Attachment 6 - Operating Expenditure

2025–30 Regulatory Proposal

January 2024

SA Power Networks

Empowering South Australia

Company information

SA Power Networks is the registered Distribution Network Service Provider for South Australia. For information about SA Power Networks visit sapowernetworks.com.au

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Disclaimer

This document forms part of SA Power Networks' Regulatory Proposal to the Australian Energy Regulator for the 1 July 2025 to 30 June 2030 regulatory control period. The Proposal and its attachments were prepared solely for the current regulatory process and are current as at the time of lodgement.

This document contains certain predictions, estimates and statements that reflect various assumptions concerning, amongst other things, economic growth and load growth forecasts. The Proposal includes documents and data that are part of SA Power Networks' normal business processes and are therefore subject to ongoing change and development.

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Note

This attachment forms part of our Proposal for the 2025–30 Regulatory Control Period. It should be read in conjunction with the other parts of the Proposal.

Our Proposal comprises the overview and attachments listed below, and the supporting documents that are listed in Attachment 20:

Document	Description
	Regulatory Proposal overview
Attachment 0	Customer and stakeholder engagement program
Attachment 1	Annual revenue requirement and control mechanism
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	Customer Service Incentive Scheme
Attachment 12	Demand management incentives and allowance
Attachment 13	Classification of services
Attachment 14	Pass through events
Attachment 15	Alternative Control Services
Attachment 16	Negotiated services framework and criteria
Attachment 17	Connection Policy
Attachment 18	Tariff Structure Statement Part A
Attachment 18	Tariff Structure Statement Part B - Explanatory Statement
Attachment 19	Legacy Metering
Attachment 20	List of Proposal documentation

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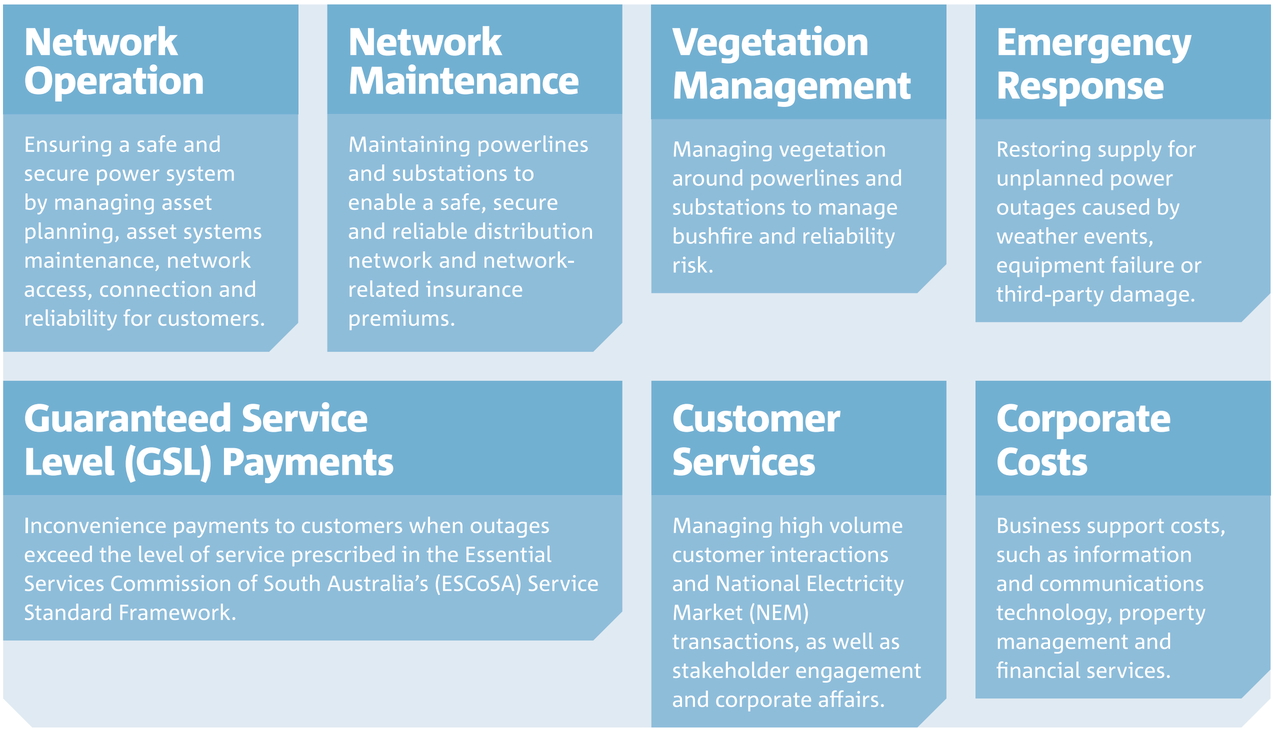
1 Background

Operating expenditure (**Opex**) is required to maintain and operate our distribution network assets and includes supporting corporate costs involved in providing distribution network services to customers.

Figure 1 includes a high-level summary of opex costs.

Figure 1: Summary of opex costs



Opex is typically recurrent in nature, however some categories of opex including guaranteed service level (**GSL**) payments and emergency response work, fluctuate with the number and severity of weather events impacting our network in any regulatory year. Some external factors may also arise which have a material impact on the recurrent nature of opex, an example being the COVID-19 pandemic which impacted our operations and affected some areas of expenditure over the last few years.

2 Overview

We forecast opex to deliver Main Standard Control Services[1] of $2.0 billion for the 2025–30 Regulatory Control Period (**RCP**) to deliver the service levels that our customers have told us that they seek, and to otherwise ensure that we meet expected demand for our services, comply with our regulatory obligations and requirements and maintain the quality, reliability, security and safety of the services we deliver to customers and our distribution system in an efficient and prudent manner.

Our forecast opex represents an 18.0 percent increase over our 2020–25 actual/forecast expenditure. The key drivers of this uplift include:

- a change in accounting treatment for procuring 'software as a service' (**SaaS**), driving capital to operating expenditure shifts;
- increased measures to address cyber security threats;
- higher insurance costs;
- the accelerated rollout of smart meters and the associated increase in network analytics;
- an uplift in resourcing costs required to deliver a proposed uplift in our network capital program; and
- an expected new regulatory obligation relating to claims and damages by customers.

Our opex forecast has been informed by an extensive customer engagement program. The totality of our opex forecast was communicated to customers within the overall total expenditure stack made transparent at each stage of our engagement program as customers evaluated options, and with our Community Advisory Board (**CAB**). Our engagement in Focused Conversations and via our People's Panel concentrated on new changes to opex, consistent with an agreed desire to 'focus on what matters' to customers. Throughout our engagement program, customers and stakeholders provided consistent feedback that they want us to:

- maintain overall service peformance with respect to network safety and reliability;
- maintain cyber security in the face of an increasing threat landscape;
- support the continued take-up of Customer Energy Resources (**CER**) and the broader energy transition;
- provide good service and communication interactions; and
- ensure that we are keeping bills as low as possible by being efficient and prudent in our investments, and examining ways of doing more for less.

Our opex forecast for the 2025–30 RCP responds to our regulatory requirements, our overall service needs, and the preferences of our customers by:

- being forecast to meet the opex requirements in clause 6.5.6 of the National Electricity Rules (**NER**), and the National Electricity Law (**NEL**);
- being forecast consistent with Australian Energy Regulator (**AER**) guidance in its Better Resets Handbook and its opex 'base-trend-step' methodology;
- reflecting the efficient base opex requirements of managing our overall and regular service performance needs for customers – based on our revealed costs as a network on the efficiency frontier;
- capturing expected changes in labour input costs, reasonable growth in network outputs and expected productivity gains of an efficient business;

[1] Main Standard Control Services operating expenditure excludes debt raising costs (discussed in **Attachment 3 – Rate of Return**), and legacy metering costs (discussed in **Attachment 19: Legacy Metering**) which are proposed to be reclassified from Alternative Control Services to Standard Control Services. All financial figures in this document are expressed in June 2025 dollars unless otherwise specified.

