# FINAL DECISION

## SA Power Networks Distribution Determination 2020 to 2025

## Overview

June 2020

AUSTRALIAN ENERGY REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: 1300 585 165
Email: SAPN2020@aer.gov.au

AER reference: 62729

# About our decision

The Australian Energy Regulator (AER) works to make all Australian energy consumers better off, now and in the future. We regulate energy networks in all jurisdictions except Western Australia. We set a maximum revenue that network businesses are allowed to recover from consumers in providing network services.

The National Electricity Law and Rules (NEL and NER) provide the regulatory framework governing electricity transmission and distribution networks. Our work under this framework is guided by the National Electricity Objective (NEO):

> …to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system. [1]

SA Power Networks is the owner and operator of the monopoly electricity distribution network in South Australia. On 31 January 2019, SA Power Networks submitted its proposal for the five year regulatory control period commencing 1 July 2020. Following the release of our draft decision on 8 October 2019, SA Power Networks submitted its revised proposal on 10 December 2019 in response to our draft decision.

This overview sets out our final decision for SA Power Networks' distribution determination. Each constituent component of our distribution determination is set out in appendix A and we have also published separate attachments.

A key component of our determination for SA Power Networks is the total revenue it can recover from consumers for the use of its network over the next 5 years. These revenues are derived from our 'building block determination' and we discuss the cost components that make up the building blocks in section 2. SA Power Networks' Tariff Structure Statement (TSS) explains the tariffs it will apply to customers to recover the total allowed revenue and we discuss this in section 3.

In making our draft and final decisions we have taken into consideration submissions from stakeholders and have referenced their views and comments throughout our decision attachments. Appendix B also lists the submissions received on our draft decision and SA Power Networks' revised proposal.

## COVID-19 impacts

We understand the current challenges faced by all stakeholders due to the COVID-19 pandemic. As set out in our *Statement of Expectations of energy businesses: Protecting consumers and the energy market during COVID-19*, energy is an essential service and the energy market plays an important role in protecting and supporting

[1] NEL, s. 7.

businesses and the community through the COVID-19 pandemic and our recovery.[2] We recognise that COVID-19 may add to the risks and uncertainties facing energy businesses, including network businesses like SA Power Networks.

Our decisions must be made in a manner that will or is likely to contribute to the achievement of the NEO.[3] The use of up-to-date available information is an important feature that contributes to achieving the NEO.

We undertake an 18 month process for making our decision. This process gives all stakeholders comprehensive opportunities to consider the positions of each other and respond accordingly. It recognises the complexity and depth of analysis required to forecast the costs of a major energy network over five years. The COVID-19 pandemic arose and only became a widely recognised factor as we were completing our final decision.

We have had regard to the impact of COVID-19 in making this distribution determination. At the time of making our decision, there are uncertainties around how COVID-19 will affect SA Power Networks' operations and costs in the next regulatory control period. However, we consider that information currently available allows us to make a decision that meets the requirements of the NEL and NER. We base our decision on current information and best forecasts that can reasonably be made in all the circumstances. We consider that the allowed revenue we have determined provides SA Power Networks a reasonable opportunity to recover at least its efficient costs.

Under our regulatory framework, once the forecasts of efficient costs for a network business are determined for a regulatory period, networks generally manage the risk on cost parameters, giving them an incentive to control these and continue to seek out efficiencies.

SA Power Networks has written to us and listed a range of factors that it states are causing its costs to increase due to COVID-19, such as movements in foreign exchange rates and the need for different ways of working. However, we consider other factors are likely to reduce network expenditures, including falling demand and the planned or unplanned deferral of works. Changes in costs may also have flow on effects to the operation of the various interrelated incentive schemes, which are a key element of the economic regulatory framework for network businesses. The various effects may act to reinforce each other, or be offsetting, and may manifest differently for different network businesses. Early information from the industry is mixed but appears to suggest that the overall impacts may not be material in terms of costs.

SA Power Networks proposed that we should delay our decision for an extended period so that the impacts of COVID-19 can be incorporated into this decision. Leaving

[2] AER, *Statement of Expectations of energy businesses: Protecting consumers and the energy market during COVID-19*, 27 March 2020.

[3] NEL, s 16(1)(a)

the decision open for an extended time creates uncertainty for all. With an extended delay, SA Power Networks would not have clear parameters for guiding its decision making and consumers would not have certainty of prices, thereby impacting their operation and investment decisions. For example, in the current regulatory period SA Power Networks underspent its capex forecast by a material amount in the first two years of the period due to a number of reasons including the revenue uncertainty arising from its appeals of our previous decision.[4] Whilst recognising the uncertainty caused by the COVID-19 pandemic, we consider that the revenue we have set based on the current information supports the ongoing operations of SA Power Networks and provides it with a reasonable opportunity to recover at least its efficient costs.

Therefore, delaying the determinations further to allow more time for the effects of COVID-19 to be assessed is not the appropriate response when balancing the importance of finalising the arrangements for the period commencing 1 July 2020, so that all stakeholders are aware of the position. In the light of these matters, we make this decision now.

Going forward, if it becomes clear that the impacts of COVID-19 are substantial, then a rule change would need to be considered to enable us to re-open existing revenue determinations. We are consulting with stakeholders to assess whether a rule change is warranted.

---

4 SA Power Networks, *Regulatory proposal, Attachment 5*, p.20, January 2019.

# Note

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

As a number of issues were settled at the draft decision stage or required only minor updates we have not prepared all attachments. The attachments have been numbered consistently with the equivalent attachments to our draft decision. In these circumstances our draft decision reasons form part of this final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Classification of services

Attachment 13 – Control mechanisms

Attachment 14 – Pass through events

Attachment 15 – Alternative control services

Attachment 17 – Connection policy

Attachment 18 – Tariff structure statement

Attachment A – Negotiating framework

# Contents

# Executive summary

This final decision determines the amount of money SA Power Networks can recover from its consumers to run its network in the 2020–25 regulatory control period.

SA Power Networks can recover $3914.2 million ($ nominal) from consumers in the 2020–25 regulatory control period.

SA Power Networks' network charges make up about 30 per cent of a standard residential retail bill (27 per cent for small businesses).

We estimate that compared to current charges, the distribution network charges for a residential consumer will drop by $40 (2.1 per cent) in the first year of the 2020–25 period and then remain fairly steady for the remaining four years. For a small business consumer, the distribution network charges will drop by $166 (1.8 per cent) in the first year of the 2020–25 period and then remain fairly steady for the remaining four years.[5]

We assess how much money SA Power Networks needs from consumers for the safe and reliable operation of its network.

We are satisfied that the amount of money SA Power Networks can recover from consumers ensure households and businesses are paying no more than necessary for safe and reliable services.

SA Power Network's distribution area represents 99 per cent of South Australia's population, supplying electricity to 860,000 businesses and homes, with a network of poles and wires spanning over 178,000 kilometres.

Our final decision approved most of SA Power Networks' proposal, the main element which we did not approve was capital expenditure (capex).

SA Power Networks proposed $1693.4 million for capex and instead we have approved $1595.8 million.

This allows SA Power Networks to provide the safe and reliable energy their consumers require and to invest in technology to maximise the uptake of solar energy.

## Ensuring consumers pay no more than they need for safe and reliable services

Ensuring consumers pay no more than necessary for safe and reliable electricity is a vital part of the regulatory determination process.

SA Power Networks submitted a well-supported revised proposal, most of which we have accepted. However, we did not support all elements of its capex proposal. We

5 Compared to the current level, holding all other components of the bill constant and adopting the current estimate of future energy consumption as forecast by SA Power Networks.

applied our standard assessment approaches such as trend analysis, replacement capex modelling and business case assessment to assess the material put to us.

We carefully reviewed the replacement capital expenditure and scaled back the proposed step up in expenditure as SA Power Networks has shown its ability to better target and prioritise its replacements, which has generally improved its asset condition.

### SA Power Networks' engagement with its consumers

Consumers were positive about SA Power Networks' improved engagement processes and the opportunities provided for consumer groups to be involved in understanding its revised proposal.

SA Power Networks' approach to its tariff changes displayed a strong commitment to collaborating with all stakeholders to develop a tariff structure statement that was capable of acceptance.

We look forward to seeing SA Power Networks using more of this type of collaboration in the development of its revenue proposals in the future. In particular, providing consumers with greater levels of involvement, and influence, over a larger range of issues as its revenue proposals develop.

### The way we use and price electricity services is changing

The way South Australians engage with electricity is changing, and the rapid uptake in rooftop solar photo-voltaic (PV) generation is having an increasing impact on the low voltage (LV) network.

We recognise the need for distributors to deal with technologies like Distributed Energy Resources (DER) to address the evolving needs of consumers. Still we must ensure that any spending is cost-efficient and in the long term interests of consumers.

An important and growing challenge in South Australia is managing the minimum demand on the system in the middle of the day as a result of significant amounts of rooftop solar PV exported onto the system. These challenges include voltage rises (which could result in network costs and customers' solar exports being curtailed or "wasted") and challenges in having a fleet of generators and storage that are flexible enough to ramp up generation output from the midday lows to evening peaks in demand.

Our final decision includes all of SA Power Networks' proposed spend relating to its interrelated DER management projects and programs. This includes SA Power Networks' LV management project that uses new technologies and harnesses data to manage energy flows and optimise generation across the network.

We have also approved a contingent project so that SA Power Networks can spend money, if directed to, to upgrade the network to maintain reliability, due to the possible impact of DER.

SA Power Networks' future tariffs include new discounted 'solar sponge' rates, which encourages consumers to consume energy when the sun is shining the most. This gives consumers more control to manage their energy costs, while helping alleviate the challenges of minimum demand in South Australia. Controlled load (eg. hot water) for consumers with smart meters will also move to the new solar sponge pricing arrangements to encourage retailers and consumers to shift hot water heating to the middle of the day. We expect the tariff reforms from SA Power Networks that we are approving to contribute to addressing these challenges and enable more solar to be integrated into the grid, in addition to encouraging more efficient use of the network.

Overall, in South Australia our decision maintains downward pressure on energy prices and supports investment.

# 1 Our final decision

Our final decision allows SA Power Networks to recover a total revenue of $3914.2 million ($ nominal) from its consumers from 1 July 2020 to 30 June 2025.[6]

SA Power Networks is regulated using a revenue cap. Incentives are provided to it to reduce costs, improve service quality and undertake efficient investments.

We determine the total revenue SA Power Networks can recover from its consumers for the provision of common distribution services (standard control services (SCS)). This forms the basis of SA Power Networks' distribution tariffs for the 2020–25 regulatory control period. SA Power Networks' TSS sets out the tariff structure through which it will recover its regulated revenue for SCS from customers.

Our decision sets out the prices SA Power Networks is allowed to charge consumers for the provision of alternative control services: ancillary network services, public lighting and metering.[7] These are considered separately to our building block determination. In setting prices for public lighting services we have accepted SA Power Networks' proposal to add $1.1 million ($ nominal) to the public lighting asset base to address an under-recovery flowing from the resolution of a past dispute over public lighting services.[8] SA Power Networks has not proposed to provide any services on a negotiated basis in the 2020–25 regulatory control period.[9]

## 1.1 What's driving revenue?

Revenue is driven by changes in real costs and inflation. We assess costs (such as capital and operating expenditure) in real terms (using 2019–20 as a common year) to reveal the underlying cost trends over a number of years or regulatory control periods. The numbers presented in this overview are in real 2019–20 dollars unless otherwise noted. Some impacts of our decision are presented in nominal terms, where required by the NER and to enable consumers to see the full impact of our determination inclusive of expected inflation.

The total revenue allowance in this 2020–25 final decision is 5.5 per cent lower than the allowed revenue provided for in our 2015–20 final decision. Figure 1 shows that real revenues are decreasing from 2019–20 levels by 9.4 per cent in the first year of the regulatory control period. After that SA Power Networks' revenue allowance has a

---

6 This is the total smoothed revenue and Table 2 below sets out both smoothed and unsmoothed revenue.

7 Public lighting services will be regulated under a price cap for the first time in the 2020–25 regulatory control period. Previously they were classified as negotiated distribution services. See: AER, *SA Power Networks 2020–25, Final framework and approach*, July 2018.

