Draft Decision

SA Power Networks Electricity Distribution Determination 2025 to 2030

(1 July 2025 to 30 June 2030)

Overview

September 2024

AUSTRALIAN ENERGY REGULATOR

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Amendment record

Version	Date	Pages
1	27 September 2024	33

Invitation for submissions

SA Power Networks has the opportunity to submit a revised proposal in response to this draft decision by **2 December 2024.**

Interested stakeholders are invited to make a submission on both our draft decision and SA Power Networks' revised proposal (once submitted) by Friday, **17 January 2025**.

Submissions should be sent to: SAPN2025@aer.gov.au and addressed to Kris Funston, Executive General Manager. Alternatively, you can main submissions to GPO Box 3131, Canberra ACT 2601.

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

We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process. We will treat submissions as public documents unless otherwise requested.

Parties wishing to submit confidential information should:

1. Clearly identify the information that is the subject of the confidential claim.
2. Provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential submission will be published on our website.

Pre-determination conference

Consumer engagement is a valuable input to our determination. We encourage all interested stakeholders to join us and SA Power Networks at an online public forum on Monday, **14 October 2024**. Details of how to register for this forum are available on our website and through Eventbrite.

List of attachments

This attachment forms part of the Australian Energy Regulator’s (AER's) draft decision on the distribution determination that will apply to SA Power Networks for the 2025–30 period. It should be read with all other parts of the draft decision.

The draft 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 11 – Demand management incentive scheme and demand management innovation allowance mechanism

Attachment 12 – Customer service incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment 20 – Metering services

Executive summary

The Australian Energy Regulator (AER) exists to ensure energy consumers are better off, now and in the future. Consumers are at the heart of our work, and we focus on ensuring a secure, reliable, and affordable energy future for Australia as it transitions to net zero emissions (the transition).

A regulated network business must periodically apply to us to determine the maximum allowed revenue it can recover from consumers for using its network. On 31 January 2024, we received revenue proposals from SA Power Networks, Ergon Energy, Energex and Directlink for the period 1 July 2025 to 30 June 2030 (2025–30 period).

It is our role to ensure that consumers pay no more than is necessary for an energy system that delivers safe, reliable, secure energy that contributes to the reduction of greenhouse gas emissions.

This draft decision relates to SA Power Networks.

Efficient investment to deliver a safe and reliable network that meets consumer needs

The past decade has seen a phase of relatively contained capital and operating expenditure while maintaining service quality. However, recent regulatory proposals, including SA Power Networks' 2025–30 proposal, have included substantial increases in forecast expenditure citing the need to adapt to an evolving energy system and to improve or maintain reliability.

We acknowledge there are factors requiring distribution network service providers (DNSPs) to invest in their networks, but this needs to be managed carefully, with a view to protecting the long-term interests of consumers. This underscores the importance of networks developing solid business cases that seek to find the most efficient investment options to meet demand and comply with state safety and technical standard obligations.

Safety is enshrined in the National Electricity Objectives (NEO) and a key component of our decision making. State and territory legislation governs the safe supply of electricity. We expect DNSPs to submit proposals that meet their safety obligations in a way that is prudent and efficient.

SA Power Networks' proposal comes at a time when asset utilisation in the networks across the National Electricity Market (NEM) is low by historical standards and network reliability near the highest it has been. We encourage DNSPs and stakeholders to seek ways to improve asset utilisation to meet the challenges of the energy transition and to manage the network over the long term. Accordingly, our draft decisions reflect our support for DNSPs to efficiently integrate consumer energy resources (CER) by improving capacity of their existing systems, modernising IT systems and implementing new tariff options.

We are supportive of tariff reform aimed at reducing the amount of network investment required to ensure sufficient network capacity and stability during peak demand and export periods. Nevertheless, our draft decision ensures that retailers are able to offer retail tariff offerings that suit their customers, including through the provision of flat retail tariffs.

The regulatory proposals we have received also respond to the ongoing challenge of maintaining service reliability and improving network and system resilience to disruptive events. Floods, bushfires and cyber risks have all affected our distribution and transmission networks across the NEM in recent years. Our draft decision supports cost effective solutions to manage these risks for consumers.

Consumer needs should be a key focus of the DNSPs' regulatory proposals. To assist, we introduced the Better Resets Handbook (the Handbook)[1], to further guide businesses to engage and design proposals that meet consumer needs through the energy transition.

Our Consumer Challenge Panel (CCP30) and the SA Power Networks Consumer Advisory Board (the CAB) both found that SA Power Networks' consumer engagement largely met the expectations in the Handbook, noting the networks' collaborative approach to engage with consumers. However, both advisory groups noted that the framing of the focused discussions guided consumer preferences toward higher service levels. This is despite reliability across the network (excluding the CBD) being within its required targets. Some stakeholders have questioned the discretionary uplift in service levels at a time when living costs have affected many consumers. While consumer views are varied, we note that the question of affordability and service level will likely remain a key issue for some consumers in the revised proposal.

Since submitting its proposal, SA Power Networks has continued with its consultative stakeholder group, now called the Community Advisory Forum, which includes a number of advisory groups, including the Reset Advisory Group. SA Power Networks has indicated that it would engage on key aspects of our draft decision. We encourage an ongoing consultative process on key elements of our draft decision to inform the revised proposal.

Early signal pathway

SA Power Networks was the third business to be selected to participate in the early signal pathway (ESP). Under the ESP, AER staff had regular pre-lodgement discussions with SA Power Networks and observed parts of the engagement with consumers.

A procedural benefit of the ESP is that businesses that meet our expectations across capital expenditure (capex) and operating expenditure (opex), depreciation and tariff structures would receive an early signal of acceptance of substantial parts of their proposal at the issues paper stage. We were unable to provide this signal for SA Power Networks' proposed expenditure forecasts because of the significant uplift in capex (up 22%) and opex (up 18.9%).

Despite this, SA Power Networks' good consumer engagement, comprehensive proposals for their planned capex and opex and tariff structures, and willingness to engage with AER staff has resulted in a draft decision that accepts substantial parts of the proposal. Nevertheless, there are areas – particularly for replacement expenditure (repex) and augmentation expenditure (augex), where we do not accept the forecast, or propose placeholder values pending further information from SA Power Networks at the revised proposal stage.

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[1] AER, *Better Resets Handbook – towards consumer-centric network proposals*, July 2024.

Our assessment of SA Power Networks' proposal

This draft decision allows SA Power Networks to recover $5,143.5 million ($ nominal, smoothed) in main standard control services (SCS) revenue from its customers for the 2025–30 period. This is $20.5 million (or 0.4%) less than the $5,164 million that SA Power Networks proposed. Our draft decision would in nominal terms lead to an average annual increase of $8 (or 0.3% per annum) in residential consumer bills over the 2025–30 period.

Our draft decision revenue is $1,235.3 million more than SA Power Networks' allowed revenue in the 2020–25 period in nominal terms.[2] We estimate that approximately 45% of the increase from the 2020–25 period is driven by market factors including higher inflation and interest rates. The other 55% of the increase is driven by expenditure and other controllable factors.

At the issues paper stage we noted that we would focus our in depth assessment on determining the efficient level of opex and capex for the next regulatory period. This involved just over 10% of opex, with a focus on the proposed step changes related to ICT, and 50% to 60% of the capex proposal, particularly major repex and augex projects, expenditure related to non-recurrent ICT and CER and the innovation fund.

SA Power Networks has been able to demonstrate that the proposed spending is prudent and efficient for most of the areas we targeted. This is due to SA Power Networks' strong consumer engagement, governance and forecasting methods as well as in-depth business cases.

Our draft decision accepts SA Power Networks' proposed opex for main standard control services. This is because we have found the real increase in opex of 18.9% is justified as being prudent and efficient. The key drivers of this increase largely relate to ICT and reflect a variety of factors including movement to cloud systems, reclassification of these costs as opex instead of capex, some new obligations, greater computing and data volumes and investment to avoid costs related to cyber events and export services curtailment.

Our draft decision for capex is 10.3% lower than SA Power Networks' proposal in real terms, driven by reductions in repex (by 15%) and augex (by 16.2%) and a $0 placeholder for the innovation fund. These are areas where some programs appear not to be efficient and prudent or lack supporting information.

We have reduced repex (by 15%) so that the uplift is more modest. Our review of the reliability performance indicators show that SA Power Networks' overall reliability performance (with the exception of the Adelaide CBD) has been improving and is meeting its jurisdictional reliability standards. We recognise that reliability performance in the Adelaide CBD has been poor. However, we would like to see further demonstration of the options to address the CBD reliability concerns to make sure that the most efficient option that is in the long-term interest of consumers is selected.

We have accepted the majority of SA Power Networks' proposed augex, including expenditure for worst serviced customers, managing bushfire risks and resilience. Nevertheless, we consider a number of projects can be deferred because actual network performance does not support the uplift proposed by SA Power Networks. We encourage

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2 Adjusting for the impact of inflation, our draft decision revenue is 7.0% higher than SA Power Networks' allowed revenue for the 2020–25 period.

SA Power Networks to continue seeking ways to utilise all options available to get the most out of its existing network before proceeding with building more.

We recognise the importance of innovation investment in supporting the energy transition. We consider that SA Power Networks needs to do further work on its proposed $20 million innovation fund. We require a firm plan with a defined scope and well-reasoned justification regarding the transformative nature of the proposal.

We commend SA Power Networks' development of a high-quality tariff structure statement that progresses network tariff reform and responds to changes taking place in the electricity sector. The proposed tariffs are compliant with the pricing principles and positively reflect SA Power Networks' extensive engagement process with its stakeholders. Our draft decision accepts nearly all elements of SA Power Networks' TSS proposal, with one adjustment to better contribute to the achievement of the NEO. The adjustment requires SA Power Networks to offer a time-of-use tariff for customers with high demand but low consumption (i.e. EV charge point operators).

Our draft decision also accepts SA Power Networks' proposal to reclassify legacy metering services from alternative control services (ACS) to standard control services (SCS) and to socialise these costs across low voltage customers. SA Power Networks' proposal is consistent with our recent decisions to accommodate the AEMC's metering review, which seeks an equitable transition from historical accumulation meters to smart meters by 2030. The change in service classification will ensure no customer is worse off as a result of when their legacy meter would be replaced. Our draft decision allows SA Power Networks to recover $29.8 million from its customers for the provision of metering services.

In this Overview and the accompanying detailed attachments, we have set out the assessment approaches applied, and enquiries made as part of our review, which have enabled us to arrive at this draft decision.

This draft decision is the mid-point in our assessment of SA Power Networks' proposal. SA Power Networks now has the opportunity to respond in a revised proposal that incorporates the substance of the changes required by, and addresses matters raised in, this draft decision.

