*market risk premium)	6.1*0.6%=3.66%	6.1*0.6%=3.66%
Return on debt (nominal pre–tax)	4.98% (indicative)	Based on criteria in the instrument
Gearing	60%	60%
Gamma (value of imputation credits)	0.585	0.585

Source: AER analysis; SA Power Networks, *2020-25 Regulatory Proposal Attachment 3*, 31 January 2019.

The instrument also sets out the process by which we will annually update the return on debt (and therefore the overall rate of return) during the regulatory control period.

SA Power Networks has proposed to depart from our standard approach of estimating debt raising costs – the result is higher debt raising costs.[11] SA Power Networks' proposal is based on including outliers in its bond sample whereas we exclude outliers. SA Power Networks also noted that we should consider accepting allowances for liquidity management and refinancing risk as the PTRM timing benefits do not fully compensate for these costs. We will assess these issues as part of our review.

3.1.2 Corporate income tax allowance

The building block approach to calculating the annual revenue requirement includes an allowance for the estimated cost of corporate income tax payable by the business. We calculate the expected allowance consistent with the requirements of the NER.[12]

---

9 Statutes Amendment (National Energy Laws) (Binding Rate of Return Instrument) Act 2018 (SA).

10 SA Power Networks, *2020-25 Regulatory Proposal Attachment 3*, 31 January 2019, p. 7.

11 Debt raising costs are not addressed in the binding instrument. SA Power Networks, *2020-25 Regulatory Proposal Attachment 3*, 31 January 2019, pp. 10–11.

12 NER, clause 6.5.3.

Our estimate of the corporate income tax allowance begins with the estimation of the assessable income that would be earned by a benchmark efficient company operating SA Power Networks' network. Estimated tax expenses to be used as tax deductions are then calculated. Estimated tax expenses include interest (using our benchmark 60 per cent gearing), depreciation, operating expenditures, and any capital expenditures that are immediately expensed in accordance with relevant tax law. The taxable income is then determined (assessable income less tax deductions) and the statutory income tax rate of 30 per cent is applied to arrive at the notional tax payable. Finally, an adjustment that reduces the notional tax payable is made to account for the value of imputation credits (gamma), thereby resulting in the net tax allowance that is determined.

In December 2018, we completed a review of our regulatory tax approach.[13] The final report presented analysis of the current tax management practices of the regulated networks and identified some required changes to the estimation of the tax expenses. The changes to our regulatory tax approach require amending our models to:[14]

- recognise immediate tax expensing of some capex forecast for a regulatory control period
- adopt the diminishing value (DV) method for tax depreciation to all future capex except for a limited number of assets which must be depreciated using the straight-line (SL) depreciation method under the tax law.

On 25 January 2019, we released for consultation our proposed amendments to the distribution and transmission PTRMs. The final amended PTRMs will be published by the end of April 2019, in time to be applied to the draft decision for SA Power Networks' 2020–25 distribution determination.

Since the amended PTRM has not been finalised at the time of the submission of SA Power Networks' regulatory proposal, SA Power Networks only provided a preliminary estimate of the corporate income tax allowance for the 2020–25 regulatory control period. The preliminary estimate shows that SA Power Networks will have zero corporate income tax allowance over this period. This is based on SA Power Networks' estimate of how immediate expensing and the adoption of the DV method of tax depreciation would impact its tax calculation.[15] However, more detailed information is required that was not included in the regulatory proposal to correctly reflect these impacts.

Our draft decision assessment will review further information to be provided by SA Power Networks including:

---

13 AER, *Final report: Review of regulatory tax approach*, December 2018, p. 76.

14 Capping of gas asset tax lives was also a finding from the final report, but does not require a model change.

15 SA Power Networks estimated the tax expenses resulting from the combined impact of the changes at $220 million per annum for the 2020–25 regulatory control period. SA Power Networks, *Regulatory Proposal Attachment 7*, pp. 10–11.

- Forecast immediately tax expensed capex for each asset class. This input is required to calculate the estimate of tax expenses. Our treatment of forecast immediate expensing of capex will be guided by SA Power Network's actual immediate expensing of capex from the past period and further information to be sought from SA Power Networks.
- Assets which are exempted from the DV tax depreciation method. Our tax review report found that we should apply the DV method as the new regulatory benchmark for calculating tax depreciation to all new capex.[16] However, there are some exceptions to this method under the tax law such as expenditures relating to in-house software, buildings and equity raising costs. We will require SA Power Networks to re-allocate (where relevant) their forecast capex related to in-house software and buildings from existing asset classes to these new prescribed asset classes if it wishes to apply the SL method of tax depreciation to these assets.[17]

We will consult with SA Power Networks to obtain these inputs and will use them to complete our modelling of the estimated corporate income tax allowance for our draft decision.

---

[16] AER, *Final report: Review of regulatory tax approach*, December 2018, p. 76.

[17] The PTRM calculates any equity raising costs requirements using a benchmark approach and applies the SL method of tax depreciation to this amount.

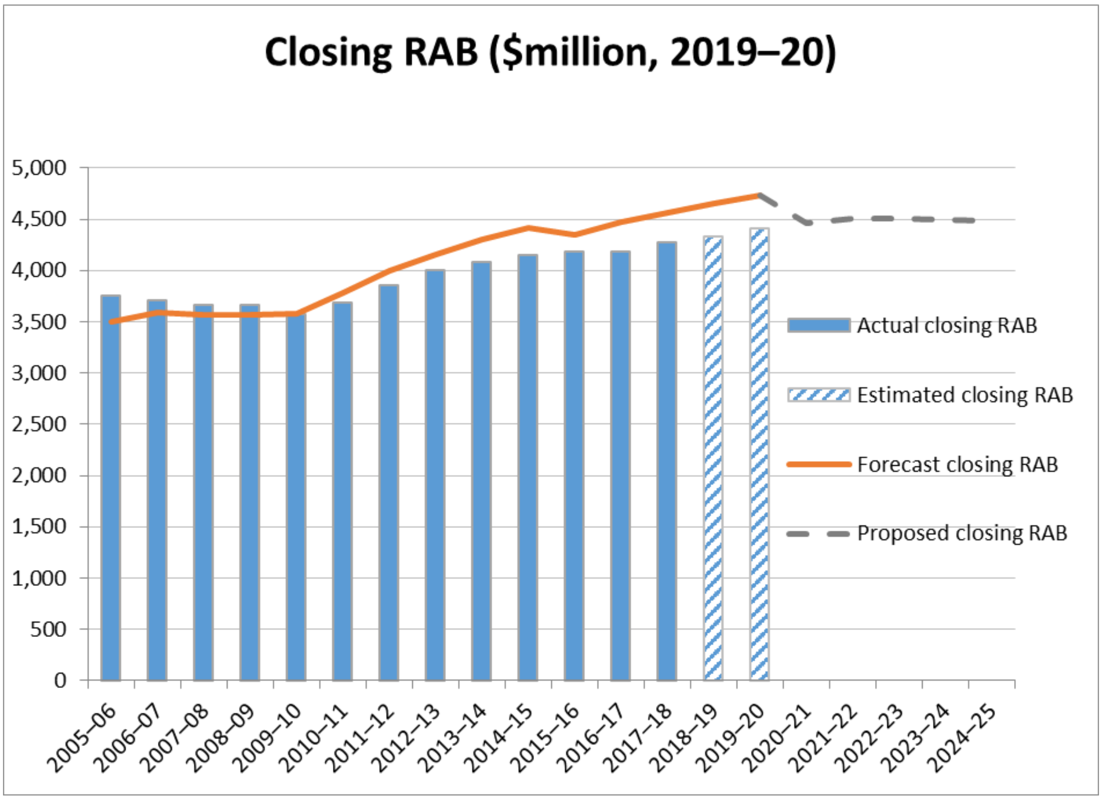
4 Key elements of SA Power Networks' revenue proposal

4.1 RAB and depreciation

The RAB is the value of assets used by SA Power Networks to provide network services. The value of the RAB substantially impacts SA Power Networks' revenue requirement, and the price consumers ultimately pay. Other things being equal, a higher RAB would increase both the return on capital and depreciation (return of capital) components of the revenue determination.

Figure 5 shows the growth in value of SA Power Networks' RAB over time. Based on SA Power Networks' regulatory proposal, its RAB value is projected to increase by around 2 per cent in real terms by the end of the 2020–25 regulatory control period.

Figure 5 SA Power Networks' RAB value over time ($million, 2019/20)



Source: AER analysis; AER, *Final decision PTRM and RFM for 2010-15 and 2015-20 regulatory periods*; SA Power Networks, *Regulatory Proposal PTRM and RFM for 2020-25 regulatory period*; SA Power Networks, DNSP performance report.

Regulatory depreciation is the allowance provided so capital investors can recover their investment over the economic life of the asset (return of capital). The regulatory depreciation allowance is the net total of straight-line depreciation less the inflation indexation adjustment of the RAB.

SA Power Networks' proposed regulatory depreciation allowance for 2020–25 is 23.4 per cent higher in real terms than the allowance we used to set revenues for 2015–20. This is driven by various factors including: an increasing RAB (which naturally increases depreciation too), lower IT depreciation in the 2015–20 regulatory control period due to a true-up issue that saw some IT depreciation from a previous period returned to customers, and the proposed introduction of new asset classes with relatively shorter asset lives (discussed below).