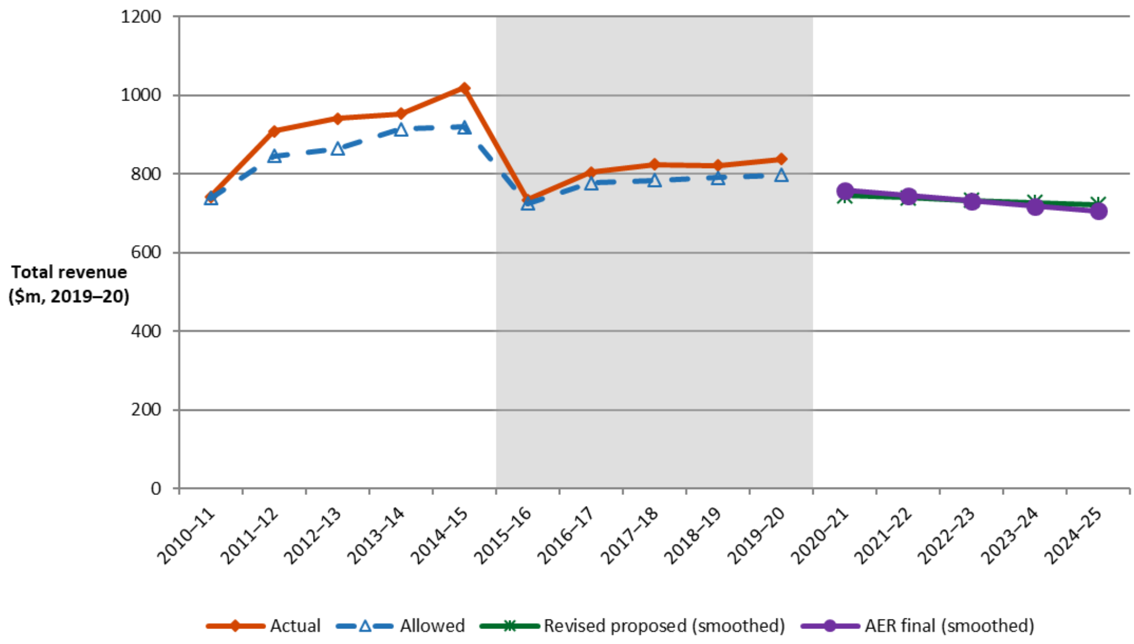
8 We discuss alternative control services in Attachment 15 to this final decision.

9 Our distribution determination for SA Power Networks includes an approved negotiating framework and negotiated distribution service criteria, as required by the NER. Because SA Power Networks has not included any negotiated services in its proposal, these elements of our determination will be inactive for the 2020–25 regulatory control period.

smaller 1.79 per cent decrease over the remaining years of the regulatory control period.

Figure 1 shows our final decision for SA Power Networks' smoothed revenue for the 2020–25 regulatory control period, and its allowed revenues over the 2010–20 regulatory control periods.

### Figure 1 Revenue over time ($ million, 2019–20)




Source: AER analysis.
Note: SA Power Networks’ revised proposal reflects the new opex step change (resubmitted on 10 February 2020).

Figure 2 highlights the key drivers of the change in SA Power Networks' allowed revenue from the 2015–20 regulatory control period compared to what we expect in the 2020–25 regulatory control period. It illustrates that the largest driver of change is the return on capital building block. The rate of return has decreased from around 6.17 per cent in the 2015–20 regulatory control period to 4.75 per cent for the 2020–25 regulatory control period. This is because interest rates have decreased markedly since we made our last decision and SA Power Networks can obtain the capital it needs to run its business more cheaply. As a result, the total cost of capital has reduced by $377.4 million.[10] In 2019, we reviewed how we calculate the tax allowance and made changes to our approach to align with the latest rulings of the Australian Tax Office. This means we expect the tax allowance for SA Power Networks will be lower

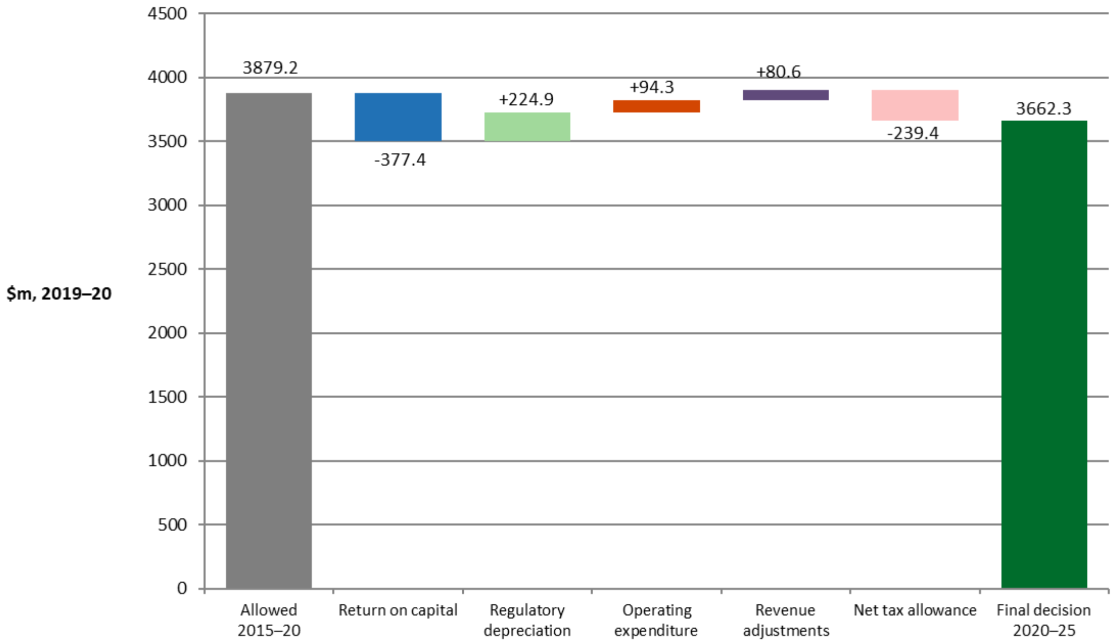
[10] The rate of return is a nominal rate of return unless stated otherwise. The real rate of return has decreased by a similar amount. Please see section 2.2 for further details.

than it was in the past. As a result, Figure 2 also shows a decrease in the net tax allowance building block of $239.4 million.[11]

On the other hand, our final decision provides for higher:

- forecast regulatory depreciation driven by the rising RAB over the 2015–20 regulatory control period and forecast capex over the 2020–25 regulatory control period.[12] This is because each year, SA Power Networks builds new equipment to keep its network running. The cost of this new equipment is added to a cumulative total called the regulatory asset base or RAB. Over time, this equipment is paid back to SA Power Networks through our depreciation allowance. Because SA Power Networks added new equipment to its network over the last five years and is proposing to add more in the next five years, its RAB is increasing and so is its depreciation:
- forecast operating expenditure (opex) compared to the 2015–20 regulatory control period.[13] This reflects output and price growth and accepted step changes
- incentive scheme payments compared to the 2015–20 regulatory control period.[14]

### Figure 2 Change in revenue from 2015–20 to 2020–25 ($ million, 2019–20)




Source: AER analysis. Building block revenue.

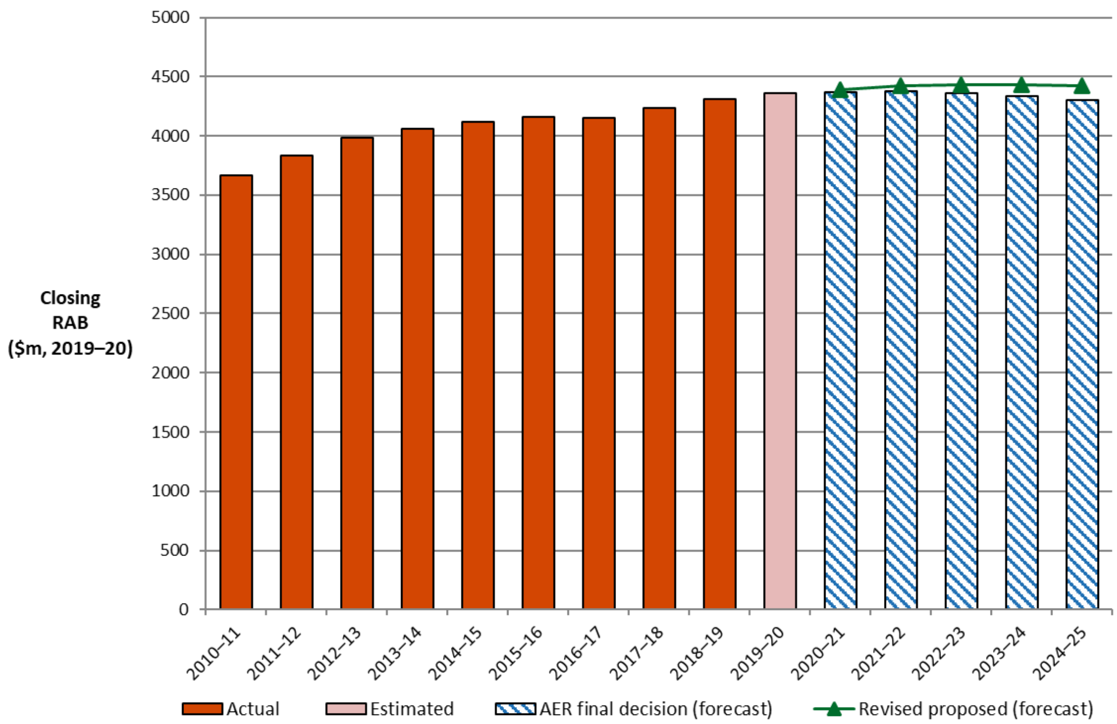
[11] Please see section 2.6 for further details.
[12] Please see section 2.3 for further details.
[13] Please see section 2.5 for further details.
[14] Please see section 2.7 for further details.

Note: Revenue adjustments include increments or decrements accrued under incentives schemes such as the CESS, EBSS, shared assets adjustments and DMIAM.

Figure 3 compares our final decision forecast RAB to SA Power Networks' proposed and actual RAB. SA Power Networks proposed to reduce its capital expenditure going forward which would have led to its RAB being stabilised. We reviewed this proposal carefully and have decided to provide a reduced capex forecast. SA Power Networks' RAB is forecast to decrease by around 0.5 per cent in real terms over the 2020–25 regulatory control period. In the previous period, its RAB increased by 5.9 per cent.[15]

Most of the assets in the RAB have a remaining asset life exceeding the length of five years for a regulatory control period. All else being equal, this means a lower RAB growth under our final decision compared to the revised proposal not only leads to a lower return on capital and depreciation for the 2020–25 regulatory control period, but also in future regulatory control periods.

### Figure 3 Value of SA Power Networks' RAB over time ($ million, 2019–20)




Source: AER analysis.

[15] Please see section 2.1 for further details

## 1.2 Key differences between our final decision and SA Power Networks' revised proposal

The total revenue we are allowing in our final decision is $3914.2 million ($ nominal) for the 2020–25 regulatory control period. This is $19.2 million or 0.5 per cent lower than SA Power Networks' revised proposal of $3933.4 million.[16]

Our final decision rate of return of 4.75 per cent is lower than SA Power Networks' revised proposed rate of 4.79 per cent because we have used updated estimates of the risk free rate and return on debt. SA Power Networks' revised proposal includes a level of forecast capex that we consider goes beyond what is efficient and prudent for the maintenance and operation of its network. Our total capex forecast of $1595.8 million is 6 per cent, or $97.5 million lower than SA Power Networks' revised capex proposal of $1693.4 million.