Contents

1 Our draft decision

Our draft decision allows SA Power Networks to recover a total revenue of $5,173.3 million ($ nominal, smoothed) from its consumers from 1 July 2025 to 30 June 2030 which comprises:

- $5,143.5 million in main standard control services (SCS) revenue
- $29.8 million in metering revenue.[3]

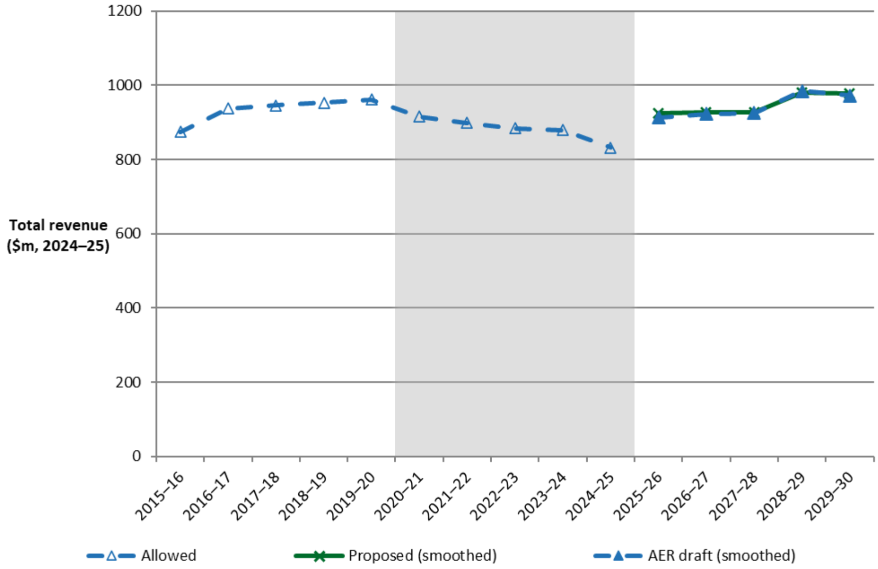
Our draft decision revenue is $1,235.3 million more than SA Power Networks' allowed revenue in the 2020–25 period in nominal terms. In the sections below we briefly outline what is driving SA Power Networks' main SCS revenue, and the key differences between our draft decision revenue of $5,143.5 million and the $5,164.0 million in SA Power Networks' proposal.[4]

1.1 What is driving revenue?

Revenue is driven by changes in real costs and inflation. To compare revenue from one period to the next on a like-for-like basis, in this section we use 'real' values based on a common year (2024–25) that have been adjusted for the impact of inflation.

In real terms, this draft decision would allow SA Power Networks to recover $4,718.9 million ($2024–25, smoothed) from consumers over the 2025–30 period. This is 7.0% higher than our decision for the current (2020–25) period. Changes in SA Power Networks' revenue over time are shown in Figure 1.

Figure 1 Changes in regulated revenue over time ($ million, 2024–25)



Source: AER analysis.

[3] This is $36.1 million less than the $65.9 million that SA Power Networks proposed for metering.

[4] This overview separates main SCS revenue from metering SCS revenue (see Attachment 20) for ease of comparison with previous regulatory periods. Moreover, most metering costs are temporary.

In real terms, this draft decision would allow SA Power Networks to recover a total building block revenue of $4,710.5 million ($2024–25, unsmoothed) over the 2025–30 period. Figure 2 highlights the key drivers of the change in real terms between the revenue approved for SA Power Networks for the 2020–25 period and in this draft decision for the 2025–30 period. It shows that our draft decision provides for increases in the building blocks for:

- return on capital, which is based on the opening regulatory asset base (RAB), forecast capex and rate of return. This is $380.8 million (31.9%) higher than the 2020–25 period, driven by:
  - a higher rate of return being applied in the 2025–30 period, in accordance with the 2022 *Rate of Return Instrument*
  - an increase in the RAB due in part to higher actual inflation in the 2020–25 period
  - higher forecast capex in the 2025–30 period.
- opex (for main standard control services), which is $259.1 million (15.0%) higher than the opex forecast we approved in the 2020–25 period. This is driven primarily by the reclassification of ICT costs for cloud and software as a service as opex (instead of capex) and 11 step changes, including several that are ICT related and will provide for cyber security uplift, greater network visibility and consumer energy resources (CER) integration.
- net tax amount, which is $28.4 million (224.0%) higher than the 2020–25 period, primarily due a higher return on equity compared to the 2020–25 period.

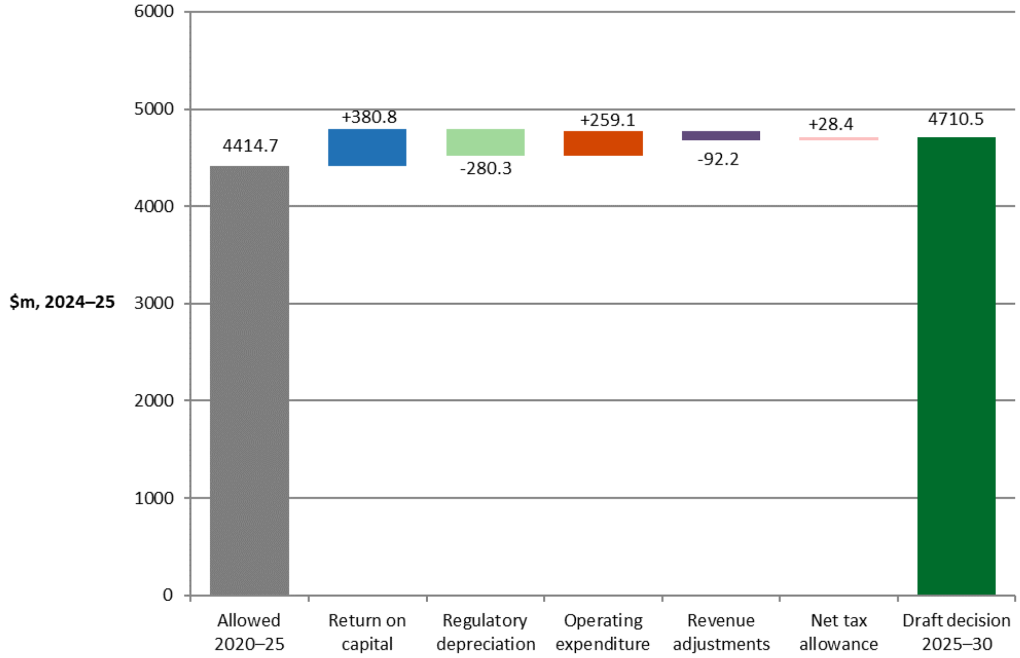
Figure 2 also shows that our draft decision provides for decreases in the building blocks for:

- return of capital (regulatory depreciation), which is $280.3 million (20.2%) lower than the 2020–25 period. This is due to:
  - a reduction to straight line depreciation as some assets become fully depreciated during the 2025–30 period.
  - a higher indexation of the regulatory asset base (RAB), mainly driven by a higher expected inflation value in the 2025–30 period.
- revenue adjustments, which are $92.2 million lower than the 2020–25 period, mainly due to negative Efficiency Benefit Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS) outcomes applied in this draft decision.

Figure 3 shows the value of SA Power Networks' RAB over time in real terms. After a RAB reduction of 1.1% over the 2020–25 period, our draft decision is expected to result in a forecast RAB increase of $326.2 million (6.3%) over the 2025–30 period. This increase in the RAB is driven by a higher forecast capex, including repex and augex, over the 2025–30 period compared to the 2020–25 period.

RAB values substantially affect a network businesses' revenue requirements, and the total costs customers ultimately pay. We expect RABs to change over time, as capital investment will depend on the network's age and technology, load characteristics, the levels of new connections and reliability and safety requirements. In 2023, SA Power Networks managed to maintain its RAB per customer in line with its historical average in real terms[5], we encourage SA Power Networks to continue along this trend.

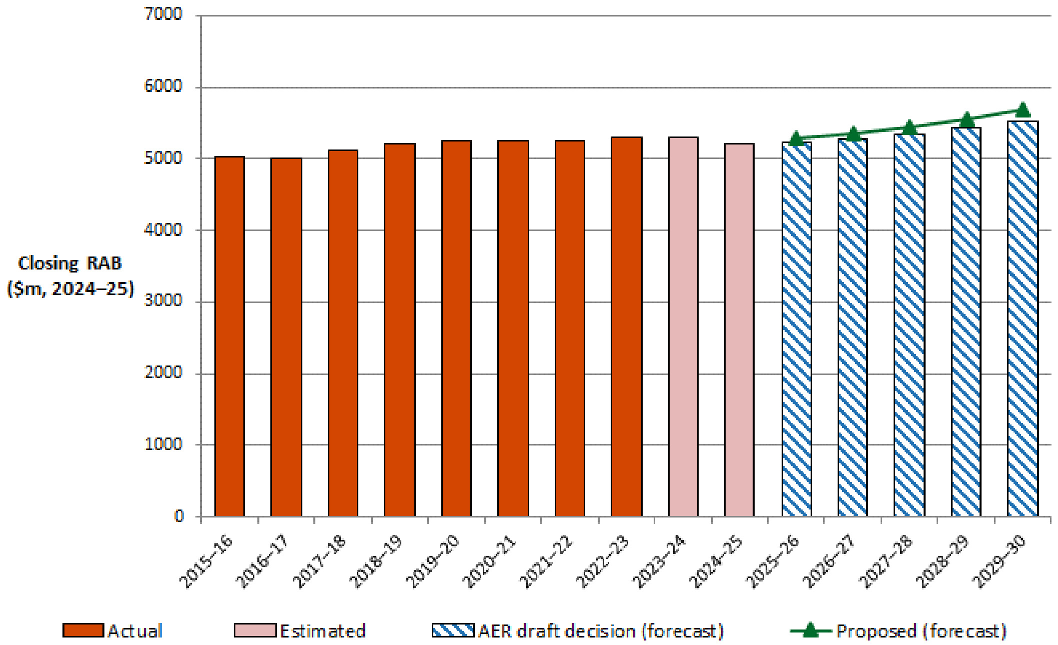
Figure 2 Changes in total revenue between 2020–25 period and 2025–30 period ($ million, 2024–25 unsmoothed)



Source: AER analysis

Note: This comparison is based on converting nominal forecast amounts to real dollar terms using lagged consumer price index (CPI).

Figure 3 SA Power Networks' RAB value over time ($ million, 2024–25)



Source: AER analysis.

[5] AER, *2024 Electricity and gas networks performance report*, September 2024.

1.2 Key differences between our draft decision and SA Power Networks' proposal

Our draft decision accepts most of SA Power Networks' proposal. For the 2025–30 period, the main area of difference between our draft decision and SA Power Networks' proposal relates to our reduced capex forecasts, primarily driven by lower replacement and augmentation expenditures. We also made updates in our draft decision to reflect movements in some market variables, such as expected inflation and rate of return, which have impacted revenue outcomes for certain building blocks.

Overall, our draft decision includes:

- a lower return on capital, driven by our reduction to forecast capex, lower rate of return[6] and a lower opening RAB
- lower regulatory depreciation amount, driven by a higher expected inflation rate in our draft decision than at the time of SA Power Networks' proposal, our reduction to forecast capex and a lower opening RAB.

The reductions we made to SA Power Networks' total revenue is partially offset by our:

- amendments to revenue adjustments, primarily driven by the removal of the SA Power Networks' proposed negative adjustment for cables and conductor repairs relating to the 2020–25 determination.
- higher estimated cost of corporate income tax, driven by lower tax depreciation in our draft decision resulting from our capex reductions. The lower tax depreciation increases the cost of corporate income tax as it is a component of tax expense.

SA Power Networks also proposed to reclassify the legacy metering services following the final decision of the Metering review by the AEMC.[7] As a result, SA Power Networks proposed that legacy metering costs move to standard control services.

1.3 Expected impact of our draft decision on electricity bills

SA Power Networks recovers its regulated revenue through distribution charges, set annually by reference to the tariff structure statement and pricing formulae approved by us as part of this decision.