SA Power Networks proposed to continue with the year-by-year tracking approach for implementing straight-line depreciation.[18] The year-by-year tracking approach results in faster regulatory depreciation and higher revenues over the earlier years of its application, compared to the standard Weighted Average Remaining Lives (WARL) approach. However, over a number of periods, the depreciation trend becomes dependant on the mix of new assets (and their economic lives) as the older assets make up a smaller proportion of the RAB.[19]

SA Power Networks also proposed to introduce three new asset classes to apply for the 2020–25 regulatory control period. The assets associated with these new classes were previously included in asset classes with longer standard asset lives.[20] The assets generally relate to refurbishment activities and SA Power Networks submitted the economic life of these assets should reflect the remaining asset life of the refurbished assets to which they relate. The new asset classes are:

- 'Sub-transmission and distribution – short life' (with proposed standard asset life of 25 years), which will include assets used to refurbish assets from the existing 'Sub-transmission lines and cables', 'Distribution lines' and 'Low voltage supply' asset classes (all three with standard asset life of 55 years).
- 'Substations and transformers – short life' (with proposed standard asset life of 20 years), which will include assets used to refurbish assets from the existing 'Distribution lines' (with standard asset life of 55 years), 'Substations' (with standard asset life of 45 years) and 'Distribution transformers' (with standard asset life of 45 years) asset classes.
- 'Electronic network assets' (with proposed standard asset life of 15 years), which is expected to have much lower economic life than distribution lines and substation classes (with standard asset life of 55 years and 45 years respectively) that they are currently grouped with.

We have allowed the creation of new asset classes for refurbishment activities and asset groupings to reflect different economic lives in recent decisions.[21] We will assess

18 SA Power Networks, *Regulatory Proposal Attachment 4*, p.7.

19 Under the WARL approach, the older assets were previously grouped together and given a single remaining asset life even though the group had assets with a variety of individual remaining asset lives.

20 SA Power Networks, *Regulatory Proposal Attachment 4*, pp.7–8.

21 Refurbishment activities: AER, *Powerlink 2017-22 Draft Decision Attachment 5*, p.12; AER, *ElectraNet 2018-23 Draft Decision Attachment 5*, pp.15-18; AER, *TransGrid 2018-23 Draft Decision Attachment 5*, pp.14-18.

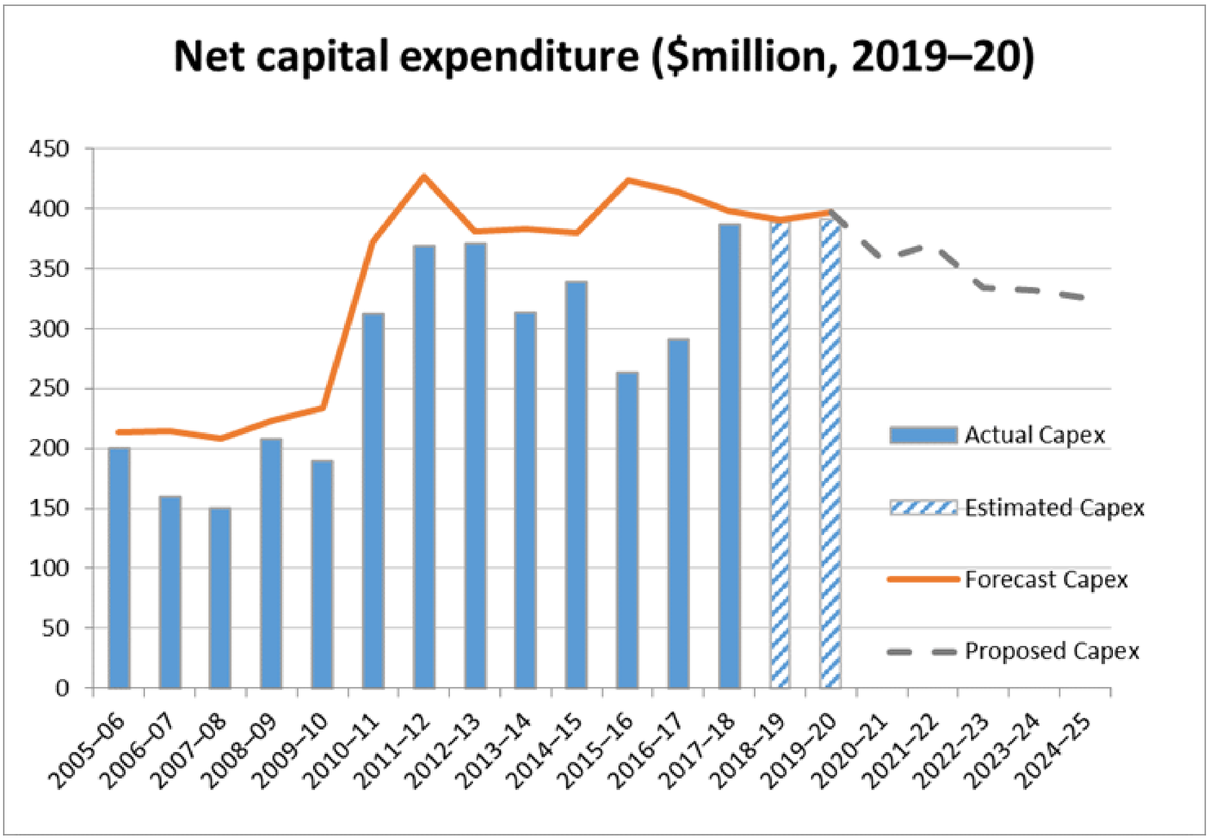
SA Power Network's proposal in a similar manner as those decisions to determine the appropriate economic lives for these assets.

4.2 Capex

Capex is added to SA Power Networks' RAB, which is used to determine the return on capital and return of capital (regulatory depreciation) building block allowances. All else being equal, higher forecast capex will lead to a higher RAB and higher return on capital and regulatory depreciation allowances.

SA Power Networks has proposed total (net) forecast of $1.7 billion ($2019-20) for the 2020–25 regulatory control period. This is approximately equal to SA Power Networks' actual capex for the 2015–20 period.[22] Figure 6 shows the trend in SA Power Networks' total capex over time.

Figure 6 Comparison of SA Power Networks' past and forecast capex



Electronic network asset class: AER, *ElectraNet transmission determination 2008-09 to 2012-13,* pp.208–209; AER, *New South Wales draft distribution determination 2009-10 to 2013-14*, pp.215–216.

22 Note that SA Power Networks' reported capex for 2018–19 and 2019–20 are estimates only. SA Power Networks, *Regulatory proposal Attachment 5*, January 2019, p. 20; SA Power Networks, *Regulatory Proposal Post Tax Revenue Model.*

Source: AER, *Final decision PTRM and RFM for 2015-20 regulatory period*; SA Power Networks, *Regulatory Proposal PTRM and RFM for the 2020-25 regulatory period*.

SA Power Networks' proposed capex forecast seeks to address stakeholder feedback and its key themes of affordability, safety and reliability, and transitioning to the new energy future by:[23]

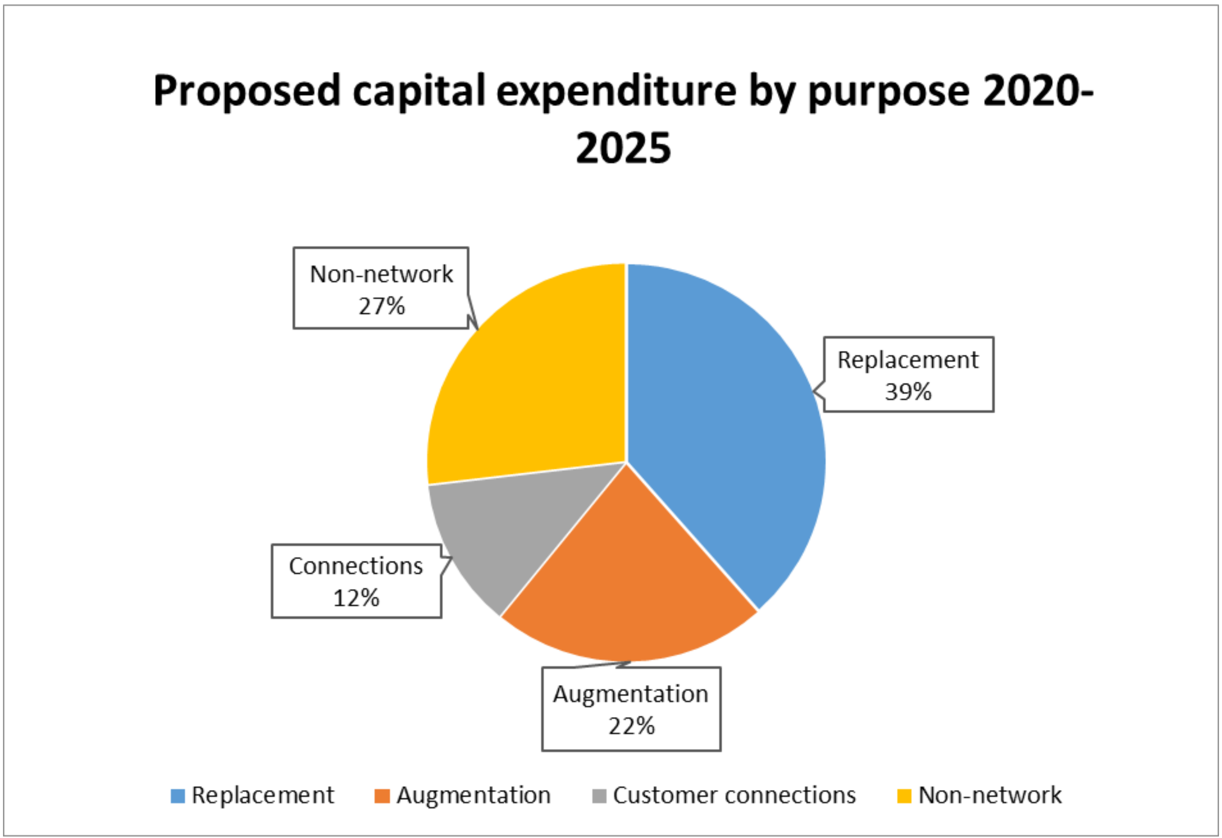
- managing risk by focusing on work that delivers the most value for customers, based on the likelihood and impact of consequence, and actively managing network constraints rather than building new assets to increase capacity.
- continuing with targeted programs to improve the resilience of storm-prone network areas and reducing the risk of its network starting fires. It also proposes a targeted program to improve reliability to customers connected to low reliability feeders.
- proposing targeted investment in new systems to monitor and manage its low voltage network more actively, allowing it to make available more of the existing asset capacity for solar exports, and avoiding expensive network asset upgrades.