Our final decision total revenue is $8.9 million ($ nominal) higher than our draft decision revenue of $3905.3 million. The lower rate of return compared to our draft decision reduced our final decision revenue by $44.4 million. This reduction is offset by the increase of $42.3 million to the regulatory depreciation. Other changes include a $45.0 million increase to efficiency reward compared our draft decision and a $14.8 million reduction to the cost of corporate income tax allowance.[17]

## 1.3 Expected impact of our final decision on electricity bills

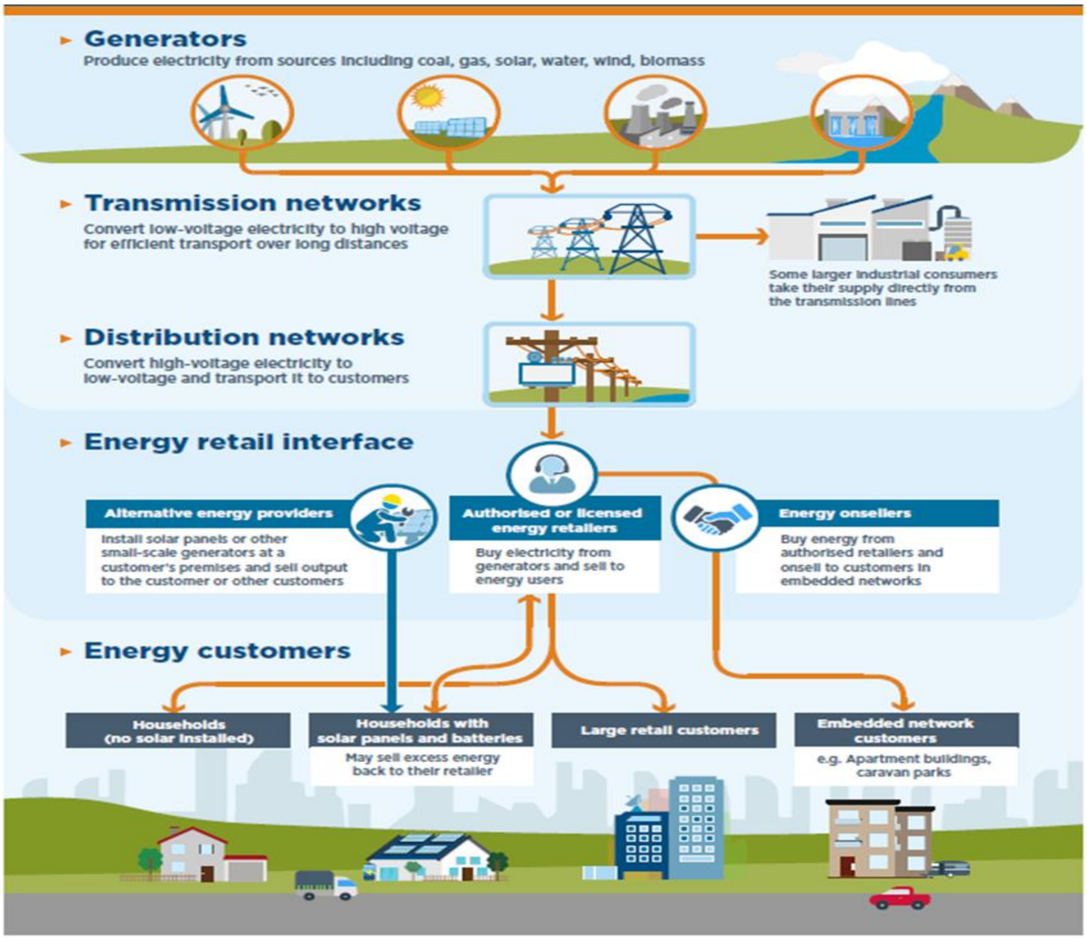
SA Power Networks' distribution network charges makes up around 30 per cent of the total residential bill and 27 per cent of the total small business retail electricity bill.[18] Other components of the electricity bill include environmental policy costs, wholesale electricity costs and retail costs. Figure 4 illustrates the different components of the electricity supply chain. Each of these costs contributes to the retail prices charged to consumers by their chosen electricity retailer.

16 Due to the increased opex proposed by SA Power Networks for bushfire liability insurance premiums in February 2020, we have updated the revised proposal revenue to reflect this change.

17 The differences between the draft and final decisions set out in this paragraph are in $, nominal.

18 AEMC, *Residential electricity price trends 2019 data – trends in SA supply chain components*, December 2019; AER, *final decision – Determination of default market offer prices* 2020–21, April 2020.

### Figure 4 Electricity supply chain




Source: AER, *State of the Energy Market*, December 2018, p.28.

For this final decision, we have estimated some indicative average distribution price impacts flowing from our allowed revenue determination. These prices are indicative and might vary with changes in demand.

Table 1 shows the estimated average annual impact of our final decision for the 2020–25 regulatory control period on electricity bills for residential and small business consumers.

We estimate the expected impact on bills by varying the distribution charges in line with our 2020–25 final decision, while holding all other components constant. This approach isolates the effect of our final decision on distribution network tariffs from other parts of the bill. However, this does not mean that other components will remain unchanged across the regulatory control period.[19]

[19] It also assumes that actual energy consumption will equal the forecast adopted in our final decision. Since SA Power Networks operates under a revenue cap, changes in energy consumption will also affect annual electricity bills across the 2020–25 regulatory control period.

Under the final decision we estimate that compared to current charges, the distribution network charges ($ nominal) in SA Power Networks' area:

- for an average residential consumer would reduce by $40 (2.1 per cent) in the first year of the 2020–25 regulatory control period and then remain fairly steady for the remaining four years
- for an average small business consumer would reduce by $166 (1.8 per cent) in the first year of the 2020–25 regulatory control period and then remain fairly steady for the remaining four years.

### Table 1 Estimated contribution to annual electricity bills for the 2020–25 regulatory control period ($ nominal)

| | 2019–20 | 2020–21 | 2021–22 | 2022–23 | 2023–24 | 2024–25 |
|---|---|---|---|---|---|---|
| **AER final decision** | | | | | | |
| Residential annual bill | 1941[a] | 1901 | 1902 | 1903 | 1903 | 1901 |
| Annual change[c] | | –40 (–2.1%) | 1 (0.1%) | 1 (0.1%) | –0 (–0.0%) | –2 (–0.1%) |
| Small business annual bill | 9120[b] | 8954 | 8959 | 8963 | 8962 | 8953 |
| Annual change[c] | | –166 (–1.8%) | 4 (0%) | 5 (0.1%) | –2 (–0.0%) | –9 (–0.1%) |
| **SA Power Networks revised proposal** | | | | | | |
| Residential annual bill | 1941[a] | 1892 | 1899 | 1906 | 1911 | 1915 |
| Annual change[c] | | –49 (–2.5%) | 7 (0.4%) | 7 (0.4%) | 6 (0.3%) | 4 (0.2%) |
| Small business annual bill | 9120[b] | 8916 | 8945 | 8974 | 8997 | 9013 |
| Annual change[c] | | –204 (–2.2%) | 28 (0.3%) | 29 (0.3%) | 23 (0.3%) | 16 (0.2%) |

Source: AER analysis; AER, *Final determination, Default Market Offer Prices 2019–20*, p. 8.

(a) Annual bill for 2019–20 is sourced from our final determination on Default Market Offer Prices for 2019–20 and reflects the average consumption of 4000 kWh for residential consumers in South Australia.

(b) Annual bill for 2019–20 is sourced from our final determination on Default Market Offer Prices for 2019–20 and reflects the average consumption of 20000 kWh for small business consumers in South Australia.

(c) Annual change amounts and percentages are indicative. They are derived by varying the distribution component of the 2019–20 bill amounts in proportion to yearly expected revenue divided by forecast energy as provided by SA Power Networks. Actual bill impacts will vary depending on electricity consumption and tariff class.

## 1.4 SA Power Networks' consumer engagement

The NEO puts the long term interests of consumers at the centre of our decisions. It is important that SA Power Networks has engaged with its consumers to determine how best to provide services that align with their long-term interests. Consumer engagement in this context is about SA Power Networks working openly and collaboratively with consumers and providing opportunities for their views and preferences to be heard and to influence SA Power Networks' decisions. We accept that SA Power Networks has undertaken a much improved consumer engagement process, with respect to past resets and has been well informed of consumer concerns and interests in framing its proposals.[20] For example, SA Power Networks' engagement on its TSS proposal and the development of its solar sponge tariff provides a positive example of collaboration between a distributor and its stakeholders.[21]

This improved and professional consumer engagement process is reflected in our Consumer Challenge Panel (CCP 14) advice to us on SA Power Networks' revised proposal. We tasked CCP14 specifically with advising us on the effectiveness of SA Power Networks' engagement activities with consumers and how this was reflected in the development of its proposal.

CCP14 remarked that the engagement framework used by SA Power Networks is a model that other utilities should consider.[22] CCP14 also complimented SA Power Network on its well-resourced, informed and engaged Consumer Consultative Panel (CCP). It also suggested that SA Power Networks could have involved its CCP in assessing greater in-depth analysis of quantitative information and business case data.[23] CCP14 further observed that in certain aspects of engagement, workshop material was descriptive and focussed on the narrative, adding that SA Power Networks could use its CCP in a more collaborative[24] role going forward.[25]

CCP14 also observed that some sections of the community are seeking actual reductions in network costs – a sentiment that is not clear in the SA Power Networks documentation.[26] AGL, SA Power Networks' CCP and CCP14 all noted that were it not for external forces outside of the control of SA Power Networks, the revenue requirement would be rising over time.[27] The Energy Consumers Australia (ECA), South Australian Minister for Energy and Mining, CCP14 and South Australian Council of Social Service were among the stakeholders who requested that we rigorously asses the forecast expenditure in SA Power Networks' revised proposal.[28] In reiterating

[20] SA Business, *Submission on SA Power Networks Revised Proposal 2020–25*, January 2020, p. 5.; SA Financial Counsellors Association, United Communities and the Energy Project - *Joint submission on SA Power Networks Draft Decision* - January 2020, p. 63.; SAPN Consumer Consultative Panel - *Submission on SA Power Networks Draft Decision 2020–25* - December 2019, p. 4.

[21] CCP14, *Submission on SA Power Networks Revised Proposal 2020–25 - Revised,* February 2020, p. 29; SAPN Consumer Consultative Panel, *Submission on SA Power Networks Revised Proposal 2020–25, p. 12.*

[22] CCP14, *Submission on SA Power Networks Revised Proposal 2020–25 - Revised,* February 2020, p. 20

[23] CCP14, *Submission on SA Power Networks Revised Proposal 2020–25 - Revised,* February 2020, p. 20

[24] As defined by the International Association for Public Participation (IAP2) spectrum: *Quality Assurance Standard for Community and Stakeholder Engagement*, p. 18.

[25] CCP14, *Submission on SA Power Networks Revised Proposal 2020–25 - Revised,* February 2020, p.7.

[26] CCP14, *Submission on SA Power Networks Revised Proposal 2020–25 - Revised,* February 2020, p.10.

[27] AGL, *Submission on SA Power Networks Draft Decision 2020–25*, January 2020, p. 2.; SAPN Consumer Consultative Panel, *Submission on SA Power Networks Draft Decision 2020–25,* January 2020, p. 2. ; CCP14, *Submission on SA Power Networks Revised Proposal 2020–25 - Revised,* February 2020, p. 7.

[28] ECA, *Submission on SA Power Networks Draft Decision 2020–25,* January 2020, p. 4; SA Minister for Energy and Mining, *Submission on SA Power Networks Draft Decision 2020–25,* January 2020, p. 1.; CCP14, *Submission on SA Power Networks Revised Proposal 2020–25 - Revised,* February 2020, p. 11; SACOSS, *Submission on SA Power Networks Draft Decision 2020–25,* January 2020, p. 20.

the key priority of keeping prices down, stakeholders wanted SA Power Networks to look for every saving it can to pass on to customers.[29]

While acknowledging South Australia's ageing electricity distribution infrastructure, stakeholders were also selective in their support of projects in the revised repex forecast.[30] The ECA, along with CCP14, submitted that technology (including increased DER) may open new options for investment, rather than on a 'like-for-like' basis.[31] The Australian Energy Market Operator's (AEMO) submission provided strong support in favour of the proposed Electricity System Security contingent project, submitting that the project is integral and essential to address the requirements of a high DER power system.[32]

We have taken into account the strong support stakeholders, including from Business SA[33] and those affected by SA Power Networks' worst performing feeders,[34] in reconsidering the Low Reliability Feeder Program.[35] The costs of this program are now reflected in our capex forecast. Stakeholder submissions also support SA Power Networks' investments to allow more DER to be accommodated on the network and transition to a new energy future.[36]

---

29 SAPN Consumer Consultative Panel, *Submission on SA Power Networks Draft Decision 2020–25,* January 2020, p. 3.

30 See: SA Minister for Energy and Mining, *Submission on SA Power Networks Draft Decision 2020–25,* January 2020, p. 3.; EWOSA, *Submission on SA Power Networks Draft Decision 2020–25,* January 2020, p. 2.; ECA, *Submission on SA Power Networks Draft Decision 2020–25,* January 2020, p. 4; CCP14, *Submission on SA Power Networks Draft Decision 2020–25 - Revised,* January 2020, p. 21.; & Business SA, *Submission on SA Power Networks Draft Decision 2020–25,* January 2020, p. 6.

31 ECA, *Submission on SA Power Networks Draft Decision 2020–25,* January 2020, p. 3; CCP14, , *Submission on SA Power Networks Draft Decision 2020–25,* January 2020, p. 27.

32 AEMO, *Submission on SA Power Networks Draft Decision 2020–25,* January 2020, p. 3

33 Business SA, *Submission on SA Power Networks Revised Proposal 2020–25,* January 2020, p. 6.

34 We received ten submissions from local shire councils in the areas of SA Power Networks' worst performing feeders. All but one supported the proposal to improve the reliability of these feeders.