For illustrative purposes only, we estimate the modelled impact of this draft decision would be a total decrease to average distribution charges of around 7.6% in real terms by 2029–30 compared to 2024–25 levels, or an average real decrease of 1.6% per annum.[8] This estimate

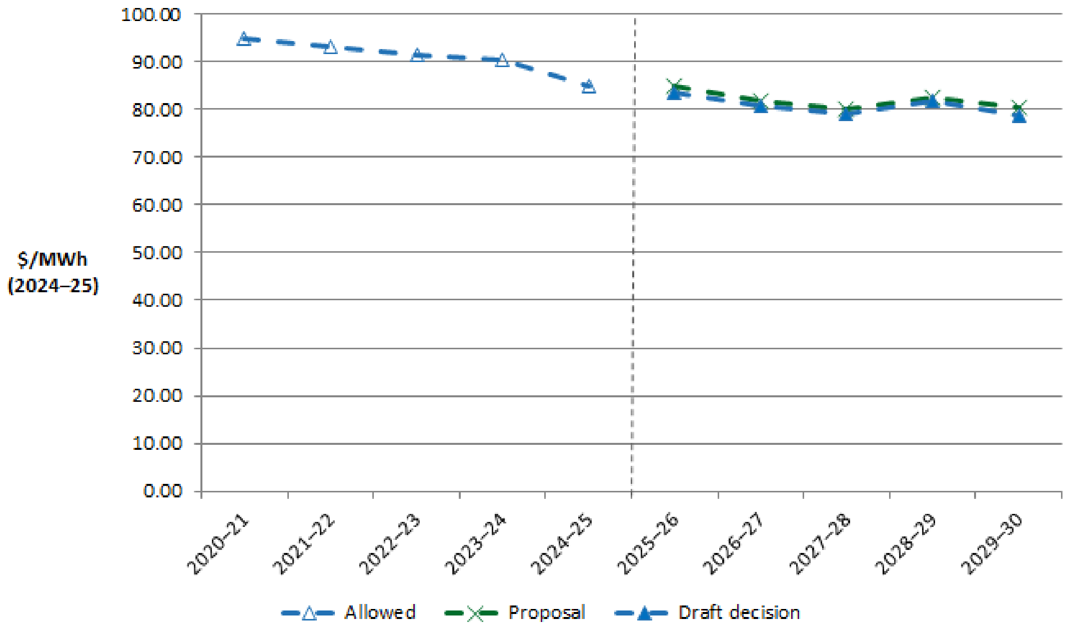
6 Average rate of return over the 2025–30 period.

7 SA Power Networks, *Attachment 1-Annual revenue requirement and control mechanism*, January 2024, p. 8.

8 The average decrease to indicative network charges of 1.6% ($2024–25) per annum reflects two components: 1) The draft decision smoothed revenue average increase of 1.8% per annum ($2024–25); and 2) The forecast energy delivered in SA Power Networks' distribution network area which is expected to increase on average by 3.4% per annum.

is subject to ongoing revenue adjustments and changes in consumer energy consumption. Figure 4 compares this indicative price path for the 2025–30 period to the 2020–25 period.

Figure 4 Change in indicative distribution charges for 2020–25 to 2025–30 ($2024–25, $/MWh)



Source: AER analysis.

Potential bill impact

SA Power Networks' network charges make up around 27.5% of its residential customers' electricity bills and 27.4% of its small business customers' electricity bills. Other components of the electricity supply chain—the cost of purchasing energy from the wholesale market, transmission network charges, environmental schemes and the costs and margins applied by electricity retailers in determining the prices they will charge consumers for supply—also contribute to the prices ultimately paid by consumers.[9] These sit outside the decision we are making here but will also continue to change throughout the period.

Our decision on SA Power Networks' proposal will set the revenue allowance that forms the major component of its network charges for the next 5 years. In nominal terms, this draft decision would lead to an increase to the distribution component of customers' electricity bills. We estimate that the modelled impact of our draft decision on the average annual electricity bill for a residential customer in SA Power Networks' network area, as it is today, would be:[10]

- a nominal increase of $39 (1.8%) by 2029–30, or an average of $8 per annum for a residential customer

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9 AEMC, *Data Portal*, *Trends in South Australia supply chain components 2023/24*.

10 Our estimated bill impact is based on the typical annual electricity usage of 4,000 kWh and 10,000 kWh for residential and small business customers in SA Power Networks' network area, respectively; AER, *Revised final determination – Default Market Offer Prices 2024–25*, June 2024, p. 6.

- a nominal increase of $94 (1.8%), or an average of $19 per annum for a small business customer.

The impact of our draft decision and final decision on consumer bills are likely to change over the 2025–30 period. A variance in energy consumption, compared to those forecast by SA Power Networks would lead to bill impacts that are higher or lower than what is estimated.

There are also several additional mechanisms under the NER that may operate to increase or decrease charges faced by consumers. These may include cost pass through events defined in the NER. They may also include additional cost pass through events proposed by SA Power Networks and approved in this draft decision. The triggers we have set out for these projects resulting from pass through events in this decision will, if met, allow SA Power Networks to apply for additional revenue for these projects throughout the period, at which point proposed costs will be subject to further consultation and assessment.

1.4 SA Power Networks' consumer engagement

Consumer engagement during the regulatory process is an important way to provide us with supporting evidence that proposals have been aligned with consumer interests and expectations. We introduced guidance on our expectations for consumer engagement to network businesses in December 2021.[11]

It is the responsibility of network businesses to ensure that consumer views are considered and represented in their regulatory proposal. Often consensus is not possible, in which case the views of the differing groups and how the network sought to make its decision should be reflected in its proposal. Our role is to consider the consumer engagement process and the stakeholder submissions when making our draft decision.

1.4.1 Early signal pathway

SA Power Networks is the third network business selected to participate in an early signal pathway (ESP), joining in December 2022. Under the ESP, AER staff had regular pre-lodgement discussions with SA Power Networks and observed parts of the engagement with consumers. We provided targeted feedback during this process to enable SA Power Networks to prepare a proposal that met the expectations outlined in the Handbook, in the key topic areas of consumer engagement, capex, opex, depreciation and the tariff structure statement.[12]

SA Power Networks provided the AER with comprehensive proposals for their planned capex and opex and tariff structure. The significant value uplift in capex and opex and the magnitude of opex step changes did not meet Handbook expectations for steady growth in spending and required us to carefully assess the proposal.

Our draft decision accepts the majority of the dollar value of the areas we targeted for an in-depth assessment at the issues paper stage. SA Power Networks' strong consumer engagement, governance, and forecasting methods as well as in-depth business cases

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[11] AER, *Better Resets Handbook – towards consumer-centric network proposals*, July 2024.

[12] AER, *Better Resets Handbook – towards consumer-centric network proposals*, July 2024.

provided the necessary support to demonstrate that the majority of the forecast expenditure is efficient and prudent.

1.4.2 SA Power Networks' engagement on its proposal

SA Power Networks engagement began in late 2021. SA Power Networks took an iterative, scenario-based and outcomes focused approach to engagement and forecasting expenditures. This involved SA Power Networks working with its Community Advisory Board (CAB), to develop key themes in late 2021, followed by deep dives on priority topics and the service price trade-offs of different expenditure scenarios.

The scenarios, as outlined in the proposal were:

- a 'Basic' scenario that kept expenditure at recurrent levels, but resulted in service degradation
- a 'Maintain' scenario that kept service at current levels (and required a greater level of investment)
- a 'New value' scenario – where higher service levels or new services are achieved.

The key themes developed by consumers, which shaped the engagement around these scenarios were:

- a reliable, resilient and safe electricity network;
- Customer experience, choice and empowerment;
- Enabling clean energy and unlocking future value for the state;
- Affordable and equitable supply.

In 2023, the Peoples Panel of 51 South Australians deliberated on the whole package of recommended initiatives to determine the overall service-price balance for customers. This underpinned the draft regulatory proposal and was incorporated into the final proposal received by the AER in January 2024.[13]

SA Power Networks' CAB and the 'Reset Subcommittee' of that Board provided oversight on the engagement process and ensured that customer views shaped the proposal.[14] The CAB engaged Spencer and Co. to develop an independent report on the network's customer engagement program.[15] The AER also appointed a Consumer Challenge Panel, subpanel 30 (CCP30), which observed and provided advice on the engagement program.

At the issues paper stage we noted that both the CCP30 and the CAB Independent report raised concerns over the framing of the focused discussions where the basic (or base case) scenario was characterised as a decline in service levels.[16]

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[13] SA Power Networks, *Regulatory proposal – Overview*, January 2024, p. 21; SA Power Networks, Customer and Stakeholder engagement, January 2024, p.12-17.

[14] SA Power Networks, *Customer and stakeholder engagement*, January 2024, p.7.

[15] SA Power Networks, *Customer and stakeholder engagement*, January 2024, p.11.

[16] AER, *Issues Paper – SA Power Networks – 2025-30 distribution revenue proposal*, March 2024, p. 10.

Since submitting its proposal, SA Power Networks has continued with its consultative stakeholder group, now called the Community Advisory Forum (formerly the Community Advisory Board), which includes a number of advisory groups, including the Reset Advisory Group (formerly the reset subcommittee). SA Power Networks have indicated that it would engage on key aspects of the draft decision. We encourage an ongoing consultative process on key elements of our draft decision to inform the revised proposal.

1.4.3 What we've heard from stakeholders

The CCP30 and the SA Power Networks CAB both found that SA Power Networks' consumer engagement largely met the expectations in the Handbook. Both CCP30 and the CAB highlighted SA Power Networks effort and collaborative approach to engage with consumers. However, both reports highlighted concerns around how the final service-price balance was achieved.

SA Power Networks received 25 submissions on the draft proposal, and we received 25 submissions on the final proposal submitted to us on 31 January 2024. Cost-of-living pressures featured prominently in the submissions, most notably in submissions from the South Australian Department of Energy and Mining and the South Australian Council of Social Services (SACCOS). SA Power Networks also noted this in their proposal, stating that 'several stakeholders recommended affordability and the price/service balance be reconsidered'. SA Power Networks considered these submissions when developing the fifth and final iteration of forecasts and their proposal for the AER. We note that there was little change between the proposal from the draft to the final we received.

In our Issues Paper, we asked stakeholders to consider whether SA Power Networks' consumer engagement had met the expectations set out in the Handbook in delivering a consumer-centric proposal. We also asked consumers whether SA Power Networks had captured the cost-of-living concerns raised by stakeholders following the draft proposal[17]

The Department for Energy and Mining considered that SA Power Networks did not strike the appropriate balance between consumer costs and service levels.

> *[The Department] considers that this regulatory proposal is a missed opportunity to place material downward pressure on energy costs for consumers while still providing for adequate expenditure to maintain and enhance the network for energy transition.*[18]

SACCOS noted that the proposal failed to address affordability and equity issues amid a cost-of-living crisis.

> *In the context of the current energy affordability and cost of living crisis, we are extremely concerned about the unprecedented network expenditure increases proposed in SAPN's Proposal for 2025-30, resulting in a 7.5%, increase in revenue (from the current regulatory period) to be recovered from consumers in 2025-30. In our view, the significant increases in capital and operating*

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[17] AER, *Issues Paper – SA Power Networks – 2025-30 distribution revenue proposal*, March 2024.

[18] Department for Energy and Mining, [Submission to the AER](), May 2024.

> *expenditure proposed for 2025-30, do not reflect the affordability or equity concerns raised by SACOSS over the past two years.*[19]

Several stakeholders also provided strong support for a range of programs that improved service levels and reliability for regional communities and worst served customers. This included the Adelaide Hills Council, District Council of Streaky Bay and the Mount Barker District Council. The Adelaide Hills Council, while supportive of these programs noted:

> *[The] Council is conscious of cost pressures faced by the community and the need for consumers to have assess to an affordable power supply. Council therefore strongly encourages SAPN to minimise costs to consumers and strike a balance between community cost of living pressures with investment in safety and reliability of power infrastructure.*[20]

Other stakeholders such as Democracy Co and SA Power Networks' Regional and Remote customers subcommittee provided submissions that supported the service/price balance proposed by the network. For example, the subcommittee noted:

> *[The subcommittee felt] that the Proposal reflects the voice of regional and remote customers and aligns with what customers told SA Power Networks during the engagement… Furthermore, consumers told us during the engagement process that reliability and resilience of the electricity network is critical to the life of regional communities…*[21]

It is clear from the submissions that stakeholder views are varied. We encourage SA Power Networks to consider this feedback in developing their revised proposal. This would include the price service balance and innovation fund expenditure.