Our role is to ensure that SA Power Networks' forecast capex for 2020–25 is consistent with the capex criteria: efficiency, prudency and a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives under the NER. As part of our assessment of SA Power Networks' capex forecast, we are interested in stakeholder views as to how well its proposal—the key drivers of which are summarised below—and the extent to which its capex forecast addresses the concerns of electricity consumers as identified in the course of its engagement on its proposal.

Figure 7 breaks SA Power Networks' 2020–25 capex forecast into its four main drivers, each of which we discuss briefly below.

[23] SA Power Networks, *Regulatory proposal Attachment 5*, January 2019, pp. 13–16.

Figure 7 SA Power Networks' forecast capex by driver



Source: AER analysis; SA Power Networks, *Regulatory Proposal Attachment 5.*

Replacement capex (repex)

SA Power Networks capex forecast includes $669.5 million ($2019-20) inclusive of overheads) for assets replacement and refurbishment, making up around 39 per cent of total capex. The expenditure is on average broadly in line with its repex over the current period.[24] However, we observed that SA Power Networks experienced a higher than usual repex in the 2017-18 year when compared to its average repex spend from 2010 to 2016. The higher than usual repex is forecast to be sustained over the last two years of the current regulatory control period and, to some extent, into the forecast period.[25]

SA Power Networks has proposed to change the treatment of expenditure relating to cable and minor repairs, which would reduce the repex forecast by $69.9 million but increase the opex forecast by approximately $68.2 million[26]. It historically categorised this expenditure as repex, particularly for underground cables and overhead

[24] SA Power Networks, *Regulatory proposal Attachment 5*, January 2019, pp. 28–29, 35.

[25] SA Power Networks, *Regulatory proposal Attachment 5*, January 2019, pp. 34.

[26] The difference between two capex and opex difference is due to the application of escalators, which differ between capex and opex, hence the variation of $1.7 million.

conductors. However, it considers that concerns raised during the AER's review of the regulatory tax approach warrants re-categorising this type of expenditure as opex rather than capex and submits that the change promotes the NEO. Our review will focus on the capex-opex trade-off leading to this proposed deviation from historical practices.

Our predictive repex modelling is a key tool in our assessment of proposed repex. A large portion of repex can be modelled using the repex model. In particular, it can model high volume, low value assets, which are generally a significant part of a business-as-usual capex spend. SA Power Networks tested its repex forecast against the AER's predictive repex model and found that for a number of asset classes, SA Power Networks' forecast is lower than the repex model forecast. As to the unmodelled component of repex, it represents around 30 per cent of total repex, and largely relates to pole top structures, SCADA and non-category specific replacement items.

Augmentation capex (augex)

SA Power Networks capex forecast includes $390.9 million ($2019-20, inclusive of overheads) to expand or upgrade network assets to address changes in demand for SCS or to maintain quality, reliability and security of supply in accordance with regulatory requirements.[27] SA Power Networks' augex proposal comprises around 23 per cent of its total capex forecast, and is 7 per cent lower than augex over the current period.[28]

The proposal includes $154.6 million for capacity augmentation, SA Power Networks submitted that while much of this augmentation is driven by capacity constraints, many constraints are unrelated to future load growth for the asset(s) concerned. Only $18.6 million of the proposed augex is intended to address forecast demand growth[29] while $101.2 million is proposed for regulatory compliance. SA Power Networks submitted that it must maintain supply voltage at customer premises within specified ranges, and the continuing uptake of residential distributed energy resources (DER), is resulting in increasing voltage issues. It has proposed to continue installation of power quality monitors on the low voltage network and to rectify voltage issues as they are identified.[30]

SA Power Networks' proposal also includes $57.5 million for safety programs, including substation security and fencing, and bushfire mitigation. A further $49 million is proposed for strategic programs, including a new $31.8m for low voltage management. It proposed to take a more active and dynamic approach to managing the integration of solar, battery storage and Virtual Power Plants (VPPs) into the distribution network, and this requires the development of new operational systems and business processes.

---

27 SA Power Networks, *Regulatory proposal Attachment 5*, January 2019, pp. 28, 54.

28 SA Power Networks, *Regulatory proposal Attachment 5*, January 2019, pp. 28–29, 35.

29 SA Power Networks, *Regulatory proposal Attachment 5*, January 2019, pp. 62–63.

30 SA Power Networks, *Regulatory proposal Attachment 5*, January 2019, pp. 64–66.

In its response to SA Power Networks' Draft Plan, CCP14 considered that it was not clear that additional funds beyond current trends were required to invest in safety, reliability, and other targeted areas.[31]

Connections capex

SA Power Networks has proposed $563.1 million ($2019-20, inclusive of overheads) in gross connections, which is 18 per cent higher than for the 2015–20 regulatory period. This includes:[32]

- $213.2 million for net connections capex, which is rolled into the RAB and recovered over time through network distribution charges
- $350.1 million for capital contributions, which is funded by connecting customers through cash contributions and gifted assets.

Compared with the current regulatory period, forecast net connections capex is about 20 per cent higher, and forecast capital contributions is 18 per cent higher. SA Power Networks' forecast that net connections capex comprises 12 per cent of its total capex forecast.

The increase in forecast capex is primarily driven by an increase in major customer connections, with strong growth forecast for non-residential building commencements.[33]

Non network capex

SA Power Networks forecast $467.4 million ($2019-20, inclusive of overheads) for non-network capex (27 per cent of total capex). This includes $284.6 million for information and communications technology (IT capex), $61.5 million for property, and $116.6 million for fleet.[34]

SA Power Networks has quantified $203.1 million in benefits relating to its IT program over 2020 to 2030.[35] It submitted that over 70 per cent of the capex ($206.5 million) is concerned with maintaining current levels of service and managing IT risk through replacement and updates to existing IT applications and infrastructure. However, the majority of the benefits arise from the initiatives aimed at efficiently using data and technology to manage (and minimise) its business and network costs. SA Power Networks has submitted that these have been incorporated into its overall proposal (most of which relates to deferred repex).[36]

---

31 Consumer Challenge Panel (subpanel 14), *CCP14 Response to the SA Power Networks 2020-25 Draft Plan and Early Engagement*, October 2018, pp. 13–14.

32 SA Power Networks, *Regulatory proposal Attachment 5*, January 2019, pp. 89, 93.

33 SA Power Networks, *Regulatory proposal Attachment 5*, January 2019, p. 92.

34 SA Power Networks, *Regulatory proposal Attachment 5*, January 2019, pp. 93–112.

35 SA Power Networks, *Regulatory proposal Attachment 5*, January 2019, p. 99.

36 SA Power Networks, *Regulatory Proposal Appendix 5.32*, January 2019, p. 38.

We are seeking stakeholder feedback in relation to SA Power Networks' proposed IT capital expenditure and whether the IT program proposed is in the long-term interests of customers.

In its response to SA Power Networks' Draft Plan, CCP14 raised concerns over the magnitude of IT expenditure proposed, in addition to the $313 million that SA Power Networks expects to spend in the 2015-20 regulatory period. It found SA Power Networks' options analysis presented in stakeholder workshops to be binary, listing either a 'do nothing' approach or to invest as planned. CCP14 encourages SA Power Networks to reconsider the discussion of the changes to risk and business performance if the IT funding was reduced.[37]

Overheads

We have observed that SA Power Networks has not split out capitalised overheads in its regulatory proposal when discussing its capex drivers. Based on information in its Regulatory determination regulatory information notice, SA Power Networks is forecasting a capitalised network overheads of $62.4 million and a capitalised corporate overheads of ($38.3) million.

Contingent projects

SA Power Networks forecast a contingent project for an Electricity System Security project to comply with AEMO's responsibility to maintain security of supply with South Australia. SA Power Networks forecast $79.2 million for the redesign and rebuild of the under-frequency load shedding (UFLS) scheme and the establishment of the capability to shed distributed energy resources (DER). SA Power Networks proposed this project as contingent capex as there is uncertainty around the costs and whether the event will occur.

4.3 Opex

Operating expenditure (opex) refers to the operating, maintenance and other noncapital expenses incurred in the provision of network services. Forecast opex is one of the building blocks we use to determine SA Power Networks' total regulated revenue requirement.

SA Power Networks' proposal includes a total forecast opex of $1550.9 million[38] ($2019-20) for the 2020–25 regulatory period.[39] This is:

- an increase of $228.8 million (or 17.3 per cent) compared to its estimated spend over the 2015–20 regulatory period

---

37 Consumer Challenge Panel (subpanel 14), *CCP14 Response to the SA Power Networks 2020-25 Draft Plan and Early Engagement*, October 2018, p. 15.