35 AER, *Draft Decision, SA Power Networks Distribution Determination 2020–25*, Attachment 5, p. 5-34.

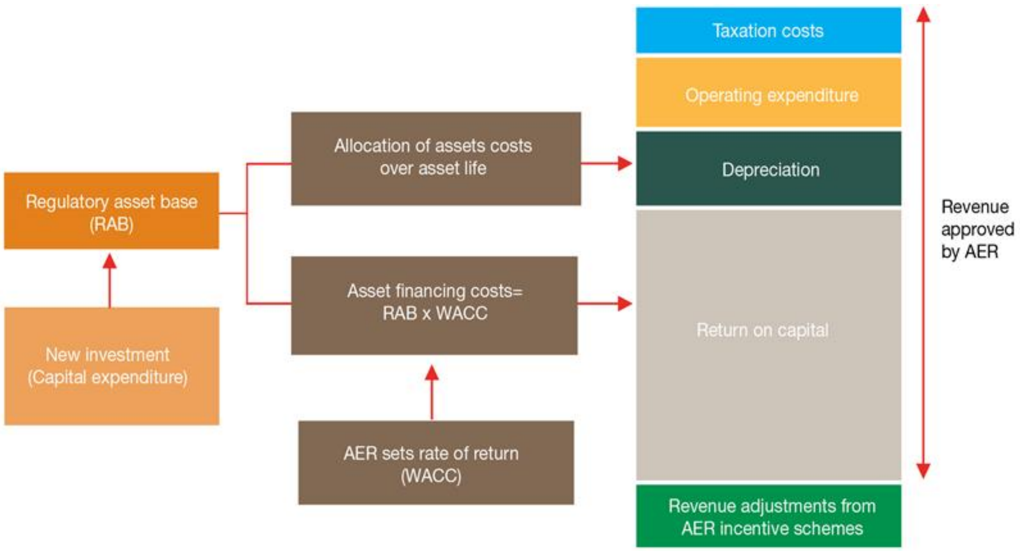
36 Clean Energy Council, *Submission on SA Power Networks Revised Proposal 2020–25, January 2020, p. 2.;* CCP14*, Submission on SA Power Networks Revised Proposal 2020–25 - Revised,* February 2020, p. 7.; Total Environment Centre, *Submission on SA Power Networks Revised Proposal 2020–25,* January 2020, p. 1.

# 2 Key components of our final decision on revenue

The total revenue SA Power Networks proposed reflects its forecast of the efficient cost of providing its distribution network services over the 2020–25 regulatory control period. SA Power Networks' proposal, and our assessment of it under the NEL and NER, are based on a 'building block' approach to determine a total revenue allowance (see Figure 5) which looks at six cost components:

- a return on the RAB (or return on capital, to compensate investors for the opportunity cost of funds invested in this business) (section 2.2)
- depreciation of the RAB (or return of capital, to return the initial investment to investors over time) (section 2.3)
- capex — the capital expenditure incurred in the provision of network services — mostly relates to assets with long lives, the cost of which are recovered over several regulatory control periods. The forecast capex approved in our decisions directly affects the projected size of the RAB and therefore the revenue generated from the return on capital and depreciation building blocks (section 2.4)
- forecast opex—the operating, maintenance and other non-capital expenses incurred in the provision of network services (section 2.5)
- the estimated cost of corporate income tax (section 2.6)
- revenue adjustments, including revenue increments or decrements resulting from the application of various incentive schemes (section 2.7).

**Figure 5 The building block model to forecast network revenue**




Source: AER, *State of the Energy Market*, December 2018, p.138.

We use an incentive approach where, once regulated revenues are set for a five year period, networks that keep actual costs below the regulatory forecast of costs retain part of the benefit. This incentive framework is a foundation of the regulatory framework, which aims to promote the NEO. Network businesses 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 final decision on SA Power Networks' distribution revenues for the 2020–25 regulatory control period is set out in Table 2.

### Table 2 AER's final decision on SA Power Networks' revenues for the 2020–25 regulatory control period ($ million, nominal)

| | 2020–21 | 2021–22 | 2022–23 | 2023–24 | 2024–25 | Total |
|---|---|---|---|---|---|---|
| Return on capital | 207.0 | 205.2 | 203.0 | 199.2 | 195.0 | 1009.3 |
| Regulatory depreciation[a] | 224.5 | 238.3 | 251.8 | 259.7 | 255.8 | 1230.1 |
| Operating expenditure[b] | 294.4 | 304.4 | 314.9 | 324.9 | 334.9 | 1573.6 |
| Revenue adjustments[c] | 27.7 | –3.2 | 24.4 | 18.4 | 16.5 | 83.8 |
| Net tax allowance | 3.3 | 3.5 | 4.8 | 5.7 | 5.4 | 22.7 |
| Annual revenue requirement (unsmoothed) | 756.9 | 748.2 | 798.9 | 807.9 | 807.7 | 3919.6 |
| **Annual expected revenue (smoothed)** | **775.9** | **779.4** | **782.8** | **786.3** | **789.8** | **3914.2** |
| X factors[d] | n/a[e] | 1.79% | 1.79% | 1.79% | 1.79% | n/a |

Source: AER analysis.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB)

(b) Includes debt raising costs.

(c) Includes revenue adjustments from the efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS), shared assets adjustments and demand management innovation allowance mechanism (DMIAM).

(d) The X factors will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

(e) SA Power Networks is not required to apply an X factor for 2020–21 because we set the 2020–21 expected revenue in this decision. The expected revenue for 2020–21 is around 9.4 per cent lower than the approved total annual revenue for 2019–20 in real terms, or 7.3 per cent lower in nominal terms.

## 2.1 Regulatory asset base

The RAB is the value of assets used by SA Power Networks to provide regulated distribution 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.

As part of our decision on SA Power Networks' revenue for 2020–25, we make a decision on SA Power Networks' opening RAB as at 1 July 2020. We use the RAB at the start of each regulatory year to determine the return of capital (regulatory depreciation) and return on capital building block allowances.

Our final decision is to determine an opening RAB value of $4361.0 million ($ nominal) as at 1 July 2020 for SA Power Networks. This amount is $4.0 million (or 0.1 per cent) higher than SA Power Networks' revised proposed opening RAB of $4357.0 million ($ nominal) as at 1 July 2020.[37] It reflects our update to the roll forward model (RFM) for 2019–20 actual inflation that is now available.

Table 3 sets out the roll forward of the RAB to the end of the 2015–20 regulatory control period.

### Table 3 AER's final decision on SA Power Networks' RAB for 2015–20 regulatory control period ($ million, nominal)

| | 2015–16 | 2016–17 | 2017–18 | 2018–19 | 2019–20 [a] |
|---|---|---|---|---|---|
| Opening RAB | 3778.4 | 3884.9 | 3931.8 | 4088.9 | 4234.7 |
| Capital expenditure[b] | 251.7 | 274.3 | 374.2 | 376.6 | 387.1 |
| Inflation indexation on opening RAB | 63.8 | 57.3 | 75.1 | 73.0 | 77.9 |
| *Less:* straight-line depreciation[c] | 208.9 | 284.8 | 292.2 | 303.7 | 318.3 |
| Interim closing RAB | 3884.9 | 3931.8 | 4088.9 | 4234.7 | 4381.4 |
| Difference between estimated and actual capex in 2014–15 | | | | | –15.7 |
| Return on difference for 2014–15 capex | | | | | –4.7 |
| **Closing RAB as at 30 June 2020** | | | | | **4361.0** |

Source: AER analysis.

(a) Based on estimated capex provided by SA Power Networks for that year. We will true-up the RAB for actual capex at the next reset.

(b) Net of disposals and capital contributions, and adjusted for actual CPI and half-year WACC.

For this final decision, we determine a forecast closing RAB value at 30 June 2025 of $4854.9 million ($ nominal) for SA Power Networks. This is $117.6 million (or 2.4 per cent) lower than SA Power Networks' revised proposal of $4972.5 million ($ nominal). Our final decision on the forecast closing RAB reflects the amended opening RAB as at 1 July 2020, and our final decisions on the expected inflation rate (section 2.2 of the Overview), forecast depreciation (attachment 4) and forecast capex (attachment 5).[38]

37 SA Power Networks, *Attachment 2 – Regulatory asset base*, December 2019, p. 10.

38 Capex enters the RAB net of forecast disposals. It includes equity raising costs (where relevant) and the half-year WACC to account for the timing assumptions in the PTRM. Therefore, our final decision on the forecast RAB also

Table 4 sets out our final decision on the forecast RAB values for SA Power Networks over the 2020–25 regulatory control period.

### Table 4 AER's final decision on SA Power Networks' RAB for 2020–25 regulatory control period ($ million, nominal)

| | 2020–21 | 2021–22 | 2022–23 | 2023–24 | 2024–25 |
|---|---|---|---|---|---|
| Opening RAB | 4361.0 | 4478.4 | 4594.6 | 4682.9 | 4768.2 |
| Capital expenditure[a] | 341.9 | 354.4 | 340.1 | 345.1 | 342.4 |
| Inflation indexation on opening RAB | 99.2 | 101.8 | 104.5 | 106.5 | 108.4 |
| *Less:* straight-line depreciation | 323.7 | 340.1 | 356.2 | 366.2 | 364.2 |
| **Closing RAB** | **4478.4** | **4594.6** | **4682.9** | **4768.2** | **4854.9** |

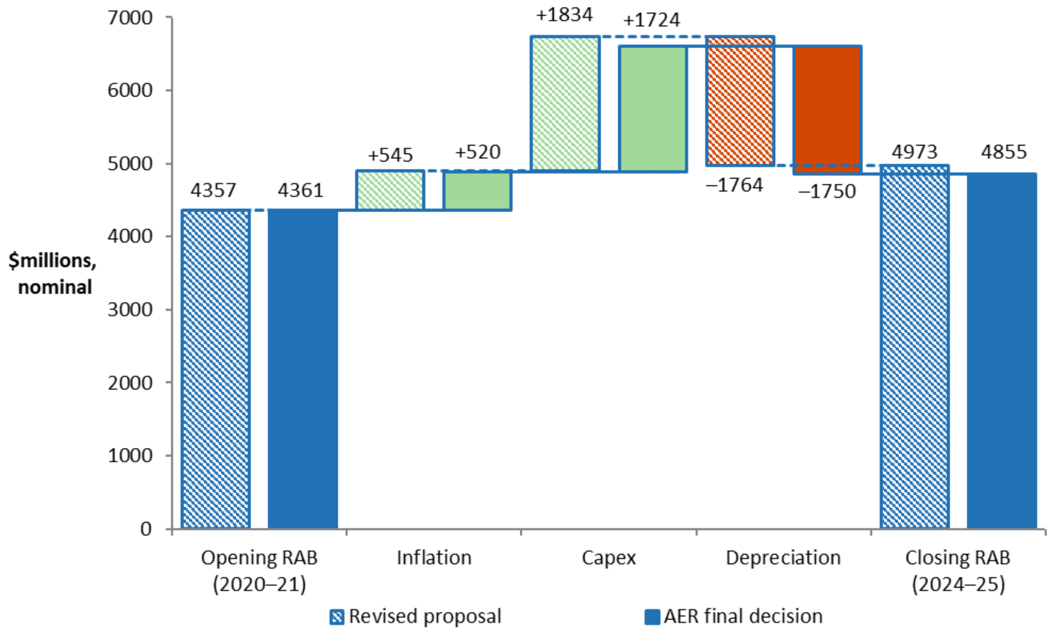
Source: AER analysis.

(a) Net of forecast disposals and capital contributions. In accordance with the timing assumptions of the post-tax revenue model (PTRM), the capex includes a half-year WACC allowance to compensate for the six-month period before capex is added to the RAB for revenue modelling.

Figure 6 shows the key drivers of the change in SA Power Networks' RAB over the 2020–25 regulatory control period for this final decision. Overall, the closing RAB at the end of the 2020–25 regulatory control period is forecast to be 11.3 per cent higher than the opening RAB at the start of that period, in nominal terms. The approved forecast net capex increases the RAB by 39.5 per cent, while expected inflation increases it by 11.9 per cent. Forecast depreciation, on the other hand, reduces the RAB by 40.1 per cent.

reflects our amendments to the rate of return for the 2020–25 regulatory control period (section 2.2 of the Overview).

**Figure 6 SA Power Networks' revised proposal and AER final decision RAB ($ million, nominal)**




Source: AER analysis.

Note: Capex is net of forecast disposals and capital contributions. It is inclusive of the half-year WACC to account for the timing assumptions in the PTRM.

Further detail on our final decision regarding the RAB is set out in attachment 2.

## 2.2 Rate of return, expected inflation and imputation credits

The return each network business is to receive on its RAB (the 'return on capital') is 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.

This means we combine the returns from the two sources of funds for investment: equity and debt. This allowed rate of return provides the network business with a return on capital to service the interest on its loans and give a return on equity to investors.

The rate of return is necessary to promote efficient prices in the long-term interests of consumers. If the rate of return is set too low, the network business may not be able to attract sufficient funds to be able to make the required investments in the network and reliability may decline. Conversely, if the rate of return is set too high, the network business may seek to spend too much and consumers will pay inefficiently high tariffs.