- accounting for changes in the nature of Information and Communication Technology (**ICT**) investments between capital expenditure (**capex**) and opex commensurate with accounting rules;
- including the costs of new regulatory requirements, and material externally driven cost increases;
- including the associated opex costs of new capex investments to deliver on efficient service outcomes that customers have told us they prefer, including with respect to cyber security, CER integration and network reliability, safety and security; and
- responding to affordability concerns by:
  - including additional productivity commitments that we have accounted for by: reducing our expected costs of resourcing our capital program; not requesting new funding to deliver two new programs requested by customers which we will deliver regardless; and not requesting additonal funding for new increases in our Essential Services Commission of South Australia (**ESCoSA**) distribution network licence fees (as advised by the of South Australian (**SA Government**)); and
  - removing some costs relative to our Draft Proposal, to take a more risk prioritised approach to cyber security investment.

A summary of our opex forecast for the 2025–30 RCP is included in Table 1[2].

Table 1: SA Power Networks opex forecast for the 2025–30 RCP ($ million, June 2025)

	2025/26	2026/27	2027/28	2028/29	2029/30	2025–30 RCP
Base year	341.2	341.2	341.2	341.2	341.2	1,706.2
Base year adjustment	16.9	16.9	16.9	16.9	16.9	84.7
Rate of change	2.3	3.5	4.4	7.7	12.4	30.2
Step changes	16.9	24.8	28.0	28.6	30.5	128.8
Opex excluding category specific forecasts	**377.4**	**386.4**	**390.6**	**394.5**	**401.0**	**1949.9**
Category specific forecast[3]	9.5	2.6	2.6	2.6	2.6	20.0
Total forecast opex, excluding debt raising costs	**386.9**	**389.1**	**393.2**	**397.1**	**403.6**	**1969.9**
Debt raising costs[4]	2.7	2.7	2.7	2.8	2.9	13.8
Total forecast opex, including debt raising costs	**389.5**	**391.8**	**396.0**	**399.9**	**406.50**	**1983.7**
Legacy metering services[5]	11.8	12.1	12.1	12.2	11.9	60.2
Total forecast opex	**401.4**	**403.8**	**408.1**	**412.1**	**418.4**	**2043.9**

2 Numbers throughout this document may not add due to rounding.

3 Relates to the National Energy Retail Law small compensation claims regime which the SA Government is considering implementing in South Australia. Further information is provided in section 6.3.

4 See **Attachment 3 - Rate of Return** for details.

5 See **Attachment 19 – Legacy Metering** for details.

3 We have delivered long term sound performance for customers

AER benchmarks confirm we are among the most efficient networks

AER annual benchmarking measures how efficient electricity Distribution Network Service Providers (**DNSP**s) are at delivering electricity distribution services over time and compared with their peers. Where DNSPs are more efficient, customers benefit through downward pressure on network charges and customer bills. SA Power Networks consistently benchmarks in the top quartile of distribution networks for a range of opex measures.

In the AER's 2023 Annual Benchmarking Report (reporting on 2021/22 performance), the AER provided benchmarking results based on the approach used in previous benchmarking reports as well as the results using its preferred approach to address capitalisation differences between DNSPs, as discussed further below.

When applying the historical reporting approach, SA Power Networks ranked third amongst electricity DNSPs in terms of Opex Multilateral Partial Factor Productivity (**MPFP**) as shown in Figure 3. We also ranked fourth amongst other electricity DNSPs in terms of opex efficiency benchmarking. Our relative performance has improved under the AER's capitalisation approach, with our Opex MPFP ranking improving to second and our opex efficiency to third.

Our opex efficiency scores remain above the 0.75 comparison point under the AER's historical method and the updated capitalisation methodology for both the long (2006-2022) and short (2012-2022) periods.

Our 2022/23 performance will be reported in the AER's 2024 benchmarking report. Noting the significant increase in our 2022/23 opex, due to extreme weather that occurred over the summer period, we are expecting to see a degradation in our benchmarking performance for 2022/23. These severe weather (non-efficiency) related events should be considered as environmental factors that should be removed when assessing benchmarking efficiency for regulatory determination purposes.

AER's preferred approach to capitalisation

The AER published its Final Guidance Note[6] addressing how it will assess the impact of capitalisation differences on benchmarking in May 2023.The AER confirmed there are material differences in application of capitalisation accounting policy and opex/capital trade-offs between DNSPs, and these are having a material impact on benchmarking results. The AER proposed to allocate a fixed proportion (100 percent) of corporate overheads to opex for benchmarking purposes.

Capitalisation policies differ substantially between DNSPs. For example, we allocate 100 percent of corporate overheads to opex while other DNSPs allocate corporate overheads between opex and capex. Aligning the capitalisation of corporate overheads across DNSPs will reduce non-efficiency related variability and improve the comparability of benchmarking outcomes into the future.

In its 2023 Annual Benchmarking Report, the AER provided the Multilateral Total Factor Productivity (**MTFP**), MPFP and econometric opex cost function results based on the final guidance note. The MTFP and MPFP models have been updated using a preliminary, fit for purpose, method for data adjustment. The AER intend to undertake further consultation on this method in preparation for its 2024 benchmarking report.

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6 AER, *How the AER will assess the impact of capitalisation differences on our benchmarking – Final Guidance note*, May 2023.

As detailed above, our relative performance has improved under the AER's updated capitalisation approach, moving from third to second in terms of our 2023 opex MPFP results (see Figure 2 and Figure 3) and from fourth to third in terms of our opex efficiency scores.

Figure 2: Opex MPFP by individual DNSP under the preferred capitalisation approach, 2006-22[7]

