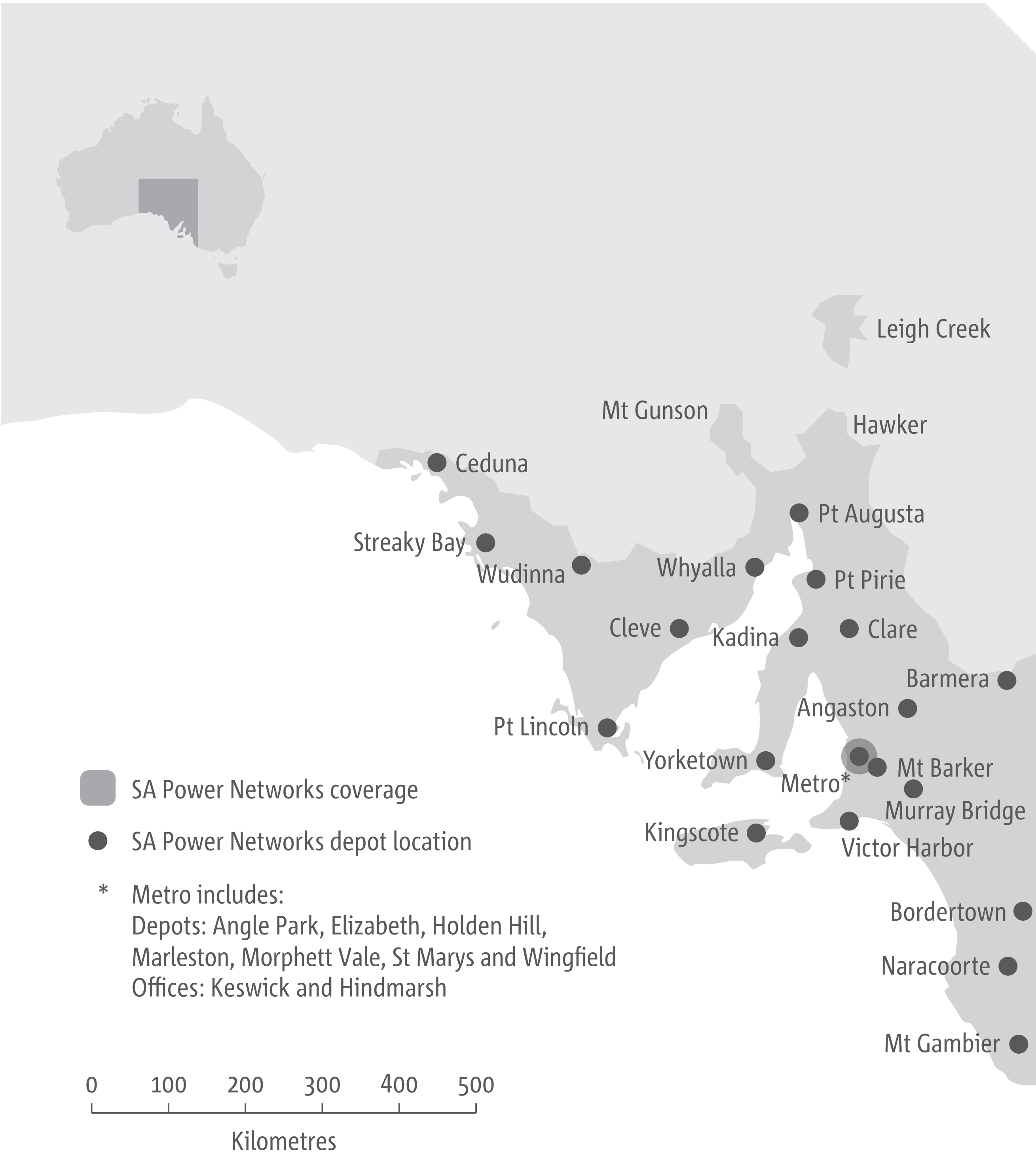
SA Power Networks

2025-30 Revised Regulatory Proposal

DECEMBER 2024

Network Service Area



Disclaimer

About this document

This document forms part of SA Power Networks' 2025-30 Revised Regulatory Proposal to the Australian Energy Regulator, along with Attachments and other supporting documents. All dollars shown in this document unless otherwise stated are in $2025.

Company information

SA Power Networks is the primary electricity distribution network service provider for South Australia. For information about SA Power Networks visit **sapowernetworks.com.au**

Disclaimer

This document contains certain predictions, estimates and statements that reflect various assumptions concerning, amongst other things, economic growth and load growth forecasts that, by their nature, may or may not prove to be correct and are subject to ongoing change and development.

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

Copyright

Acknowledgement of Country

In the spirit of reconciliation, SA Power Networks acknowledges the multiple Traditional Owners of the lands that host the South Australian electricity network and their connections to land, sea and community. We would also like to pay our respects to Elders past and present and acknowledge that these are living cultures by paying respect to emerging leaders.

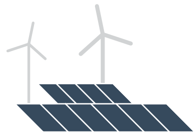
Presten Warren (b. 2000), ***Empowering South Australia,*** 2023, Acrylic on Canvas, 170cm x 90 cm

Commisioned by SA Power Networks for our 2023 Reconciliation Action Plan.

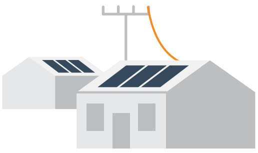
About SA Power Networks: Network Highlights

SA Government committed to 100% net renewable energy generation in SA by **2027**

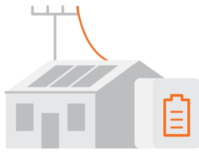
71% of energy demand in SA met by variable renewables – second only to Denmark



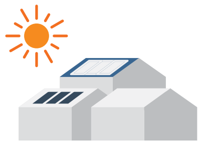
Around **$20 billion** of renewable energy projects in the pipeline in SA



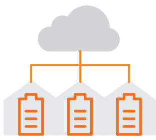
~370,000 solar PV systems enabled



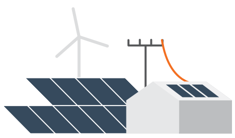
~45,000 home batteries enabled



38% of customers in SA with solar



Facilitating **18** Virtual Power Plants (VPPs) in SA



100% of distribution network demand regularly met by renewables

#1 ranked distributor for efficiency by the Australian Energy Regulator

SA Power Networks details

- **Primary distributor** in South Australia
- Supply South Australia's **1.7 million** population
- Supplying over **934,000** homes and businesses
- **1,800 employees** in more than 30 sites across the State
- Recruited over **790 apprenticeships** since 2000
- Peak demand **3,193MW**
- Electricity distributed **9,820GWh p.a.**
- Network coverage over **178,000km²**
- Route length around **90,000km**
- **Oldest network assets** in the NEM

Foreword

Peter Tulloch
Chair, SA Power Networks

Andrew Bills
Chief Executive Officer, SA Power Networks

We are pleased to submit SA Power Networks' 2025-30 Revised Regulatory Proposal (Revised Proposal) for managing South Australia's electricity distribution network.

The Australian Energy Regulator (AER) accepted much of our original proposal, lodged in January 2024. This was enabled through constructive early engagement with the AER, our comprehensive consumer engagement, sound governance, reliable forecasting methods, and high-quality analysis and evidence of investment efficiency.

However, in the Draft Decision we received feedback from the AER on several key capital expenditure areas, where our proposed expenditure was not approved in full. These primarily relate to network asset replacement expenditure, network capacity augmentation expenditure, our underlying reliability and CBD reliability programs, and our proposed Innovation Fund.

We firmly believe appropriate investment in these areas is necessary to meet both current and emerging challenges in our operating environment, including our ageing asset base, reliability trends, Adelaide CBD reliability obligations, and projected demand increases. We have given further consideration to these areas and sought to address all AER feedback in our Revised Proposal.

We have also continued our extensive program of engagement on these issues with our Consumer Advisory Forum (CAF) and our Reset Advisory Group (RAG), and our other advisory groups, to inform our reconsideration of these specific areas.

Our engagement with the community and our key stakeholders has been central throughout the development of our original and revised proposals. We have always sought to reflect an appropriate balance of our customers' preferred service level outcomes and price. Customers and stakeholders have been consistent in their feedback that they do not want service levels to decline. However, we are also acutely aware of cost-of-living pressures and the importance of affordability for all customers. As a result, downward conservatism has deliberately been applied throughout our forecasts.

In real terms, this will see customers' distribution bills across the 2025-30 period reduce by 7%. This is a good outcome for customers and heavily influenced by our stakeholders' involvement.

We would like to thank our CAF, RAG and other stakeholders for their valuable input over an extended timeframe. We look forward to continuing to work closely with them to deliver positive outcomes for the South Australian community over the 2025-30 regulatory period and beyond.

Following close consideration of the AER's feedback in relation to our original proposal, we believe our Revised Proposal is well-positioned for acceptance.

We look forward to finalising our 2025-30 proposal for the benefit of all South Australians.

Community Advisory Forum
Reset Advisory Group

SA Power Networks' Community Advisory Forum (CAF) and its predecessor, the Community Advisory Board (CAB), have worked closely with SA Power Networks in the planning and delivery of the consumer engagement process for its Regulatory Reset Proposal and Revised Proposal.

Dr Andrew Nance
Chair, Community Advisory Forum

Chris Marsden
Chair, Reset Advisory Group

The Reset consumer engagement process commenced in late 2021 and has required significant commitment and time from SA Power Networks and the CAF/CAB (and the numerous subordinate committees) members.

SA Power Networks restructured and refreshed its formal engagement structure in April 2024 which has led to some continuity issues even though several CAB members remain on the CAF. It is also important to acknowledge Kelvin Trimper's outstanding contribution to SA Power Networks' consumer engagement for over a decade. Kelvin was Deputy Chair of the CAB and chair of the Reset Advisory Group at his passing in January 2024.

We would like consumers to understand that the engagement process has very little influence over the total revenue (due primarily to the current regulatory processes), rather we have been able to influence the ways the *proposed* expenditure will deliver the outcomes that matter the most to customers.

Given the proposal's volume of information (around 100 separate documents), and the diversity of CAF members, consensus was not possible on the Proposal or the Revised Proposal. We highlight that SA Power Networks has been very much aware of the CAF's concerns about balancing service levels, an ageing network with the pricing and affordability of an essential service to SA.

The consultation process from the AER's Draft Determination (late September 2024) and the lodgement of the Final Proposal (early December 2024) was always going to be challenging. The Draft Decision itself comprised dozens of documents, spreadsheet models and Consultant Reports. SA Power Networks has however sought to advise CAF and its subordinate committees of the Draft Determination's primary outcomes, determine consumer priorities for the proposed Innovation Fund and inform the CAF on its final proposal.

In the end, the AER will approve a total revenue allowance, and our role will shift to ensuring that *actual* expenditure delivers outcomes valued by customers and to prepare for the next reset cycle.

CAF encourages the Australian Energy Regulator (AER) to continue to refine its Better Resets Handbook to better manage expectations for consumers and networks. We have also raised concerns on the concept of the 'average SA electricity consumer.' With the increased take-up of Consumer Energy Resources (CER) behind the meter, the CAF would welcome a better articulation by the AER of this Determination's (and subsequent Annual Pricing Proposals) impacts on SA consumers, with or without CER.