As required under the NEL, we apply the 2018 rate of return instrument (2018 Instrument) to estimate the rate of return for SA Power Networks.[39]

This leads to a rate of return of 4.75 per cent (nominal vanilla) for this final decision. This is 0.2 percentage points lower than our draft decision placeholder estimate of 4.95 per cent (nominal vanilla).[40]

This rate of return, in Table 5, will apply to the first year of the 2020–25 regulatory control period. A different rate of return will apply for the remaining regulatory years of the period. This is because we will update the return on debt component of the rate of return each year in accordance with the 2018 Instrument, which uses a 10-year trailing average portfolio return on debt that is rolled-forward each year. Hence, only 10 per cent of the return on debt is calculated from the most recent averaging period with 90 per cent from prior periods.[41]

We also note that SA Power Networks' proposed risk free rate[42] and debt averaging periods have been (and will be) used to estimate its rate of return because they complied with conditions set out in the 2018 Instrument.[43]

---

39 AER, *Rate of return instrument*, December 2018. See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-guideline-2018/final-decision.

40 AER, *Draft Decision, SA Power Networks Distribution Determination 2020–25,* October 2019, Overview, p. 27.

41 This is the reason why, in SA Power Networks' revised proposal and this final decision, the return on equity is below the return on debt. Our most recent estimate of the return on debt is below the contemporaneous return on equity (as expected, given debtholders face less risk than equity investors). However, the return on debt in past years was substantially higher than current estimates, and the trailing average reflects the interest costs facing a network that spreads its debt issuance across time.

42 This is also known as the return on equity averaging period.

43 AER, *Rate of return instrument*, December 2018, clauses 7–8, 23–25, 36.

## Table 5 Final decision on SA Power Networks' rate of return (% nominal)

| | AER draft decision (2020–25) | SA Power Networks' revised proposal (2020–25) | AER final decision (2020–25) | Allowed return over regulatory control period |
|---|---|---|---|---|
| Nominal risk free rate | 1.32%[a] | 0.96% | 0.90%[b] | |
| Market risk premium | 6.1% | 6.1% | 6.1% | |
| Equity beta | 0.6 | 0.6 | 0.6 | |
| Return on equity (nominal post–tax) | 4.98% | 4.62% | 4.56% | Constant (%) |
| Return on debt (nominal pre–tax) | 4.93% | 4.91% | 4.87%[c] | Updated annually |
| Gearing | 60% | 60% | 60% | Constant (60%) |
| Nominal vanilla WACC | 4.95% | 4.79% | 4.75% | Updated annually for return on debt |
| Expected inflation | 2.45% | 2.36% | 2.27% | Constant (%) |

Source: AER analysis; SA Power Networks, *Revised regulatory proposal, Attachment 3 Rate of Return,* December 2019, p. 9.

a Calculated using a placeholder averaging period of 20 business days ending 31 July 2019.

b Calculated using an averaging period of 20 business days ending 27 March 2020.

c We use the proposed debt averaging period. The return on debt has been updated for this averaging period.

SA Power Networks made a number of late submissions to us on rate of return and inflation issues with regard to the impact of COVID-19 on financial markets.[44] It identified several possible options for addressing its concerns, but the rate of return elements involved departure from the application of the 2018 rate of return instrument.[45] Under the NEL, the rate of return instrument is binding.

### Expected inflation

Our estimate of expected inflation is 2.27 per cent. It is an estimate of the average annual rate of inflation expected over a 10 year period. We estimate expected inflation over this 10 year term to align with the term of the rate of return. Our estimate of expected inflation is estimated in accordance with the method set out in the post-tax

44 SA Power Networks, *Letter re: SA Power Networks - Determination 2020–25*, 4 March 2020, SA Power Networks, *SA Power Networks 2020–25 distribution determination in light of COVID-19*, 7 April 2020, SA Power Networks, *Email re: URGENT SA Power Networks 2020–25 Revised Proposal, Covid-19*, 14 April 2020, SA Power Networks, *Letter re: Proposal to delay final decisions for SA Power Networks, Energex, Ergon Energy, Directlink and Jemena Gas Networks*, 28 April 2020, SA Power Networks, *Inflation forecast for SA Power Networks 2020–25 revenue determination*, 11 May 2020.

45 This is distinct from the inflation elements discussed immediately below.

revenue model (PTRM). The NER set out how we are to apply the PTRM and the expected inflation estimation method in the model in our electricity determinations.[46]

SA Power Networks adopted our approach to estimating expected inflation in its revised proposal, but proposed that we conduct a review into the method for estimating expected inflation and then apply the result of that review to its final decision.

Further, SA Power Networks stated that we should reconsider our inflation approach in light of 'the outbreak of coronavirus and the effect of this on global financial markets'.[47] Other network service providers also made a number of recent submissions to us on inflation, and in particular the inflation approach that would be applied to final decisions for Energex, Ergon Energy, Jemena Gas Networks and Directlink (prior to the completion of the inflation review).

For this final decision, we estimate expected inflation in a manner that is consistent with the method specified in the PTRM.[48] In applying this method we have made two adjustments to our usual practice:

- We use inflation forecasts from the most recent Reserve Bank of Australia's (RBA) Statement on Monetary Policy (SMP) released on 8 May 2020. The RBA's SMP is released quarterly. Our usual approach is to use the RBA's February SMP in the PTRM in April final decisions for network businesses with regulatory years starting 1 July (that is, the regulatory period is based on financial years).[49] However, we delayed our decision to allow us to use the RBA's May SMP as we expected this would provide a more accurate reflection of the economic circumstances expected for the next regulatory control period.
- We use the RBA's trimmed mean inflation (TMI) forecasts for the first two regulatory years (year-to-June 2021, and year-to-June 2022).[50] Our usual implementation is to use the (headline) consumer price index (CPI) forecasts for these periods.[51] In the current circumstances of COVID-19, we consider that the TMI series better reflects expectations of core inflation as set out in the RBA's

46 NER, r. 6.4.2(a) and (b)(1).

47 SA Power Networks, *Letter re: SA Power Networks - Determination 2020–25*, 4 March 2020; see also SA Power Networks, *SA Power Networks 2020–25 distribution determination in light of COVID-19*, 8 April 2020, CONFIDENTIAL, SA Power Networks, *Email re: URGENT SA Power Networks 2020–25 Revised Proposal, Covid-19*, 14 April 2020, SA Power Networks, *Letter re: Proposal to delay final decisions for SA Power Networks, Energex, Ergon Energy, Directlink and Jemena Gas Networks*, 28 April 2020, SA Power Networks, *Inflation forecast for SA Power Networks 2020–25 revenue determination*, 11 May 2020.

48 AER, *Final decision, SA Power Networks determination 2015–16 to 2019–20*, October 2015 (attachment 3 – Rate of return), p. 3-253 (table 3-37 and notes). See also AER, *Draft decision, SA Power Networks distribution determination 2020 to 2025*, October 2019, Attachment 3, p. 3-7.

49 The PTRM method specifies that we will use the *latest available* RBA SMP.

50 We have consistently used the TMI inflation forecasts from the May RBA SMP in other related areas of our decision, in particular our opex assessment (see attachment 6).

51 The PTRM method specifies that we will use RBA SMP inflation forecasts for the first two years, but does not specify the series used.

SMP. Further, the TMI smooths the transient volatility in the CPI forecasts in the RBA's May SMP.

We ran a short consultation process on the proposal to delay our final decision and use the May forecasts. SA Power Networks supported the delay and the use of forecasts from the RBA's May SMP, although it maintained its position that there were a number of other deficiencies in our method for estimating expected inflation.[52]

We have considered SA Power Networks' submissions on these matters in this final decision, attachment 3 (Rate of Return).

### Debt and equity raising costs

In addition to compensating for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. We include debt raising costs in the opex forecast because these are regular and ongoing costs. We include equity raising costs in the capex forecast because these costs are only incurred once and would be associated with funding the particular capital investments.

Our final decision is to accept SA Power Networks' method of using an annual rate of 8.50 basis points to estimate total debt raising costs of $11.24 million ($2019–20).[53] We have considered this annual rate and found that our alternative benchmark estimate (7.98 basis points per annum) is not materially different from SA Power Networks' revised proposal.[54] The key difference between our draft decision and SA Power Networks' revised proposal was the basis for estimation of the 'arrangement fee'. After consideration of SA Power Networks' submission, we accept that the Bloomberg data is the most suitable source of information on the 'arrangement fee' available at present.[55]

SA Power Networks' revised proposal calculated equity raising costs using our benchmark approach in the PTRM. Using this approach SA Power Networks forecast zero equity raising costs.[56] We have updated our estimate for this distribution determination based on the benchmark approach using updated inputs. This results in zero equity raising costs.

---

[52] SA Power Networks, *Letter re: SA Power Networks - Determination 2020 –25*, 4 March 2020; see also SA Power Networks, *SA Power Networks 2020–25 distribution determination in light of COVID-19*, 8 April 2020, CONFIDENTIAL, SA Power Networks, *Email re: URGENT SA Power Networks 2020–25 Revised Proposal, Covid-19*, 14 April 2020, SA Power Networks, *Letter re: Proposal to delay final decisions for SA Power Networks, Energex, Ergon Energy, Directlink and Jemena Gas Networks*, 28 April 2020, SA Power Networks, *Inflation forecast for SA Power Networks 2020–25 revenue determination*, 11 May 2020.

[53] SA Power Networks, *2020–25 Revised regulatory proposal – Attachment 3,* December 2019, p. 21.

[54] See section 2.5 for our final decision on overall opex (which encompasses debt raising costs).

[55] CEG, *The cost of arranging debt issues*, November 2019 (attachment 3.1 to the SA Power Networks revised proposal).

[56] SA Power Networks, *2020–25 Revised regulatory proposal – Attachment 3,* December 2019, p. 19; SA Power Networks, *Revised Proposal – 1.1 – PTRM* – December 2019.

### Imputation credits

Our final decision applies a value of imputation credits (gamma) 0.585 as set out in the binding 2018 Instrument.[57] This was the result of extensive analysis and consultation conducted as part of the 2018 rate of return review.[58] SA Power Networks' revised proposal has adopted the value of gamma set out in the 2018 Instrument.[59]

Further detail on our final decision in regards to SA Power Networks' allowed rate of return, expected inflation, debt and equity raising costs and imputation credits is set out in attachment 3.

## 2.3 Regulatory depreciation (return of capital)

Regulatory depreciation is the allowance provided so capital investors recover their investment over the economic life of the asset (return of capital). SA Power Networks invests capital in assets to provide electricity network services to its consumers. The costs of these assets are recovered over the asset's useful life, which in many cases can be 50 or more years. This means only a small part of the cost of such assets are recovered from consumers upfront or in any year. The greater proportion is recovered over time through the depreciation allowance. The regulatory depreciation allowance is the net total of the straight-line depreciation less the inflation indexation adjustment of the RAB.

Our final decision on SA Power Networks' revenue for 2020–25 includes a regulatory depreciation allowance of $1230.1 million ($ nominal). This is $11.1 million (0.9 per cent) higher than SA Power Networks' revised proposal.

We adopt the same approach to regulatory depreciation as SA Power Networks, including its standard asset lives which determine how quickly an asset class is removed from the RAB. We have, in principle, accepted SA Power Networks' revised proposal to include new asset classes for shorter lived assets but have accepted that only some of the assets it proposed should be included in these asset classes.

We accept SA Power Networks' revised proposal to continue with its year-by-year tracking approach. SA Power Networks used our depreciation tracking model to apply the year-by-year tracking method. We required only minor changes to its depreciation tracking model.

We have also made determinations on other components of SA Power Networks' revised proposal, which affect the RAB and in turn impacts the forecast regulatory depreciation allowance. The increase to the regulatory depreciation allowance from the revised proposal primarily reflects our final decision expected inflation rate for the 2020–25 regulatory control period. Our final decision for SA Power Networks' straight-

57 AER, *Rate of return instrument*, December 2018, clause 27.

58 AER, *Rate of return instrument, Explanatory Statement*, December 2018, pp. 307–382.

59 SA Power Networks, *Revised regulatory proposal, Attachment 3 Rate of Return,* December 2019, p. 9.

line depreciation component of regulatory depreciation is lower than the revised proposal by $13.7 million due to our determination of the opening RABs (attachment 2) and the forecast capex (attachment 5). However, this reduction is offset by our final decision on the indexation of the RAB, which is $24.8 million lower than the revised proposal. This is largely due to applying a lower expected inflation rate of 2.27 per cent per annum in this final decision (attachment 3) compared to SA Power Networks' revised proposal of 2.36 per cent per annum. Subsequently, the net effect is an increase in the regulatory depreciation allowance of $11.1 million.

Further detail on our final decision regarding depreciation is set out in attachment 4.

## 2.4 Capital expenditure

Capital expenditure (capex) refers to the investment in assets to provide network services. This investment mostly relates to assets with long lives and these costs are recovered over several regulatory periods. 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 projected RAB value and higher return on capital and regulatory depreciation allowances.