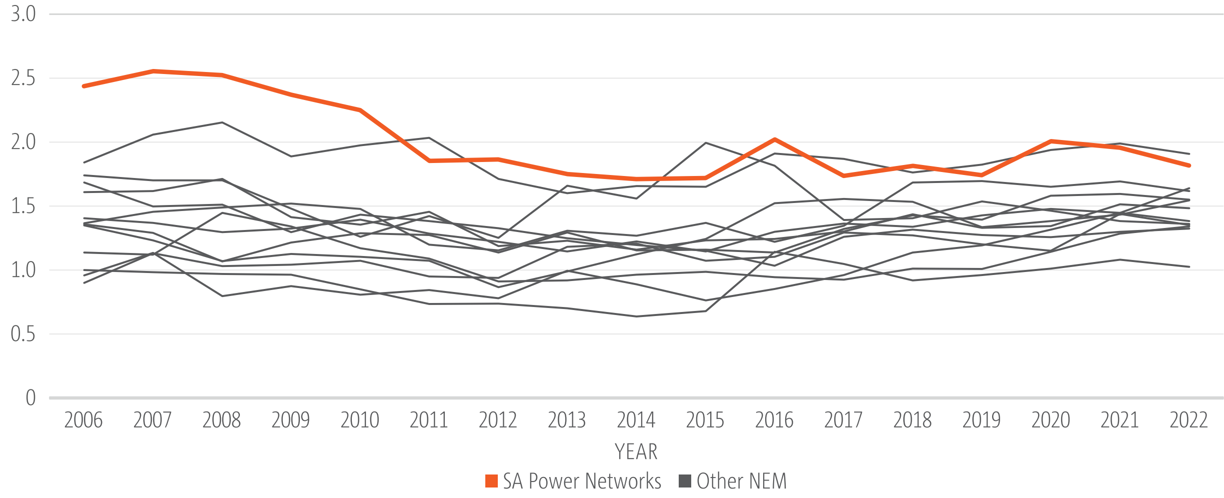
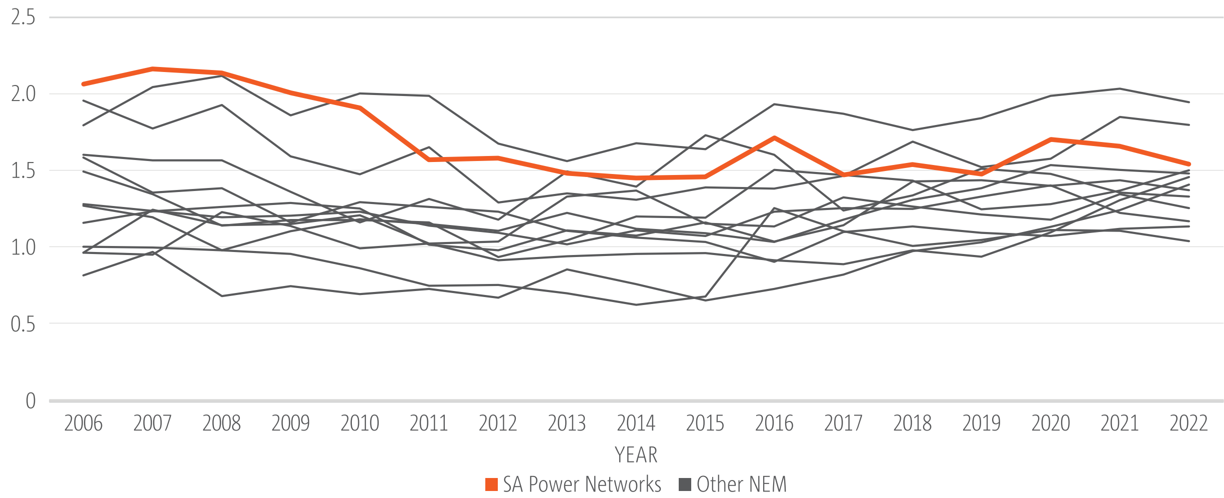


Figure 3: Opex MPFP by individual DNSP under the previous capitalisation approach, 2006-22[8]



Our long term spends have stably followed our efficient practices

Despite facing significant challenges of managing a network that has the oldest asset fleet in the NEM, SA Power Networks is at the forefront of the renewable energy transformation, and has implemented major changes to its ICT infrastructure, we have continued to deliver opex below allowance while not compromising on service delivery.

As we are consistently among the most efficient DNSPs in the NEM and have remained on the efficiency frontier, our spend trajectory has not been driven by a need to 'catch-up' to the efficiency frontier by making widespread changes to our operations. However, we still continually strive to find innovative ways to reduce opex over time, to improve our benchmarking and maintain our position as an efficient industry leader. We

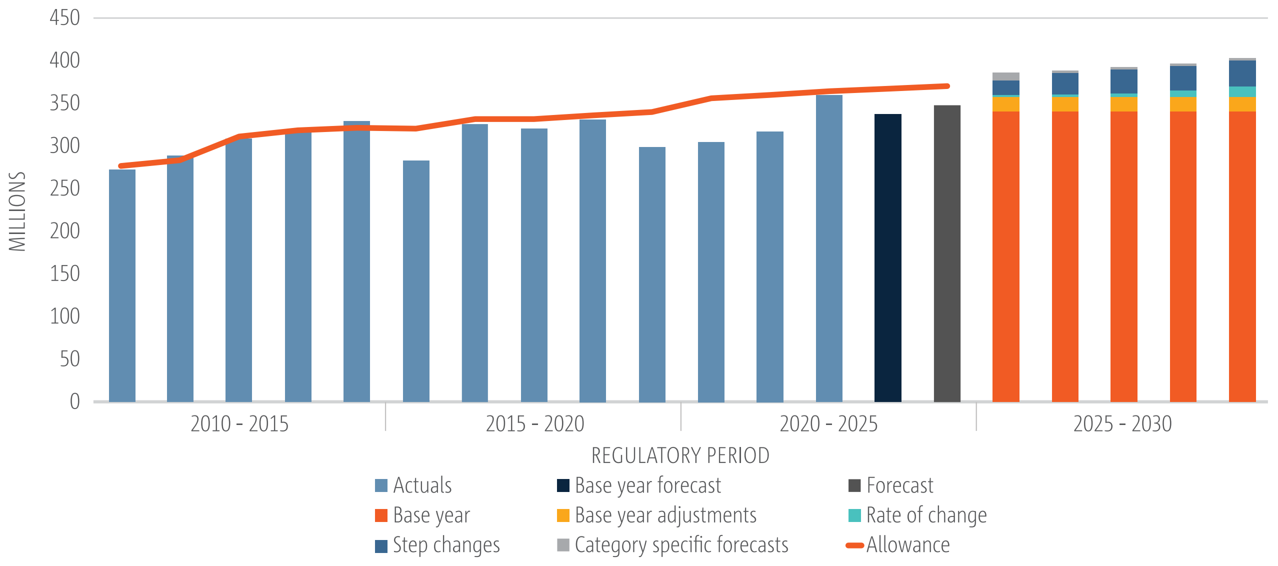
7 AER, *Annual benchmarking report - Electricity Distribution Network Service Providers*, November 2023, p 36.

8 AER, *Annual benchmarking report - Electricity Distribution Network Service Providers*, November 2023, p 35.

have also over time continued to respond effectively to incentive schemes and in order to meet AER productivity targets.

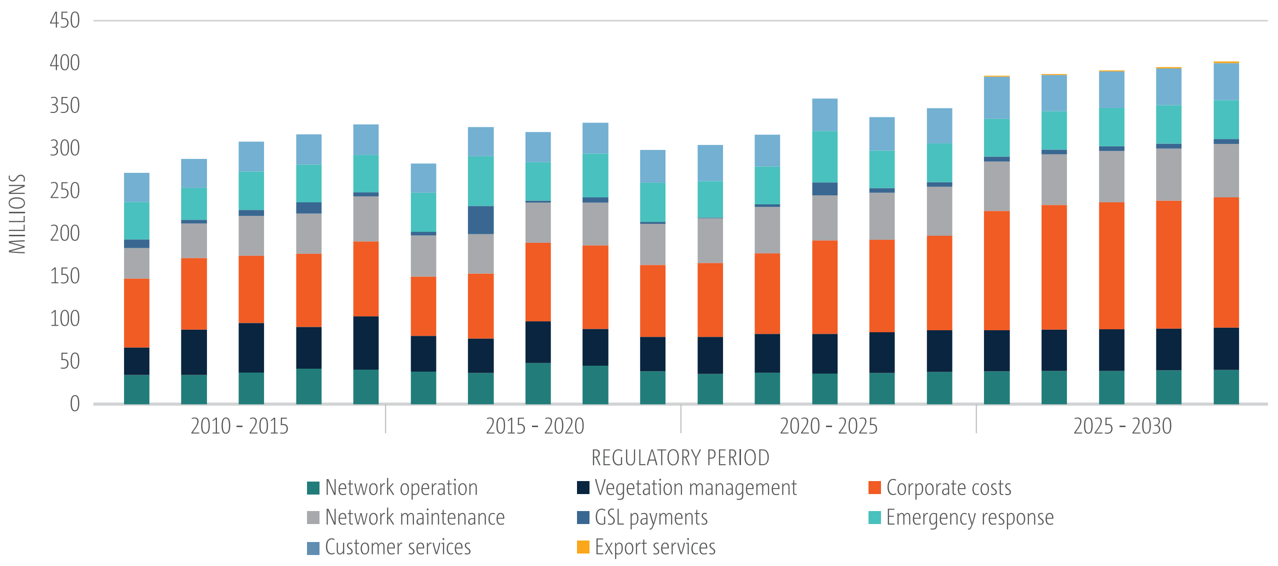
Our annual historical and forecast opex is shown in Figure 4.