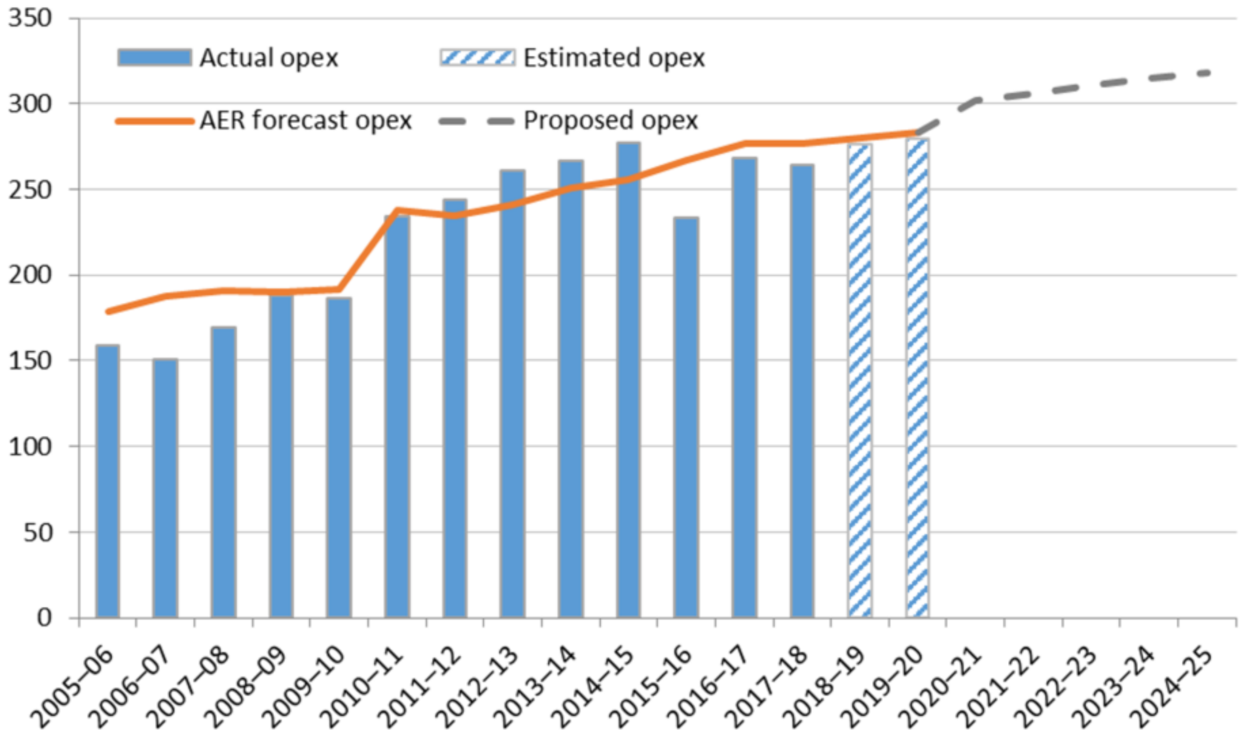
38 Includes $20.5 million of debt raising costs.

39 SA Power Networks, *Regulatory Proposal Attachment 6*, 31 January 2019, p. 7.

- an increase of $170.0 million (or 11.0 per cent) over its base year opex[40]
- $167.2 million more (or 12.1 per cent) than the opex forecast included in our final decision for the 2015–20 regulatory period.

Figure 8 provides a comparison between SA Power Networks' historical opex, its estimated opex in 2018–19 and 2019–20, and its forecast opex for the 2020–25 regulatory period.[41]

Figure 8 SA Power Networks' historical and forecast opex



Source: SA Power Networks, *2020–25 economic benchmarking RIN*; SA Power Networks, *2020–25 reset RIN operating expenditure*; SA Power Networks, *Regulatory Proposal PTRM 2020–25 regulatory period*.

SA Power Networks has used a base-step-trend approach to forecast opex. This is consistent with our preferred approach to assessing opex, as outlined in our *Expenditure forecast assessment guideline*. It proposes to use 2018–19 as the base year because it considered that 2018–19 best reflects the future costs required to efficiently maintain and operate its network.[42]

---

40 This reflects opex of $276.2 million in the base year of 2018-19.

41 Actual (2010-11 to 2014-15) and forecast (2020-25) opex includes debt raising costs. However; it is unclear whether debt raising costs are included in the actual and estimated opex for the period 2015-16 to 2019-20. For the purposes of this issues paper we have assumed that actual and estimated debt raising costs for the 2015-16 to 2019-20 period have been incorporated into the total opex amount, or that they have a $0 value over this period.

42 SA Power Networks, *Regulatory Proposal Attachment 6*, 31 January 2019, p.22.

SA Power Networks has escalated its base year expenditure to reflect:

- an increase in opex in the final year of the current regulatory period ($18.0 million, $2019-20)
- increases for forecast changes in real prices of key inputs ($25.7 million, $2019-20) using the weights and methodology generally applied by the AER[43]
- changes driven by expected output growth ($30.6 million, $2019-20) using weights derived from the Cobb Douglas econometric models[44]
- expected productivity growth of zero per cent per.

SA Power Networks noted it has formed the view that a positive productivity growth factor cannot be justified, taking into account the available evidence, and the issues it raised in its submission to our review of opex productivity growth.[45] In March 2019 we determined through our review that 0.5 per cent per year represents an appropriate opex productivity growth forecast for electricity distributors.[46] This, in our view, reflects the best estimate of the opex productivity growth that an electricity distributor on the efficiency frontier should be able to achieve going forward.

SA Power Networks has also proposed six step changes to its base opex.[47] A summary of SA Power Networks' proposed step changes is provided in Table 5.

Table 5 Summary of proposed step changes ($2019-20 million)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
Cable and Conductor minor repair	14.2	13.5	13.5	13.5	13.5	68.2
Critical Infrastructure Compliance	2.4	2.4	2.4	2.4	2.4	12.1
Cloud transition—Hosting	1.0	1.2	1.6	1.7	1.8	7.2
Cloud transition—Scheduling	0.8	0.8	0.8	0.8	0.8	3.8
LV Management	–	0.4	0.9	1.1	1.3	3.8
GSL Reliability	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(19.9)
Total	**14.3**	**14.3**	**15.3**	**15.5**	**15.8**	**75.1**

Source: SA Power Networks, *2020–25 Regulatory Proposal Attachment 6.*

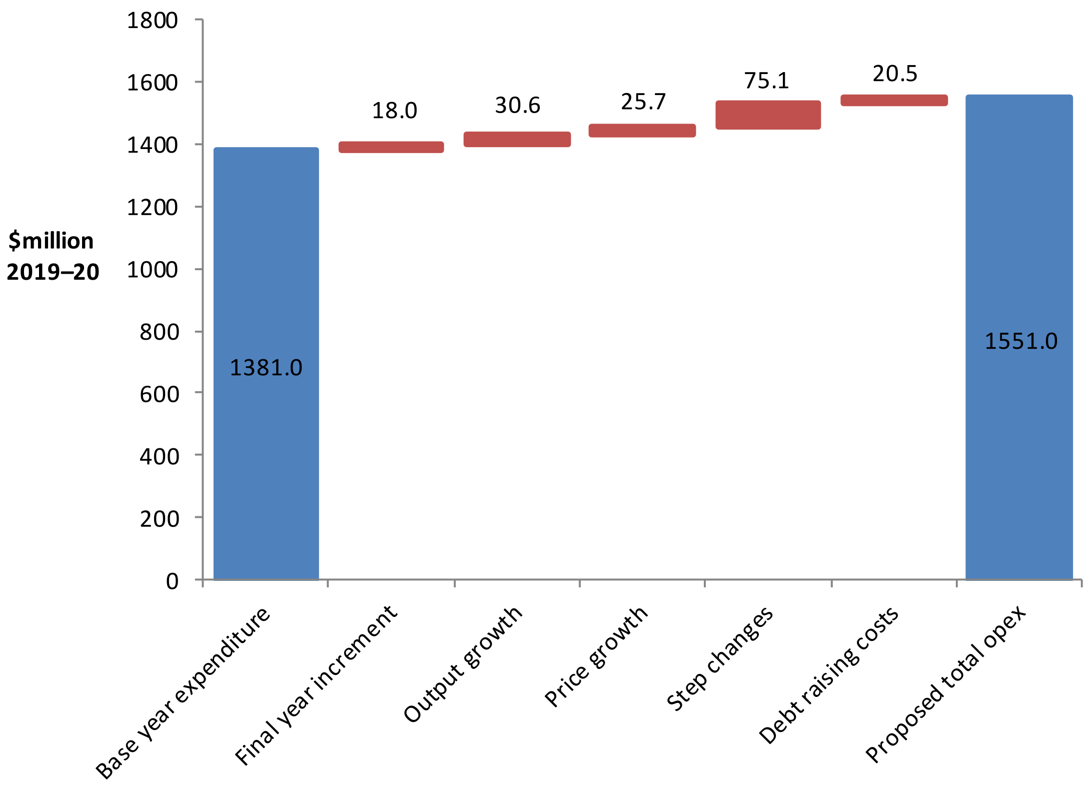
43 SA Power Networks, *Regulatory Proposal Attachment 6*, 31 January 2019, pp.31-32.
44 SA Power Networks, *Regulatory Proposal Attachment 6*, 31 January 2019, pp.29-31.
45 SA Power Networks, *Regulatory Proposal Attachment 6*, 31 January 2019, p. 33.
46 AER, *Final decision paper – Forecasting productivity growth for electricity distributors*, March 2019.
47 SA Power Networks, *Regulatory Proposal Attachment 6*, 31 January 2019, pp.22-29.

The most material step change proposed relates to the treatment of expenditure on cable and conductor minor repairs. SA Power Networks has proposed treating this type of expenditure as opex rather than capex (that is, a capex/opex trade-off) resulting in a $68.2 million ($2019-20) increase to opex over the 2020–21 to 2024–25 regulatory period. It considered this helps to address potential inter-generational inequities that could be caused by treating this expenditure as capex, as contemplated in the AER's final report on the Review of regulatory tax approach.[48]

SA Power Networks also included a negative step change of $19.9 million ($2019-20) for changes to its GSL scheme from 2020–21 (individual duration payments replaced by total annual duration payments and frequency payments simplified to one level of payment).

Figure 9 shows how each of the opex components discussed above have contributed to SA Power Networks' total opex forecast.

Figure 9 Breakdown of SA Power Networks' opex forecast ($Jun2020, million)



Source: AER analysis; SA Power Networks, *2020–25 Reset RIN.*

48 SA Power Networks, *Regulatory Proposal Attachment 6*, 31 January 2019, p. 22.

We are interested in understanding stakeholder views on how well SA Power Networks' forecast opex reasonably reflects the efficient costs of a prudent operator. We are also interested in gauging the extent to which electricity consumers consider SA Power Networks' opex forecast addressed the concerns identified over the course of its consumer engagement program.