Our final decision on SA Power Networks’ revenue includes a total net capex forecast of $1595.8 million ($2019–20) for the 2020–25 regulatory control period. This is 6 per cent lower than SA Power Networks' revised proposal of $1693.4 million ($2019–20).

We are satisfied that our substitute estimate reasonably reflects the capex criteria. Table 6 shows our final decision compared to SA Power Networks revised proposal forecast.

### Table 6 AER’s final decision on total net capex ($ million, 2019–20)

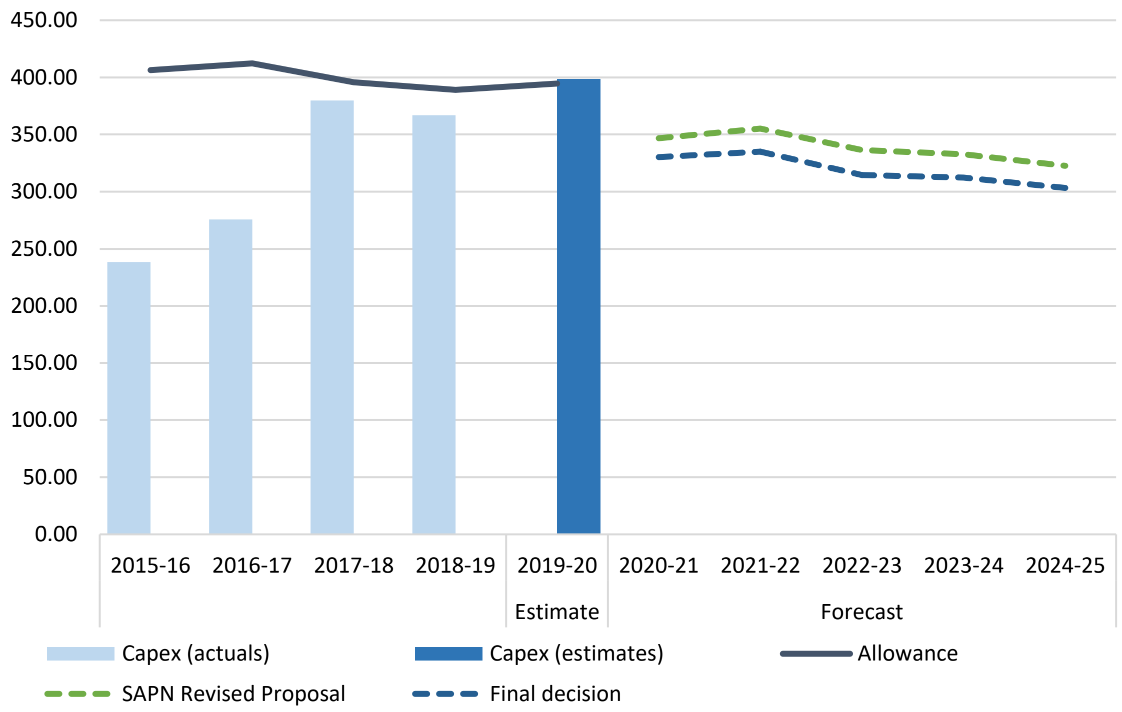
| | 2020–21 | 2021–22 | 2022–23 | 2023–24 | 2024–25 | Total |
|---|---|---|---|---|---|---|
| SA Power Networks' revised proposal | $346.6 | $355.2 | $336.3 | $332.6 | $322.6 | $1,693.4 |
| Final decision | $330.4 | $335.1 | $314.6 | $312.4 | $303.3 | $1,595.8 |
| Difference | -$16.3 | -$20.1 | -$21.7 | -$20.2 | -$19.2 | -$97.5 |
| Percentage difference (%) | -5% | -6% | -6% | -6% | -6% | -6% |

Source: AER analysis.

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

Figure 7 shows our capex final decision compared to SA Power Networks’ revised proposal, its past allowance and past actual expenditure.

## Figure 7 AER's final decision on total forecast capex ($ million, 2019–20)




Source: AER analysis

In our draft decision, we noted that SA Power Networks' proposal lacked sufficient supporting material to satisfy us that its proposed capex reasonably reflects the capex criteria. Our draft decision capex forecast was $1246.9 million ($2019–20) or 27.5 per cent lower than SA Power Networks' initial proposal. SA Power Networks has responded to our draft decision concerns and we note that a number of stakeholders have commended SA Power Networks on its positive consumer engagement when preparing its revised proposal.[60] The new material provided with the revised proposal has led us to largely accept SA Power Networks' capex proposal leading to a more modest difference between the revised proposal and our final decision. We applied our standard assessment approaches such as trend analysis, repex modelling and business case assessment to assess the material put to us.

The key aspects of our final decision are the following:

- We have accepted SA Power Networks' DER Management revised capex forecast. SA Power networks has addressed our concerns, particularly around the benefits of its Low Voltage (LV) monitoring program as well as the quality of supply remediation program.
- We have accepted SA Power Networks' Information communications technology revised capex forecast, which largely includes the Assets and Work

60 Business SA, Consumer Challenge Panel, Energy Consumers Australia, SA Government and SA Power Networks' Customer Consultative Panel.

program and the SAP upgrade. For the Assets and Work, we acknowledge that SA Power Networks has largely responded to our draft decision concerns and provided supporting analysis, however, we do not consider the methodology used to forecast the benefits, mainly the replacement capital expenditure (repex) deferrals, to be reasonable. The benefits' calculation method overstates the repex requirements in the absence of the Asset and Work program. In light of our analysis, we have accepted the Assets and Work program, subject to an adjustment to its repex forecast.

- SA Power Networks has not fully justified its revised repex forecast. Our substitute estimate is 11 per cent lower than SA Power Networks revised proposal. We have relied on the repex model to assess SA Power Networks' modelled repex. Our repex modelling showed that SA Power Networks compares well with its peers on unit costs and replacement lives for its modelled component of repex. However, for SA Power Networks' un-modelled repex, our bottom-up review has identified that some of SA Power Networks' assumptions and inputs continue to overstate the risk to be mitigated, and its cost benefit analysis does not support its proposed projects. In particular, for the poles forecast, which is treated as un-modelled repex in this decision,[61] there is insufficient evidence of a change in the underlying condition of SA Power Networks' poles that would justify a step up in forecast repex. In coming to our decision, we had regard to SA Power Networks' existing volume of poles defects. Our analysis has identified that the outstanding defects are either low priority or associated with low consequence if they failed. We have concluded that the evidence does not support the increase from its historical expenditure on replacement.
- For SA Power Networks' proposed reliability capex, [62] we have some remaining concerns with the cost-benefit analysis. However, on balance, we have placed more weight on stakeholder support, which supported the need to undertake the low reliability feeders program. Conversely, for the Hardening the Network program, we have maintained our draft decision position. There was limited stakeholder support and the benefits program may be overstated, because it is unclear to what extent the program mitigates against one-off rather than recurrent events.
- We have accepted SA Power Networks' fleet revised capex forecast. However, we did not accept SA Power Networks' property capex, as it has not justified an increase from its historical revealed costs.
- We have accepted both of SA Power Networks' proposed contingent projects. For the electricity system security contingent project, SA Power Networks and

[61] Even though poles are usually part of modelled repex under our standard modelling approach, in this final decision and consistent with the draft decision, we have excluded Stobie poles from modelled repex due to their unique nature.

[62] The reliability capex include the low reliability feeders program and hardening the network program.

AEMO provided us new information and analysis, which establishes appropriate triggers and the need of the project. As for the 2019–20 Bushfire Review contingent project, we are satisfied that SA Power Networks may incur capex to address bushfire risk, as electricity infrastructure is a focus area for the South Australian government's independent review into South Australia's 2019–20 bushfire season.

Our assessment looks at the main factors that influence the need for capex. We do not determine which programs or projects a distributor should or should not undertake. Rather, once we set a capex forecast, it is up to the distributor to prioritise its capex program over the course of the regulatory control period.

Further detail on our final decision on capex is set out in attachment 5.

## 2.5 Operating expenditure

Opex is the forecast of operating, maintenance and other non-capital costs incurred in the provision of standard control services.

We accept SA Power Networks' total opex forecast of $1469.5 million ($2019–20), including debt raising costs, for the 2020–25 regulatory control period.[63] This is $26.3 million ($2019–20) (or 1.8 per cent) higher than our alternative total opex estimate of $1443.2 million ($2019–20)[64] which is not materially different from SA Power Networks' revised proposal. We note our draft decision did not accept SA Power Networks' initial opex proposal as our alternative estimate was 5.0 per cent lower than its forecast. SA Power Networks' revised opex proposal is 5.3 per cent lower than its initial opex proposal and 0.2 per cent lower than our alternative estimate in the draft decision.[65]

The key driver of the difference between our alternative estimate for the final decision and SA Power Networks' revised proposal relates to our assessment of several step changes, where we have either not included the proposed step change, or included a different amount, in our alternative estimate. This includes the step change proposed for higher bushfire insurance costs, which we have not included in our alternative estimate as we are not persuaded that SA Power networks has demonstrated that non-labour price growth does not adequately compensate the forecast increases. These differences and the full reasons for our final decision are set out in attachment 6. Figure 8 shows the opex included in SA Power Network's revised proposal, its past allowance and past actual expenditure.

63 This includes the increased opex proposed by SA Power Networks in February 2020 for higher bushfire liability insurance premiums.

64 We use the RBA's May 2020 SMP trimmed mean inflation forecasts for the year ending June 2020. See section 2.2 – Rate of return, expected inflation and value of imputation credits for more details.

65 Comparisons are inclusive of debt raising costs

**Figure 8 Historical and forecast opex ($ million, 2019–20)**


Source: SA Power Networks, *Regulatory Accounts 2010–11 to 2018–19*; SA Power Networks, *2020–2025 Revised regulatory proposal – Attachment 6 – Operating expenditure*, 10 December 2019; SA Power Networks, *2020–2025 Revised regulatory proposal – Addendum to Attachment 6*, February 2020; AER analysis.

Note: Includes debt raising costs. Numbers may not add up to total due to rounding

## 2.6 Corporate income tax

The building block approach to the calculation of revenue includes an allowance for the estimated cost of corporate income tax payable by SA Power Networks. Our final decision on SA Power Networks' estimated cost of corporate income tax is $22.7 million ($ nominal) over the 2020–25 regulatory control period. This represents an increase of $12.3 million (or 116.8 per cent) from SA Power Networks' revised proposed cost of corporate income tax of $10.5 million ($ nominal). The key reasons for this change are:

- Our final decision to reduce the immediately expensed capex for tax purposes to $680.4 million from $751.7 million.[66]

[66] All else equal, a lower immediately expensed capex amount will increase the cost of corporate income tax because it reduces the tax expense.

- Our final decision on regulatory depreciation (attachment 4).[67]
- Our final decision rate of return on equity (attachment 3).[68]

We accept the revised proposed opening tax asset base (TAB) value as at 1 July 2020 of $3459.1 million. We note that SA Power Networks' revised proposal did not include its earlier claim for this opening value to be adjusted for past immediate expensing of capital expenditure (capex).[69] We also accept SA Power Networks' revised proposal on the standard tax asset lives for all of its asset classes and to continue using the year-by-year tracking approach for tax depreciation, where the capex for each year is depreciated individually for tax purposes.

### Table 7 AER's final decision on SA Power Networks' corporate income tax ($ million, nominal)

| | 2020–21 | 2021–22 | 2022–23 | 2024–24 | 2024–25 | Total |
|---|---|---|---|---|---|---|
| Tax payable | 8.0 | 8.5 | 11.6 | 13.6 | 13.1 | 54.8 |
| *Less:* value of imputation credits | 4.7 | 5.0 | 6.8 | 8.0 | 7.7 | 32.1 |
| **Net corporate income tax allowance** | **3.3** | **3.5** | **4.8** | **5.7** | **5.4** | **22.7** |

Source: AER analysis.

Further detail on our final decision on corporate income tax is set out in attachment 7.

## 2.7 Revenue adjustments and incentive schemes

Our final decision on SA Power Networks’ total revenue also included a number of adjustments:

- Efficiency benefit sharing scheme (EBSS)—SA Power Networks accrued EBSS carryovers totalling $4.5 million ($2019–20)[70] from the application of the EBSS in the 2015–20 regulatory control period. SA Power Networks included amounts totalling $4.6 million ($2019–20) in its revised proposal. The EBSS is intended to provide a continuous incentive for distributors to pursue efficiency improvements in opex, and provide for a fair sharing of these between distributors and network users. Consumers benefit from improved efficiencies through lower forecast opex in subsequent periods. Attachment 8 sets out our final decision on SA Power Networks' EBSS.

---

[67] All else equal, a higher regulatory depreciation will increase the cost of corporate income tax because it increases the taxable income.