The CAF encourages all consumers who read the SA Power Networks' Final Proposal to provide feedback to the AER by 17 January 2025.

We look forward to continuing to work collaboratively with SA Power Networks as it delivers its 2025-30 program from July 2025. We will hold SA Power Networks accountable for the customer outcomes that formed the basis for the Regulatory Proposal.

Our 2025-30 Revised Regulatory Proposal

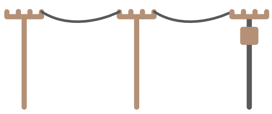
Key outcomes for customers

Customer experience, choice and empowerment

- ✓ Digital enhancements to improve customer service
- ✓ Refined connection policy to encourage flexible connections and support a two-way network

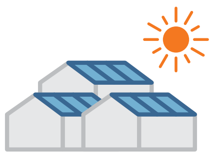
Affordable and equitable energy supply

- ✓ Distribution bills decrease by 7% in real terms by 2029/30.
- ✓ New solar export tariffs avoid costs for customers locked out from solar



A reliable, resilient and safe network

- ✓ Improvements in bushfire risk
- ✓ Reliability and resilience improvements to worst-served customers
- ✓ Cyber security resilience maintained
- Maintain network safety & reliability
  - Updated maintain underlying reliability program
  - New CBD reliability option
  - Updated demand forecasts for capacity program
  - Revised network asset replacement modelling



Enabling clean energy and unlocking future value for our state

- ✓ Network upgrades to support continued solar take-up
- ✓ New connection options and incentives for electric vehicles and smart appliances
- New Innovation Fund exploring initiatives which increase resilience, sustainability and unlock value for customers
  - Refined Innovation Fund priority projects

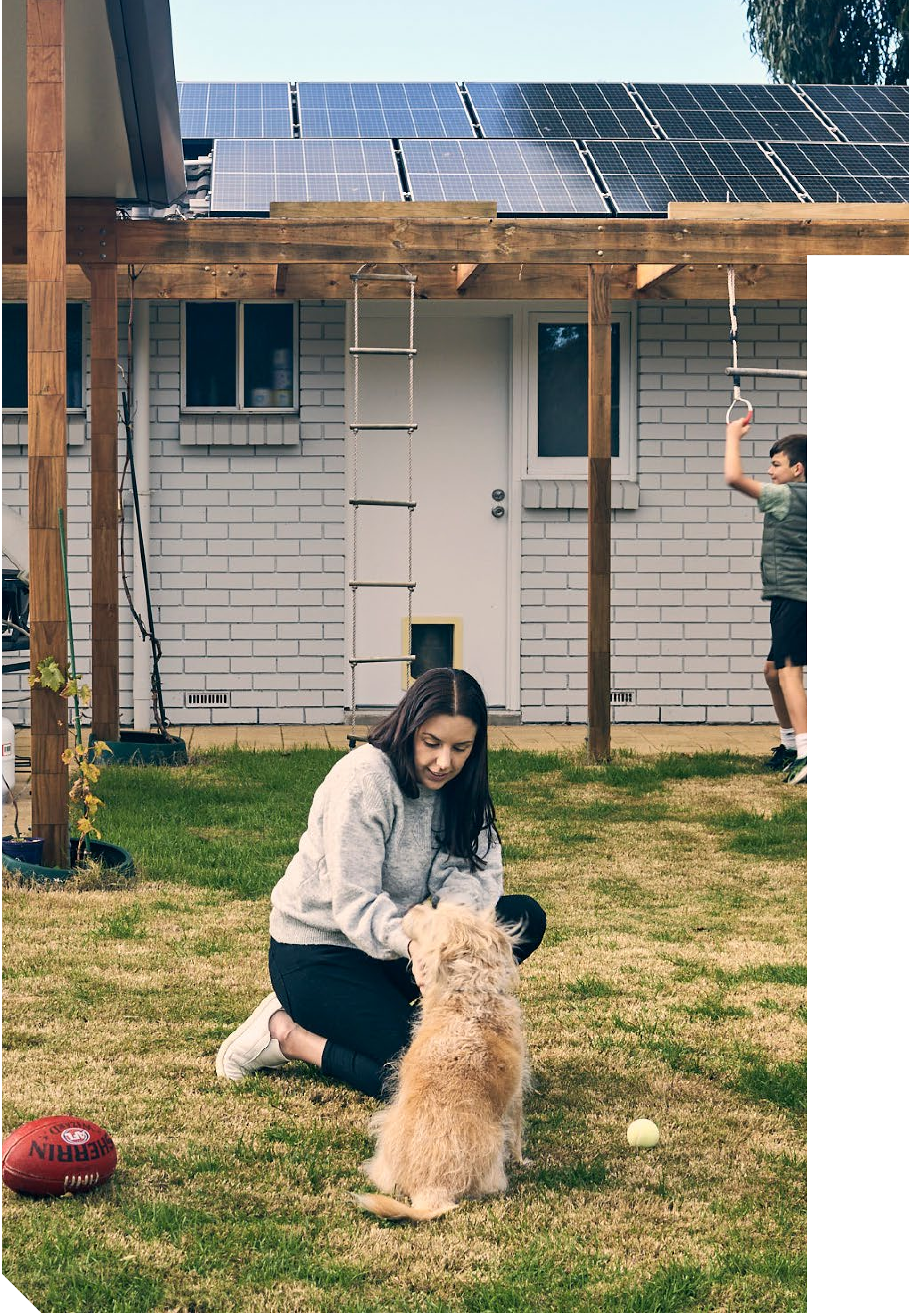
✓ Programs contributing to these outcomes approved by AER in its Draft Decision

Revised Proposal addresses AER concerns with proposed programs contributing to this outcome

Annual Distribution Bills	Original Proposal	AER Draft Decision	Revised Proposal
Real Residential Customer Distribution Bills in 2029/30 (based on annual consumption of 4,000kWh) Compares to 2024/25 Default Market Offer of $613	$582	$567	$570
Real Small Business Customer Distribution Bills in 2029/30 (based on annual consumption of 10,000kWh) Compares to 2024/25 Default Market Offer of $1,466	$1,391	$1,355	$1,362

2025-30 Revenue and Expenditure†	Original Proposal	AER Draft Decision	Revised Proposal
Revenue	$5,164 million	$5,143 million	$5,168 million
Operating Expenditure (excl. debt raising costs)	$1,970 million	$1,970 million	$2,023 million
Capital Expenditure (after disposals)	$2,379 million	$2,135 million	$2,338 million

†Revenue expressed in nominal terms and expenditure expressed in $2025 terms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Contents

1. Our Response to the AER's Draft Decision

Our proposed 2025-30 work plans, expenditure forecasts, revenue requirement and tariff structures were submitted to the AER in our Regulatory Proposal in January 2024 (Original Proposal). They were prepared following extensive consultation with customers and stakeholders, balancing affordability and equity concerns with ensuring our network delivers the services and service levels our customers want and expect in the 2025-30 period. Our capital and operating forecasts were prepared using methodologies and assumptions in accordance with AER expectations.

Our aim was to submit a Regulatory Proposal that was capable of acceptance at the Draft Decision stage. Since lodging our Original Proposal in January, we have continued to work closely with AER staff and their consultants to clarify our approaches in some areas and provide further information where requested. We are pleased that the AER's Draft Decision accepted the vast majority of our Original Proposal, allowing us to focus our Revised Proposal response on a relatively small number of outstanding matters that are largely of a technical nature. We are now aiming for a Revised Proposal that is capable of acceptance.

Expenditure Forecasts

In our capital expenditure (Capex) forecast, the AER accepted our forecast expenditures for Connections, Customer Energy Resources, Property and ICT in their entirety. It did not accept some of our forecast network asset replacement expenditure (Repex) and some areas of our network augmentation expenditure (Augex) - which resulted in consequential reductions in Fleet and capitalised overheads forecasts. It also did not accept our proposed Innovation Fund.

The $244 million expenditure cuts made by the AER to our forecast Capex are significant in some areas and would lead to reduced service outcomes. They relate to certain Repex and Augex programs where the AER has challenged our assumptions or analysis and costings (the efficiency of our forecasts), rather than disputing the investment needs or prudency for the expenditure, or requiring further insights on customer price-service preferences.

The AER also developed an alternative forecast to our proposed operating expenditure (Opex) which was not materially different from our Original Proposal and therefore the AER accepted our proposed Opex in total.

This Revised Proposal addresses each concern raised by the AER and contains revised forecasts for:

- Repex – revised modelling assumptions accounting for more recent and corrected data including in relation to asset failures, with further evidence of how the forecast only seeks to maintain service.
- Augex – updated demand forecasts and more thorough demonstration of economically optimal timing for capacity projects, and updated analysis demonstrating that maintaining our current spend on the maintain underlying reliability program will be needed to just maintain reliability going forward
- Repex / Augex – a new investment option to restore CBD reliability to the jurisdictional target that optimises the use of all available solutions (replacement, automation, topology changes)
- ICT – updated forecast expenditure for market-facing system changes, triggered by market requirements specified by the Australian Energy Market Operator, and resulting from the accelerated metering reforms by the Australian Energy Market Commission
- Innovation Fund (Capex) – retained our original forecast with further justification of the transformative nature of the proposed innovation projects, their costs, expected consumer benefits, and approach to governance with our customer groups
- Opex – updated the base year Opex with actual revealed 2023/24 expenditure, reduced forecast step change expenditure, updated output and price growth trend, removed expenditure for the small compensation claims regime and included the Opex portion of the Innovation Fund.

Tariff Structure Statement

The AER substantively accepted our proposed 2025-30 Tariff Structure Statement, with one tariff assignment policy change. We have accepted this change in our Revised Proposal. We have also provided more clarity on the eligibility of customers to access individually-calculated tariffs and demonstrated how our Alternative Control Services prices are compliant with the pricing principles in the National Electricity Rules.

Other developments

Revocation and substitution of the 2020 Distribution Determination

The AER's June 2020 Distribution Determination set the 2020-25 revenue requirement for SA Power Networks. This determination contained an error in the capital and operating expenditure allowances associated with minor cable and conductor repairs, resulting in SA Power Networks collecting $67 million (nominal) more revenue than it required over the first four years of the 2020-25 period. Our Original Proposal included a downwards revenue adjustment to correct for this error over the first three years of the 2025-30 period.

However, in March 2024 the AER corrected this error by revoking its 2020 Distribution Determination and substituting a new determination. This resulted in SA Power Networks returning $67 million revenue to its customers (by lowering tariffs) in the 2024/25 regulatory year.

Consequently, we have removed this revenue correction from our 2025-30 Revised Proposal.

Small compensation claims regime

Our Original Proposal included a step change in Opex to administer and pay compensation to small customers for a proposed new small compensation claims scheme, pending a policy response from the South Australian Government. The South Australian Government is now proposing to invoke the Small Compensation Claims regime outlined in the National Energy Retail Law through new Regulations[1]. This regime will commence when the new Regulations are proclaimed, expected in Quarter 1 2025. We will then request the AER determine this regime to be a 'jurisdictional scheme' under the National Electricity Rules whereby compensation costs will be recovered in network charges (not distribution tariffs).