5 Incentive schemes

Incentive schemes are a component of incentive based regulation and complement our approach to assessing efficient costs. The incentive schemes that might apply to businesses are:

- the opex efficiency benefit sharing scheme (EBSS)
- the capital expenditure sharing scheme (CESS)
- the service target performance incentive scheme (STPIS)
- the demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIAM).

Once we determine how network revenues will be calculated networks have an incentive to provide services at the lowest possible cost, because returns are determined by their actual costs of providing services. If networks reduce their costs to below our forecast of efficient costs, the savings are shared with their customers in future regulatory periods through the EBSS and CESS. The DMIS and DMIAM encourage businesses to pursue demand side alternatives to opex and capex. The STPIS ensures that the network is not simply cutting costs at the expense of service quality.

Our incentive schemes encourage network businesses to make efficient decisions. They give network businesses an incentive to pursue efficiency improvements in opex and capex, and to share them with consumers. Incentives for opex and capex are balanced with the incentives under the STPIS to maintain or improve service quality. The incentive schemes encourage businesses to make efficient decisions on when and what type of expenditure to incur, and meet service reliability targets.

SA Power Networks has proposed the application of our EBSS, CESS, STPIS, DMIS and DMIAM. These provide important balancing incentives under our revenue determinations to encourage distributors to pursue expenditure efficiencies and demand side alternatives to capex and opex, while maintaining the reliability and overall performance of their networks.

5.1 EBSS

Our efficiency benefit sharing scheme (EBSS) is intended to provide a continuous incentive for distributors to pursue efficiency improvements in opex, and to fairly share these between distributors and consumers. Consumers benefit from improved efficiencies through lower network tariffs in future regulatory control periods.

SA Power Networks is subject to the EBSS in the current regulatory period (2015–16 to 2019–20). It forecasts that its opex will be below the AER allowance for each regulatory year of the current period but that the timing of its expenditure has resulted in an estimated EBSS decrement of $30.1 million, to be returned to consumers in the 2020–21 to 2024–25 regulatory period.

SA Power Networks proposed that we continue to apply version 2[49] of the EBSS for the 2020–21 to 2024–25 regulatory period. It notes we stated in the Framework and Approach paper that we would only apply an EBSS if our opex forecast is based on revealed costs under the base-step-trend methodology.[50] This relies on our assessing that SA Power Networks' revealed costs (or actual costs) in the base year are not materially higher than the opex that would have been incurred by a benchmark efficient DNSP.[51]

5.2 CESS

Our capital expenditure sharing scheme (CESS) aims to incentivise businesses to undertake efficient capex throughout the regulatory control period by rewarding efficiency gains and penalising efficiency losses (each measured by reference to the difference between forecast and actual capex).

In our final Framework and Approach paper, we set out our intention to apply the CESS (as set out in our capex incentives guideline)[52] to SA Power Networks in each regulatory year of the 2020−25 regulatory control period.[53]

SA Power Networks forecast a CESS carryover of $69.7 million, in accordance with version 1 of the CESS, for the 2015–20 regulatory control period. SA Power Networks identified lower augmentation and customer driven capex as well as prudent delays in replacing network assets as the driver of its capex underspend in the 2015–20 regulatory control period.[54]

5.3 Service target performance incentive scheme

Our distribution STPIS[55] provides a financial incentive to distributors to maintain and improve service performance. The scheme aims to ensure that cost efficiencies incentivised under our expenditure schemes do not arise through the deterioration of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributor's incentives towards efficient tariff and non-tariff outcomes with the long-term interests of consumers.

SA Power Networks' revenue proposal accepted the STPIS application approach as set out in the Framework and Approach paper but submitted that its targets will need to be adjusted as the actual performance outcome of the current regulatory period has

---

49 AER, *Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013.

50 AER, *Final framework and approach, SA Power Networks 2020-25*, July 2018, p. 68.

51 AER, *Final framework and approach, SA Power Networks 2020-25*, July 2018, p. 71.

52 AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–9.

53 AER, *Final framework and approach, SA Power Networks 2020-25*, July 2018, p. 72.

54 SA Power Networks, *Regulatory proposal Attachment 9*, January 2019, p. 6.

55 AER, *Electricity distribution network service providers - service target performance incentive scheme V2*, November 2018.

been much better than the performance targets. As such, its reward was capped at the revenue at risk limit set under the current scheme.[56]

When a distributor's actual performance is much better or worse than the performance targets, this may lead to a financial reward or penalty under the STPIS exceeding the revenue at risk under the scheme. In such a case, the distributor's actual performance in a particular period must be adjusted for the purpose of setting the performance targets for the subsequent period.[57]

This is to ensure that the distributor's performance targets in the future reflect the financial reward/penalty that they have received. In particular, a distributor should not be allocated with an easy target because of historical poor performance. This is particularly so when customers have not received the appropriate compensation for poor performance. The STPIS guideline provides a standardised approach to make such adjustment that will result in a balanced outcome for both the distributor and its customers.

5.4 Demand management incentive scheme and innovation allowance mechanism

On 13 December 2017, we published a new demand management incentive scheme (DMIS). This rewards electricity distribution businesses for using efficient demand management projects to deliver value to consumers. At the same time, we also published a new demand management innovation allowance mechanism (DMIAM), which provides research and development funding to electricity distribution businesses so they can better use demand management to reduce long term network costs.

The new schemes were finalised in December 2017. We are interested to hear stakeholders' views on how well these proposals have embraced the new incentives, including the businesses' plans to identify suitable application areas and to seek and evaluate proposals for demand management solutions.

DMIS

SA Power Networks support the new DMIS, which operates as an incentive cost uplift of up to 50 percent of expected costs of efficient demand management projects, subject to certain constraints. SA Power Networks propose that the new DMIS apply during the 2020-25 regulatory control period, consistent with our proposed approach set out in the Framework and Approach paper.

SA Power Networks have so far identified approximately $28 million of future network augmentation works that could be candidates for non-network solutions and will

---

[56] SA Power Networks, *Regulatory Proposal 2020-25 Attachment 10*, 31 January 2019, pp. 8–9.

[57] AER, *Electricity distribution network service providers - service target performance incentive scheme V2*, November 2018, Appendix F.

continue to explore opportunities throughout the forthcoming regulatory control period.[58]

DMIAM

SA Power Networks support the new DMIAM as outlined in the Framework and Approach paper and propose that it apply during the 2020-25 regulatory control period. Applying the calculation as set out in section 2.1(2) of the DMIAM[59] SA Power Networks propose a maximum allowance of $4.003 million for the 2020-25 regulatory control period see Table 6 below.

Table 6 Proposed DMIAM allowances for SA Power Networks the 2020-25 regulatory control period

$M, Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Total 2020-25
Fixed allowance	0.213	0.213	0.213	0.213	0.213	1.063
Annual Revenue Requirement (AAR) – unsmoothed – prior to shared asset & DMIA adjustment	770.564	754.474	792.237	796.849	805.944	3920.069
Variable allowance (0.075% of AAR)	0.578	0.566	0.594	0.598	0.604	2.940
DMIAM	**0.790**	**0.778**	**0.807**	**0.810**	**0.817**	**4.003**

Source: SA Power Networks, *Regulatory Proposal Attachment 11*, p. 7.

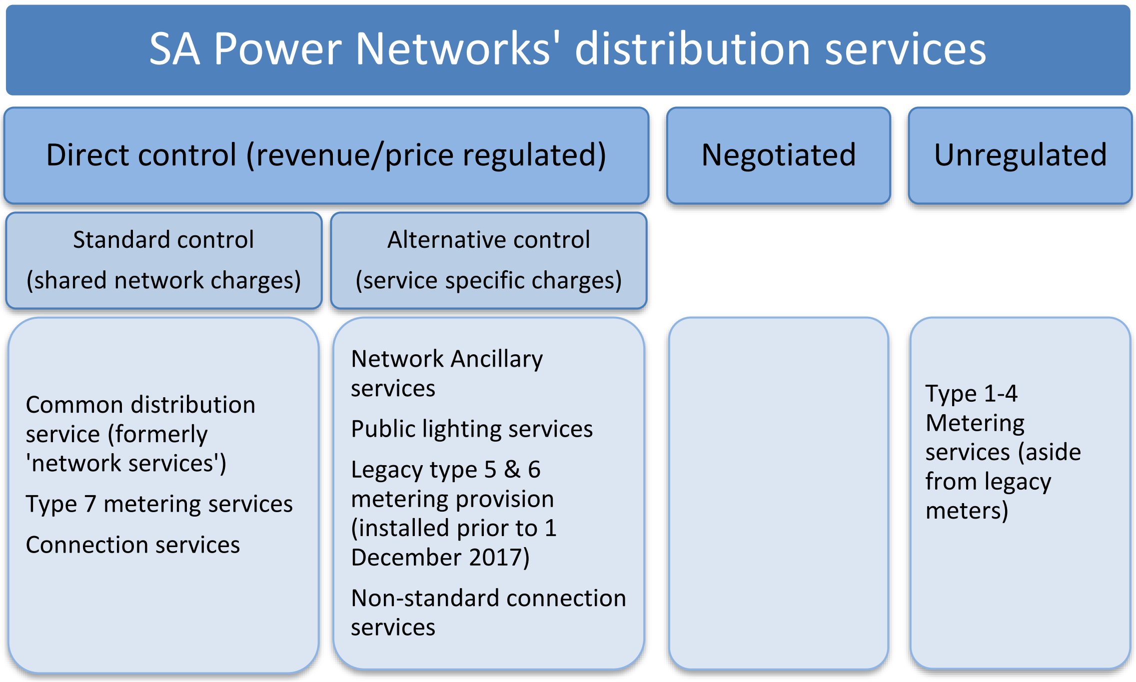
58 SA Power Networks; *Regulatory Proposal Attachment 11*, p.8.

59 AER, *Demand Management Innovation Allowance Mechanism – Electricity distribution network service providers*, December 2017, pp. 7-8.