Figure 4: SA Power Networks historical and forecast opex ($ million, June 2025)



In forecasting opex, we not only considered our total opex, but also opex on a category basis. In accordance with clause S6.1.2(7) of the NER, Figure 5 provides a breakdown of our historical/forecast opex by category. For most categories, the opex year-on-year is relatively constant, which aligns with applying the base-trend-step methodology. The exceptions are the volatility and impact of Major Event Days extreme weather on GSL inconvenience payments and emergency response expenditure, and the cyclicality of our vegetation management program.

Figure 5: SA Power Networks historical and forecast opex by category ($ million, June 2025)



We have delivered in 2020–25 while responding to external factors

In 2020–25, expenditure is forecast to be lower than allowances each year. In the first two years, we spent $51.2 million or 14.4 percent lower than allowance in 2020/21, and $43.1 million or 12.0 percent lower than allowance in 2021/22. These underspends were due to a number of factors including:

- benign weather resulting in lower emergency response and GSL payments;
- the COVID-19 pandemic which impacted several areas of expenditure;
- a change to the South Australian GSL scheme which affected the timing of GSL payments (2020/21 only)[9];
- reduced labour capacities from protected industrial action (2021/22 only); and
- an error which is reflected in our last AER determination resulting in an increase to our opex allowance that was not required[10].

Opex in 2022/23 was $4.6 million or 1.3 percent below allowance. Higher opex in this year was primarily driven by periods of extreme weather which saw an increase in GSL payments as well as resources deployed to manage our response to flooding that occurred over summer in parts of the State. South Australia is the only jurisdiction with an uncapped liability for GSL payments on major event days.

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9 SA Power Networks' jurisdictional GSL scheme changed in the 2020/21 regulatory year with individual duration payments replaced by total annual duration payments, and frequency payments simplified to one level of payment.

10 This is discussed further in **Attachment 1 – Annual revenue requirement and control mechanism** including how we propose to correct for this error by adjusting down our 2025–30 forecast revenue to ensure that we do not benefit from this issue, and that customers are not financially disadvantaged from it.

4 Our proposal reflects customer preferences

Our forecast opex for the 2025–30 RCP will enable us to deliver the service levels that our customers have told us they seek, and to otherwise ensure that we meet our regulatory obligations in delivering reliable, safe and secure services to customers in an efficient and prudent manner.

In developing our Regulatory Proposal, we applied an iterative, scenario-based, and outcomes focused approach to consumer engagement and expenditure forecasting. Our engagement program sought to understand the expectations, priorities and concerns of our customers and stakeholders, to ensure that forecast expenditure for the 2025–30 RCP is in their long-term interests.

Our opex forecast and the components that comprise opex, were discussed throughout our engagement program. Total forecast opex was included in the total expenditure stack that we presented at each key stage of our engagement program so that customers could make informed recommendations. We also consulted with our CAB on the totality of our opex at each engagement stage. However, our consumer engagement program focused more specifically on several discrete areas of new opex, reflecting the decision made together with our CAB to 'focus on what matters' to customers. This is further detailed along with the feedback received in section 6.3 where we discuss our proposed step changes.

Throughout our engagement, four key themes were consistency reinforced and refined at each stage[11]. Below is a summary of how our opex forecast has addressed these key themes.

A reliable, resilient and safe network

- Investing in the next stage of 'Assets and Work' to deliver network investment more efficiently;
- Increasing cyber security investment, by taking a customised and risk prioritised approach to building additional controls to protect against the cyber threat landscape; and
- Supporting the network program uplift.

Customer experience, choice and empowerment

- Replacing multiple legacy ICT systems and customer facing solutions with consolidated, secure and fit for purpose solutions; and
- Increasing investment to manage higher data volumes associated with more interval (smart) meters.

Enabling clean energy

- Enabling CER by continuing the scaling and maintenance of ICT systems to enable our flexible exports (ie Dynamic Operating Envelopes) program and
- Investing in CER Compliance to ensure the broader electricity system can be operated safely and reliably at the very high levels of CER penetration in South Australia.

Affordable and equitable energy supply

- Self funding a 'Knock Before You Disconnect' program to better assist vulnerable customers facing financial hardship;
- Working with the SA Government to investigate the merits of invoking the National Energy Retail Law (**NERL**) small compensation claims regime; and
- Through further top-down challenge, we are also incorporating into our opex forecast several signficant commitments on productivity including:

[11] This is discussed further in our Regulatory Proposal Overview.

- taking on greater risk by including strong assumptions on direct efficiency gains from our proposed Assets and Work investment in terms of network capital work delivery, and factoring these efficiencies into the additional forecast opex resourcing requirements that are needed to support capital work delivery;
- incorporating the AER's standard assumption on opex productivity;
- applying negative step changes to account for efficiencies expected to result from our proposed reliability improvement programs and electric vehicle (**EV**) transition;
- deciding to not propose additional expenditure for a number of scope increases that resulted from customer preferences (eg the Vulnerable Customer Assistance Program and Knock Before You Disconnect Program) and government required increases in our distribution licence fee; and
- in addition to these productivity commitments a number of our proposed step changes drive quantified benefits across both our capital and operating costs.[12]

4.1 Key changes since our Draft Proposal

We published a Draft Proposal in July 2023, for consultation with our customers and stakeholders. This was to play back how we have given effect to customer recommendations and to confirm that these remain valid given continued cost of living pressures and to obtain further input to refine and shape our Regulatory Proposal for 2025–30.

Our opex forecast has increased by $40.4 million, or 2.1 percent relative to our Draft Proposal[13]. This has been mainly driven by either market factors such as changes to price and output growth forecasts or externally driven scope increases. These increases have also been partially offset by refinements to our step changes. A summary of the changes is outlined below:

Updates to our price and output growth forecasts:

- Price growth (labour escalation) was updated to reflect more recent forecasts from Oxford Economics;
- We applied the legislated superannuation guarantee 0.5 percent increase in 2025/26[14];
- Customer numbers and circuit length were updated to reflect 2022/23 Regulatory Information Notice (**RIN**) results;
- Ratcheted Maximum Demand forecast were updated to reflect the Australian Energy Market Operator's (**AEMO**) 2023 Electricity Statement of Opportunities (**ESOO**); and
- Output growth inputs were updated based on data from the AER 2023 Annual Benchmarking Report.

Externally driven scope increases:

- Included a 'Network Visibility' program – to significantly enhance our network visibility capability enabled by and resulting from, the Australian Energy Market Commission's (**AEMC**) Metering Contestability Review, which seeks to accelerate the pace of the smart meter rollout. This was included as a placeholder in our Draft Proposal;
- Included costs arising from the Smart Meter Rollout – the proposed accelerated smart meter rollout will result in additional expenditure requirements to increase data storage and secure more data associated with smart meters, which is used for network billing and servicing customer queries. This was included as a placeholder in our Draft Proposal; and

12 These benefits are described within the supporting business case of each step change.

13 Note that this increase does not take into account the impact of updated CPI forecasts.

14 This was incorrectly omitted from the draft proposal.

- Included costs expected to arise from the SA Government implementing the NERL's small compensation claims regime in South Australia. This was included as a placeholder in our Draft Proposal but forecast costs have increased based on updated guidance.

Further capex to opex shifts to accord with accounting practices:

- We identified additional SaaS related expenditure which increased our proposed base year adjustment.