Consequently, we have removed our expenditure forecasts for this scheme from our Revised Proposal Opex.

Smart meter roll-out

When our Original Proposal was developed late in 2023, we had very early estimates for the additional costs we would incur associated with the Australian Energy Market Commission (AEMC) proposal for 'Accelerating smart meter deployment' and its impact on the provision of legacy metering services over the 2025-30 period. The AEMC issued its final Rule on 28 November 2024.

Since our Original Proposal, we have updated our legacy meter expenditure to reflect the latest actual base year expenditure and forecast legacy metering volumes. We have also significantly reduced our forecast transitional costs associated with this new Rule and our Revised Proposal now includes lower forecast Opex associated with legacy metering step changes. We note, there has been a small increase in capital associated with system changes required to support the smart meter roll-out.

1) *National Energy Retail Law (Local Provisions) (Small Compensation Claims Regime) Amendment Regulations 2024.*

EV charger of last resort

The South Australian Government is supportive of accelerating the take up of electric vehicles (EVs) by South Australians, with predictions for over 250,000 EVs on South Australian roads by 2030. We believe, however, there will be transitional issues where it is not economic for third party providers to install EV charging infrastructure in some locations due to low EV density.

Since lodging our Original Proposal we have participated in discussions with councils and the South Australian Government on our ability to provide an EV 'Charger of Last Resort' service in the 2025-30 period. Councils and the Royal Automobile Association of Australia are supportive of SA Power Networks being able to provide this service.

Accordingly, our Revised Proposal requests the AER classify this new service as an Alternative Control Service (ACS) for the 2025-30 period. As an ACS, the cost of providing this service will be funded in full by the requesting party, not electricity consumers.

Customer Service Incentive Scheme

In our Original Proposal we proposed a new Customer Service Incentive Scheme (CSIS). However, a lack of robust historical data to establish an appropriate baseline performance target for one of the two CSIS measures we proposed (First call resolution) led us to consider a revised CSIS. It also led the AER in its Draft Decision to not accept our proposed CSIS and instead retain the current customer service measure (telephone answering) parameter of the Service Target Performance Incentive Scheme (STPIS).

With stakeholder support we considered alternative measures for a revised CSIS but do not yet have sufficient data to propose a suitable baseline target for these measures. We will therefore accept the AER's Draft Decision to retain the telephone answering component of the STPIS for the 2025-30 period and will continue to work with our stakeholders to establish a suitable CSIS from 2030.

Connection Policy

The AER approved our proposed 2025-30 Connection Policy. With stakeholder support, we are proposing an update to our payment terms in the Policy as part of our Revised Proposal.

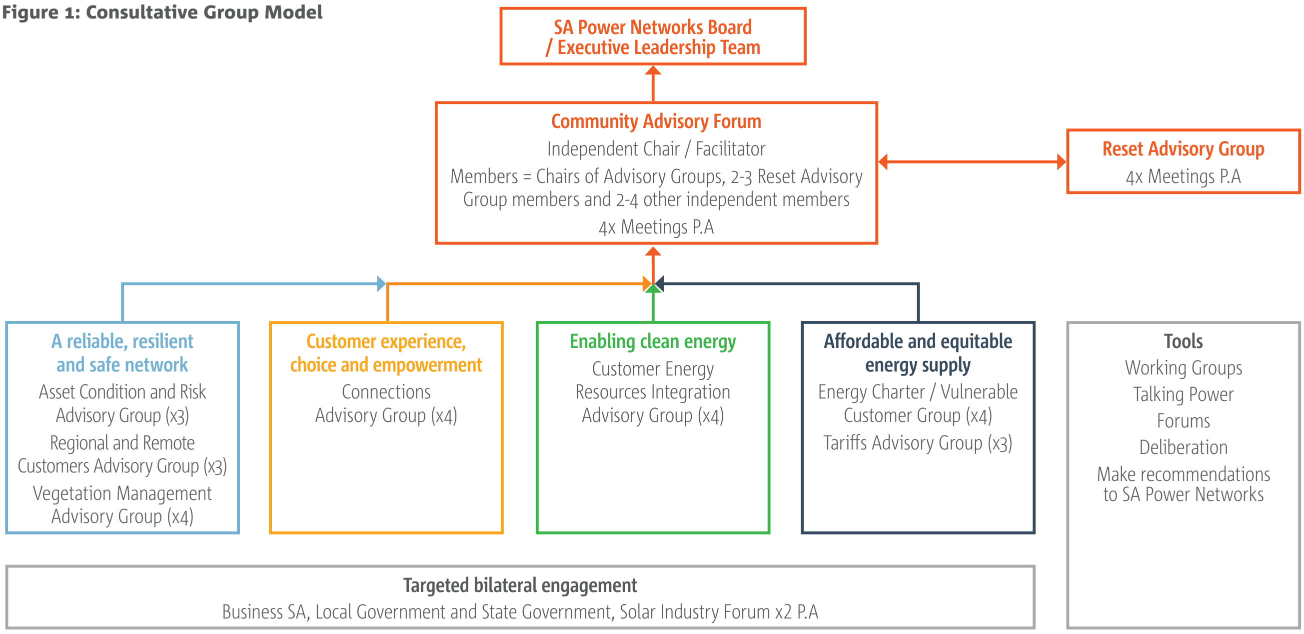
2. Customer and Stakeholder Engagement

Since lodging our Original Proposal in January 2024, our engagement with key stakeholder and consumer representatives has continued.

We engaged with our consultative groups throughout the year, and this engagement has provided valuable input for our Revised Proposal.

In April 2024 we implemented our new and revamped consultative group model, including our Community Advisory Forum (formerly our Community Advisory Board), an ongoing Reset Advisory Group as part of our 'business as usual' engagement and seven advisory groups (refer Figure 1), aligned with the key priorities customers and stakeholders identified through engagement on our Original Proposal.

Figure 1: Consultative Group Model



Reset Advisory Group (RAG)

Over the course of 2024 we continued to meet with our revamped RAG on the regulatory process, including AER information requests, potential areas for review, and the engagement process. The RAG endorsed our Revised Proposal engagement approach at its August meeting, noting the small window between the release of the AER's Draft Decision, the lodging of our Revised Proposal and the need for any engagement to be meaningful.

Engagement following the Draft Decision

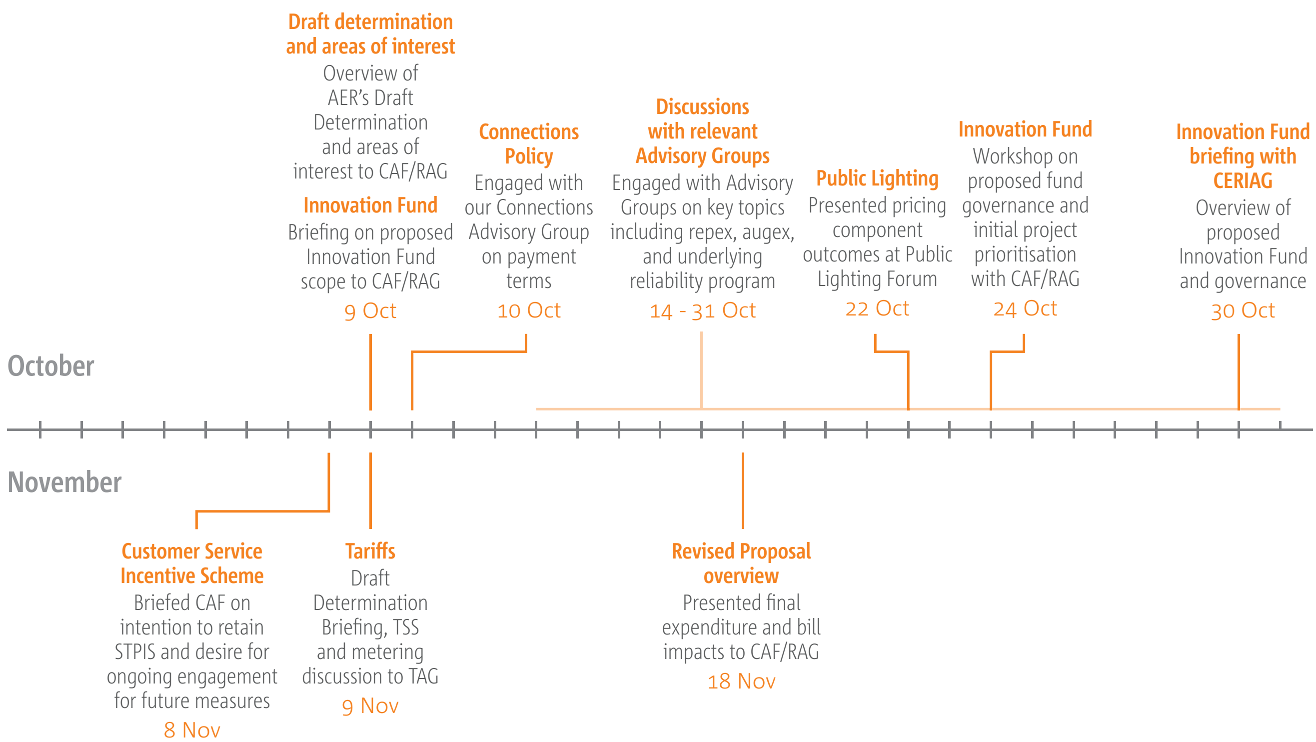
We have engaged with our advisory groups on the Draft Decision, its implications and how we have responded to address the concerns raised by the AER. Given much of the AER's feedback was largely technical in nature, deeper engagement for our Revised Proposal focussed on areas where our customers and stakeholders could influence the outcome or provide meaningful input into the Revised Proposal.

This included engagement with our CAF and Reset Advisory Group on the Customer Service Incentive Scheme (CSIS) and the proposed Innovation Fund, and relevant Advisory Groups on specific topics, for example:

- our Asset Condition and Risk Advisory Group on Repex, Augex and CBD reliability;
- the Regional and Remote Advisory Group on our underlying reliability program and proposed expenditure;
- our Connections Advisory Group on an amendment to the payment terms in the Connections Policy; and
- Tariff Advisory Group on legacy metering and new EV charging service.

A summary of our engagement in October and November is provided in Figure 2.

Figure 2: Our Revised Proposal engagement process



Customer Service Incentive Scheme (CSIS)

The focus of CSIS engagement was on the transition of the customer service component of the current Service Target Performance Incentive Scheme (STPIS) to a new CSIS that reflects the provision of quality services that are valued by customers.

The CAF has been very supportive of our efforts to establish a CSIS and have explored a range of potential measures with us through ongoing engagement. However, we have established that we do not yet have sufficient data to propose a suitable baseline target for these preferred CSIS measures.

We will therefore accept the AER's Draft Decision to retain the telephone answering component of the STPIS for the 2025-30 period and will continue to work with our stakeholders to establish a suitable CSIS from 2030. The CAF supported this approach at the 8 November meeting and we thank them for their ongoing focus on driving improved customer outcomes.