6 Service classification

In the Framework & Approach (F&A) paper we published last year, we set out our intended classification of the services SA Power Networks provides to its customers.

Figure 10 AER's proposed approach to classification of SA distribution services



Source: AER.

Our classification of services determines which services we regulate and how distributors will recover the cost of providing those services.

Standard control services are those that can only be provided by the relevant distributor, and are common to most, if not all, of a distributor's customers. The costs of providing these services are captured in the building block revenue determination we've discussed in the previous sections of this paper and shared between all customers. SA Power Networks has proposed updates to its tariff structure statement (TSS), which sets out the tariff structure through which tit will recover its regulated revenue for standard control services. We discuss the TSS proposal in section 7, below.

Alternative control services are either:

- services that can only be provided by the relevant distributor, but will only be required by some of its customers, some of the time; or
- services that can be purchased from the relevant distributor, but which can also—or have the potential to be—purchased from a competing provider.

The cost of providing alternative control services is recovered from the direct users of those services, through a capped price on each individual service.[60]

We discuss the alternative control services proposals in section 8.

In September 2018, we published our Service Classification Guideline (the Guideline) for electricity distribution businesses, which came into effect on 1 October 2018.[61] The Guideline sets out our approach to the classification of distribution services with the aim to provide clarity, transparency and predictability for DNSPs in the service classification process. The Guideline is not binding on distributors. However, where we depart from the Guideline, we must provide reasons for doing so.[62]

Similarly, the classification of distribution services must be as set out in our final F&A unless we consider that a material change in circumstances justifies departing from that approach.[63] We consider that the release of the Guideline, published subsequent to the final Framework and Approach paper for SA Power Networks, represents a material change of circumstances warranting departure from the approach to classification taken in our final Framework and Approach paper. SA Power Networks agreed, requesting a number of changes to the classified services list. It also requested a number of departures from the Service Classification Guideline, consistent with the approach taken in the final Framework and Approach paper. The six distribution service groupings where SA Power Networks is proposing departures, either from the final Framework and Approach paper or the Guideline, are summarised below.

It would like to maintain, in descriptions, the wording from the final Framework and Approach paper for activities related to the Common Distribution Service and Network Ancillary Services. Likewise, it would like to ensure that a number of Metering services, as well as Enhanced connection services – classified in the final Framework and Approach paper, but not listed in the Guideline – remain regulated, and therefore as classified services in the forthcoming regulatory period. Similarly, SA Power Networks argues that maintaining a fuller list of unregulated services as part of the classified services list provides increased clarity for stakeholders. SA Power Networks are proposing to align classification of connection services with the Service Classification Guideline. These are discussed in additional detail below.

Common distribution services

SA Power Networks highlighted the difference between the description of demand management activities in the final Framework and Approach paper to that in the Guideline. In the Guideline the activity is: *procurement and provision of network*

---

60 AER, *Framework & Approach for SA Power Networks 2020-25*, July 2018, p. 56.

61 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/distribution-service-classification-guidelines-and-asset-exemption-guidelines/final-decision.

62 AER, *Electricity Service Classification Guideline*, p.5.

63 NER cl. 6.12.3(b).

demand management activities for distribution purposes, whereas in the final Framework and Approach paper it is described as*: procurement and provision of demand management activities for distribution or system reliability, efficiency or security purposes*. SA Power Networks submits that the description as provided in the Guideline does not accurately reflect the nature of the activities as performed in providing services to its customers. The proposed change is to the description of the service and does not affect classification, or the control mechanism by which the activity is regulated.

Network ancillary services

SA Power Networks is proposing to depart from both the Guideline and the final F&A in proposing a change to an activity related to Network safety services to reflect the nature of the services it provides to customers. The new activity would replace "*inspection and rectification of a customer fault where there may be a safety and or reliability impact on the network or related component"*[64] and be called: "*inspection work undertaken to determine the cause of a customer fault where there may be a safety or reliability impact on the network or related component and associated works to rectify the impact on the network caused by a customer".*[65] This proposed change is to the description of the service only and does not affect classification.

Metering services

SA Power Networks have proposed including three metering services, classified in the final F&A, but not in the Service Classification Guideline. These services are:

- Type 5 and 6 meter installation and provision (prior to 1 December 2017);
- Third party requested outage for purposes of replacing a meter; and
- Emergency maintenance of failed metering equipment not owned by a DNSP.

Enhanced connection services

SA Power Networks have requested to retain the provision of 'Other additional customer dedicated lines / assets' as part of Enhanced connection services, which was classified in the final F&A, but not included in the Service Classification Guideline. The proposed inclusion of these services has already been taken into account in the F&A and does not affect classification.

Connection services

SA Power Networks are proposing to depart from the classification provided in the final F&A for 'Other connection services', to align with the framework for these services

---

64 AER, *Framework & Approach for SA Power Networks 2020-25*, July 2018, p. 95.

65 SA Power Networks, *Letter to AER—Request to replace Framework and Approach*, 31 October 2017, p.11.

outlined in the Service Classification Guideline. To be specific, SA Power Networks are requesting the following:

- Standard Connections' and 'Negotiated Connections' involving work to connect a premises be classified as ACS; and
- 'Standard Connections' and 'Negotiated Connections' involving extension and augmentation be classified as SCS.

In the final F&A, we did not delineate between basic, standard and negotiated connections, bundling all connections, with the exception of enhanced connection services, in with basic connection services. As a result, all basic connections, including those requiring extension or augmentation of the network, were classified as Standard control. The SA Power Networks proposal to create new ACS classified standard and negotiated connection services, means that users of the services would be charged a capped price, reflecting the efficient provision of the service requested.[66]

For the new standard and negotiated connection services, ACS charges would be limited to those premises connections which do not require extensions or augmentations. SA Power Networks have proposed that Standard and negotiated premises connections, requiring an extension and or augmentation, will continue to be classified SCS and subject to a capital contribution. We note that the new services would align with the connections typology of the NER[67] and the connections classification framework set out in our Service Classification Guideline.[68]

Given that the creation of new ACS classified connection services is likely to have a price impact on customers, we welcome stakeholder feedback on the effect of the proposed changes to connections classification.

---

[66] AER, *Framework & Approach for SA Power Networks 2020-25*, July 2018, p. 56.

[67] For Standard connections see: NER cl. 5A.B.4, and cl. 5A.C.1 for negotiated connections.

[68] AER, *Electricity Service Classification Guideline*, September 2019, p.21.

7 Tariff structure statements

The requirement on distributors to prepare a tariff structure statement (TSS) arises from a significant process of reform to the NER governing distribution network pricing. The purpose of the reforms is to empower customers to make informed choices by:

- providing better price signals—tariffs that reflect what it costs to use electricity at different times so that customers can make informed decisions to better manage their bills
- transitioning to greater cost reflectivity—requiring distributors to explicitly consider the impacts of tariff changes on customers, and engaging with customers, customer representatives and retailers in developing network tariff proposals over time
- managing future expectations—providing guidance for retailers, customers and suppliers of services such as local generation, batteries and demand management by setting out the distributor's tariff approaches for the entire duration of the regulatory control period.

Among other matters, a TSS must set out a distributor's proposed tariffs, structures and charging parameters for each proposed tariff, and the policies and procedures the distributer proposes to apply assigning customers to tariffs or reassigning customers from one tariff to another.[69] An indicative pricing schedule must accompany the TSS.[70] The final prices for each tariff continue to be determined on an annual basis.

This is SA Power Networks second TSS and applies to the 2020–25 regulatory control period. Its first TSS applies to the current 2017–20 period. In the 2020–25 period, SA Power Networks proposes to move towards more cost reflective network pricing by:

- amending its approach to setting network tariffs for small customers, including changing the default tariff design and assignment policy for these customers and allowing residential customers to opt–in to a 'prosumer' network tariff
- similarly changing its tariff assignment and design approach to large customers, including by introducing a seasonal large business demand tariff for the Adelaide CBD that is different to other non–CBD large business customers.

In Table 7 we summarise the expectations we set out in 2017 and compare these to the TSS SA Power Networks has proposed for 2020–25. We encourage stakeholders to look at our 2017–19 final decision regarding future directions for tariff reform and provide their views on how SA Power Networks has responded to these.

---

[69] NER, cl. 6.18.5.

[70] NER, cl. 6.8.2(d1).

Table 7 AER expectations for 2020–25 TSS proposals

AER's expectations for 2020-25 proposals	SA Power Networks' proposal
All customers in new premises who are connecting their premise to the network are assigned by default to a cost–reflective tariff	For residential and small business customers SA Power Networks is proposing to close access to anytime energy tariffs. Instead it will base its default tariff for these small customers on time of use charges.
For existing customers who remain on flat rate or block tariffs, consideration should be given to increasing the relative levels of these network tariffs compared to more cost reflective tariff options	SA Power Networks is proposing to 'rebalance' the existing tariffs for small customers by increasing the supply charge as a proportion of overall distribution network charges.
While maintaining technology neutrality in the TSS, consider whether the installation of distributed energy resources should be a trigger reassignment. In doing so, address any impediments and consider incentives needed to ensure the efficient utilisation of these resources.	SA Power Networks has included an opt–in 'prosumer' tariff which seeks to reward customers for 'soaking up' surpluses of solar energy in the middle of the day and defer demand outside peak periods.
Refinement of a distributor's method for estimating long run marginal cost (LRMC), including the inclusion of replacement capex within marginal cost estimates	SA Power Networks proposal has applied the average incremental cost approach to determine the network LRMC for each tariff class including repex.

Do stakeholders support SA Power Networks approach to small customer's network tariff design and assignment policies?

SA Power Networks has included initiatives for the 2020–25 regulatory control period to move small customers towards more cost reflective tariffs. We are seeking stakeholder views on whether they support SA Power Networks initiatives, in particular its proposal to:

- amend its existing tariffs by rebalancing tariffs to increase supply charges as a proportion of overall network charges and replace inclining block energy charges with a single flat rate.
- introduce time of use tariffs for small customers and in particular the proposal to include demand charges for small business where their maximum demand exceeds 70 kVA
- introduce an opt–in 'prosumer tariff' to provide incentives for efficient utilisation of DER

Below we provide further background on these aspects of SA Power Networks' TSS.