Customer feedback highlighting affordiblity challenges:

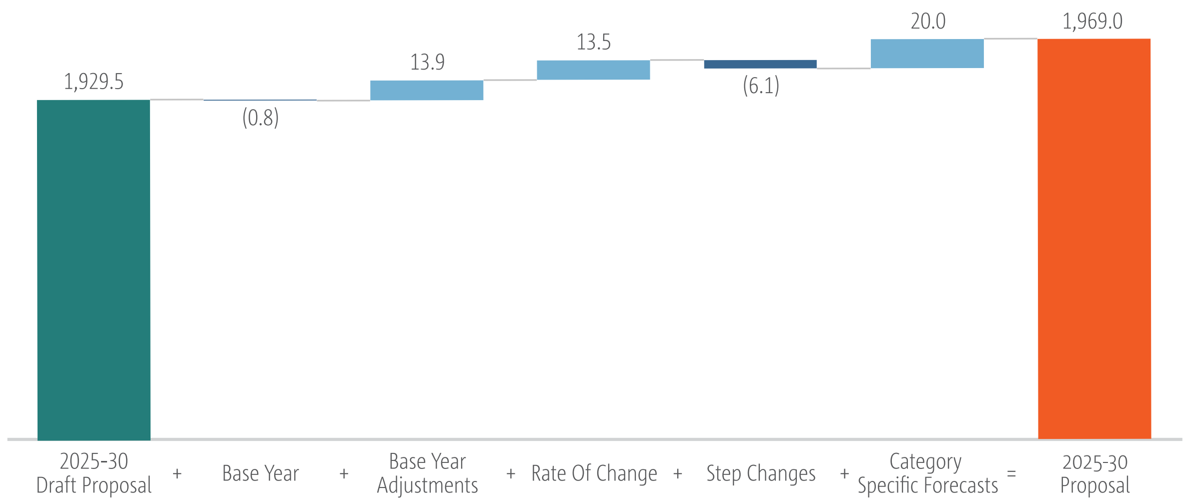
- While still committing to progress our 'Knock Before You Disconnect' program we will no longer be seeking to include this in our forecast opex.

Making sure we are only putting forward what is efficient and prudent:

- Cyber Security Uplift – we have taken a risk-prioritised approach to improve our cyber capability, as threats increase and inline with customer expectations and expected increases in cyber standards, reducing forecast costs relative to our Draft Proposal; and
- Network Program Uplift – we reduced our overall network capex program by accounting for productivity gains resulting from our proposed 'Assets and Work' ICT investment, which also reduced related resourcing support costs.

We have made small refinements to a number of other step changes.

Figure 6: Movement in opex forecast to 2025–30 Draft Proposal ($ million, June 2025)[15]



15 Draft Proposal has been updated to take into account the August RBA CPI forecast.

5 How we have forecast operating expenditure

The AER's Better Resets Handbook[16] and Expenditure Forecast Assessment Guideline[17] (**EFAG**), set out its expected approach to forecasting and assessing opex. We applied the AER's expected 'base-trend-step' methodology to forecast our opex for the 2025–30 RCP (Figure 7).

In addition, our proposed opex approach and forecast:

- as required by NER clause 6.5.6, meets the opex objectives and opex criteria, while taking into account the opex factors;
- achieves the National Electricity Objective to promote efficient investment in, and efficient operation and use of, our electricity services for the long-term interests of our customers with respect to price, quality, safety, reliability and security[18]; and
- meets the revenue and pricing principles by providing us with a reasonable opportunity to recover at least the efficient costs we incur in providing direct control services and complying with our regulatory obligations or requirements.[19]

Figure 7: Base-trend-step methodology

Base

A recent regulatory year in the current period that is representative of normal costs is selected as a base year.

The proposed base year will be tested for efficiency by the AER using benchmarking and other assessment tools. Revealed expenditure in 2020–25 is deemed to represent an efficient base providing that the network benchmarks better than 0.75.

Non-recurrent costs incurred in the base year may be removed to better represent future costs.

An adjustment will be made to the base year to forecast the final year of expenditure in the current regulatory period (2024/25).

Trend

Having defined an efficient base year, a rate of change is applied to trend this base year forward into the next period. The rate of change includes:

Output Growth – the growth in the scale of operations as measured by changes in customer numbers, circuit length and peak demand.

Price Growth – the increases in price growth that are expected to occur over and above inflation.

Productivity Change – reflects the improvements that it is reasonable to expect a prudent Network Service Provider to achieve.

Step

Finally, any step changes or trade-offs that are not already compensated for in the base year or trend are identified.

These changes will be driven by:

- Efficient capex/opex tradeoffs
- New regulatory obligations
- Major external factors outside the control of the business.

16 AER, *Better Resets Handbook Towards Consumer Centric Network Proposals*, December 2021.

17 AER, *Better Regulation, Expenditure Forecast Assessment Guideline for Electricity Distribution*, August 2022.

18 National Electricity Law, section 7.

19 National Electricity Law, section 7A.

5.1 Alignment to regulatory expectations

As a deliberate action in seeking to align to regulatory expectations, we volunteered to participate in the AER's new Early Signal Pathway program, where over the course of two years, we subjected our forecasting approaches, forecasts, and business cases, to collaborative workshopping and scrutiny by AER expenditure assessment teams and technical advisors.

Our opex forecasting approaches comply with the expectations of the AER Better Resets Handbook as summarised in Table 2.

Table 2: Alignment to AER Better Resets Handbook expectations of opex forecasting

Expectation		Explanation
Opex forecasting approach	Opex is forecast using the 'base-trend-step' approach set out in the EFAG.	Base-trend-step method was applied as per expectations.
	Inputs and assumptions used to forecast opex are consistent with those used to calculate opex Efficiency Benefit Sharing Scheme (**EBSS**) carryover amounts.	Inputs and assumptions are consistent between the opex model and the EBSS model.
Base opex	Forecast opex uses a base year for which audited actual opex is available.	Our proposed base year of 2023/24, will have audited actual results at the time of the AERs Final Decision.
	Demonstrate it is not materially inefficient based on analysis in the latest annual benchmarking report and show that the network business has an efficiency score greater than 0.75.	Latest AER benchmarking report (2023) indicates that our efficiency rating is above the 0.75 threshold (at 0.93) used by the AER to determine the efficient fronter[20].
	Use the equation in the AER's EFAG to estimate opex in the final year of the current RCP.	Estimated opex for the final year of the current RCP has been estimated using the expected equation.
	Where a business seeks to make further adjustments to base opex it should consult with the AER prior to submitting.	In accordance with AER guidance and accounting standards, the base year was adjusted to account for capex to opex shifts pertaining to ICT SaaS activities which were previously categorised as capex. These adjustments were discussed with the AER via the Early Signal Pathway.
Trend – output growth	Use the AER's preferred output specification, including output weights, as set out in the latest Annual Benchmarking Report.	Output specifications from the AER's November 2023 benchmarking report are applied with no departures.
	Adopt AEMO's forecasts of consumption and demand.	Adopted AEMO's 2023 ESOO demand forecasts.
	Forecasting customer number growth consistent with the historic trend.	Customer number growth forecast and circuit length forecast consistent with historic trend (10-years).
Trend – price growth	Use the AER's input price weights as set out in the latest Annual Benchmarking Report.	Labour input weightings applied consistent with AER expectation and November 2023 benchmarking results.
	Forecasting zero real non-labour price growth.	No real escalation in materials was applied.

[20] Quantonomics, *Economic Benchmarking Results for the Australian Energy Regulator's 2023 DNSP Annual Benchmarking Report*, 3 November 2023, pg. 52. Long period efficiency score under preferred capitalisation method.