Innovation Fund

To address AER feedback in the Draft Determination, a workshop with our RAG and Advisory Group Chairs was held on 24 October to:

- Provide an overview of the Innovation Fund in the context of our broader innovation program;
- Seek endorsement for the initial project list and prioritisation; and
- Seek endorsement of the proposed governance model and agreement on principles / criteria for assessing projects during the regulatory period together with our customer groups.

The AER provided some framing, highlighting the importance of innovation for us as industry leaders and a desire for strong governance to allow consumer input.

The workshop endorsed our proposed governance model, including the establishment of an Innovation Advisory Group to input into fund projects as well as having visibility into our broader innovation framework.

The assessment criteria for the Innovation Fund projects were supported following their input to specific drafting of the criteria. Further, following the workshop, a survey was sent to attendees seeking feedback on the prioritised list of projects to submit as part of this proposal.

3. Summary of our Revised Proposal

This Overview document contains our overall response to the AER's Draft Decision, and our Revised Proposal for 2025-30. In many areas, the AER accepted or accepted with minor changes our Original Proposal. The AER, however, made substantial cuts to some categories of our proposed Capex, which we do not accept. We have also updated our Opex forecast since our Original Proposal.

For our Revised Proposal, we are retaining the same structure and Attachment numbering as our Original Proposal. Where we accept or substantively accept the AER's Draft Decision (in some cases with only minor or consequential changes from other areas) we outline these in this Overview document and have not submitted a revised Attachment with our Revised Proposal. Where we propose more substantive changes in our Revised Proposal we have submitted a revised Attachment.

Table 1 summarises how we are responding to the AER's Draft Decision in this Revised Proposal.

Table 1: Revised Proposal and Attachments

Document	Description	Our response to the Draft Decision	Revised Proposal Attachements
Overview			This **Overview** document summarises our Revised Proposal.
Attachment 1	Annual revenue requirement and control mechanism	**Do not accept.**	**Attachment 1** updated to reflect updated forecasts as indicated below.
Attachment 2	Regulatory Asset Base	**Substantively accept.**	No Attachment 2 with this Revised Proposal. Updated forecast incorporated in Attachment 1.
Attachment 3	Rate of Return	**Substantively accept.**	No Attachment 3 with this Revised Proposal. Updated forecast incorporated in Attachment 1.
Attachment 4	Regulatory Depreciation	**Substantively accept.**	No Attachment 4 with this Revised Proposal. Updated forecast incorporated in Attachment 1.
Attachment 5	Capital Expenditure	**Do not accept.**	**Attachment 5** updated with revised Capex forecast.
Attachment 6	Operating Expenditure	**Substantively accept.**	**Attachment 6** updated with revised base, step, trend forecast
Attachment 7	Corporate Income tax	**Substantively accept.**	No Attachment 7 with this Revised Proposal. Updated forecast incorporated in Attachment 1.
Attachment 8	Efficiency Benefit Sharing Scheme	**Substantively accept.**	No Attachment 8 with this Revised Proposal. Updated forecast incorporated in Attachment 1.
Attachment 9	Capital Expenditure Sharing Scheme	**Substantively accept.**	No Attachment 9 with this Revised Proposal. Updated forecast incorporated in Attachment 1.
Attachment 10	Serv. Target Perf. Inc. Scheme	**Substantively accept.**	**Attachment 10** updates targets with latest (2023/24) data.
Attachment 11	Customer Service Incentive Scheme	**Accept.**	No Attachment 11 with this Revised Proposal.
Attachment 12	Demand management incentives and allowance	**Substantively accept.**	No Attachment 12 with this Revised Proposal. Updated allowances incorporated in Attachment 1.
Attachment 13	Classification of Services	**Substantively accept.**	**Attachment 13** updated to propose amendments to provision of standardised data sets to customers, and classifying a new EV charging infrastructure service.
Attachment 14	Pass-through events	**Accept.**	No Attachment 14 with this Revised Proposal.
Attachment 15	Alternative Control Services	**Accept.**	No Attachment 15 with this Revised Proposal. Updated ACS fees incorporated into updated TSS Part A in Attachment 18.
Attachment 16	Negotiated services framework and criteria	**Accept.**	No Attachment 16 with this Revised Proposal.
Attachment 17	Connection Policy	**Substantively accept.**	**Attachment 17** includes a proposed change in payment terms.
Attachment 18	Tariff Structure Statement	**Substantively accept.**	**Attachment 18** updates to Part A.
Attachment 19	Legacy Metering Services	**Do not accept.**	**Attachment 19** updates legacy metering forecasts.
Attachment 20	List of Proposal Documentation		**Attachment 20** summarises updated information provided with the Revised Proposal.

3.1 Annual revenue requirement and control mechanism

Our Revised Proposal nominal smoothed revenue requirement for Main Standard Control Services is $5,168 million, $25 million more than the AER's Draft Decision and equates to $4,739 million in real 2025 dollar terms.

Our Original Proposal forecast a smoothed revenue requirement for Main Standard Control Services revenue of $5,164 million in nominal terms.

This amount was based on forecast expenditure requirements and, notably, included a proposed revenue reduction to correct for an error in the treatment of expenditure allowances for cable and conductor repairs in the 2020-25 period. However, the AER made this correction in March 2024, after we submitted our Original Proposal, by revoking its 2020 Distribution Determination and making a substitute determination, which corrected this error in full by lowering allowed 2024/25 revenue by $67 million.

The AER's Draft Decision has forecast a nominal Standard Control Services smoothed revenue amount of $5,143 million, which is $21 million lower than we proposed. The lower revenue is largely the result of the AER adopting more recent CPI and weighted average cost of capital forecasts and reductions in the forecast Capex which were partially offset by the correction for the cable and conductor error having now occurred in the 2020-25 period, removing the need for an adjustment in the 2025-30 period.

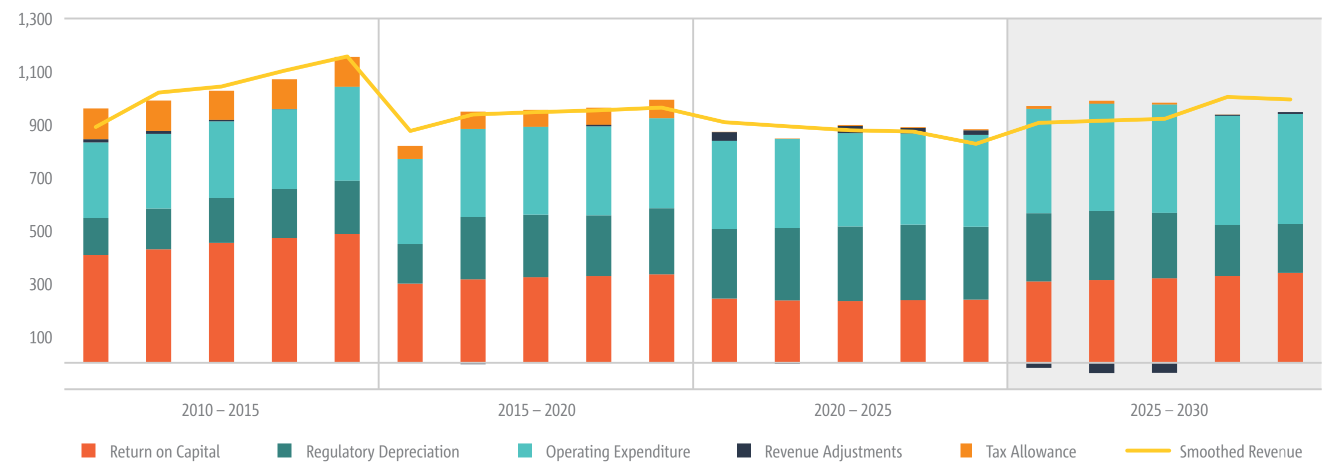
SA Power Networks has reviewed each of the revenue building block components and our responses are summarised in the following sections of this Overview document, and detailed further in the individual Attachments which form part of this Revised Proposal.

In our Original Proposal we proposed a revenue smoothing approach which kept distribution prices lower in the first three years of the 2025-30 period, but with a 6% step increase in year four. We took this approach cognisant of current cost of living pressures and recognising that customers' total electricity bills will reduce after 2027/28 when the South Australian Government's solar feed-in-tariff scheme concludes, offsetting the 6% distribution price increase in year four.

We note that in its Draft Decision, the AER adoped a similar revenue smoothing approach. Our Revised Proposal also retains this approach.

Figure 3 illustrates the revised revenue smoothing profile, keeping customer prices down in the early years of the 2025-30 period with a 9% step increase in year four.

Figure 3: Forecast 2025-30 Main Standard Control Services revenue (ie excluding legacy metering services revenue) shown in real 2025 dollar terms



The resulting increase in customer distribution prices from year four will be fully offset by the conclusion of the South Australian Government's feed-in-tariff scheme in June 2028.

Our Revised Proposal also includes nominal smoothed revenue for legacy metering of $46 million.

As per the AER's Framework and Approach decision for 2025-30, we continue to be regulated via a revenue cap form of control.

Table 2: Main Standard Control Services revenue Building Block parameters ($ million, nominal)

Main Standard Control	Original Proposal	AER Draft Decision	Revised Proposal
Return On Capital	1,760	1,716	1,752
Regulatory depreciation	1,293	1,201	1,237
Operating expenditure	2,139	2,161	2,219
Revenue adjustments	(67)	4	(88)
Tax allowance	30	44	31
Unsmoothed revenue	**5,155**	**5,126**	**5,150**
Smoothed revenue	**5,164**	**5,143**	**5,168**
WACC (forecast 2025-30 average)	6.18%	6.11%	6.11%
Regulatory asset base at 30 June 2030	6,539	6,362	6,587

Revised Proposal Attachment 1 - Annual Revenue Requirement and Control Mechanism, contains further revenue details, including our revised legacy metering revenue requirement.