Amendments to existing network tariffs for small customers

SA Power Networks has proposed two key amendments to its existing suite of network tariffs for small business customers during the 2020–25 regulatory control period.

Firstly, SA Power Networks is seeking to rebalance its existing tariffs for small customers by increasing the supply charge as a proportion of overall distribution network charges. By rebalance, SA Power Networks intends to increase the proportion of revenue recovered from fixed charges and decrease the proportion of revenue recovered from usage charges. We have previously accepted distributors' use of this technique as being consistent with the distribution pricing principles as it allocates residual cost recovery towards fixed charges thereby minimising distortions to price signals.[71] SA Power Networks projects that this will increase the supply charges for residential and small business customers by $10 and $20 respectively.[72] Further, given the gradual nature of the rebalancing the majority of customers' network charges will remain variable such that customers can continue to manage their bills through usage decisions.[73]

Secondly, SA Power Networks is proposing to alter its existing anytime energy tariffs by basing its energy charges on a flat rate – currently as consumption exceeds aggregate bands energy charges increase.[74] We will assess how flat and inclining block tariffs signal network congestion regarding the timing of consumption. There are advantages and disadvantages to inclining block tariffs. Our review will assess the inclining block tariff in the context of encouraging network underutilisation as consumers forgo consumption during off–peak periods, as well as assessing whether it is designed appropriately to provide incentives for customers to voluntarily switch to a more cost–reflective tariff. This relies on setting relative tariff levels to create a financial incentive to switch, however this may have a distortionary impact as usage decisions disconnect from long run marginal cost.

We are interested in stakeholder views on whether these amendments to existing network tariffs are appropriate, and if not, what (if any) changes may be preferable including the associated reasons.

Introducing time of use charges for small customers

For residential and small business customers, SA Power Networks is proposing to introduce tariffs with time of use charges. Specifically:

- for residential customers these tariffs include a supply charge with peak charging windows in the morning and evening and also an off–peak period between 10:00am and 3:00pm. This middle of the day off–peak period would act as a 'solar sponge' to stimulate demand to mitigate potential voltage issues associated with low demand and high distributed solar output.
- for small business customers the proposed tariffs include a supply charge with peak, shoulder and off–peak energy charges as well as an anytime demand charge for customer's whose demand exceeds 70kVA. These tariffs will also include a seasonal aspect.

We note that it is not an individual customer’s demand for distribution services that drives network costs, but the extent to which that customer’s demand contributes to

---

71 AER, *Ausgrid 2019–24 Tariff Structure Statement Draft Decision,* November 2018*,* p.20.

72 SA Power Networks, *Regulatory Proposal Attachment 17,* January 2019, p.35.

73 SA Power Networks, *Regulatory Proposal Attachment 17,* January 2019, pp.37-38.

74 SA Power Networks, *Regulatory Proposal Attachment 17,* January 2019, p.40.

network congestion and capacity constraints. This being the case, tariffs with a cost–reflective structure signal network congestion during periods of 'coincident demand' which varies with time. For example, alpine and coastal tourist areas will experience coincident peak demand at different times of the year and time of day. Network tariffs which include time of use components (both consumption and demand charges) aim to achieve cost–reflectivity. We are interested in stakeholder views on SA Power Networks' proposal to introduce these time of use network tariffs,

Opt–in 'Prosumer' tariff

SA Power Networks proposal allows residential customers to opt–in to a 'prosumer' demand tariff. This tariff mirrors the residential time of use energy tariff structure but includes a peak demand tariff in November to March, this structure seeks to reward customers for 'soaking up' surpluses of solar energy in the middle of the day and avoiding use during peak demand periods, or to use any stored energy during this time.

This prosumer tariff has an equivalent supply charge as the default residential tariff with lower time of use energy charges and includes a seasonal peak demand charge not present in the default tariff.[75] Similar to SA Power Networks' proposal to introduce time of use tariffs for small customers, targeted consumption and demand charges can achieve cost–reflectivity. SA Power Networks stated aim for the prosumer tariff is to provide customers with batteries an incentive to shift load out of the peak period.[76] We will review SA Power Networks proposal and assess whether it integrates pricing approaches with broader network planning and expenditure forecasting. In doing so, SA Power Networks should balance consideration of potential demand management initiatives against pricing options – particularly if solar penetration is straining the network in localised areas.

We are interested in stakeholder views on SA Power Networks' proposal to allow customers to opt–in to this prosumer tariff.

Is SA Power Networks approach to large customer's network tariff design and assignment something stakeholders support?

SA Power Networks is proposing to make two key changes to its large customer network tariffs for the 2020–25 regulatory control period. These tariffs will apply to customers with annual demand of more than 1000kVA. Specifically, SA Power Networks is proposing to:

- allow customers in the Adelaide CBD to opt–in to a seasonal large business demand tariff, this seeks to recognise that the time of local peak demand in the CBD of Adelaide is different to the rest of South Australia.
- change the existing charging window for customers outside the CBD

---

[75] SA Power Networks, *Regulatory Proposal Attachment 19,* January 2019 p.69.

[76] SA Power Networks, *Regulatory Proposal Attachment 19,* January 2019 p.32.

The large customer network tariffs include a supply charge with peak, shoulder and off–peak energy charges, an anytime demand charge as well as a seasonal peak demand charge. For CBD customers this seasonal peak demand charge will apply between 11:00am and 5:00pm on workdays between November and March, while non–CBD customers the charging window is between 5pm and 9pm on work days between November and March.[77] SA Power Networks is also proposing different tariff levels with the anytime demand charge for the opt–in tariff lower than the default tariff, this is offset by higher supply charges.[78]

The NER require distributors to comply with the distribution pricing principles when determining their tariffs. Part of this is the requirement that distributors base their network tariffs on the long run marginal cost (LRMC) of providing direct control services.[79] Further, when determining the LRMC calculation method distributors are required to have regard to the location of retail customers and the extent to which costs vary between different locations in the distribution network.[80] We are interested in stakeholder views on whether SA Power Networks large customer tariffs meet the NER requirements, and if not, what (if any) changes may be preferable.

---

77 SA Power Networks, *Regulatory Proposal Attachment 19,* January 2019, p.14.

78 SA Power Networks, *Regulatory Proposal Attachment 19,* January 2019, p.70.

79 NER 6.18.5.

80 NER 6.18.5(f)(3).

8 Alternative control services

Alternative control services (ACS) are services provided by SA Power Networks to specific customers. The costs of providing these services are not included in the revenue proposals we discussed in section 4. They are recovered separately in accordance with an approved pricing mechanism, with most charged on a 'user pays' basis.

There are four broad categories of alternative control services in SA Power Networks' proposal:

- public lighting
- metering
- ancillary (or miscellaneous) network services
- standard Connections' and 'Negotiated Connections' involving work to connect a premises.

We reclassified public lighting services and numerous ancillary services as alternative control service in our Framework and Approach paper for the 2020–25 regulatory control period. These services were previously unregulated or classified as negotiated distribution services.

8.1 Public lighting

Public lighting services encompass the provision, construction and maintenance of public lighting assets. Customers of public lighting services are local government councils and jurisdictional main roads departments.

There are a number of different tariff classes and charges for public lights. The factors influencing the charging system that applies to a particular installation are:

- responsibility for capital provision
- responsibility for maintenance
- responsibility for replacing the installation.

This will be the first regulatory period where SA Power Networks' public lighting services will be treated as alternative control services. SA Power Networks' proposed public lighting prices are based on a building block model. Currently, SA Power Networks' public lighting services are classified as negotiated distribution services, requiring SA Power Networks to enters into contracts with its public lighting customers. However, SA Power Networks intends to adopt our price cap form of control for all public lighting services for the 2020–25 regulatory control period, with all public lighting customers transitioning to our approved prices from 1 July 2020. SA Power Networks' initial forecast is that customers would see an average increase of around 6 per cent in their annual bill for public lighting services from 1 July 2020.[81]

Our review will assess SA Power Networks proposed costs that make up its building block model.

SA Power Networks expects to continue their progressive roll out of LEDs into the next regulatory period, in line with customer support, with approximately 74 per cent of lights expected to be converted to LEDs by 2025.[82]

Finally, SA Power Networks’ public lighting proposal contains minimum service standards for public lighting customers. The minimum standards include repair times, specifications for invoice details, available data and replacement and maintenance parameters.

We are interested in hearing views on whether SA Power Networks’ public lighting proposal aligns with stakeholder expectations.

In February, we issued a draft determination having arbitrated a dispute between SA Power Networks and councils, as the parties were unable to negotiate an agreeable outcome for maintenance pricing of public lights during the 2010–15 period. The parties’ responses to our draft determination have only recently been received and are currently being considered. We will issue our final determination in due course. Our final determination for this arbitration may impact the modelling used to calculate alternative control service prices, but not our decision to reclassify public lighting services as alternative control services for the 2019–24 regulatory control period.

8.2 Metering

Metering charges capture both capital and operating and maintenance costs.

The AEMC's Power of Choice reforms, which came into effect on 1 December 2017, made a number of changes to the way metering services are provided. These include

- retailers will facilitate the provision of metering services for new and replacement meters through contestable metering coordinators
- new and replacement meters will be a minimum of a Type 4 (smart) meter
- distributors will no longer be able to install basic meters.

Over time, these reforms will see customers progressively take up smart meters while the older accumulation and interval (Types 5 and 6) meters are gradually phased out.