Expectation		Explanation
	Use an average of two state-specific utilities industry wage price index growth forecasts for forecast real labour price growth, including one engaged by the AER.	Real labour price escalation was applied to internal labour costs, using a forecast of the South Australian Electricity Gas Waste Water Services Wage Price Index obtained from independent forecasters, Oxford Economics Australia. The method used an average of our forecast and a placeholder for the AER's independent forecast from KPMG as expected – the KPMG placeholder was based on an average of the forecast prepared for the South Australian transmission network service provider, Electranet.
Trend – productivity	Use a forecast no less than the AER's preferred productivity growth forecast, which is currently 0.5 percent.	Applied the preferred productivity adjustment forecast of 0.5 percent per annum as expected.
Step Changes	The number of forecast step changes is limited to a few well justified ones, or none at all.	While we have several proposed step changes, these are well justified as per the requirements in the Better Resets Handbook and are required to meet the opex objectives, factors and criteria in the NER.
	Step changes should be explored with customers.	All of our opex was communicated and discussed with our customers. The totality of our opex forecast was included in the total expenditure stack shown at each engagement stage for transparency as customers evaluated options and formed recommendations. We also engaged with our CAB regularly at each expenditure iteration. Our engagement with customers via our Focused Conversations and People's Panel process focused on service area topics that together with our CAB were deemed commensurate with a desire to 'focus on what matters' to customers. These deliberations specifically concerned a sub-set of our proposed step changes including in relation to: uplift resourcing; cyber security; personalised and on demand ICT costs; and CER integration.
	Step changes are expected to fall into at least one of the following categories to be well justified: • New regulatory obligation • Capex/opex substitution • Driven by a major external factor outside the control of the business	Step changes assessed and forecast by reference to the AER categories.
Category specific forecasts	Category specific forecasts should be limited to cost categories that have been included as category specific costs in previous AER decisions. If a network business considers new cost categories are warranted, this should be discussed with consumers and the AER.	We indicated in our Draft Proposal that a new cost line pertaining to a new claims and damages scheme could be required as a result of new SA Government obligations. We have included this new obligation in our opex forecast however, the SA Government is still in the process of forming these new obligations.
Genuine consumer engagement on opex forecasts	There should be evidence of genuine consumer engagement, this includes: • The impact that the business' proposed total opex forecast will have on the service level outcomes. • How the proposed forecast opex is consistent with, or takes into account consumer preferences and outcomes identified in the course of consumer engagement.	We conducted an outcomes focused engagement program. We engaged on service needs by presenting three alternative scenarios of expenditure, service level, and price trade-offs. Via multiple engagement stages—'Broad and Diverse' discussions, 'Focused Conversation' workshops, a 'People's Panel', and a Draft Proposal—we iteratively refined the scenarios. This resulted in an expenditure forecast that was iteratively shaped by our customers' preferences.

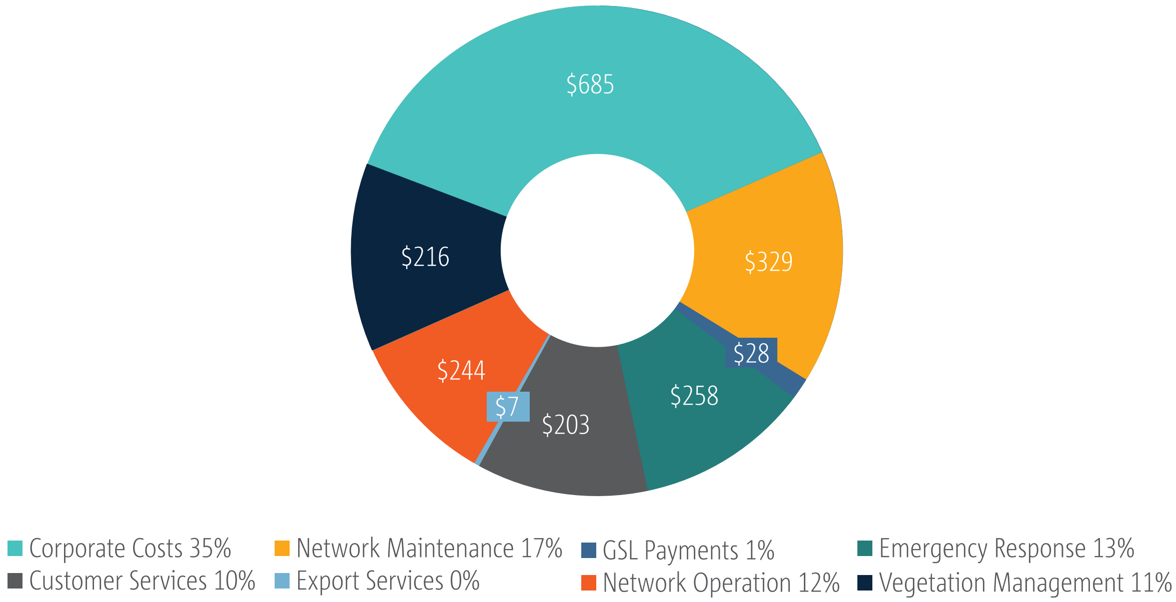
Expectation		Explanation
	The proposal should highlight the parts of the opex proposal that are either not supported by customers or have not been the subject of customer engagement.	Our opex forecast was discussed throughout our engagement process with the total forecast opex presented at each engagement stage as part of the total expenditure stack. We also consulted with our CAB on the totality of our opex at each engagement stage. However, our engagement program with customers focused more specifically on discrete areas of new opex, reflecting the decision made together with our CAB to ‘focus on what matters’ to customers.

6 Our operating expenditure forecast for 2025–30

We forecast total opex of $2.0 billion, representing an 18.0 percent increase on our expected actual spend in 2020–25. The major drivers of the increase in our forecast opex are:

- a change in accounting treatment for procuring 'SaaS';
- increased measures to address cyber security threats;
- higher insurance costs;
- the accelerated rollout of smart meters and the associated increase in network analytics;
- an uplift in resourcing costs to deliver an uplift in our network capital program; and
- an expected new regulatory obligation relating to claims and damages.

Figure 8: Forecast opex for the 2025–30 RCP by category ($ million, June 2025)



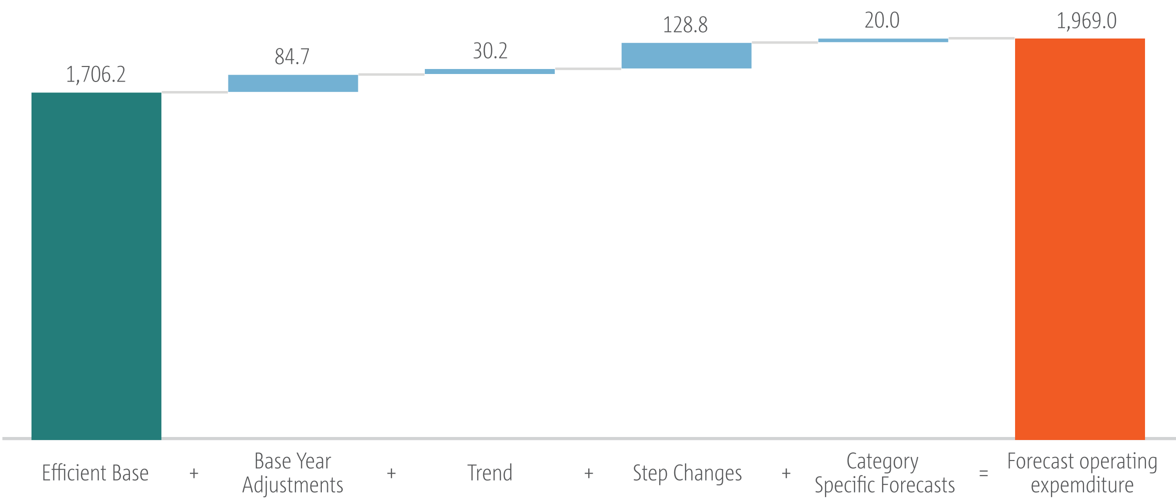
The following sections detail the components of our forecast opex applying the base-trend-step methodology outlined in the AER's 'Better Resets Handbook' and EFAG. This opex forecast reflects the prudent and efficient costs of meeting the opex objectives of the NER and is required to ensure that we are provided with a reasonable opportunity to recover at least our efficient costs of service provision consistent with the NEL.[21] This is on the basis that:

- our base opex is efficient, being based on our revealed costs as a network on the efficiency frontier with a rating of 0.93;
- we escalated our base costs by reflecting reasonably expected growth in network outputs, input costs of labour, and productivity expected of an efficient firm;
- we adjusted the base year expenditure movements from capex to opex in line with accounting practice and AER guidance; and
- we included step changes that are incremental to costs included in our base year and growth factors, including new regulatory obligations, capex-to-opex shifts arising from cloud transitions, costs of CER integration services not accounted for in AER benchmarking measures; and material costs driven by

[21] Further, and pursuant to the opex factor in NER clause 6.5.6(e)(9), **supporting document 20.6 – Related Party Transactions Overview** discusses our arrangements in relation to outsourcing activities.

major external factors. Consistent with the EFAG and Better Resets Handbook, we have assessed our proposed step changes to ensure there is no double counting.

Figure 9: Opex base-trend-step methodology ($ million, June 2025)



6.1 Base year

We propose the 2023/24 regulatory year (year four of the 2020-25 period) as our efficient base as:

- our most recent benchmarked position indicates an efficiency score above the required 0.75 comparison point which confirms that our opex is efficient;[22]
- it will be the most recent year for which actual audited data will be available at the time of the AER's final decision (due in April 2025);
- it is expected to best reflect the costs required to efficiently maintain and operate the distribution network over the 2025–30 period; and
- earlier years of the 2020–25 RCP do not provide an adequate base for the 2025–30 period due to a number of external factors as covered in section 3.

For our proposed base year of 2023/24, we used a forecast because at the time of submitting this Proposal the actual results for 2023/24 were unavailable. If required, our Revised Regulatory Proposal will incorporate our actual opex for the 2023/24 regulatory year and any required adjustments. Due to the volatility in our GSL inconvenience payments, resulting from unpredictable weather outcomes, our estimate of GSL expenditure for 2023/24 has been based on a five-year average of historical payments.

Our base year opex complies with the requirements of the Reset RIN and has been calculated in accordance with our approved Cost Allocation Method.

Base Year Adjustments

There may be certain categories of expenditure where the expenditure profile is not well reflected in the base year. In these cases, we adjust the base year to reflect these costs. For the 2025–30 RCP we identified one base year adjustment. Other adjustments may be identified once actual expenditure for the base year is known.

22 See Section 3 for further information on our benchmarking results.

Software as a service

An accounting rule clarification in 2021 confirmed that the costs of configuring and customising application software in a cloud-computing, or SaaS arrangement, should not be capitalised. As per AER advice, this capex to opex transfer has been treated as a base year adjustment rather than a step change. The total base year adjustment is $16.9 million and results from several SaaS related programs as described in Table 3.

Table 3: Base year adjustments, program detail ($ million, June 2025)

Program	Total value[23]	Description	Supporting Document
ICT Applications Refresh	16.3	To prudently maintain our existing customer, network and business services and manage risk via a program of periodic application version upgrades, security patching, minor enhancements, and defect remediation for the SA Power Networks' ICT application portfolio.	5.12.4 - ICT Applications Refresh
Data, Analytics and Intelligent Systems Refresh	3.2	To ensure our enterprise data, analytics and intelligent systems and services are maintained and secure within acceptable levels of risk.	5.12.8 - Data, Analytics and Intelligent Systems Refresh
Click Replacement	16.2	To ensure that our critical Field Service management systems and services are maintained and secure with the current acceptable levels of risk.	5.12.10 - Click Replacement
Enterprise Data Warehouse Replacement & Consolidation	2.1	To consolidate our legacy data warehouse onto the more modern Enterprise Data Platform in Microsoft Azure.	5.12.11 - Enterprise Data Warehouse Replacement & Consolidation
SAP Small Module Lifecycle Management and Optimisation	1.2	To replace a number of small SAP modules that are coming to the end of their support lives in the 2025–30 RCP.	5.12.14 - SAP Small Module Lifecycle Management and Optimisation
Assets & Work Phase 3 (Asset Management Transformation Program)	11.4	To support continued investment in our asset management systems to improve asset management processes and thereby improve the cost efficiency of our delivery of network capital work.	5.12.15 - Assets & Work Phase 3 (Asset Management Transformation Program)
Customer Technology Program	34.3	This program is predominantly focused on refreshing our core customer systems which are reaching end of life and/or are no longer fit for purpose particularly given the continued energy transition. We also propose targeted increases in new self-service capabilities to continue to evolve our customer services.	5.12.27 – Program Overview – Customer Technology Program 5.12.22 - Customer Program: Personalised on Demand Services 5.12.18 - Customer Program: Consolidate Customer Portals 5.12.17 - Customer Program: Website Replacement 5.12.20 - Customer Program: Meter Data Insights System Replacement 5.12.21 - Customer Program: CRM Replacement & Data Consolidation
Total	**84.7**		

23 The values included here are the total opex cost associated with each program over the five-year period. The base year adjustment of $16.9 million is the average annual cost of all programs combined.

6.2 Rate of change

We adopted a rate of change approach consistent with the formula in the EFAG[24], and the Better Resets Handbook. Outlined below are the individual forecast approaches we applied for output growth, real price growth and productivity growth.

6.2.1 Output growth

Our base year opex forecast reflects the costs of operating and maintaining current outputs. An output growth factor is applied to our base year to account for changes in output levels over the 2025–30 RCP. The output growth factor is derived from three inputs:

- Customer numbers: 2025–30 period is forecast using a ten-year average based on historic actual RIN data;
- Circuit length: 2025–30 period is forecast using a ten-year average based on historic actual RIN data; and
- Ratcheted maximum demand: 2025–30 period is forecast using 2022/23 RIN data which is then escalated based on the AEMO 2023 ESOO central scenario.

Table 4 shows the forecast growth for these inputs over the 2025–30 period.

Table 4: SA Power Networks output growth inputs forecast for the 2025–30 RCP

	2025/26	2026/27	2027/28	2028/29	2029/30	Average/Total
Customer Numbers	0.92%	0.92%	0.92%	0.92%	0.93%	0.92%
Circuit length	0.30%	0.31%	0.31%	0.32%	0.32%	0.31%
Ratcheted maximum demand	0.00%	0.00%	0.00%	1.37%	2.19%	0.71%

Table 5 shows the 2023 benchmarking weightings for the four econometric models that have been used in recent determinations.

Table 5: AER output specifications and weights derived from economic benchmarking models[25]

	SFA CD	LSE CD	LSE TLG	SFA TLG
Customer Numbers	37.49%	58.07%	41.95%	40.73%
Circuit length	13.59%	17.47%	19.04%	10.15%
Ratcheted maximum demand	48.92%	24.46%	39.02%	49.12%

The resulting output growth forecast is shown in Table 6. These forecast output growth escalators reflect a realistic expectation of the cost inputs required to achieve the opex objectives.[26]

Table 6: SA Power Networks forecast output growth for the 2025-30 RCP

	2025/26	2026/27	2027/28	2028/29	2029/30	Average/Total
Weighted output growth	0.46%	0.46%	0.46%	1.01%	1.34%	0.75%
Output growth ($ million, June 2025)	**1.6**	**3.3**	**4.9**	**8.6**	**13.6**	**32.1**

24 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, August 2022, page 25.