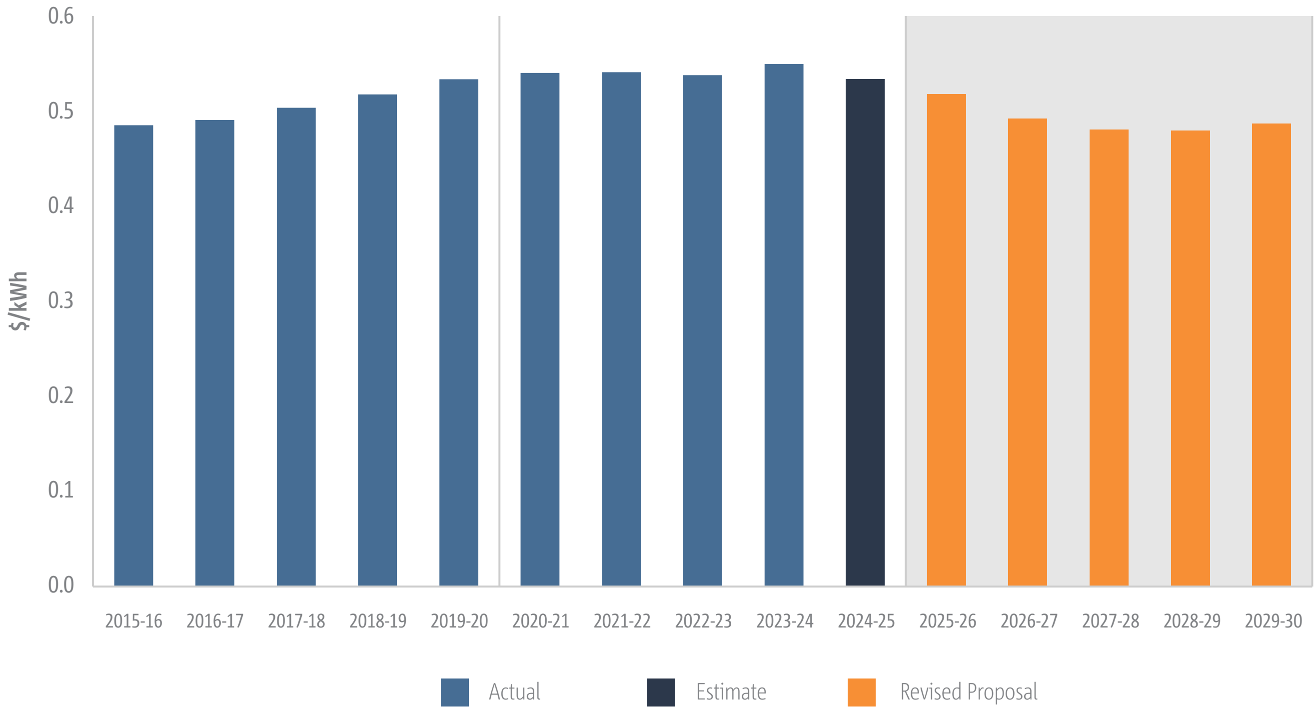
3.2 RAB, Rate of return, depreciation and tax

Regulatory Asset Base (RAB)

Our Revised Proposal capital program results in a nominal closing Regulatory Asset Base (RAB) at 30 June 2030 of $6,587 million, a regulatory depreciation allowance of $1,237 million and a taxation allowance of $31 million for the 2025-30 period. Our Original Proposal forecast a nominal closing RAB at 30 June 2030 of $6,539 million, a regulatory depreciation allowance of $1,293 million and a nominal taxation allowance of $30 million.

While our RAB is growing in real terms by 9% over the 2025-30 period, it is also forecast to deliver 20% more electricity volume (kWh) to customers. The RAB value per kWh of electricity delivered, reduces by 9% or 5 cents/kWh over the 2025-30 period (Figure 4).

Figure 4: Regulated Asset Base $ per kWh delivered ($, 2025)



We are not providing a Revised Proposal Attachment 2 – Regulatory Asset Base.

Rate of Return

Our Original Proposal applied the AER's 2022 Rate of Return Instrument to determine the forecast rate of return (post-tax nominal weighted average cost of capital, WACC) as 6.18% over 2025-30. This forecast WACC included placeholder estimates for the risk-free rate and pre-tax cost of debt. In its Draft Decision the AER accepted our methodology for forecasting WACC but updated the placeholder estimates to the forecast WACC which now averages 6.11% over 2025-30. We accept this decision and have adopted the same placeholder WACC across 2025-30 in this Revised Proposal for determining the return on capital revenue component.

We are not providing a Revised Proposal Attachment 3 – Rate of Return.

Depreciation

The AER's Draft Decision accepted our Original Proposal depreciation methodology but introduced a new asset class for Stobie Poles, commencing 1 July 2025, with an 80-year life for regulatory purposes, removing these assets from the Distribution Lines asset class. The Distribution Lines asset class currently has a 55-year life for regulatory purposes but from 1 July 2025, the AER's Draft Decision is that assets remaining in this class will have a reduced life of 52.1 years for regulatory purposes. These changes are designed to be revenue neutral in 2025-30.

SA Power Networks accepts the AER's decision to introduce a new asset class for Stobie poles, with an 80-year life.

We are not providing a Revised Proposal Attachment 4 – Regulatory Depreciation. 4.1 RAB Depreciation Model Dec24 provides further detail.

Tax

Our Original Proposal taxation allowance was calculated in accordance with the AER's 2018 Review of the Regulatory tax approach and the value of imputation credits (gamma) in the AER's 2022 Rate of Return Instrument. The AER's Draft Decision accepted the approach but adjusted the forecast allowance to reflect its lower capital expenditure Draft Decision. This decision increased the taxation allowance forecast by $14 million (nominal) as the Draft Decision capital program contains less forecast asset replacement expenditure - which is immediately deductible for taxation purposes – contributing to a higher taxation allowance.

Our Revised Proposal taxation allowance reflects our revised capital program and has been included in Attachment 1. The calculation for immediately deductible Capex has been updated to reflect 2023/24 overhead rates.

We are not providing a Revised Proposal Attachment 7 – Corporate Income Tax.

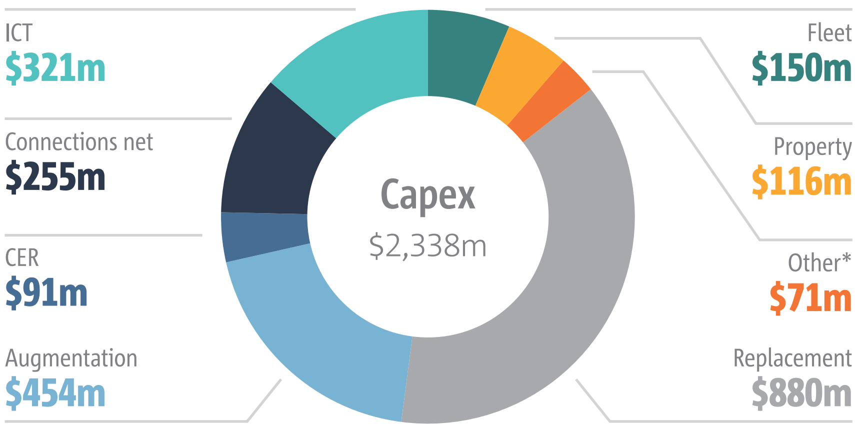
3.3 Capital Expenditure

Original Proposal
$2,379m

AER Draft Decision
$2,135m

Revised Proposal
$2,338m

Capital Expenditure (after disposals)($2025)



*Other includes: other non-network, capitalised overheads, disposals, modelling adjustments

In our Original Proposal, we forecast a capital program of $2,379 million after disposals in real 2025 dollar terms. In its Draft Decision the AER found our proposed expenditure was largely prudent and efficient, approving close to 90 percent of our forecast Capex. The Draft Decision allowed $2,135 million, or $244 million (10.3%) lower than we originally proposed.

The AER accepted our proposed expenditure in the following areas:

- Network Connections;
- Customer Energy Resources;
- ICT, with the exception of market-driven investment that wasn't fully known at the time of the Original Proposal;
- Fleet; and
- Property.

It did not accept our proposed expenditure for:

- Network asset replacement (Repex) – reducing our forecast by 15%;
- Network augmentation (Augex) – reducing our forecast by 31% for the maintain underlying reliability program, and 15% for the demand driven capacity program;
- CBD reliability – reducing our forecast expenditure by 87% (reflected in the abovementioned reductions to repex and augex) as a placeholder decision; and
- the Innovation Fund – allowing no expenditure as a placeholder decision.

Reductions in the network programs also resulted in consequent decreases in allowed expenditure for Fleet and Network Overheads.

The AER accepted all the identified needs for our investments (the customer outcomes of service levels, new efficiencies, and compliance needs), leaving only technical issues to address in our Revised Proposal.

We acknowledge these concerns and have incorporated most suggestions from the AER, including:

- better aligning our modelling input assumptions and calibrations with recent actual data in a standardised way across our network expenditures;
- assessing additional investment options via a more granular optimisation of all least cost solutions;
- modelling using updated external data and forecasts;
- improving project selection using economically optimal timing and evidenced our enhanced process; and
- more specifically justified our innovation projects applying new AER assessment criteria.

We have only revised our forecasts in response to the areas where the AER raised concerns. These revisions are set out in Table 3.

Table 3: Capital expenditure revisions made

Area	Revised Proposal	Change vs Proposal	Revisions made
Network asset replacement (Repex)	$880 m	3.3% lower	Addressed AER concerns with modelled Repex by revising / updating risk input assumptions and model calibrations with consistent use of actual data averaging periods. Also verified that our proposal will do no more than maintain the service levels in metrics of outage duration and frequency.
CBD reliability program (Repex & Augex)	$61 m	32.2% lower	AER forecast was a placeholder. Addressed concerns by better calculating the baseline service level (determining the size of the gap to the compliance service level to achieve) and a more granular/locational analysis to select an investment option optimising on least cost across all available solutions including network topology alterations.
Augex - capacity	$204 m	15.5% lower	Addressed AER concerns with demand driven projects by updating demand forecast inputs and improving project selection using economic timing.
Augex - maintain underlying reliability program	$74 m	2.6% higher	Addressed AER concerns via additional / updated analysis of continued worsening reliability and the drivers (weather, vegetation contact, animals and third party outages) which remain unabated, and adjusted the forecast to maintain the latest 5 year actual spend. Also better explained why the expenditure forecast is needed to maintain the current reliability that customers have experienced over the period 2019/20 to 2023/24.
ICT AEMO changes	$15 m	549.2% higher	AER forecast was a placeholder. Revised options analysis and costings based on clearer indication of requirements for our market systems arising from AEMO's ESB post 2025 market changes work program.
ICT metering transition	$7 m	n/a	AER accepted forecast would be revised. Costings revised based on the now clearer implications to our IT systems arising from the AEMC reforms to accelerate the rollout of smart meters.
Fleet	$150 m	2.9% lower	Revised the AER modelling adjustment reflecting the level of network expenditure for our Revised Proposal
Innovation Fund	$16 m	0.3% higher	AER forecast was a placeholder. Addressed AER concerns by justifying projects against the AER's new assessment criteria, and explained costs, benefits, governance arrangements, and reconciled project/proposal costs.
Network overheads	$32 m	3.6% lower	Revised AER adjustment reflecting the level of network expenditure of our Revised Proposal.
Modelling adjustments	$10 m	n/a	Applied the AER Draft Decision CPI and revised real labour price escalators using latest forecasts.

We consider our proposal evidences our revised Capex forecast is in customers' interests, on the basis that:

- the Draft Decision already approved 90 percent of our forecast Capex as prudent and efficient;
- our identified customer service needs are evidenced as prudent and found to be so in the Draft Decision;
- forecast Capex has only been revised to address the Draft Decision and the remaining and largely technical concerns, driving several improvements and a lower forecast relative to our original forecast;
- proposed service outcomes (service levels, new efficiencies, compliance) remain aligned to customer preferences;
- the expenditure to achieve our proposed service outcomes are individually evidenced as efficient, being either least cost or having quantified benefits to customers exceeding costs; and
- the total of our forecast capital and new operating expenditure, as a further top-down assurance on efficiency, is evidenced to be materially efficient, with benefits significantly exceeding costs and resulting in a net present value of circa $650 million.