Prior to the Power of Choice reforms, distributors were required to ensure all customers had a working meter. To meet this regulatory obligation distributors funded the capital cost of all their residential and small business customers' meters at the time

81 SA Power Networks, *Regulatory Proposal Attachment 14*, 31 January 2019, p. 21.

82 SA Power Networks, *Regulatory Proposal Attachment 14*, 31 January 2019, p. 25.

of installation. Distributors then recovered their initial outlay of capital via metering charges imposed on customers over the life of the meter.[83]

As a result of the Power of Choice reforms, SA Power Networks is no longer responsible for installing new meters or replacing them when they fail. Its proposal does not include any new capital expenditure for installing and replacing meters (direct metering capex).

SA Power Networks proposed accelerating its depreciation to write down its total metering asset base (MAB) by 2025, otherwise it would have half a year of remaining life at the end of the 2020–25 regulatory period. SA Power Networks' proposed that this will reduce its administrative burden in 2025-30 and provide better clarity to customers as to when capital costs will be fully recovered. SA Power Networks indicated that the impact of this accelerated depreciation will be an average increase of $0.84 per customer per regulatory year.[84]

SA Power Networks submitted that per customer cost of providing metering services will increase over 2020–25 even as its total metering service costs decline. This is because lower customer density results in increased travel times and therefore increased costs of servicing individual meters.[85] At the same time, SA Power Networks expect fixed costs (maintenance, data services) will need to be spread over a smaller customer base. Overall, SA Power Networks' propose to significantly reduce the amount of revenue it expects to collect for metering.

In developing its metering charges, SA Power Networks proposed removing the different charges associated with whole current (WC) and current transformer (CT) connected meters, given it is no longer forecasting opex by meter type.[86] The non-capital component of this new tariff is expected to be marginally higher than the current WC tariff, but the capital component is expected to be much lower. Both components of the new tariff are also significantly lower than the current tariff expected for CT connected metering. We will analyse this merging of different meter tariffs.

[83] Under the new arrangements, new or replacement smart meters will be sourced from a range of meter suppliers. Existing customers receiving a replacement meter will be required to contribute to paying off the existing stock of older accumulation and interval meters (types 5 and 6) until that metering asset base is fully depreciated. We expect this to take between 5 and 10 years. During this period customers will see declining capital charge reflecting the steadily diminishing value of unrecovered metering investment.

[84] SA Power Networks, *Regulatory Proposal Attachment 14*, 31 January 2019, p. 12.

[85] SA Power Networks, *Regulatory Proposal Attachment 14*, 31 January 2019, p. 14.

[86] SA Power Networks, *Regulatory Proposal Attachment 14*, 31 January 2019, p. 11.

Table 8 details the metering opex per customer proposed by SA Power Networks.

Table 8 Proposed metering opex per customer ($2019-20)

SA Power Networks	2020-21	2021-22	2022-23	2023-24	2024-25
Forecast customer numbers	677,249	638,138	599,027	599,916	520,805
Metering opex per customer	13.09	13.55	14.06	14.61	15.18

Sources: AER Analysis; SA Power Networks, *14.2 Metering Model and PTRM*, January 2019.

8.3 Ancillary network services

Ancillary (or miscellaneous) network services are non-routine services provided to individual customers on an as requested basis:

- Charges for fee based services are predetermined, based on the cost of providing the service and the average time taken to perform it. These services tend to be homogenous in nature and scope, and can be costed in advance of supply with reasonable certainty.
- Charges for quoted services are determined at the time of a customer's enquiry, with most input costs predetermined by us, and reflect the individual requirements of the customer and service requested.

The costs of providing ancillary services are heavily weighted towards labour costs. The other significant cost element is the time taken to perform the service. For many ancillary services there are little to no materials costs. We have engaged a consultant, Marsden Jacob, to conduct an independent review of the labour costs and estimated times to perform the most commonly demanded ancillary network services.

This is the first regulatory period where numerous ancillary network services have been classified as alternative control service. However, SA Power Networks has adopted a similar methodology to other distributors in building up their proposed prices Specifically, SA Power Networks has generated fee-based prices by using proposed labour rates and labour times, combined with materials, contractors and operational vehicle costs and an overhead rate, based on its historical experience.[87] We will analyse proposed prices with regard to our consultant's report on labour rates.

SA Power Networks has suggested that the prices for several services, for example, 'connection management services – permanent abolition of low voltage service', are not currently cost reflective and that it intends to shift these to cost reflective pricing at the start of the next regulatory period.[88] We will assess the expected price changes between its current charges and the proposed alternative control charges for all services, including those shifting to cost reflective pricing.

[87] SA Power Networks, *Regulatory Proposal Attachment 14*, 31 January 2019, p. 17.
[88] SA Power Networks, *Regulatory Proposal Attachment 14*, 31 January 2019, p. 17.

For quoted services, SA Power Networks proposed adding a 'margin' to its form of control at the rate of 6 per cent, consistent with the principle of competitive neutrality.[89] While our F&A did not include a margin, we have previously accepted its inclusion. We will consider this in forming our decision. SA Power Networks has also included this margin in building up its prices for fee-based based services.

We also note that SA Power Networks has proposed a method of pricing new services within period as both quoted and fee based services. Our Framework and Approach proposed that we treat new services identified within a regulatory control period as a quoted service for pricing purposes. Therefore, we will consider SA Power Networks' proposal to introduce a service at a fixed fee within period. [90]

8.4 Standard Connections' and 'Negotiated Connections' involving work to connect a premises

SA Power Networks proposed reclassifying 'Standard Connections' and 'Negotiated Connections' involving work to connect a premises[91] as alternative control services from standard control. SA Power Networks contends that this will allow for cost reflective charging for activities which can be attributed to connecting customers. These connections involve works and assets/components that relate solely to the connection applicant and not to other customers.[92] If we accept SA Power Networks' proposal to reclassify these services, SA Power Networks contends that prices be determined in the same way outlined in the 'ancillary network services' section above. Should this occur, we will conduct a similar analysis outlined in the above section to determine cost-reflective prices.

---

89 SA Power Networks, *Regulatory Proposal Attachment 14*, 31 January 2019, p. 17.

90 SA Power Networks, *Regulatory Proposal Attachment 14*, 31 January 2019, p. 37.

91 Metering services are excluded.

92 SA Power Networks, *Regulatory proposal Attachment 12*, January 2019, p. 15.

A The regulatory framework for these determinations

The NEL requires us to make our decisions in a manner that contributes, or is likely to contribute, to achieving the NEO.[93] The focus of the NEO is on promoting efficient investment in, and operation and use of, electricity services (rather than assets) in the long term interests of consumers.[94] This is not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[95]

We consider that the long-term interests of consumers are best served where consumers receive a reasonable level of safe and reliable service, which they value, at least cost in the long run.[96] A decision that places too much emphasis on short term considerations may not lead to the best overall outcomes for consumers once the longer term implications of that decision are taken into account.[97]

There may be a range of economically efficient decisions that we could make in a revenue determination, each with different implications for the long term interests of consumers.[98] A particular economically efficient outcome may nevertheless not be in the long term interests of consumers, depending on how prices are structured and risks allocated within the market.[99] There are also a range of outcomes that are unlikely to advance the NEO, or advance the NEO to the degree that others would. For example, we consider that:

- the long term interests of consumers would not be advanced if we encourage overinvestment which results in prices so high that consumers are unwilling or unable to efficiently use the network.[100] This could have significant longer term pricing implications for those consumers who continue to use network services.
- equally, the long-term interests of consumers would not be advanced if allowed revenues result in prices so low that investors do not invest to sufficiently maintain the appropriate quality and level of service, and where customers are making more use of the network than is sustainable.[101] This could create longer term problems in the network, and could have adverse consequences for safety, security and reliability of the network.

---

93 NEL, section 16(1).

94 This is also the view of the Australian Energy Markets Commission (the AEMC). See, for example, the AEMC, *Applying the Energy Objectives: A guide for stakeholders*, 1 December 2016, p. 5.

95 Hansard, *SA House of Assembly*, 26 September 2013, p. 7173. See also the AEMC, *Applying the Energy Objectives: A guide for stakeholders*, 1 December 2016, pp. 7–8.

96 Hansard, *SA House of Assembly*, 9 February 2005, p. 1452.

97 See, for example, the AEMC, *Applying the Energy Objectives: A guide for stakeholders*, 1 December 2016, pp. 6–7.

98 Re Michael: Ex parte Epic Energy [2002] WASCA 231 at [143].

99 See, for example, the AEMC, *Applying the Energy Objectives: A guide for stakeholders*, 1 December 2016, p. 5.

100 NEL, s. 7A(7).

101 NEL, s. 7A(6).

The legislative framework recognises the complexity of this task by providing us with significant discretion in many aspects of the decision-making process to make judgements on these matters.

Electricity determinations are complex decisions, made up of a number of interrelated parts. Examining any one part in isolation ignores the importance of the interrelationships between components of the overall decision, and would not contribute to the achievement of the NEO. For example:

- there are underlying drivers and context which are likely to affect many constituent components of our decisions. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period.
- there are direct mathematical links between different components of a decision. For example, the level of gamma has an impact on the appropriate tax allowance; the benchmark efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return
- there are trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex or vice versa.

In most cases, the provisions of the NER do not point to a single answer, either for our decision as a whole or in respect of particular components. They require us to exercise our regulatory judgement. For example, in making our determinations the NER requires us to prepare forecasts, which are predictions about unknown future circumstances. Very often, there will be more than one plausible forecast, [102] and much debate amongst stakeholders about relevant costs. For certain components of our decisions there may therefore be several plausible answers or several plausible point estimates.

When the constituent components of a decision are considered together, this means there will almost always be several potential, overall decisions. More than one of these may contribute to the achievement of the NEO. In these cases, our role is to make an overall decision that we are satisfied contributes to the achievement of the NEO to the greatest degree.[103]

We approach this from a practical perspective, accepting that it is not possible to consider every permutation specifically. Where there are choices to be made among several plausible alternatives, we select what we are satisfied would result in an overall decision that contributes to the achievement of the NEO to the greatest degree.

---

102 AEMC, *Rule Determination: National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006*, 16 November 2006, p. 52.

103 NEL, s. 16(1)(d).