[68] All else equal, a lower rate of return on equity will lower the cost of corporate income tax because it reduces the return on equity, a component of the taxable income.

[69] SA Power Networks, *Revised proposal, attachment 7,* 10 December 2019, p. 7.

[70] We use the RBA’s May 2020 SMP trimmed mean inflation forecasts for the year ending June 2020. See section 2.2 – Rate of return, expected inflation and value of imputation credits for more details.

- Capital expenditure sharing scheme (CESS) — we have included a CESS revenue increment of $76.4 million ($2019–20) for the application of the CESS during the 2015–20 regulatory control period. This amount is different to the $76.3 million included in SA Power Networks' revised proposal. This difference reflects updates to inflation and the weighted average cost of capital (WACC). We have made no further adjustments as we are satisfied our substitute forecast of capex does not include any material deferral of capex. The CESS rewards efficiency gains and penalises efficiency losses, each measured by reference to the difference between forecast and actual capex. Attachment 9 sets out our final decision on SA Power Networks' CESS.
- Service target performance incentive scheme (STPIS) — our final decision is to apply our national STPIS version 2.0 (November 2018)[71] to SA Power Networks for the 2020–25 regulatory control period. We will not apply the guaranteed service level component to SA Power Networks as the existing jurisdictional arrangements will continue to apply. Attachment 10 sets out our final decision on SA Power Networks' STPIS.
- Demand management incentive scheme (DMIS) and Demand management innovation allowance mechanism (DMIAM) — our final decision is to apply the DMIS[72] and the DMIAM[73] to SA Power Networks for the 2020–25 regulatory control period, without any modification. Our draft decision reasons form part of this final decision. Table 8 sets out the DMIAM allowance for SA Power Networks for the 2020–25 regulatory control period, based on the final PTRM for SA Power Networks.

### Table 8 AER's final decision on SA Power Networks' demand management innovation allowance ($ million, 2019–20)

| | 2020–21 | 2021–22 | 2022–23 | 2023–24 | 2024–25 | Total |
|---|---|---|---|---|---|---|
| DMIAM | 0.77 | 0.75 | 0.77 | 0.77 | 0.75 | 3.80 |

Source: AER analysis

71 AER, *Electricity distribution network service providers—service target performance incentive scheme version 2.0*, November 2018. (AER, *STPIS v2.0*, November 2018).

72 AER, *Demand management incentive scheme*, *Electricity distribution network service providers*, December 2017.

73 AER, *Demand management innovation allowance mechanism*, *Electricity distribution network service providers*, December 2017.

# 3 Tariff structure statement

SA Power Networks' 2020–25 proposal includes the second iteration of its TSS. Its current TSS applies from 1 July 2017 to 30 June 2020.

A TSS applies to a distributor's tariffs for the duration of the regulatory control period. It describes a distributor's tariff classes and structures, the distributor's policies and procedures for assigning consumers to tariffs, the changing parameters for each tariff, and a description of the approach the distributor takes to setting tariffs in pricing proposals. It is accompanied by an indicative pricing schedule.[74] A TSS provides consumers and retailers with certainty and transparency in relation to how and when network tariff structures will change.

While an indicative pricing schedule must accompany the TSS, SA Power Networks' tariff levels for the entire 2020–25 regulatory control period are not set as part of this determination. Rather, tariff levels for 2020–21 will be subject to a separate annual approval process.

Our draft decision on SA Power Networks' TSS was to approve the proposal, although we suggested a few revisions including separating the explanatory material from that relating to regulatory compliance.[75] SA Power Networks accepted our proposed revisions and incorporated them into a revised TSS proposal with two components. A number of stakeholders supported our draft decision in their submissions on SA Power Networks' revised proposal.[76] Our final decision is consistent with our draft decision and the revised proposal, with one main exception. In light of the uncertainty and impacts of the COVID-19 pandemic on residential and business consumers, we have decided to include transitional arrangements in the first year of the regulatory control period to help consumers and retailers adjust to the new tariff structures. These transitional arrangements are explained in Attachment 18 of this decision. There are also some minor wording changes we have made to SA Power Networks' TSS to improve clarity in a few areas.

In forming our view to accept all other elements of SA Power Networks' proposal, we note the extensive engagement undertaken by SA Power Networks both in the development of the initial TSS proposal, as well as that focused on implementation following our draft decision. During this time SA Power Networks has formed a tariff working group and held a roundtable with retailers in addition to bilateral engagement with stakeholders. A number of stakeholders commended the genuine efforts of SA Power Networks to understand the impact on consumers and engage with them which

---

74 NER cl.6.18.1A(a)

75 AER, *Draft Decision SA Power Networks distribution determination 2020–25, Attachment 18 Tariff Structure Statement,* October 2019

76 See for example submissions from AGL and CCP14 on *SA Power Networks Revised regulatory proposal 2020–25*

culminated in the formation of an ongoing tariff working group which could support an increase in the take up of cost reflective network tariffs.[77]

In developing its TSS proposal, we consider SA Power Networks reasonably balanced a number of factors including:

- progressing tariff reform by making tariff structures more reflective of underlying costs
- the change from network maximums (peak) being the primary cost driver to network minimums now also being important to manage
- responding to consumers and retailers requesting greater simplicity
- complying with the South Australian Government's policy to offer a single tariff for all residential customers state-wide and also for small business customers.

An important and growing challenge in South Australia is managing the minimum demand on the system in the middle of the day as a result of significant amounts of solar exported onto the system. These challenges include voltage rises (which can result in network costs and customers' solar exports being curtailed or "wasted") and challenges in having a fleet of generators and storage that are flexible enough to ramp up generation output from the midday lows to evening peaks in demand. We expect the tariff reforms from SA Power Networks that we are approving to contribute to addressing these challenges and enable more solar to be integrated into the grid, in addition to encouraging more efficient use of the network.

A key element of SA Power Networks' proposal is the application of "solar sponge" pricing in its network tariff design for residential customers. Usage rates during the solar sponge period of 10am to 3pm are set at a 75 per cent discount to the single rate network tariff. This is designed to provide an incentive to residential customers who are able to shift consumption to the middle of the day to do so to address the system challenges in the low voltage network. These tariffs should also encourage those customers with solar and storage to save some of that solar to offset their consumption during peak periods. For consumers currently on controlled load arrangements (e.g. for hot water) and who have a smart meter (type 4), the timing of the controlled load will also be amended to take advantage of the low solar sponge rates during the middle of the day.

From the second year of the regulatory control period (1 July 2021 onwards), retailers will face cost reflective tariff networks for all of their residential and small business consumers who have a smart meter (type 4 and type 5). For the first year of the regulatory period (1 July 2020 tariffs) we have decided to include transitional arrangements where retailers will face a cost reflective network tariff by default for some of their consumers (new connections; existing consumers who upgrade their

[77] See for example submissions from Business SA and the SA Government on *SA Power Networks Revised Regulatory Proposal 2020–25*

connection) with the ability to opt-out to legacy tariffs in the first year only. As noted, these transitional arrangements are in response to the COVID-19 pandemic to provide retailers and consumers with more time to adjust to the new pricing arrangements. The changes to controlled load arrangements to include the solar sponge rates will apply from 1 July 2020 (ie. we do not consider transitional arrangements are required for controlled load reforms and these will apply without delay).

The fact that retailers are the focus of network tariffs and that it will be up to them to determine how this change affects their retailer offers was also a common theme across submissions.[78] Namely, in developing their retail offers, retailers manage a number of risks including volatile wholesale market prices and network tariff signals. In recognition of this, SA Power Networks arranged a retailer roundtable in November 2019 to communicate their plans, engage with retailers on the implications, and enhance discussions regarding the implementation of these tariffs in July 2020.

To better understand what these network tariff reforms are likely to mean for retail offers, we held a series of one-on-one discussions with retailers. This engagement suggests that retailers are likely to respond through their retail offers in different ways providing end consumers with greater choice on how they managing their energy bills.

Our engagement with retailers suggests that responses also depend on retailer size:

- Small retailers are more likely to offer retail tariffs that reflect the underlying network tariff structures including the solar sponge for residential customers.
- Large retailers are more likely to continue to offer simple flat rate retail tariffs in addition to some retailers offering retail tariffs that reflect the underlying network tariff structure.
- A couple of retailers are also working on more innovative options in designing retail packages that provide customers with tools to help them manage their energy consumption.

We will shortly be publishing a summary of what we heard from retailers in a separate document.[79]

---

78 See for example submissions from the AER and SAPN Consumers Challenge Panels on *SA Power Networks Revised regulatory proposal 2020–25*

79 This will be available on our dedicated Network Tariff Reform webpage: [https://www.aer.gov.au/networks-pipelines/network-tariff-reform.](https://www.aer.gov.au/networks-pipelines/network-tariff-reform)

# 4 Other price terms and conditions

In this section, we consider the other aspects of our determination. These may be described as the terms and conditions of our determination that cover how SA Power Networks must set its prices. These include the classification of services, the conditions under which we may grant SA Power Networks additional revenues to cover unforeseen circumstances and the framework for SA Power Networks' negotiated services and customer connections.

## 4.1 Classification of services

Service classification determines the nature of economic regulation, if any, that is applicable to specific distribution services. Classification is important to customers as it determines which network services are included in basic electricity charges, the basis on which additional services are sold, and which services we will not regulate. Our decision reflects our assessment of a number of factors, including existing and potential competition to supply these services.

In its revised proposal, SA Power Networks adopted our draft decision subject to the correction of some minor drafting issues and omissions from the services list.[80] Our final decision is to retain the classification structure, but amend the services list to correct for the issues identified by SA Power Networks. The amended services list, is in attachment 12 to our final decision.

## 4.2 Pass through events

SA Power Networks' proposal included five nominated pass through events (insurance cap, insurer credit risk, natural disaster, terrorism and corporate income tax). Our draft decision accepted the first four of these nominated pass through events, but with amended definitions so that the pass through events that apply to SA Power Networks were consistent with recent decisions for other network service providers.

SA Power Networks' revised proposal:

- Adopted our amended definitions in relation to insurer credit risk and terrorism nominated pass through events and we approve these in our final decision.
- Suggested further amendments to the insurance cap and natural disaster events which we have considered. In this final decision we have included further refinements to these nominated pass through event definitions which address most of the issues raised by SA Power Networks.
- Included a new pass through event in relation to corporate income tax events which we have considered and have not included in this final decision.

80 SA Power Networks, *2020–25 Revised Regulatory Proposal*, Attachment 12 Classification of services, p. 6.

SA Power Networks' wrote to us on 1 April 2020[81] making a further submission relating to the natural disaster pass through event and sought additional amendments to capture pandemics or epidemics. SA Power Networks sought this amendment in response to the COVID-19 pandemic.

In assessing this proposal, we have had regard to the nominated pass through event considerations. In this regard, while the proposal meets some of these, there is still uncertainty around the cost impact of a pandemic and it is not clear whether those costs could be mitigated by a prudent service operator. In addition, we considered whether the proposed amendments would contribute to the achievement of the NEO. We have concerns that the adoption of SA Power Networks' proposal may have adverse effects, including that it may not reflect a balanced treatment of all the impacts of a pandemic. This could adversely impact future prices faced by consumers.

A further reason why we decided not to allow the pass through was our view that we could not adequately consult affected stakeholders. While this decision was delayed, we do not consider this provided sufficient time to examine the issues and consult adequately with stakeholders given the novel, and not insignificant, nature of the proposed amendments and the complex issues raised. As noted above, we also considered that delaying the determinations further to allow more time for the effects of COVID-19 to be assessed is not the appropriate response when balancing the importance of finalising the arrangements for 1 July 2020.

The COVID-19 pandemic potentially affects all of the network businesses we regulate, and all of their customers. In making our decision about SA Power Network's proposal we considered that consistency in approach across all regulated businesses means that any impacts of the COVID-19 pandemic are likely to be more appropriately considered across the industry as a whole through a rule change.

Going forward, if it becomes clear that the impacts of COVID-19 are substantial, then a rule change would need to be considered to enable us to re-open existing revenue determinations.

Further detail on our final decision in relation to the nominated pass through events that will apply during the 2020–25 regulatory control period, including the approved nominated pass through events, is set out in attachment 14.

## 4.3 Negotiating framework and criteria

In our draft decision, we approved SA Power Networks' proposed distribution negotiating framework for the 2020–25 regulatory control period.[82] We did not receive any objections or submissions on our draft decision. In the revised proposal SA Power Networks adopted our draft decision and did not propose any amendments to the

[81] SA Power Networks, *Letter – to AER re natural disaster pass through event,* 1 April 2020

[82] AER, *Draft Decision, SA Power Networks Distribution Determination 2020–25,* October 2019, Attachment 16, p, 16-5.

negotiating framework and criteria.[83] Our final decision is to approve SA Power Networks' negotiating framework. The distribution negotiating framework that will apply to SA Power Networks for the period of this determination is set out in Attachment A.