Our Revised Proposal results in a revised capital expenditure forecast of $2,338 million, $41 million (1.7%) less than our original forecast and $203 million (9.5%) more than the AER's Draft Decision.

Our revised capital expenditure proposal is set out in **Revised Proposal Attachment 5 – Capital Expenditure.**

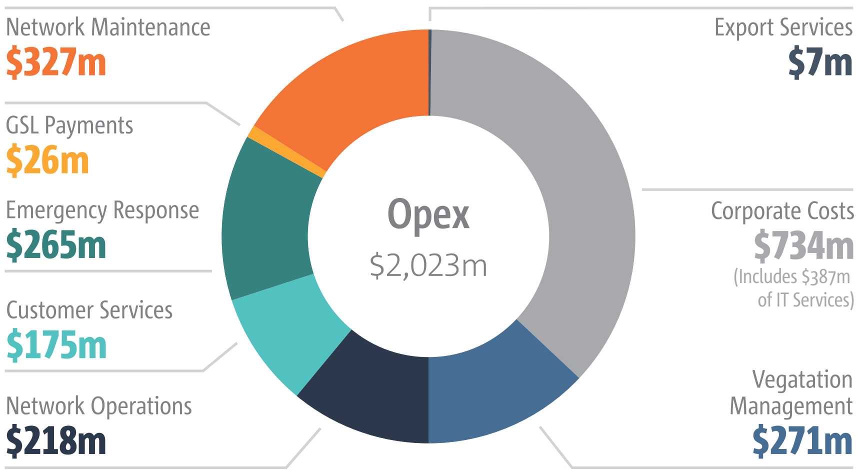
3.4 Operating Expenditure

Original Proposal
$1,970m

AER Draft Decision
$1,970m

Revised Proposal
$2,023m

Operating Expenditure (excluding debt raising costs)($2025)



In our Original Proposal, we proposed $1,970 million operating expenditure (excluding debt raising costs), forecast in accordance with the AER's preferred 'base-step-trend' approach. In its Draft Decision, the AER accepted our proposed expenditure because their alternative estimate was not materially different ($38 million or 1.9% lower) from our proposal.

The AER's decision accepted 2023/24 as an efficient base year, but consistent with regulatory practice for operating expenditure, its Final Decision is subject to receiving final audited actual data for the 2023/24 year and will also be updated for the latest inflation, labour price growth and output growth forecasts. The AER also encouraged us to provide updated forecasts for the smart meter rollout - IT upgrades step change and including a category specific operating forecast for the Innovation Fund.

Our revised forecast responds to the Draft Decision by:

- accounting for latest available information, including updating for actual revealed costs, and updating forecasts on inputs for network output growth and input cost escalation; and
- addressing issues the AER raised with some of our originally proposed step changes, including revising costs for changes where only 'placeholders' were available at the time.

We have revised the:

- base year – updated to now audited revealed (2023/24) operating expenditure – as per standard regulatory practice;
- trend escalation - updated output growth and real labour price escalation forecasts using latest available information – as per standard regulatory practice;
- step changes – addressing AER concerns by removing a step change that the AER disagreed with (Network Program Uplift, $18 million) and increasing one of our negative step changes (Reliability Improvements to $1 million); and revising the costs of one of our step changes the AER had accepted was only a 'placeholder' to (Smart Meter Rollout – IT Upgrades to $1 million); and
- category specific forecasts – removing a forecast no longer requiring ex-ante funding (small compensation claims scheme, $20 million), no longer seeking ex-ante funding for the resourcing costs included in this item ($2 million) and adding in a forecast to align to the AER's preference on cost recovery (Innovation Fund, $4 million).

We have only revised our proposal to address issues raised in the AER Draft Decision and otherwise expected by typical regulatory practice, leaving all other areas of our Original Proposal unchanged. Our revisions are summarised in Table 4.

Table 4: Operating expenditure revisions made

Area	Revised Proposal	Change vs Proposal	Revisions made
Base Opex	$1,879 m	4.9% higher	We updated our base year for audited revealed Opex for our nominated 2023/24 base year as is typical practice, noting that only an estimate was available at the time of our proposal. We also reviewed base year expenditure, removed an item that represented a 'one-off' cost, accounted for movements in provisions, updated 2024-25 year incremental adjustment and retained the Software as a Service adjustment.
Trend	$32 m	7.0% higher	We updated forecasts based on latest available information on output weights, forecast demand, customer number growth and circuit length growth – consistent with AER typical practice. We also updated for the latest available information on real labour price escalation.
Step changes	$107 m	17.0% lower	While we disagreed with the AER that our originally proposed step change to cover the costs of resourcing the uplift in our network capital program in 2025-30 is already provided for in the Opex framework, we have decided to remove this item from our forecast. We have also accepted the AER's view that our originally proposed negative step change to account for lower costs of emergency response and GSL payments arising from our Worst Served Customers Reliability improvement programs (approved in the Draft Decision) needed to apply a larger estimated reduction.
Category specific forecasts	$4 m	80.0% lower	We agreed to remove the costs of the 'small customer claims compensation scheme'. The SA Government is now establishing a new Small Compensation Claims Scheme in South Australia through amending the National Energy Retail Law. We also included the operating component of our proposed Innovation Fund, to align to the AER's preferred treatment of these costs, having now enhanced our justification for the fund.

Our revised operating expenditure proposal amounts to $2,023 million, $53 million (2.7%) higher than our original forecast and the AER's Draft Decision.

Our revised operating expenditure proposal is set out in **Revised Proposal Attachment 6 – Operating Expenditure.**

3.5 Incentive Schemes

Efficiency Benefit Sharing Scheme (EBSS)

In its Draft Decision, the AER included an EBSS carryover of -$41 million ($ June 2025) for SA Power Networks. This is $21 million less than our Original Proposal EBSS carryover of -$20 million.

In March 2024, after we submitted our Original Proposal, the AER revoked its 2020 Distribution Determination for SA Power Networks and made a substitute determination, including revising the operating expenditure allowance for 2020-25. The AER's Draft Decision on EBSS reflects this revised allowance.

We substantively accept the AER's Draft Decision but have further updated the EBSS outcome to reflect actual (audited) 2023/24 operating expenditure and latest inflation data. This results in a EBSS carryover loss of -$115 million ($ June 2025). Table 5 summarises the changes, and we have incorporated the revised EBSS outcome in our Revised Proposal Attachment 1.

Table 5: EBSS carryover in 2025-30 ($ million, June 2025)

EBSS Carryover	Total
Original Proposal (based on preliminary 2023/24 forecast Opex)	-20
Draft Decision (based on updated 2023/24 forecast Opex)	-41
Revised Proposal (based on final audited 2023/24 Opex)	-115

We are not providing a Revised Proposal Attachment 8 – Efficiency Benefit Sharing Scheme. We have submitted an updated EBSS model and EBSS data in revised Regulatory Information Notice templates.

Capital Expenditure Sharing Scheme (CESS)

In its Draft Decision, the AER included a CESS revenue adjustment of $49 million ($ June 2025) for SA Power Networks. This is $26 million higher than Our Original Proposal forecast of $23 million.

As noted above, the AER revoked its 2020 Distribution Determination for SA Power Networks in March 2024 and made a substitute determination which also revised the capital expenditure allowance for 2020-2025. The AER's Draft Decision on CESS reflects this revised allowance.

We substantively accept the AER's Draft Decision but have further updated the CESS outcome to reflect actual (audited) 2023/24 capital expenditure and updated capital expenditure forecasts for 2024/25. This results in a CESS revenue increment of $36 million ($ June 2025).

Table 6 summarises the changes, and we have incorporated the revised CESS outcome into our Revised Proposal Attachment 1.

Table 6: CESS carryover in 2025-30 ($ million, June 2025)

CESS Carryover	Total
Original Proposal	23
Draft Decision	49
Revised Proposal	36

We are not providing a Revised Proposal Attachment 9 – Capital Expenditure Sharing Scheme. We have submitted an updated CESS model and CESS data in revised Regulatory Information Notice templates.

Service Target Performance Incentive Scheme (STPIS)

We accept the AER's Draft Decision to apply the reliability of supply component of version 2.0 of the STPIS for the 2025-30 period. SA Power Networks' performance under this STPIS component will result in rewards or penalties of up to +/- 4.5% of annual revenue.

However, we have two detailed concerns with the AER's Draft Decision for STPIS:

- the AER has overstated the improvement in reliability that will be achieved from our reliability improvement projects by not allowing for the reduction in the number of Major Event Days that result; and
- the AER rejected our proposed adjustment to accommodate the removal of a derogation which exempted us from notifying customers of planned outages of up to 15 minutes duration.

Our Revised Proposal addresses these two matters and also updates the 2025-30 targets to incorporate audited 2023/24 outcomes.

Refer **Revised Proposal Attachment 10 – Service Target Performance Incentive Scheme.**

Customer Service Incentive Scheme (CSIS)

In our Original Proposal, we proposed replacing the customer service component of STPIS version 2.0 with a new CSIS, with performance under the CSIS resulting in rewards or penalties of up to +/- 0.5% of annual revenue (equivalent to the revenue at risk under the customer service component of STPIS version 2.0). Our Original Proposal CSIS proposed two new measures:

- Percentage of General Enquiries calls to our Contact Centre that were resolved on the first call; and
- Percentage of field crew status updates of 'arrived on site' provided to customers (via SMS, website) during unplanned power interruptions.

These measures were developed in consultation with customers through our deep dive workshops (Focussed Conversations), who strongly supported their inclusion for the 2025-30 period.

Following submission of our Original Proposal, we continued to scrutinise and test our proposed CSIS measures and, unfortunately, determined we did not have sufficient robust data to set reliable targets.

This led the AER in its Draft Decision to not accept our proposed CSIS, instead appling the customer service (telephone answering) parameter of the STPIS Version 2.0.

Following the AER's Draft Decision, we continued to explore options for a revised CSIS further with stakeholders[2]. This included consideration of the AER's Draft Decision to retain the current STPIS customer service measure of the percentage of Faults and Emergencies calls answered within 30 seconds.

While stakeholders strongly supported the inclusion of a revised CSIS, unfortunately we did not have sufficient data providing a consistent baseline over a twelve-month period to set CSIS targets. We have advised stakeholders of this[3] and will continue to work with our Community Advisory Forum and other groups to establish a suitable CSIS from 2030.

We will therefore accept the AER's Draft Decision to retain the telephone answering component of the STPIS for 2025-30.

We are not submitting a revised Revised Proposal Attachment 11 – Customer Service Incentive Scheme. Instead, we have proposed 2025-30 telephone answering targets based on the five-years to 2023/24 historical performance average, in **Revised Proposal Attachment 10 – Service Target Performance Incentive Scheme.**

Demand Management Incentive Scheme and Allowance

We accept the AER's Draft Decision to apply both the demand management incentive scheme and demand management innovation allowance (DMIAM) for the 2025-30 period. As the DMIAM includes a component based on percentage of revenue allowance, our Revised Proposal proposes a revised DMIAM amount based on our Revised Proposal Revenue.