Stakeholders also provided a range of feedback covering many issues including tariffs, CER incentive schemes, smart meters and public lighting. Our consideration of stakeholder feedback on these range of issues are reflected in the relevant draft decision attachments.

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[19] South Australian Council of Social Services, *Submission to the AER*, May 2024.

[20] Adelaide Hills Council, *Submission to the AER,* May 2024.

[21] Regional and Remote Customers sub-committee, *Submission to the AER*, May 2024.

2 Key components of our draft decision on revenue

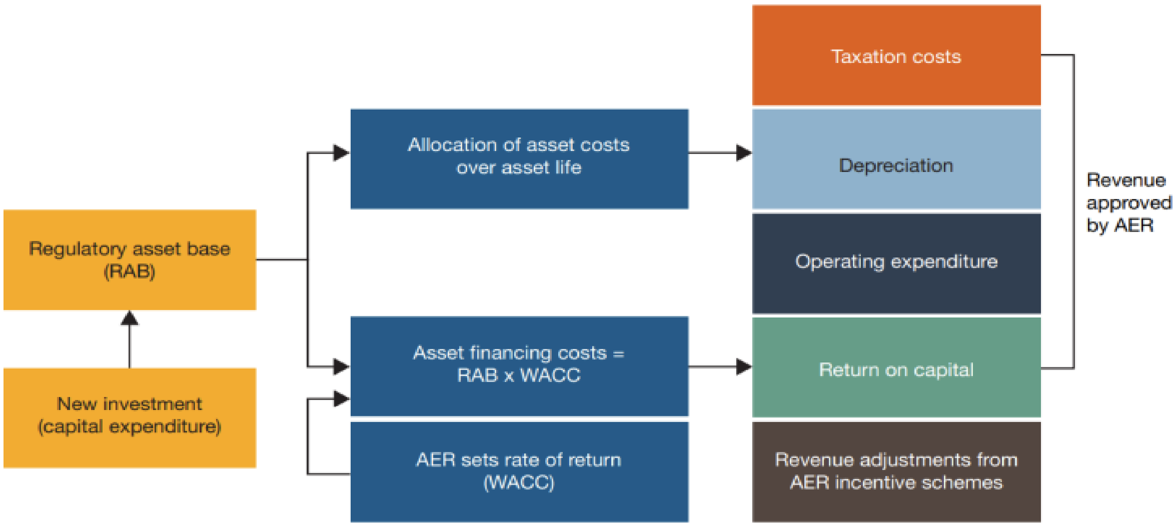
Building block approach

The foundation of our regulatory approach is a benchmark incentive framework to setting maximum revenues: once regulated revenues are set for a 5-year period, a network that keeps its actual costs below the regulatory forecast of costs retains part of the benefit. This provides an incentive for service providers to become more efficient over time. It delivers benefits to consumers as efficient costs are revealed and drive lower cost benchmarks in subsequent regulatory periods. By only allowing efficient costs in our approved revenues, we promote achievement of the NEO and ensure consumers pay no more than necessary for the safe and reliable delivery of electricity.

SA Power Networks' proposed revenue reflects its forecast of the efficient cost of providing distribution network services over the 2025–30 period. Its proposal, and our assessment of it under the NEL and NER, are based on a 'building block' approach which looks at five cost components (see Figure 5):

- return on the RAB – or return on capital, to compensate investors for the opportunity cost of funds invested in this business
- depreciation of the RAB – or return of capital, to return the initial investment cost to investors over time
- forecast opex – the operating, maintenance and other non-capital expenses, incurred in the provision of network services
- revenue increments/decrements – resulting from the application of incentive schemes, such as the EBSS and CESS
- estimated cost of corporate income tax.

Figure 5 The building block model to forecast network revenue



Source: AER.

Following the AEMC's metering review, SA Power Networks proposed to reclassify legacy metering services from alternative control services to standard control services and proposed to recover through a flat charge per low voltage customer. This issue is discussed further at section 5.

As a result of this change in classification for legacy metering services, all standard control services building block components for SA Power Networks have been affected. For the purpose of our decision, the associated impacts of the metering revenue have been set apart for consistency and are discussed in Attachment 20 – Metering Services. For example, the revenue smoothing profile determined for SA Power Networks' draft decision is based on main standard control services, without the inclusion of metering.

Revenue smoothing

Our draft decision includes a determination of SA Power Networks' annual revenue requirement (ARR) (unsmoothed revenue) and annual expected revenue (smoothed revenue) across the 2025–30 period. The smoothed revenues we set in this draft decision are the amounts that SA Power Networks will target for its annual pricing purposes and recover from its customers for the provision of standard control services for each year of the 2025–30 period.[22]

The ARR is the sum of the various building block costs for each year of the regulatory control period, which can be lumpy over the period. To minimise price shocks, revenues are smoothed within a regulatory control period while maintaining the principle of cost recovery under the building block approach. As such, revenue smoothing requires diverting some of the cost recovery to adjacent years within the regulatory control period.

Our standard approach has been to keep a divergence of up to ±3% between the smoothed and unsmoothed revenues for the last year of the regulatory period, if this can achieve smoother price changes across the regulatory control periods.

For this draft decision, we approved lower revenues than SA Power Networks' proposal. This is mainly driven by external economic factors involving data updates to reflect a higher expected inflation rate, which reduces the regulatory depreciation building block and lower interest rates, which reduce the return on capital. Further reductions to revenues are due to our reductions to SA Power Networks' forecast capex and opening RAB at 1 July 2025.

On the other hand, our draft decision allows for higher revenues than those determined in the 2020–25 period for the reasons discussed in section 1.1 of this Overview. SA Power Networks' unsmoothed revenue for the first year of the 2025–30 period (2025–26) is about 11.6% (nominal) higher than its approved revenue for the last year of the 2020–25 period (2024–25). We are mindful that the magnitude of this increase in revenue would have a significant impact on network charges for SA Power Networks' customers.

Consequently, we have smoothed the increase in expected revenues over the first 3 years of the 2025–30 period for SA Power Networks. As part of this, we have adopted SA Power

[22] Our draft decision expected revenues have not factored in any changes arising from incentive scheme amounts, cost pass throughs or unders/overs reconciliation that usually occur in the annual pricing process to come up with the total allowed revenue.

Networks' proposed adjustment of the revenue smoothing profile to account for the impact of the cessation of the South Australian Government's Solar Feed-in Tariff Scheme from 1 July 2028. We have also relaxed our standard approach to the final year difference between the smoothed and unsmoothed revenues being kept to ±3%, to further help ease the price increases for customers in the earlier years of the 2025–30 period. In the present circumstances, we have determined that the final year revenue difference is about 5%.

Our draft decision results in an initial increase of 5.9% (nominal) in 2025–26, followed by average annual increases of 3.5% for the next 2 years (2026–27 and 2027–28). There are further average annual increases of 5.5% for the remaining 2 years of the 2025–30 period (2028–29 and 2029–30) which will be offset by the impact of the abolishment of the Solar Feed-in Tariff Scheme.

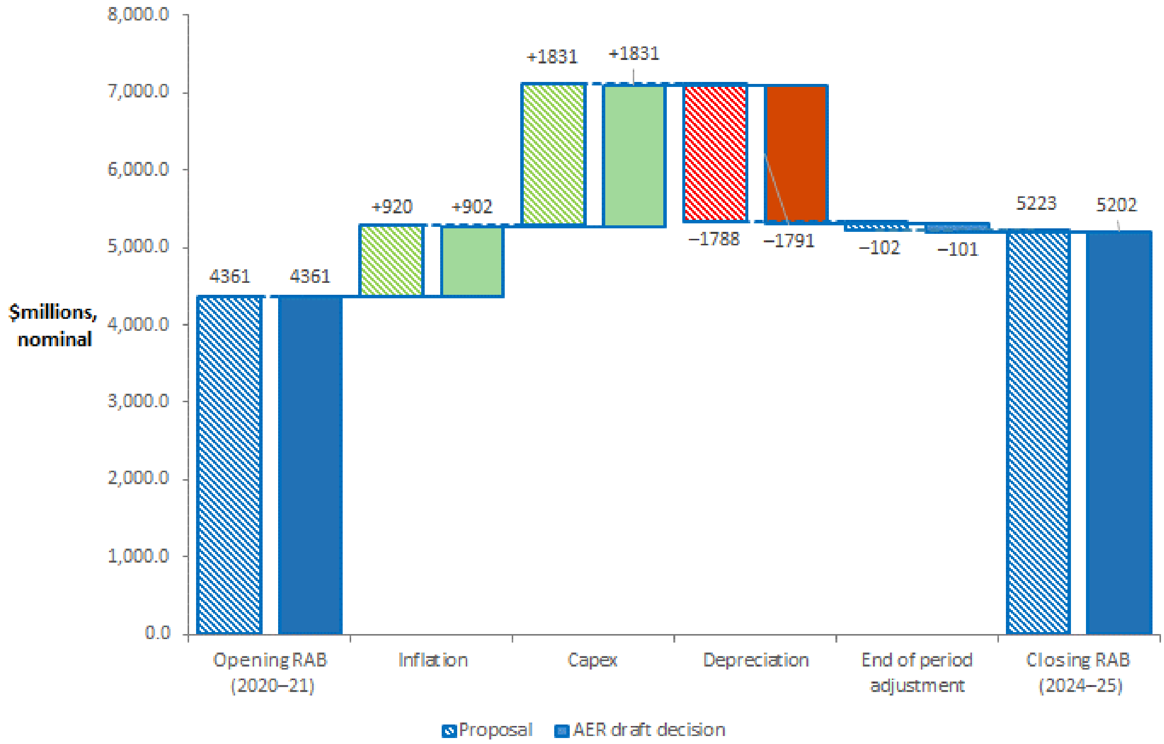
2.1 Regulatory asset base

The RAB accounts for the value of regulated assets over time. To set revenue for a new regulatory period, we take the opening value of the RAB from the end of the last period and roll it forward year by year by indexing it for inflation, adding new capex and subtracting depreciation and other possible factors (such as disposals). This gives us a closing value for the RAB at the end of each year of the regulatory period. The value of the RAB is used to determine the return on capital and regulatory depreciation building blocks. It 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 regulatory depreciation components of the revenue determination.

For this draft decision, we have determined an opening RAB value of $5,201.7 million ($ nominal) as at 1 July 2025. This value is $21.2 million (0.4%) lower than SA Power Networks' proposed opening RAB value of $5,222.9 million. This reduction is largely due to the updates we made to the consumer price index (CPI) inputs for 2023–24 and 2024–25 in the roll forward model (RFM) to reflect more up-to-date values. Figure 6 shows the key drivers ($ nominal) of the change in SA Power Networks' RAB over the 2020–25 period compared to its proposal.