We are also required to make a decision on the negotiated distribution service criteria (NDSC) for the distributor.[84] Our final decision is to retain the NDSC that we published for SA Power Networks in October 2019 for the 2020–25 regulatory control period.[85] The NDSC gives effect to the negotiated distribution services principles.[86]

## 4.4 Connection policy

In our draft decision, we approved SA Power Networks' proposed connection policy for the 2020–25 regulatory control period.[87] SA Power Networks accepted our draft decision in its revised proposal. In our final decision, we have included attachment 17 to respond to a stakeholder's earlier submission to the Issues Paper. We have not made any amendment to our draft decision.

The approved connection policy for SA Power Networks for the 2020–25 regulatory control period is appended to attachment 17 of our draft decision.

---

83 SA Power Networks, *2020–25 Revised regulatory proposal*, Attachment 15 Negotiated services framework and criteria, p, 5.

84 NER, cl. 6.12.1(16).

85 AER, *Draft Decision, SA Power Networks Distribution Determination 2020–25,* October 2019, Attachment 16, p, 16-10, 11.

86 NER, cl. 6.7.1.

87 AER, *Draft Decision, Ergon Energy Distribution Determination 2020–25,* October 2019, Attachment 17.

# 5 The National Electricity Law and Rules

The NEL and NER provide the regulatory framework governing electricity distribution networks. Our work under this framework is guided by the NEO:

> …to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system. [88]

The NEL requires us to make our decision in a manner that contributes, or is likely to contribute, to achieving the NEO.[89] 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.[90] This is not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[91]

Electricity determinations are complex decisions. 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. Where there are choices to be made among several plausible alternatives, we have selected what we are satisfied would result in an overall decision that contributes to the achievement of the NEO to the greatest degree. [92]

Our distribution determinations are predicated on a number of constituent decisions that we are required to make.[93] These are set out in appendix A and the relevant attachments. In coming to a decision that contributes to the achievement of the NEO, we have considered interrelationships of the constituent components of our final decision in the relevant attachments. Examples include:

- underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period (see attachment 5 and 6)
- 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 (see attachments 3 and 7)

---

88 NEL, s. 7.

89 NEL, s. 16(1)(a).

90 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.

91 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.

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

93 NER, cl. 6.12.1.

- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex or vice versa (see attachments 5 and 6).

In general, we consider that the long-term interests of consumers are best served where consumers receive a reasonable level of safe and reliable service that they value at least cost in the long run.[94] 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.[95]

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.[96] 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.[97] 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[98]
- 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 leading to safety, security and reliability concerns.[99]

---

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

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

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

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

98 NEL, s. 7A(7).

99 NEL, s. 7A(6).

# A Constituent decisions

Our final decision on SA Power Networks' distribution determination for the 2020–25 regulatory control period includes the following constituent components:

| Constituent decision |
|---|
| In accordance with clause 6.12.1(1) of the NER, the AER's final decision is that the classification of services as set out in attachment 12 will apply to SA Power Networks for the 2020–25 regulatory control period. |
| In accordance with clause 6.12.1(2)(i) of the NER, the AER's final decision is not to approve the annual revenue requirement set out in SA Power Networks' building block proposal. Our final decision on SA Power Networks' annual revenue requirement for each year of the 2020–25 regulatory control period is set out in attachment 1 of this final decision. |
| In accordance with clause 6.12.1(2)(ii) of the NER, the AER's final decision is to approve SA Power Networks' proposal that the regulatory control period will commence on 1 July 2020. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER's final decision is to approve SA Power Networks' proposal that the length of the regulatory control period will be 5 years from 1 July 2020 to 30 June 2025. |
| The AER did not receive a request for an asset exemption under clause 6.4.B.1(a)(1) and therefore has not made a decision in accordance with clause 6.12.1(2A) of the NER. |
| In accordance with clause 6.12.1(3)(ii) of the NER and acting in accordance with clause 6.5.7(d), the AER's final decision is not to accept SA Power Networks' proposed total forecast net capital expenditure of $1693.4 million ($2019–20). Our final decision therefore includes a substitute estimate of SA Power Networks' total forecast net capex for the 2020–25 regulatory control period of $1595.8 million ($2019–20). The reasons for our final decision are set out in attachment 5. |
| In accordance with clause 6.12.1(4)(ii) of the NER and acting in accordance with clause 6.5.6(d), the AER's final decision is to accept SA Power Networks' proposed total forecast operating expenditure, inclusive of debt raising costs and exclusive of DMIA of $1469.5 million ($2019–20). The reasons for our final decision are set out in attachment 6. |
| In accordance with clause 6.12.1(4A)(i) of the NER, the AER's final decision is to accept the contingent projects proposed by SA Power Networks. The reasons for our final decision are set out in attachment 5. |
| In accordance with clause 6.12.1(5) of the NER and the 2018 Rate of Return Instrument, the AER's final decision is that the allowed rate of return for the 2020–21 regulatory year is 4.75 per cent (nominal vanilla) as set out in Attachment 3 of this final decision. The rate of return for the remaining regulatory years 2021–25 will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt. |
| In accordance with clause 6.12.1(5A) of the NER and the 2018 Rate of Return Instrument, the AER's final decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.585. This is discussed in section 2.2 of this final decision overview. |

## Constituent decision

In accordance with clause 6.12.1(6) of the NER, the AER's final decision on SA Power Networks' regulatory asset base as at 1 July 2020 in accordance with clause 6.5.1 and schedule 6.2 is $4361.0 million ($ nominal). This is discussed in attachment 2 of this final decision.

In accordance with clause 6.12.1(7) of the NER, the AER's final decision on the estimate of SA Power Networks' corporate income tax is $22.7 million ($ nominal). This is discussed in attachment 7 of this final decision.

In accordance with clause 6.12.1(8) of the NER, the AER's final decision is to not approve the depreciation schedules submitted by SA Power Networks. Our final decision substitutes alternative depreciation schedules that accord with clause 6.5.5(b) and is discussed in attachment 4 of this final decision.

In accordance with clause 6.12.1(9) of the NER, the AER makes the following final decisions on how any applicable efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS), service target performance incentive scheme (STPIS), demand management incentive scheme (DMIS), demand management innovation allowance mechanism (DMIAM) or small-scale incentive scheme is to apply:

- We will apply version 2 of the EBSS to SA Power Networks in the 2020–25 regulatory control period. This is discussed in attachment 8 of this final decision.
- We will apply the CESS as set out in the Capital Expenditure Incentives Guideline to SA Power Networks in the 2020–25 regulatory control period. This is discussed in attachment 9 of this final decision.
- We will apply our STPIS to SA Power Networks for the 2020–25 regulatory control period. This is discussed in attachment 10 of this final decision.
- We will apply the DMIS and DMIAM to SA Power Networks in the 2020–25 regulatory control period. This is discussed in section 2.7 of this final decision overview.

In accordance with clause 6.12.1(10) of the NER, the AER's final decision is that all other appropriate amounts, values and inputs are as set out in this final decision including attachments.

In accordance with clause 6.12.1(11) of the NER and our framework and approach paper, the AER's final decision on the form of control mechanisms (including the X factor) for standard control services is a revenue cap. The revenue cap for SA Power Networks for any given regulatory year is the total annual revenue calculated using the formula in attachment 13 plus any adjustment required to move the distribution use of system (DUoS) under/over account to zero. This is discussed in attachment 13 of this final decision.

In accordance with clause 6.12.1(12) of the NER and our framework and approach paper, the AER's final decision on the form of the control mechanism for alternative control services is to apply price caps for all these services. This is discussed in attachment 13 of this final decision.

In accordance with clause 6.12.1(13) of the NER, to demonstrate compliance with its distribution determination, the AER's final decision is that SA Power Networks must maintain a DUoS unders and overs account. It must provide information on this account to us in its annual pricing proposal. This is discussed in attachment 13 of this final decision.

| Constituent decision |
| --- |
| In accordance with clause 6.12.1(14) of the NER, the AER's final decision is to apply the following nominated pass through events to SA Power Networks for the 2020–25 regulatory control period in accordance with clause 6.5.10:<br>• Terrorism event<br>• Insurance coverage event<br>• Natural disaster event<br>• Insurer credit risk event.<br>These events have the definitions set out in Attachment 14 of this final decision. |
| In accordance with clause 6.12.1(14A) of the NER, the AER's final decision is to approve the tariff structure statement proposed by SA Power Networks. This is discussed in attachment 18 of this final decision. |
| In accordance with clause 6.12.1(15) of the NER, the AER's final decision is to apply the negotiating framework as proposed by SA Power Networks. This is discussed in section 4.3 of this final decision overview and the negotiating framework is in attachment A of this final decision. |
| In accordance with clause 6.12.1(16) of the NER, the AER's final decision is to apply the negotiated distribution services criteria as published in our draft decision, in October 2019, to SA Power Networks for the 2020–25 regulatory control period. This is set out in section 4.3 of this final decision overview. |
| In accordance with clause 6.12.1(17) of the NER, the AER's final decision on the policies and procedures for assigning retail customers to tariff classes for SA Power Networks is discussed in attachment 18 of this final decision. |
| In accordance with clause 6.12.1(18) of the NER, the AER's final decision is that the depreciation approach based on forecast capex (forecast depreciation) is to be used to establish the RAB at the commencement of SA Power Networks' regulatory control period as at 1 July 2025. This is discussed in attachment 2 of this final decision. |
| In accordance with clause 6.12.1(19) of the NER, the AER's final decision on how SA Power Networks is to report to the AER on its recovery of designated pricing proposal charges is to set this out in its annual pricing proposal. The method to account for the under and over recovery of designated pricing proposal charges is discussed in attachment 13 of this final decision. |
| In accordance with clause 6.12.1(20) of the NER, the AER's final decision is to require SA Power Networks to maintain a jurisdictional scheme unders and overs account. It must provide information on this account to us in its annual pricing proposal as set out in attachment 13 of this final decision. |
| In accordance with clause 6.12.1(21) of the NER, the AER's final decision is to apply SA Power Networks' proposed connection policy as set out in attachment 17 of our draft decision for SA Power Networks. |

# B List of submissions

We received 29 public submissions in response to our draft decision and SA Power Networks' revised proposal. These are listed below:

| Submission from | Date received |
|---|---|
| Adelaide Plains Council | 15/01/2020 |
| AEMO | 20/01/2020 |
| AGL | 15/01/2020 |
| Business SA | 16/01/2020 |
| CCP14 (Revised) | 28/02/2020 |
| Clean Energy Council | 16/01/2020 |
| City of Victor Harbour | 13/01/2020 |
| Council of Streaky Bay | 19/12/2019 |
| Cross Border Commissioner | 15/01/2020 |
| Energy Consumers Australia | 23/01/2020 |
| Endeavour Energy | 22/01/2020 |
| EWOSA | 13/01/2020 |
| John Herbst | 05/02/2020 |
| Hon Dan van Holst Pellekaan MP | 17/01/2020 |
| Local Government Association | 07/01/2020 |
| Lower Eyre Peninsula Council | 16/01/2020 |
| Origin Energy | 15/01/2020 |
| Port Pirie Council | 07/01/2020 |
| Regional Council of Goyder | 16/01/2020 |
| Regional Development Australia – Far North | 23/01/2020 |
| South Australian Council of Social Service | 17/01/2020 |
| SA Financial Councillors Association/ Uniting Communities/ The Energy Project | 21/01/2020 |
| SA Power Networks | 24/01/2020 |
| SAPN Consumer Consultative Panel | 07/01/2020 |

| Submission from | Date received |
|---|---|
| Tatiara Council | 16/01/2020 |
| Total Environment Centre | 15/01/2020 |
| Town of Gawler | 15/01/2020 |
| Tumby Bay Council | 15/01/2020 |
| Yorke Peninsula Council | 15/01/2020 |

# Shortened forms

| Shortened form | Extended form |
|---|---|
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| augex | augmentation expenditure |
| capex | capital expenditure |
| CCP14 | Consumer Challenge Panel, sub-panel 14 |
| CESS | capital expenditure sharing scheme |
| CPI | consumer price index |
| DMIAM | demand management innovation allowance mechanism |
| DMIS | demand management incentive scheme |
| distributor | distribution network service provider |
| DUoS | distribution use of system |
| EBSS | efficiency benefit sharing scheme |
| ECA | Energy Consumers Australia |
| NEL | National Electricity Law |
| NEM | National Electricity Market |
| NEO | National Electricity Objective |
| NER | National Electricity Rules |
| opex | operating expenditure |
| PTRM | post-tax revenue model |
| RAB | regulatory asset base |
| repex | replacement expenditure |
| RFM | roll forward model |
| STPIS | service target performance incentive scheme |
| WACC | weighted average cost of capital |