The revised DMIAM is included in **Revised Proposal Attachment 1 – Annual Revenue Requirement.**

2) Customer Advisory Forum 14 August 2024 meeting and Reset Advisory Group 27 August 2024 meeting.
3) Customer Advisory Forum 8 November 2024.

3.6 Classification of Services

In our Original Proposal, SA Power Networks' proposed classifications of services were consistent with the AER's final Framework and Approach[4] except for legacy metering services which we proposed to reclassify as Standard Control Services, consistent with a Guidance note[5] issued by the AER in October 2023. In its Draft Decision, the AER confirmed the classification of legacy metering services as Standard Control Services. We accept the AER's Draft Decision on this matter. However, there are two service classification matters we seek the AER to consider further.

Provision of Standardised data sets

In its Draft Decision, the AER made the following adjustments for 'data services' in line with its final decision for the 2024-29 Resets:

- The "provision of standardised data sets and/or data that is provided to a distributor, at no cost to the distributor, in accordance with obligations under the rules" as a new common distribution, standard control service; and
- "data requests by customers or third parties for the provision of electricity network data beyond standardised data sets or obligations under the rules" as an alternative control service.

The AER stated these amendments were to give effect to the intentions of the AEMC's metering review, also noting the Rule change request lodged by Energy Consumers Australia for customers' access to real-time data.

We are concerned that this drafting could be interpreted as obligating SA Power Networks to provide any data we receive from third parties at no cost, where we are not otherwise required to provide this data under the rules. This would include the provision of power quality data received from metering coordinators. To extract and provide this data for customers at scale will require systems modifications, not costed or included in our 2025-30 expenditure forecasts. In its November 2024 Rule change[6], the AEMC did not impose any new obligations on distributors to provide additional data to customers.

We also note, the common distribution services suite of activities includes, but is not limited to, the activities listed within the classification table in Appendix A. Where a new obligation is imposed on SA Power Networks to provide additional data to customers free of charge (as a standard control service), we do not consider the service needs to be specifically listed within the classification table. Therefore, we propose to delete the additional wording in standard control services and remove reference to standardised data sets in alternative control services in our Revised Proposal.

Revised Proposal Attachment 13 – Classification of services provides further details.

EV Charger of Last Resort

Since lodging our Original Proposal, we have participated in discussions with councils and the South Australian Government on the provision of Electric Vehicle (EV) charging services in South Australia. The SA Government is very supportive of accelerating the take up of EVs by South Australians, with predictions for over 250,000 EVs on South Australian roads by 2030. We believe, however, there will be transitional issues where it is not economic for third party providers to install EV charging infrastructure in some locations due to low EV density.

Councils and the Royal Automobile Association of Australia (RAA) are supportive of SA Power Networks being able to provide an EV 'Charger of Last Resort' service in the 2025-30 period on an as requested basis.

In this Revised Proposal we are proposing this new service be classified as an Alternative Control Service (ACS) quoted service, noting this service would only be provided on request from councils or other parties, and would not prevent other parties from also providing a kerbside charging service.

Accordingly, our Revised Proposal requests the AER classify this new service as an ACS for the 2025-30 period. As an ACS, the cost of providing this service will be funded in full by the requesting party.

4) AER, *Framework and approach*, SA Power Networks 2025-30, July 2023.
5) AER, *Legacy metering services* – guidance note, November 2023.
6) AEMC Rule change published 28 November 2024.

3.7 Pass-through events

The following pass-through events are provided in the National Electricity Rules:

- a 'regulatory change event';
- a 'service standard event';
- a 'tax change event';
- a 'retailer insolvency event'; and
- any other event specified in a distribution determination as a pass-through event for the determination.

In our Original Proposal, we proposed the following four additional pass-through events for the 2025-30 period:

- natural disaster event;
- insurer's credit risk event; and
- insurance coverage event; and
- terrorism event.

The AER approved these four additional pass-through events in its Draft Decision for SA Power Networks' 2025-30 Distribution Determination. It also approved these same events in their April 2024 Final Decisions for NSW, ACT, TAS and NT distribution determinations.

We accept the AER's Draft Decision. We are not submitting a Revised Proposal Attachment 14 – Pass-through events.

3.8 Alternative Control Services

In 2025-30, Alternative Control Services include public lighting services and a range of ancillary network services which are fee-based or quoted price services paid by the individual customers who request these services.

Public lighting

The suite of public lighting tariffs proposed for 2025-30 is unchanged from the 2020-25 period.

In its Draft Decision, the AER indicated our public lighting services proposal was largely reasonable. However, it updated labour price escalators, weighted average cost of capital (WACC) and consumer price index (CPI) assumptions for consistency with other aspects of its Draft Decision, resulting in minor adjustments to the proposed prices for public lighting.

While in principle we accept the AER's decision on public lighting prices, we have further updated the public lighting models to reflect SA Power Networks' actual capital expenditure incurred in 2023/24 and the updated labour escalation rates received from Oxford Economics. We have also corrected the application of the AER's Draft Decision WACC across all the public lighting models. These amendments have resulted in minor adjustments to the pricing contained in the AER's Draft Decision. We discussed these amendments with public lighting customers at our public lighting forum on 22 October 2024, with broad support for the 2025-30 pricing outcomes proposed. We have included the adjusted prices in Part A of our Revised Proposal Attachment 18 - Tariff Structure Statement.

We are not submitting a Revised Proposal Attachment 15 – Alternative Control Services, for public lighting prices. We have provided updated Public Lighting models as part of our Revised Proposal.

Ancillary Network Services

For 2025-30 we proposed to maintain the list of fee-based services currently offered in 2020-25 and introduce three new fee-based services for multi-site outages, retailer by-pass request and retailer-requested a 'Knock before you disconnect' service.

In its Draft Decision, the AER indicated our proposal for ancillary network services was largely reasonable but did not accept two (of twelve) labour rate categories: Administrative Office (business hours) and Field Worker (business hours). The AER also substituted proposed year one (2025/26) prices for fee-based services reflecting its Draft Decision CPI and X factors.

As none of the adjusted prices are materially different from our Original Proposal prices, we accept the AER's decision on labour rates and forecast CPI. For consistency, we have updated the labour escalation rates received from Oxford Economics. This has resulted in minor reductions from the AER's Draft Decision price outcomes.

We have proposed a new EV charging of last resort service to support the uptake of EVs in South Australia, as detailed in Attachment 13 – Classification of Services. We propose to provide this service as a quoted service for the 2025-30 period.

We are not submitting a Revised Proposal Attachment 15 – Alternative Control Services, for ancillary network services. The adjusted prices are set out in Part A of our **Revised Proposal Attachment 18 - Tariff Structure Statement** and 15.1.1 – Standardised ANS Model.

3.9 Negotiated Services Framework

In our Original Proposal, SA Power Networks proposed a negotiated services framework as required by the National Electricity Rules. The framework is the same as applied in the 2020-25 period. The AER accepted our 2025-30 Negotiating Framework in its Draft Decision and SA Power Networks accepts this decision.

We note that there are no distribution services classified as negotiated distribution services for 2025-30 period and therefore the expectation is that the Negotiating Framework will not be required for the 2025-30 period.

We are not submitting a Revised Proposal Attachment 16 – Negotiated services framework and criteria.

3.10 Connection Policy

In our Original Proposal, SA Power Networks proposed a Connection Policy for the 2025-30 period. The Policy was updated to reflect the nature of more complex and flexible loads and generation (particularly large battery energy storage systems) and updates included:

- Lower upfront costs for customers selecting a flexible option where applicable;
- A firm capacity option for load customers where capacity is reserved for the customer (including in demand and constraint forecasting) but not guaranteed under certain network operational scenarios;
- A 'Flex' option for certain types of customers where the customer has agreed to dynamically adjust their import or export power profile to operate within network operating limits and therefore may not be charged an augmentation cost; and
- A 'Load plus Generation' pricing option to ensure there is no double counting for those customers choosing a load and generation connection (such as Battery Energy Storage Systems, Load and solar combinations).

The AER accepted our proposed Connection Policy in its Draft Decision. Following discussion with and endorsement from stakeholders[7], we are proposing updates to the Connection Policy's payment terms.

We are proposing that where the charges payable by a connecting customer are $10,000 (June 2025) or less, that these are payable on the customer's acceptance of our connection offer. This is an increase from the current threshold of $5,000. We and our stakeholders feel this increase is reasonable noting the $5,000 threshold was set referencing 2012 dollar terms. Where connection charges exceed $10,000 (June 2025), these would be subject to a payment schedule determined by SA Power Networks.

Refer supporting document 17.1 – Connection Policy – Amendment to payment terms threshold for further details.

Proposed drafting reflecting these changes are marked-up in **Revised Proposal Attachment 17 – Connection Policy.**

7) Connections Advisory Group 10 October 2024 meeting.

3.11 Tariff Structure Statement (TSS)

In its Draft Decision, the AER substantively accepted our proposed 2025-30 Tariff Structure Statement, and requested three areas of revision for the Revised Proposal:

- the ability for business customers with 'peaky demand' (customers with relatively low average demand compared to their maximum demand) to opt out of the time-of-use with demand tariff and into a time-of-use only tariff;
- more clarity on the eligibility of customers to access individually calculated tariffs; and
- demonstration of how our alternative control services (ACS) are compliant with the pricing principles.

In our Original Proposal, we proposed to mandatorily assign business customers with usage less than 160MWh pa and demand greater than 120kVA to our time-of-use with demand tariff, Medium Business Time of Use Demand (MBTOUD), without the ability to opt out to a time-of-use only tariff. The proposed assignment policy was a continuation of the current policy in 2020-25 and is cost reflective, that is, there is an appropriate pricing signal for customers with peaky demands on the distribution network. This approach was supported by the majority of our stakeholders but not the EV Council. The AER's Draft Decision did not accept our proposal, believing that by allowing customers to opt out of demand charges it supported broader objectives of emission reductions by allowing for a consistent approach across the National Electricity Market.

We accept the AER's decision. In our Revised Proposal Attachment 18 – Tariff Structure Statement Part A we have amended the tariff assignment policy for the Small Business Tariff class to allow customers assigned to MBTOUD to opt for a time-of-use only tariff.

Our Original Proposal outlined our approach to the individually-calculated customer tariffs for Major Customers connected to our network at a Zone Substation or at the Sub Transmission (66kV or 33kV) levels in our network. Individually-calculated tariffs are for customers with unique supply arrangements and/or with greater than 10MVA demand or 40GWh pa consumption who are subject to locational transmission pricing. In our Revised Proposal Attachment 18 – Tariff Structure Statement Part A we have provided clarity on our approach to individually-calculated tariffs for all our customers.

Our Original Proposal included ACS indicative pricing for 2025-30, however it did not explicitly demonstrate how these prices complied with the pricing principles. In our Revised Proposal Attachment 18 – Tariff Structure Statement Part A we have demonstrated compliance with the pricing principles.

We are not submitting a Revised Proposal Attachment 18 – Tariff Structure Statement Part B.

Refer **Revised Proposal Attachment 18 - Tariff Stucture Statement Part A** for further details.