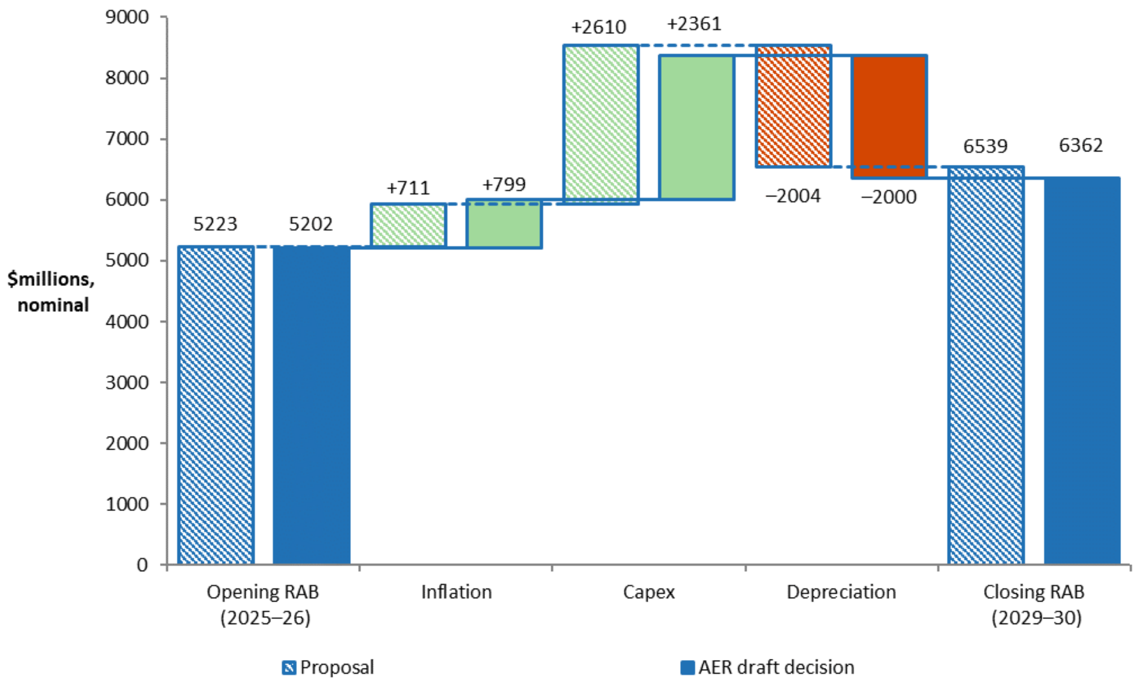
Figure 7 likewise shows the key drivers ($ nominal) of the change in SA Power Networks' forecast RAB over the 2025–30 period compared to its proposal. Our draft decision projects an increase of $1,160.1 million (22.3%) to the RAB by the end of the 2025–30 period compared to the $1,316.4 million (25.2%) increase in SA Power Networks' proposal. We have determined a projected closing RAB of $6,361.8 million ($ nominal) as at 30 June 2030, which is $177.5 million (2.7%) lower than SA Power Networks' proposed $6,539.3 million. This lower value is mainly due to our draft decision to reduce SA Power Networks' forecast capex (discussed in attachment 5). It also reflects our draft decisions on the opening RAB as at 1 July 2025, forecast depreciation and expected inflation.

Figure 6 Key drivers of changes in the RAB over the 2020–25 period – proposal compared with AER's draft decision ($ million, nominal)



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

Figure 7 Key drivers of changes in the RAB over the 2025–30 period – proposal compared with AER's draft decision ($ 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.

2.2 Rate of return and value of imputation credits

The return each business is to receive on its capital base (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 capital base. We estimate the rate of return by combining the returns of two sources of funds for investment – equity and debt. The allowed rate of return provides the business with a return on capital to service the interest rate on its loans and gives a return on equity to investors.

SA Power Networks' proposal and this draft decision applies the 2022 Rate of Return Instrument:[23]

- Our draft decision applies a rate of return of 6.02% for the first year of the regulatory period, compared to the placeholder rate of return of 6.04% used in SA Power Networks' proposal. This difference is due to updates to the return on debt and the risk-free rate.
- Our draft decision and SA Power Networks' proposal apply a value of imputation credits (gamma) of 0.57 as set out in the 2022 Instrument.[24]

Our estimate of expected inflation for the purposes of this draft decision is 2.85% per annum. It is an estimate of the average annual rate of inflation expected over a five-year period based on the approach adopted in our 2020 Inflation Review[25] and the forecast from the Reserve Bank of Australia's August 2024 Statement on Monetary Policy.[26] This is higher than the estimate used in SA Power Networks' proposal (2.50%), which was taken from an earlier Statement on Monetary Policy.

Figure 8 isolates the impact of expected inflation from other parts of our draft decision, to illustrate its impact on the return on capital and regulatory depreciation building blocks and the total revenue allowance. Other elements held constant, lower inflation reduces the return on capital but increases regulatory depreciation.

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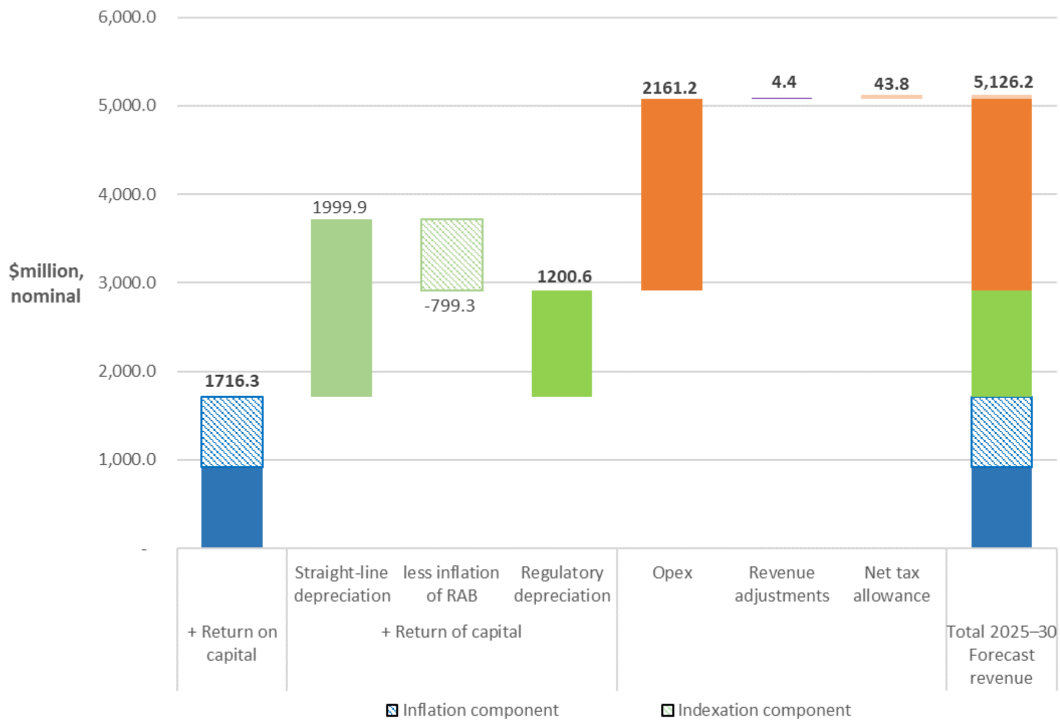
23 The 2022 *Rate of Return Instrument was amended in* March 2024. See https://www.aer.gov.au/publications/guidelines-schemes-models/rate-of-return-instrument-2022/final-decision

24 AER, *Rate of return Instrument 2022,* Clause 27*.* The 2022 *Rate of Return Instrument was amended in* March 2024. See https://www.aer.gov.au/publications/guidelines-schemes-models/rate-of-return-instrument-2022/final-decision

25 AER, *Final position – Regulatory treatment of inflation*, December 2020.

26 RBA, *Statement on Monetary Policy,* August 2024, Table 3.1: Forecast Table. See https://www.rba.gov.au/publications/smp/2024/aug/outlook.html#table-3-1

Figure 8 Inflation components in draft decision revenue building blocks ($ million, nominal)



Source: AER analysis

2.3 Regulatory depreciation (return of capital)

Depreciation is a method used in our decision to allocate the cost of an asset over its useful life. It is the amount provided so capital investors recover their investment over the economic life of the asset (otherwise referred to as 'return of capital'). When determining total revenue, we include an amount for the depreciation of the projected RAB. The regulatory depreciation amount is the net total of the straight-line depreciation less the indexation of the RAB.

Our draft decision determines a regulatory depreciation amount of $1,200.6 million ($ nominal) for the 2025–30 period. This is a reduction of $92.8 million (7.2%) from SA Power Networks' proposal of $1,293.3 million.

This reduction is primarily due to our draft decision to apply a higher value of expected inflation than that proposed by SA Power Networks, which has increased the indexation on the RAB.[27] The reduction is also driven by our draft decisions to reduce forecast capex and the opening RAB as at 1 July 2025, which have reduced straight-line depreciation in the 2025–30 period.

[27] Since RAB indexation is deducted from straight-line depreciation, the higher RAB indexation has also resulted in a lower regulatory depreciation.

2.4 Capital expenditure

Capital expenditure – the capital costs and expenditure incurred to provide network services – mostly relates to assets with long lives, the costs of which are recovered over several regulatory control 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 higher projected RAB value and higher return on capital and regulatory depreciation allowances.

Our draft decision is to not accept SA Power Networks' proposed total forecast capex of $2,379.1 million ($2024–25) because we are not satisfied it reasonably reflects the capex criteria. Our substitute forecast is $2,135.2 million, which is 10.3% below SA Power Networks' forecast. Table 1 outlines our substitute estimate of forecast capex and compares this to SA Power Networks' proposed forecast capex.

Table 1 AER's draft decision on SA Power Networks' total net capex forecast ($ million, $2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
SA Power Networks' proposal	465.0	479.5	486.8	469.4	478.5	2,379.1
AER's draft decision	423.9	440.2	435.5	408.5	427.1	2,135.2
Difference ($)	-41.1	-39.3	-51.3	-60.9	-51.4	-243.9
Difference (%)	-8.8%	-8.2%	-10.5%	-13.0%	-10.7%	-10.3%

Source: AER analysis and SA Power Networks' proposal.

Note: Numbers may not add up due to rounding. Modelling adjustments relate to updates to the consumer price index (CPI) and real cost escalation assumptions.

Figure 9 outlines SA Power Networks' historical capex trend, its proposed forecast for the 2025–30 regulatory control period, and our draft decision.

Within the current regulatory period (2020–25), SA Power Networks expects to underspend by $14.4 million or 0.7% of the AER forecast.[28] SA Power Networks' capex for the 2020–25 period was impacted by lower economic activity and a higher rate of return, decisions by ElectraNet resulting in lower than expected connection point upgrades, and general delays in field work due to Covid restrictions in the first two years of the period.

SA Power Networks considers that the declining depreciation as some assets reach the end of their economic life signals an opportunity for network investment given its aging network and expanding customer network service expectations.[29] SA Power Networks is proposing to increase its replacement expenditure by 29% to manage and maintain its ageing network, which it considers necessary to meet its reliability and safety obligations. It is also proposing to increase augmentation expenditure by 44% to accommodate increasing growth for its services, including business and residential growth, electrification, and customer

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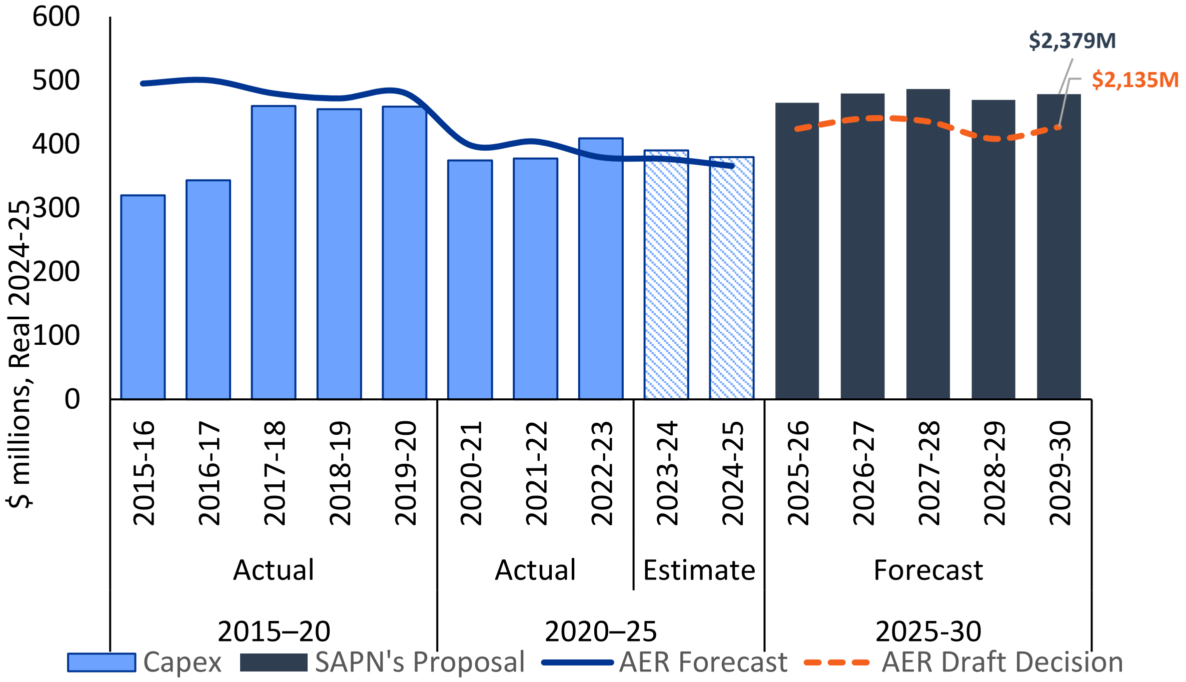
28 SA Power Networks, *Attachment 5: Capital Expenditure Policy 2025–30*, January 2024, p. 12.

29 SA Power Networks, *2025–30 Regulatory Proposal Overview*, January 2024, p. 15.

expectations (such as bushfire management, safety and reliability including worst served customers).

Figure 9 SA Power Networks' historical and forecast capex ($ million, $2024–25)



Source: AER analysis

As part of this draft decision, we have not included some elements of SA Power Networks' proposed capex forecast:

- replacement expenditure forecast

  SA Power Networks proposed $909.4 million ($2024–25) for replacement capex. Our draft decision is to include $772.0 million for replacement capex. This is $137.4 million or 15% less than what SA Power Networks proposed.

  Replacement expenditure is required to maintain the safety, security and reliability of the network. We observed that SA Power Networks' overall reliability performance (with the exception of the Adelaide CBD) has been improving and it is meeting its jurisdictional reliability standards.

  We recognise the increasing age of SA Power Networks distribution network but consider the risks and resulting expenditure to be overstated. Our draft decision repex forecast is 9% above SA Power Networks actual/estimated repex for the current 2020–25 period, reflecting a more modest uplift compared to what was proposed by SA Power Networks.

- augmentation expenditure forecast

  SA Power Networks proposed $505.5 million ($2024–25) for augmentation capex. Our draft decision is to include $423.5 million for augmentation capex. This is $82.0 million or 16.2% less than what SA Power Networks proposed.

Augmentation expenditure (augex) supports the network to address changes in demand and network utilisation. We have accepted the majority of SA Power Networks' proposed augex, including expenditure for worst serviced customers, managing bushfire risks and resilience. We have developed an alternative forecast, as some demand-driven augex projects can be prudently deferred, and network performance does not justify the level of increase in reliability augex that SA Power Networks proposed.

We consider SA Power Networks should be seeking to utilise all options to get the most out of what is available from its existing network before proceeding to building more. We have adopted the demand forecast proposed by SA Power Networks subject to SA Power Networks addressing our concerns about duplication between the trend and additional load adjustments, as well as updating the forecast for more recent data.

- CBD reliability program

  We acknowledge that SA Power Networks needs to improve the reliability in the Adelaide CBD and a program of works is necessary. However, we consider SA Power Networks' proposed program did not consider all viable options from a system wide planning perspective, including a more effective configuration of the network in the CBD.

  Our draft decision is to include a placeholder alternative forecast expenditure of $12.2 million ($2024–25) based on historical expenditure given the absence of information and the need to undertake further work. This is 87% less than the $90.7 million proposed by SA Power Networks, however, the assessment is on-going and we expect this component of SA Power Networks' expenditure proposal to be revised for the final decision.

- Innovation fund

  We recognise the importance of innovation investment in supporting the energy transition. SA Power Networks proposed $20 million ($2024–25) in innovation expenditure ($16 million in capex and $4 million in opex). We found that there was no firm plan, with a continuously evolving scope and related costs. We consider that SA Power Networks needs to do further work on its innovation plans with its customers.

  We have not included SA Power Networks' proposed innovation fund in our draft decision and have substituted this with a placeholder of zero dollars. We expect SA Power Networks to provide further information in its revised proposal, including a firm list of projects, scope of works, costs, options and expected benefits that clearly demonstrate the transformative nature of the investment. Similar to the CBD reliability program, we expect this component of SA Power Networks' expenditure proposal to be revised for the final decision.

Our draft decision on SA Power Networks' capital expenditure is set out in Attachment 5.

2.5 Operating expenditure

Operating expenditure (opex) refers to the operating, maintenance and other non-capital expenses incurred in the provision of network services.

Our draft decision for main standard control services is to accept SA Power Networks' total opex forecast of $1,983.7 million ($2024–25), including debt raising costs, for the 2025–30 regulatory control period.[30] This is because our alternative estimate of $1,945.3 million ($2024–25) is not materially different ($38.4 million ($2024–25), or 1.9% lower) than SA Power Networks' total opex forecast proposal. Therefore, we consider that SA Power Networks' total opex forecast satisfies the opex criteria.[31]

Our draft decision, which is SA Power Networks' proposed total opex forecast, is:

- $200.7 million($2024–25) (or 11.3%) higher than the opex forecast we approved in our final decision for the 2020–25 regulatory control period[32]
- $314.8 million ($2024–25) (or 18.9%) higher than SA Power Networks' actual (and estimated) opex in the 2020–25 regulatory control period.

In Figure 10 we compare our alternative estimate of opex to SA Power Networks' proposal for the next regulatory control period. We also show the forecasts we approved for the last two regulatory control periods and SA Power Networks' actual and estimated opex over these periods. The significant drivers of the increase in opex over the next regulatory control period are consistent with our base-trend-step framework. They include:

- The reclassification of Information and Communication Technology (ICT) costs from capex to opex, largely as a result of the use of cloud and Software as a Service (SaaS) solutions as well as the ongoing operationalisation of cyber security responses.
- Other ICT related costs, including for cyber security uplift and greater network visibility, reflecting various legislative requirements and guidance and customer preferences and benefit.
- Other costs such as those for Consumer Energy Resources (CER) integration, insurance premiums and increased data requirements driven by major external factors outside the control of the business.

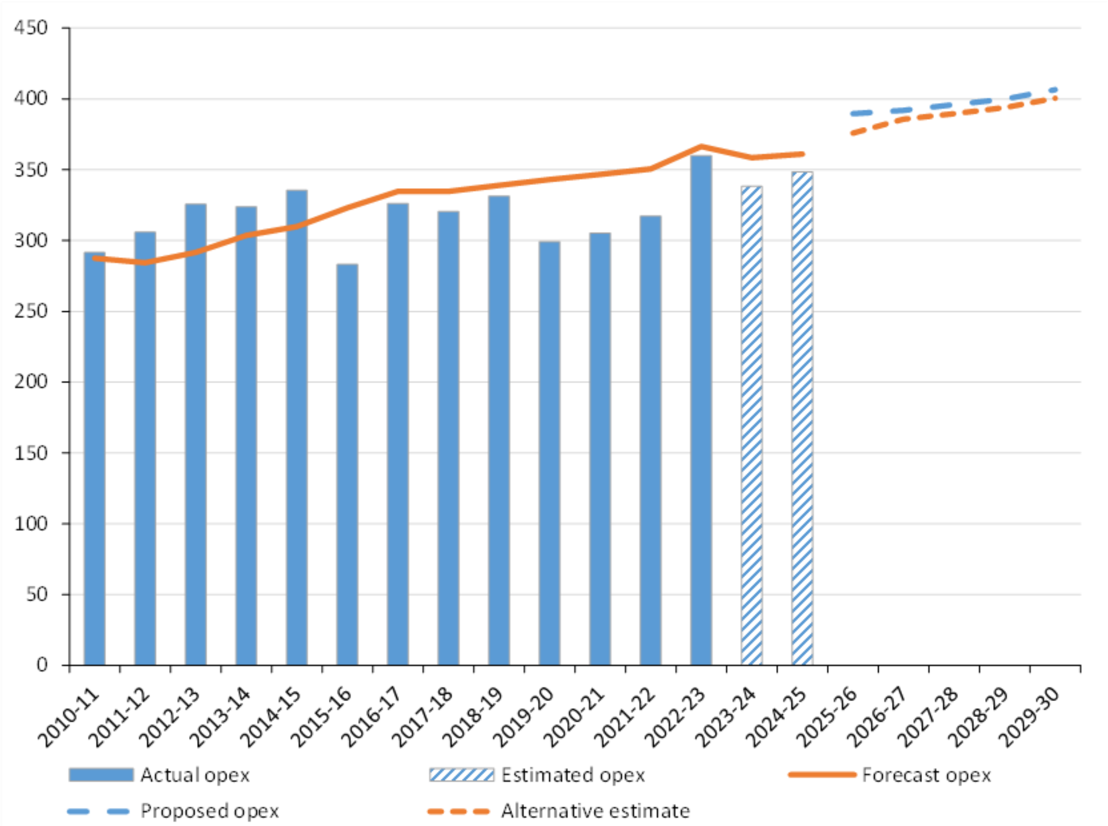
In our final decision, we will update our alternative estimate of total opex to reflect actual opex for 2023–24 (currently an estimate) and make any required mechanical adjustments (e.g. latest inflation and labour price growth forecasts).

30 SA Power Networks, *SAPN – 6.1 – Opex Model,* January 2024.

31 NER, cl. 6.5.6(c)-(d).

32 This difference is calculated using the opex allowance for the five-year 2020–25 period converted to real $2024–25 using unlagged inflation. The difference of $259.1 million (15%) stated in section 1.1 has been calculated using lagged inflation.

Figure 10 Historical and forecast opex ($million, 2024–25)



Source: SA Power Networks, SAPN – 6.1 – Opex Model, January 2024; AER, AER – SAPN d*istribution determination 2020*–25 – PTRM – 2024–25 RoD update, March 2024; AER, AER – SA Power Networks distribution determination – 2019–20 return on debt update – PTRM, April 2019: AER, AER Final decision – SA distribution determination 2010–2011 to 2014–2015, May 2010; AER analysis.

Note: Includes debt raising costs. Forecast opex includes updated forecasts for the revocation and substitution determination (for the minor cable and conductor repairs error) and the 2022–23 River Murray flood event cost pass through.

While there is not a material difference between our alternative estimate of total opex and SA Power Networks' proposed opex, we have arrived at our alternative estimate in a different way to SA Power Networks. The key differences between SA Power Networks' opex proposal, which we have accepted, and our alternative estimate are that we have:

- Included price growth based on our latest wage price index (WPI) forecasts, which are higher than the placeholder forecasts SA Power Networks used in its proposal ($10.3 million ($2024–25)).
- Not included the smart meter rollout step change ($4.8 million ($2024–25) as initially proposed). This is a placeholder decision and is expected to be updated in the final decision in light of further information.
- Not included the network program uplift step change ($18.0 million ($2024–25)) proposed to account for the expected uplift in resourcing costs to support the proposed uplift in capex. We do not consider this is required as it is already accounted for by our trend forecast (via output growth).
- Not included the Small Compensation Claims Scheme (SCCS) category specific forecast ($20.0 million ($2024–25)). We do not consider this is required given it will likely be

treated as a Jurisdictional Scheme and revenues will therefore be recovered via annal tariff true-ups.

- Updated the 2020–25 total forecast opex allowance to calculate the final year increment, accounting for the revocation and substitution determination and the 2022–23 River Murray flood event cost pass through (–$2.3 million ($2024–25)).
- Used the latest data for the inflation.