3.12 Legacy Metering

In our Original Proposal, we proposed to reclassify legacy metering services to Standard Control Services, where the costs would be recovered across the broader customer base. This will reduce price inequities as legacy meters are progressively replaced with smart meters over the period. We used a 'base-step-trend' methodology to estimate our Opex forecast for legacy metering services, where the incremental costs associated with supporting the Australian Energy Market Commission's (AEMC's) 'Accelerating smart meter deployment' are included as a step change. This step change was developed based on our best estimates and understanding at that time. Since our Original Proposal and following further analysis, we revised down our cost estimates for the legacy metering transition step change.

The AER accepted SA Power Networks' proposal to reclassify legacy metering services to Standard Control Services, however it did not accept our legacy metering expenditure forecasts, pending finalisation of the AEMC Rule change.

The AEMC issued its Rule change on 28 November 2024 which, amongst other things, has delayed the commencement of the roll-out from July 2025 to December 2025.

In this Revised Proposal we have further refined our forecasts, assuming these revised dates. **Revised Proposal Attachment 19 – Legacy Metering** provides further details.

4. What it means for customers

In real terms our proposed expenditure, along with current financial market conditions, should see average distribution bills across the 2025-30 period remaining comparable to those of today.

Longer term, we expect distribution bills will reduce in real terms, particularly as the depreciation component of our revenue allowance will reduce as our existing network assets constructed prior to 2010 become fully depreciated for regulatory purposes.

As in our Original Proposal, in recognising customers' current affordability concerns, we have deliberately adjusted the profile of our revenue recovery (and hence customer bill outcomes) over 2025-30. This adjusted profile lowers average distribution bills (and therefore average retail bills) in the first three years of the period. The subsequent step increase in distribution bills from 2028/29 will flow through to retail bills but will be offset by savings in other components of the network bill, specifically the South Australian Government's solar 44c/kWh feed-in-tariff scheme concluding in June 2028. Consequently, customers should not see any step increase in their network bills from 2028/29.

The AER adopted a similar revenue profile in its Draft Decision.

Figures 5 and 6 represent average distribution bills. Individual customers' bills will vary. These charts exclude the forecast costs for metering which are approximately $10 p.a. for residential and small business customers.

Figure 5: Forecast annual average Residential customer distribution bills ($ 2025)

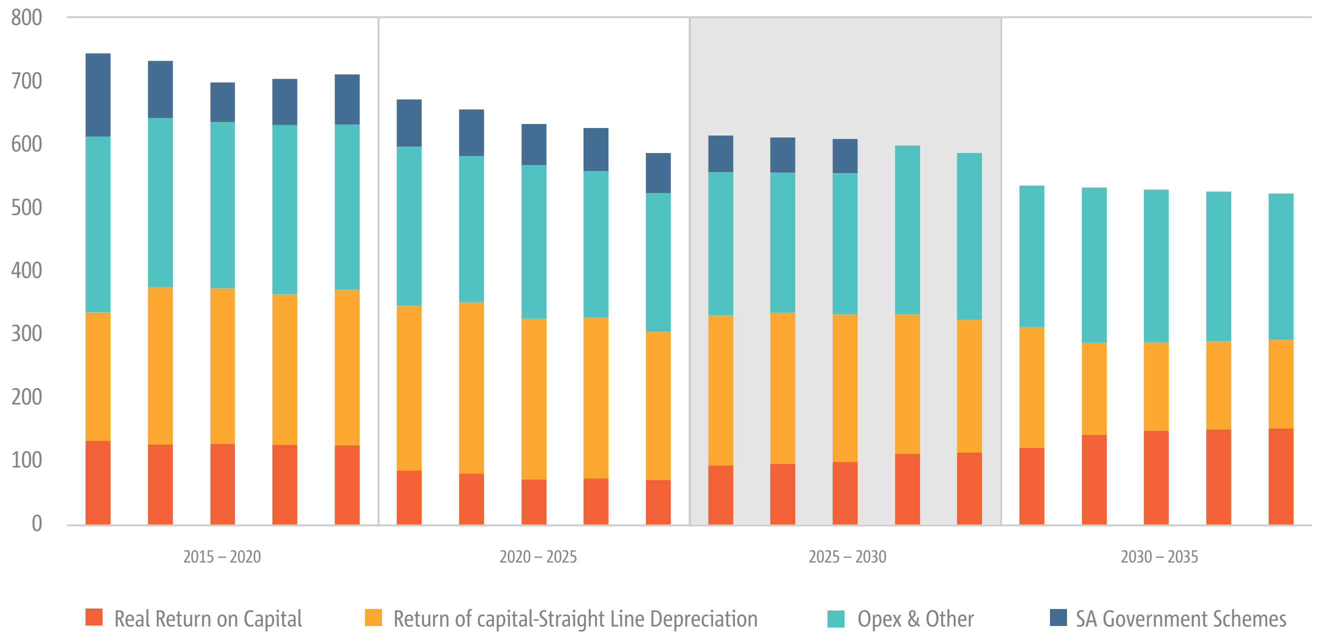
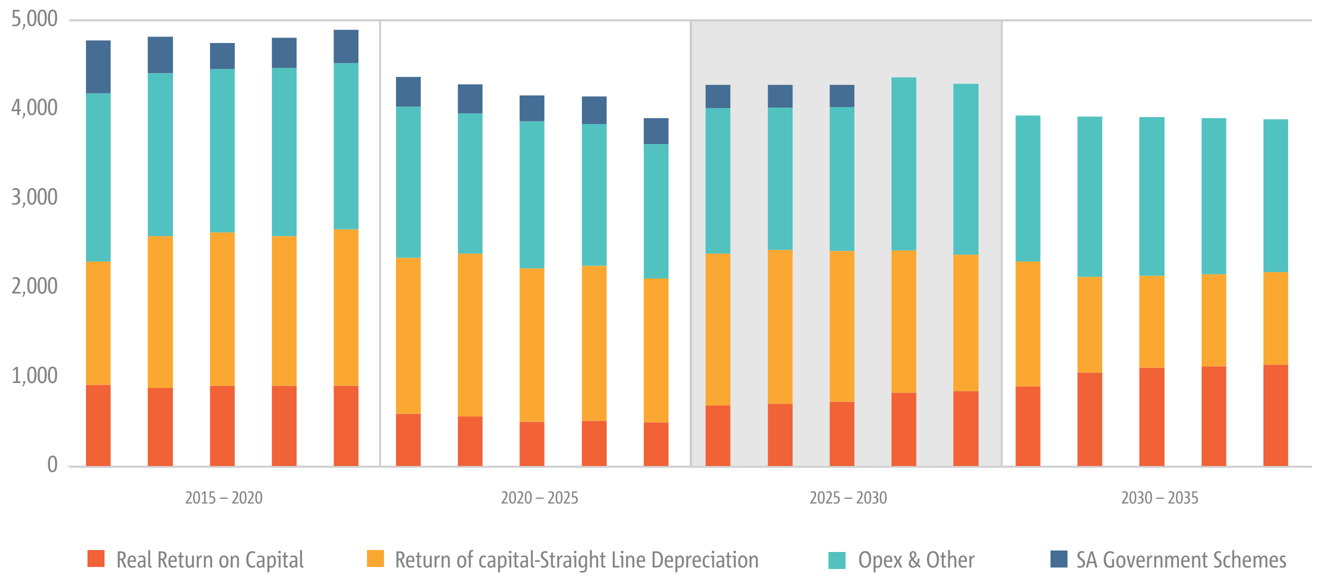


Figure 6: Forecast annual average Business customer distribution bills ($ 2025)



Have your say

We extend our thanks to the many stakeholders and customer representatives who helped shape our Original Proposal and this Revised Regulatory Proposal for the 2025-30 period.

Written submissions on our Revised Proposal should be forwarded to the AER at: **SAPN2025@aer.gov.au** by 17 January 2025.

We also encourage customers and stakeholders to continue to engage with us. Please visit **talkingpower.com.au** or email us at: **talkingpower@sapowernetworks.com.au**

Glossary

Term	Definition
ACS	Alternative Control Services include public lighting services and a range of ancillary network services which are fee-based or quoted price services paid by the individual customers who request these services.
AEMC	Australian Energy Market Commission – the body responsible for developing energy market rules and providing policy advice to the Australian government.
AEMO	Australian Energy Market Operator – the organisation responsible for operating Australia's electricity and gas markets and systems.
AER	Australian Energy Regulator – the body responsible for regulating electricity and gas network service providers in Australia.
Augex	Network Augmentation Expenditure – capital expenditure for the expansion of the network to meet increased demand or to improve network performance.
Capex	Capital Expenditure – funds used by a company to create and upgrade physical assets such as the electricity distribution network, property, fleet and ICT systems.
CAF	Community Advisory Forum – a group providing input from the community on SA Power Networks' services and proposals
CESS	Capital Expenditure Sharing Scheme – an incentive mechanism that shares the benefits or costs of capital expenditure variations with customers.
CSIS	Customer Service Incentive Scheme – a scheme designed to incentivise the network service provider to improve customer service levels.
CSIRO	Commonwealth Scientific and Industrial Research Organisation
EBSS	Efficiency Benefit Sharing Scheme – an incentive mechanism that encourages network service providers to pursue operating cost efficiencies, which are shared with customers.
EV	Electric Vehicle – a vehicle that uses one or more electric motors for propulsion.
ICT	Information and Communications Technology – the use of computing and telecommunications technology, systems and tools to facilitate the way information is created, collected, processed transmitted and stored.

This glossary includes key terms and units relevant to the Revised Regulatory Proposal for SA Power Networks.
It is designed to assist readers in understanding the technical aspects of the document.

Term	Definition
kW	Kilowatt – a unit of power equal to one thousand watts, used to measure the rate of energy conversion.
kWh	Kilowatt-hour – a unit of energy equal to one kilowatt of power expended for one hour of time.
Legacy Metering	The existing meters which will be replaced by smart meters as part of the AEMC's 'Accelerating smart meter deployment' rule.
MWh	Megawatt-hour – a unit of energy equal to one million watts of power expended for one hour of time.
NER	National Electricity Rules – the rules that govern the operation of the Australian National Electricity Market.
NERL	National Energy Retail Law – the legislation governing the retail sale of electricity and gas to consumers.
Opex	Operating Expenditure – the ongoing cost for maintaining and operating a business.
RAB	Regulatory Asset Base – the value of the regulated assets of a network service provider, used to calculate the allowed return on investment.
RAG	Reset Advisory Group - a group providing input from the community on SA Power Networks' Regulatory Reset.
Repex	Network Asset Replacement Expenditure – capital expenditure for the replacement of existing network assets to maintain the safety and reliability of the network.
STPIS	Service Target Performance Incentive Scheme – an incentive mechanism that sets performance targets for network reliability and customer service.
TSS	Tariff Structure Statement - A document outlining the structure of tariffs that a network service provider will offer for the use of its network.
WACC	Weighted Average Cost of Capital – the rate of return on assets a network business can earn, reflecting its cost of equity and cost of debt funding sources.

SA Power Networks

Empowering South Australia