Our reasoning behind these positions is outlined in further detail in Attachment 6.

2.6 Corporate income tax

Our determination of the total revenue requirement includes the estimated cost of corporate income tax for 2025–30 period. Under the post-tax framework, this amount is calculated as part of the building blocks assessment using our post-tax revenue model (PTRM).

Our draft decision determines an estimated cost of corporate income tax amount of $43.8 million ($ nominal) for SA Power Networks over the 2025–30 period. This is an increase of $13.8 million (46.2%) from SA Power Networks' proposal of $29.9 million.

This increase is primarily due to our draft decision on a lower tax depreciation amount, caused by our draft decisions to reduce forecast capex and the opening tax asset base as at 1 July 2025. Tax depreciation is a tax expense. Therefore, lower tax depreciation increases the estimated taxable income for SA Power Networks which in turn increases the estimated cost of corporate income tax.

2.7 Revenue adjustments

Our calculation of SA Power Networks' total revenue includes adjustments for incentive schemes that applied in its determination for the current period, such as under the EBSS and CESS. These mechanisms provide a continuous incentive for SA Power Networks to pursue efficiency improvements in opex and capex, and a fair sharing of these between SA Power Networks and its users.

Our draft decision includes:

- EBSS - A revenue decrement of –$41.3 million ($2024–25) under the EBSS. This is $20.9 million lower than SA Power Networks' proposal of –$20.4 million ($2024–25). This is because we have updated SA Power Networks' 2020–25 approved total opex allowance to reflect the revocation and substitution determination we made and for the 2022–23 River Murray flood event cost pass through. We also updated for inflation. The full detail on our draft decision for the EBSS is in Attachment 8.
- CESS - A revenue increment of $48.5 million ($2024–25) under the CESS. This is $25.2 million more than SA Power Networks' forecast of $23.4 million ($2024–25) because we applied updated modelling inputs, including inflation, rate of return and an adjustment for 2018–19 to reflect the difference between actual and estimated capex. The full detail on our draft decision regarding CESS is set out in attachment 9.
- DMIAM - comprises a fixed allowance of $0.2 million ($2017), plus 0.075% of the annual revenue requirement for each regulatory year, as set out in our PTRM. In our final distribution determination, we will determine the amount of the DMIAM allowance for SA

Power Networks for the 2025–30 period, based on the final PTRM for SA Power Networks.

- A shared asset adjustment of –$9.6 million ($2024–25) to be shared with customers across the 2025–30 period.

Our draft decision has not included:

- SA Power Networks' proposed $4.0 million ($2024-25) Innovation Fund (opex) revenue adjustment. This is because we consider the Innovation Fund does not satisfy the criteria for a revenue adjustment under the NER (clause 6.4.3.(b)(5)) because it is not listed as an allowable revenue increment application. Our draft decision for innovation opex is in Attachment 6 section 6.4.5.2.
- SA Power Networks' proposed adjustment of –$68.5 million ($2024–25) for cable and conductors repairs which related to an over-recovery of revenue in the 2020–25 determination. Subsequent to SA Power Networks' proposal, we accounted for this by revoking and substituting our 2020–25 determination in March 2024.

The combined effect of these revenue adjustments is a positive $2.4 million ($2024–25) revenue adjustment building block in this draft decision compared to the negative $66.0 million in SA Power Networks' proposal.

3 Incentive schemes

Incentive schemes are a component of incentive-based regulation and complement our approach to assessing efficient costs. They provide important balancing incentives under network determinations, encouraging businesses to pursue expenditure efficiencies while maintaining the reliability and overall performance of the network.

Our draft decision on the application of these schemes and allowances is consistent with the position taken in our Framework and Approach paper and is set out in Attachments 8-12 of this draft decision. Our draft decision is that the following incentive schemes will continue to apply to SA Power Networks in the 2025–30 period:

- Efficiency benefit sharing scheme (EBSS). This provides a continuous incentive to pursue efficiency improvements in main standard control services opex and provide for a fair sharing of these between networks and network users. Consumers benefit from improved efficiencies through lower opex in regulated revenues for future periods. The full detail on our draft decision for the EBSS is in Attachment 8.
- Capital expenditure sharing scheme (CESS). This incentivises efficient capex throughout the period by rewarding efficiency gains and penalising efficiency losses, each measured by reference to the difference between forecast and actual capex. Consumers benefit from improved efficiencies through a lower RAB, which is reflected in regulated revenues for future periods. The full detail on our draft decision for the CESS is in Attachment 9.
- Service target performance incentive scheme (STPIS). The STPIS balances a business' incentive to reduce expenditure with the need to maintain or improve service quality. It achieves this by providing financial incentives to businesses to maintain and improve service performance and not by simply reducing costs at the expense of service quality. Once improvements are made, the benchmark performance targets will be tightened in future years. The parameters that will apply to each of component of the STPIS for SA Power Networks are set out in Attachment 10.
- Demand Management Incentive Scheme (DMIS) and Demand Management Innovation Allowance Mechanism (DMIAM). The DMIS provides network service providers with financial incentives for undertaking efficient demand management activities. The DMIAM funds research and development in demand management projects that have the potential to reduce long-term network costs. The full detail on our draft decision for DMIS and DMIAM is in Attachment 11.

Our draft decision is to not accept SA Power Networks' proposed Customer Service Incentive Scheme (CSIS). The CSIS is designed to encourage electricity distributors to engage with their customers, identify (through customer engagement) the customer services their customers want improved, and then set targets to improve those services based on their customers' preferences. The full detail on our draft decision for the CSIS is in Attachment 12.

4 Tariff structure statement

The requirement on distributors to prepare a tariff structure statement stemmed from significant reforms in 2014 to the rules governing distribution network pricing. A tariff structure statement informs customer choices by:

- providing clear price signals—network tariffs which reflect what it costs to use electricity at different times can allow customers (or their retailer) to make informed decisions to better manage their bills
- transitioning tariffs to greater cost reflectivity—with the requirement that distributors explicitly consider the impacts on retail customers, by engaging with customers, customer representatives and retailers in developing network tariff proposals
- managing future expectations—providing guidance for retailers, customers and suppliers of services such as local generation, batteries, and demand management by setting out the distributor's tariff approaches for a set period of time.

It is important to note that the network tariff price signals we approve may not be directly passed on to end-use customers (i.e. the retail customer). This is because distributors charge the relevant retailers for the transport of electricity to serve end-use customers connected to their networks. Network costs and price signals are charged directly to retailers who then pass these costs on to end-use customers in their retail offers. A retailer may choose to pass on the network price signals exactly or repackage them into their retail offers (including in insurance style flat rate retail offers). Cost reflective network tariffs should not inhibit consumer choice over retail tariff structures. Customers should have access to a range of retail tariff structures across different retailers, including because distributors typically offer at least two cost reflective tariffs structures for small customers, and because retail tariffs are not required to reflect the structure of the underlying network tariff.

Network tariff reform enables distributors to charge retailers in a manner which more closely reflects the cost of providing electricity network capacity to end-use customers and can support the energy transition currently underway. Where price signals are passed through, and if customers are well placed to respond to these price signals, appropriately structured tariffs can enable growth in the value and number of people with consumer energy resources (CER). At the same time, this response to price signals can reduce network constraints and minimum load issues and therefore reduce the level of network investment required, resulting in lower prices for all consumers.

The tariff structure statement must set out several matters. These include tariff classes, proposed tariffs and the structures and charging parameters, the strategy for introduction of export tariffs, and the approach to setting tariff levels in each year of the regulatory control period.[33] The policies and procedures that will be used to assign customers to tariffs or reassign customers from one tariff to another must also be outlined.

In this determination we must decide whether to approve SA Power Networks' tariff structure statement, which will form the basis of annual pricing proposals throughout the 2025–30

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[33] NER, cl. 6.18.1A(a).

period.[34] We are also required to decide the policies and procedures for assigning or re-assigning customers to tariff classes.[35] Principally, we are making a determination on whether the proposed tariff structure statement complies with the pricing principles of the NER, and any other applicable rules. After that, our decision takes the NEO into account and considers whether the tariff structure statement will or is likely to contribute to achievement of the NEO. For tariff structure statements, we consider the NEO elements of price and achievement of jurisdictional emissions reduction targets to be most relevant.

While an indicative pricing schedule must accompany the tariff structure statement, the tariff levels for each tariff for each year of the 2025–30 period are not set as part of this determination.[36] Tariff pricing levels for the regulatory year commencing 1 July 2025 will be subject to a separate approval process in May 2025, after we have made our final revenue determination in April 2024. Tariff price levels for the four years from 1 July 2026 will also be approved on an annual basis.[37]

We commend SA Power Networks for submitting a high-quality proposal that demonstrated how it incorporated stakeholder feedback in its proposal, considered customer impacts, and provides a forward-looking path to transition customers to more cost-reflective tariffs. We have given weight to the considerable stakeholder engagement SA Power Networks undertook in developing its tariff structure statement, as well as the submissions we have received. We have also given weight to ongoing AEMC rule change processes, an accelerating smart meter roll out and feedback from stakeholders that some customers are unable to respond to cost reflective tariffs.

In its proposed tariff structure statement, SA Power Networks continues to move towards more cost reflective tariff structures in recognition of the changes taking place in the electricity sector and the increasing levels of CER connected to its network. This is evidenced by the introduction of two-way pricing, an optional time-of-use (Electrify) tariff with sharper price signals, and an optional flexible demand tariff for large customers. These tariffs encourage more energy consumption during solar peak periods, less during peak load times, and, for customers on the Electrify tariff, reward people for exporting energy to the grid when it is most needed.

While our draft decision accepts nearly all elements of SA Power Networks' proposal, we have required SA Power Networks to offer a time-of-use tariff for customers with consumption greater than 120 kVA but less than 160 MWh, to contribute to the achievement of the NEO, in particular to the achievement of jurisdictional targets for emissions reduction. This provides access to consistent network tariff structures for EV charging point operators across the NEM, further supporting uptake and utilisation of EVs, thereby contributing to jurisdictional emissions reduction targets. We also consider that SA Power Networks should demonstrate how its alternative control services are compliant with the pricing principles.

In Attachment 19, we describe in further detail these changes that we consider necessary for us to approve SA Power Networks' tariff structure statement proposal.

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34 NER, cl. 6.12.1(14A).

35 NER, cl. 6.12.1(17).

36 NER, cl. 6.8.2(d1).

37 This will occur pursuant to obligations in cl. 6.18.2 and cl. 6.18.8 of the NER.

5 Metering

Smart meters are foundational to a more connected, modern, and efficient energy system and one mechanism to ensure that future technologies, services, and innovations are supported. Throughout the 2025–30 regulatory determinations, we signalled that we would consider the implications of the AEMC's final decision on the transitioning of legacy meters. This includes different classification and/or price/revenue control settings for legacy metering services.

The key objective of the AEMC's final decision, released in August 2023, is to target a 100% replacement of distribution network owned accumulation meters with smart meters offered by other parties by 30 June 2030.[38] Our draft decision considers this constitutes a material change in circumstances, which would justify departure from the classification of legacy metering services in the Framework and approach (F&A).

Our draft decision accepts SA Power Networks' proposal to reclassify legacy metering as standard control services and the application of a revenue cap. This includes a metering SCS revenue cap that operates independently to the main SCS revenue cap. Under this metering SCS revenue cap, we set the maximum revenue SA Power Networks can recover in relation to metering services. This is set out in Attachment 20. We consider this is the most appropriate outcome because it is consistent with our guidance note and provides an outcome that is in the long-term interests of consumers. It ensures no customer is worse off than other customers as a result of when their legacy meter is replaced. By comparison, customers whose meters are replaced later in the replacement program would incur inequitably higher prices than those whose meters are replaced earlier under the approach in the final F&A.

In addition, our draft decision accepts SA Power Networks' proposed cost recovery approach (a flat per customer charge to low voltage customers). However, our draft decision is to not accept SA Power Networks' proposal overall because we substitute alternate estimates for forecast metering opex and subsequently the annual revenue requirement due to updated inputs and our placeholder forecast of zero for SA Power Networks' legacy metering step changes. The reasons for our decision are discussed in detail at attachment 20 and outcomes relating to service classification to support the AEMC's intention are discussed at attachment 13.

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38 AEMC, *Final Report: Review of the regulatory framework for metering services*, August 2023.

6 Constituent decisions

Our draft decision on SA Power Networks' distribution determination for the 2025–30 regulatory control period includes the following constituent decision components:

Constituent component
In accordance with clause 6.12.1(1) of the NER, the AER's draft decision is that the classification of services set out in Attachment 13 will apply to SA Power Networks for the 2025–30 regulatory control period, for the reasons set out in that attachment.
In accordance with clause 6.12.1(2)(i) of the NER, the AER's draft decision is to not approve the annual revenue requirement set out in SA Power Networks' building block proposal. Our draft decision on SA Power Networks' annual revenue requirement for standard control services other than legacy metering services (main standard control services) for each year of the 2025–30 regulatory control period is set out in Attachment 1. Our draft decision on SA Power Networks' legacy metering annual revenue requirement for each year of the 2025–30 regulatory control period is set out in Attachment 20.
In accordance with clause 6.12.1(2)(ii) of the NER, the AER's draft decision is to approve SA Power Networks' proposal that the regulatory control period will commence on 1 July 2025. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER's draft decision is to approve SA Power Networks' proposal that the length of the regulatory control period will be five years from 1 July 2025 to 30 June 2030.
The AER did not receive a request for an asset exemption under clause 6.4B.1(a)(1) and therefore did not make a decision in accordance with clause 6.12.1(2A) of the NER.
In accordance with clause 6.12.1(3)(ii) and acting in accordance with clause 6.5.7(d) of the NER, the AER's draft decision is to not accept SA Power Networks' proposed total forecast capital expenditure. For main standard control services, we do not accept SA Power Networks' total forecast capital expenditure of $2,379.1 million ($2024–25). Our draft decision includes an alternative estimate of $2,135.2 million ($2024–25). The reasons for our draft decision are set out in Attachment 5. For metering, we accept SA Power Networks' proposal forecast of no capital expenditure. This is set out in Attachment 20.
In accordance with clause 6.12.1(4)(ii) and acting in accordance with clause 6.5.6(d) of the NER, the AER's draft decision is to not accept SA Power Networks' proposed total forecast operating expenditure. For main standard control services, we accept SA Power Networks' proposed total forecasting operating expenditure, inclusive of debt raising costs and exclusive of DMIAM

Constituent component
of $1,983.7 million ($2024–25). The reasons for our draft decision are set out in Attachment 6. For metering, we do not accept SA Power Networks' proposed total forecast operating expenditure of $60.2 million ($2024–25) and replace it with a forecast of $26.2 million ($2024–25). This is set out in Attachment 20.
SA Power Networks did not propose any contingent projects and therefore the AER has not made a draft decision under clause 6.12.1(4A) of the NER.
In accordance with clause 6.12.1(5) of the NER and the 2022 Rate of Return Instrument, the AER's draft decision is that the allowed rate of return for the 2025–26 regulatory year is 6.02% (nominal vanilla) for the reasons set out in Attachment 3. The rate of return for the remaining regulatory years of the 2025–30 regulatory control period 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 2022 Rate of Return Instrument, the AER's draft decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.57. The reasons for our draft decision are set out in Attachment 3.
In accordance with clause 6.12.1(6) of the NER, and acting in accordance with clause 6.5.1 and schedule 6.2 of the NER, the AER's draft decision on SA Power Networks' main standard control services regulatory asset base as at 1 July 2025 is $5,201.7 million ($ nominal). The reasons for our draft decision are set out in Attachment 2. The AER's draft decision on SA Power Networks' metering regulatory asset base as at 1 July 2025 is $0.8 million ($ nominal). This is discussed in Attachment 20.
In accordance with clause 6.12.1(7) of the NER, the AER's draft decision on SA Power Networks' estimated cost of corporate income tax for main standard control services is $43.8 million ($ nominal) for the 2025–30 regulatory control period. The reasons for our draft decision are set out in Attachment 7 and the amount for each regulatory year of the 2025–30 regulatory control period is set out in the table below.

($ million, nominal)	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Tax payable	29.2	31.3	24.3	11.0	6.1	101.8
Less: value of imputation credits	16.7	17.8	13.8	6.3	3.5	58.1
Net cost of corporate income tax	**12.6**	**13.4**	**10.4**	**4.7**	**2.6**	**43.8**

The AER's draft decision on SA Power Networks' cost of corporate income tax for legacy metering is $0.1 million ($ nominal) for the 2025–30 regulatory control period.

Constituent component
In accordance with clause 6.12.1(8) of the NER, the AER's draft decision is to not approve the depreciation schedules submitted by SA Power Networks. For main standard control services, our draft decision substitutes alternative depreciation schedules that accord with clause 6.5.5(b). The regulatory depreciation amount approved in this draft decision is $1,200.6 million ($ nominal) for the 2025–30 regulatory control period. The reasons for our draft decision are set out in Attachment 4. For legacy metering, our draft decision substitutes alternative schedules amounting to regulatory depreciation for the 2025–30 regulatory control period of $0.8 million ($ nominal). This is discussed in Attachment 20.
In accordance with clause 6.12.1(9) of the NER, the AER makes the following draft decisions on how any applicable efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS), export services incentive scheme (ESIS), service target performance incentive scheme (STPIS), demand management incentive scheme (DMIS), demand management innovation allowance mechanism (DMIAM) or small-scale incentive scheme (customer service incentive scheme) is to apply: • We will apply version 2 of the EBSS to SA Power Networks in the 2025–30 regulatory control period. Our reasons are set out in Attachment 8. • We will apply the CESS as set out in the 2023 Capital Expenditure Incentives Guideline to SA Power Networks in the 2025–30 regulatory control period. Our reasons are set out in Attachment 9. • We will not apply the ESIS for the 2025–30 regulatory control period. • We will apply the STPIS version 2 to SA Power Networks for the 2025–30 regulatory control period. Our reasons are set out in Attachment 10. • We will apply the DMIS and DMIAM to SA Power Networks for the 2025–30 regulatory control period. Our reasons are set out in Attachment 11. • We will not apply the customer service incentive scheme (CSIS) to SA Power Networks for the 2025–30 regulatory control period. Our reasons are set out in Attachment 12.
In accordance with clause 6.12.1(10) of the NER, the AER's draft decision is that all other appropriate amounts, values and inputs are as set out in this draft determination including attachments.
In accordance with clause 6.12.1(11) of the NER and our framework and approach paper, the AER's draft 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 14, which includes any adjustment required to move the Distribution Use of Service (DUoS) and metering unders and overs accounts to zero. The reasons for our draft decision are set out in Attachment 14.

Constituent component
In accordance with clause 6.12.1(12) of the NER and our framework and approach paper, the AER's draft decision on the form of the control mechanism for alternative control services is to apply price caps for all alternative control services. The reasons for our draft decision are set out in Attachment 14.
In accordance with clause 6.12.1(13) of the NER, to demonstrate compliance with its distribution determination, the AER's draft decision is that SA Power Networks must maintain both DUoS and metering unders and overs mechanisms. It must provide information on these mechanisms to us in its annual pricing proposal. The reasons for our draft decision are set out in Attachment 14.
In accordance with clause 6.12.1(14) of the NER the AER's draft decision is to apply the following nominated pass through events to SA Power Networks for the 2025–30 regulatory control period in accordance with clause 6.5.10: • Insurance coverage event • Insurer's credit risk event • Terrorism event • Natural disaster event These events have the definitions set out in Attachment 15 of the draft decision. Our reasons for this constituent decision are also set out in that attachment.
In accordance with clause 6.12.1(14A) of the NER, the AER's draft decision is to not approve the tariff structure statement proposed by SA Power Networks. The reasons for our draft decision are set out in Attachment 19.
In accordance with clause 6.12.1(15) of the NER, the AER's draft decision is that the negotiating framework as proposed by SA Power Networks will apply for the 2025–30 regulatory control period. The reasons for our draft decision are set out in Attachment 17.
In accordance with clause 6.12.1(16) of the NER, the AER's draft decision is to apply the negotiated distribution services criteria published in February 2024 to SA Power Networks. The reasons for our draft decision are set out in Attachment 17.
In accordance with clause 6.12.1(17) of the NER, the AER's draft decision on the procedures for assigning retail customers to tariff classes for SA Power Networks is set out in Attachment 19.
In accordance with clause 6.12.1(18) of the NER, the AER's draft decision is that the depreciation approach to be used to establish the RAB at the commencement of SA Power

Constituent component
Networks regulatory control period as at 1 July 2030 is to be based on forecast capex. The reasons for our draft decision are set out in Attachment 2.
In accordance with clause 6.12.1(19) of the NER, the AER's draft decision on how SA Power Networks is to report to the AER on its recovery of designated pricing proposal charges and account for the under and over recovery of designated pricing proposal charges is the unders and overs mechanism. It must provide information on this mechanism to us in its annual pricing proposal. The reasons for our draft decision are set out in Attachment 14.
In accordance with clause 6.12.1(20) of the NER, the AER's draft decision on how SA Power Networks is to report to the AER on its recovery of jurisdictional scheme amounts and account for the under and over recovery of jurisdictional scheme amounts is the unders and overs mechanism. It must provide information on this mechanism to us in its annual pricing proposal. The reasons for our draft decision are set out in Attachment 14.
In accordance with clause 6.12.1(21) of the NER, the AER's draft decision is to approve the connection policy proposed by SA Power Networks. Our reasons are set out in Attachment 18.

7 List of submissions

We received 25 submissions in response to SA Power Networks 2025-30 distribution revenue proposal. These are listed below.[39]

Submissions from	
Adelaide Hills Council	South Australian Council of Social Service (SACOSS)
AER Consumer Challenge Panel (CCP) Sub-Panel 30 (CCP30)	South Australian Wine Industry Association (SAWIA)
Amber Electric	Strategic Policy and Delivery Division (SPD), Department for Energy and Mining
CAB Reset Subcommittee	SwitchDin Pty Ltd
City of Adelaide	Tesla
Clean Energy Council	Vegetation Management Advisory Group
democracyCo	
District Council of Streaky Bay	
Electric Vehicle Council	
Energy and Water Ombudsman (SA) Limited (EWOSA)	
Mount Barker District Council	
Origin Energy	
Public Lighting Working Group	
Red Energy and Lumo Energy	
Regional and Remote Customers sub-committee, SA Power Networks Community Advisory Board	
SA Business Chamber	
SMA Australia	
Smart Energy Council	
sonnen Australia Pty Ltd	

39 Submissions are available on the AER website at https://www.aer.gov.au/industry/registers/determinations/sa-power-networks-determination-2025-30/proposal#submissions

Shortened forms

Terms	Definition
ACS	alternative control services
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
Capex	capital expenditure
CCP30	Consumer Challenge Panel, sub-panel 30
CER	Consumer Energy Resources
CESS	capital expenditure sharing scheme
CSIS	customer service incentive scheme
DMIAM	demand management innovation allowance mechanism
DMIS	demand management incentive scheme
DNSP or distributor	Distribution Network Service Provider
DUoS	Distribution Use of System Charges
EBSS	efficiency benefit sharing scheme
F&A	framework and approach
ICT	information and communication technology
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
opex	operating expenditure
RAB	regulated asset base
repex	replacement expenditure
SCS	standard control service
STPIS	service target performance incentive scheme