25 SFA CD = Cobb Douglas stochastic frontier analysis, LSE CD = Cobb Douglas least squares estimation, LSE TLG = Translog least squares estimation, SFA TLG = Translog stochastic frontier analysis.

26 NER 6.5.6(c)(3).

6.2.2 Real price growth

Our opex forecast adopts the AER forecast price growth weightings of 59.2 percent labour and 40.8 percent non-labour, consistent with recent AER determinations. Table 7 displays the real price growth included in our forecast opex based on these weightings. The next section further details how we have derived these weightings. These forecasts afford us an opportunity to recover a realistic expectation of our cost inputs in accordance with the NER.[27]

Table 7: SA Power Networks forecast real price growth for the 2025–30 RCP

	2025/26	2026/27	2027/28	2028/29	2029/30	Average/Total
Labour price growth	0.69%	0.36%	0.31%	0.39%	0.44%	0.44%
Non-labour price growth	-	-	-	-	-	-
Weighted real price growth	0.69%	0.36%	0.31%	0.39%	0.44%	0.44%
Real price growth ($ million, June 2025)	**2.5**	**3.8**	**4.9**	**6.3**	**7.9**	**25.4**

Labour price growth

Real price growth occurs where annual price increases exceed the growth rate of the Consumer Price Index (**CPI**). To forecast real labour price growth, we engaged Oxford Economics to provide a forecast for the Wage Price Index for the Electricity, Gas, Water and Waste Services for South Australia.

Consistent with AER expectations, we adopted an average of Oxford Economics and KPMG's utilities sector real labour price growth forecasts (as a placeholder for the AER's forecast).

A copy of Oxford Economics' full report is included as Supporting Document **6.2 – BIS Oxford Economics – Utilities Construction Wage Forecasts to 2029-30**. The KPMG forecast is based on the report prepared for the AER and applied in the final determination for ElectraNet's 2023-28 RCP (as relevant to South Australia)[28].

In addition to the real labour price growth forecast, we have also included the impact of the legislated superannuation guaranteed increases (**SGI**). This increase has not been included in either Oxford Economics' or KPMG's forecasts.

Table 8: SA Power Networks annual labour price growth for the 2025–30 RCP

	2025/26	2026/27	2027/28	2028/29	2029/30
Oxford Economics forecast	1.13%	1.04%	0.86%	1.13%	1.28%
KPMG forecast	0.19%	0.19%	0.19%	0.19%	0.19%
Average labour price growth	0.66%	0.61%	0.52%	0.66%	0.74%
Legislated SGI	0.5%	-	-	-	-
Average labour price growth + SGI	**1.16%**	**0.61%**	**0.52%**	**0.66%**	**0.74%**

Non-labour price growth

For the 2025–30 RCP we are proposing no real price increases for non-labour costs.

27 NER 6.5.6(c)(3).

28 KPMG*, Wage Price Index Forecasts, 15 March 2023,* page 10. Note that forecasts are only reported up to 2027/28 therefore an average of the period was used.

6.2.3 Productivity growth

The productivity factor assumes that an efficient network service provider should each year generate additional savings through the delivery of new productive, or efficient, initiatives.

Finding ongoing efficiencies year-on-year is increasingly difficult for us as a network that is not coming off an inefficient historical base, but instead has consistently benchmarked in the most efficient quartile of distributors for a range of opex measures.

Nonetheless, we have committed to achieving an opex productivity factor of 0.5 percent per annum for the 2025–30 period, consistent with expectations in the AER Better Resets Handbook.

Table 9: SA Power Networks forecast productivity growth for the 2025–30 RCP

	2025/26	2026/27	2027/28	2028/29	2029/30	Average/Total
Productivity growth	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
Productivity growth ($ million, June 2025)	**(1.8)**	**(3.6)**	**(5.3)**	**(7.1)**	**(8.9)**	**(26.7)**

6.3 Step changes

Where there are material cost increases or decreases to our opex forecast, step changes may be added (or subtracted) to ensure that we have an opportunity to at least recover our efficient costs consistent with the NEL, and the opex objectives and criteria in the NER. The AER Better Resets Handbook outlines that step changes should pertain to three categories:

- new regulatory obligations;
- capex / opex substitutions; and
- major external factor(s) outside the control of the business.

To ensure that our proposed step changes afford us a reasonable opportunity to at least recover our efficient costs, while also avoiding double counting, we:

- included the full cost of new regulatory obligations and cost lines, as these are incremental to costs included in the base year;
- included the full cost of step changes pertaining to CER integration, on the basis that the AER has not yet specifically amended its benchmarking measures (used to set the output growth factor) to account for CER integration; and
- adjusted the cost of step changes that pertain to existing cost lines, such as insurance and network resourcing, by escalating base costs by the trend factor before calculating any required step change.

In each supporting business case we discuss the credible and non-credible options considered including non-network options where relevant[29]. The three step changes relating to CER (CER compliance, CER integration and Network visibility) all involve approaches that serve to minimise the costs or need for network side options as set out in each business case.

Our proposed step changes are listed in Table 10 and briefly explained in the following section.

Table 10: Summary of step changes for the 2025–30 RCP ($ million, June 2025)

	2025/26	2026/27	2027/28	2028/29	2029/30	2025–30 RCP
Regulatory Obligation						
Cyber security uplift	4.6	10.9	11.3	10.4	10.4	47.6
Smart meter rollout – ICT upgrades	0.4	0.6	0.8	1.2	1.8	4.8
Small compensation claims regime[30]	9.5	2.6	2.6	2.6	2.6	20.0
Capex / Opex Trade-off						
ICT infrastructure refresh	0.8	1.3	2.0	2.7	3.2	9.9
Major External Factor						
Operationalising cyber security	3.5	3.5	3.5	3.5	3.5	17.4
CER compliance	0.3	0.5	0.5	0.6	0.6	2.5
CER integration	0.6	0.7	0.9	1.0	1.1	4.4
Network visibility	1.0	1.2	1.4	1.5	1.6	6.8
Increases to insurance premiums	2.2	3.3	4.1	4.6	5.1	19.4
Network program uplift	3.5	3.0	3.9	3.6	4.0	18.0
Negative Step Changes						
Reliability improvements	(0.0)	(0.1)	(0.1)	(0.2)	(0.2)	(0.7)
Transition to electric vehicles	(0.0)	(0.1)	(0.3)	(0.4)	(0.5)	(1.3)
Total Step Changes	**26.4**	**27.4**	**30.6**	**31.2**	**33.1**	**148.8**

29 NER, clause 6.5.6(3)(10).

30 This is being included as a category specific forecast.

6.3.1 New Regulatory Obligations

6.3.1.1 Cyber security uplift

This step change forecasts opex of $47.6 million[31] over 2025–30 to implement a comprehensive cyber security uplift program, to maintain cyber security by improving our controls in order to reduce both the likelihood and consequence of cyber threats. The program will adopt a risk-based approach to cyber security maturity that focuses on increasing the scope of cyber security preventative controls, automation, and resilience to reduce risks.

Cyber security is fundamental to the delivery of our electricity distribution services. Over 2020–25, the critical infrastructure threat landscape has evolved rapidly, with a proliferation of new tactics, techniques and procedures being implemented and undertaken by cyber threat actors and criminals. Moving forward, threats will continue to evolve and increase in prevalence and sophistication. With this growth in threat level, the government has developed legislation to ensure the public is protected from these attacks and with this comes additional obligations and enhanced responsibilities. In 2018, AEMO developed a cyber security capability framework and maturity model (the **AESCSF**), in collaboration with industry and government stakeholders.

We have a mature and stable cyber security function, with an ongoing recurrent level of investment that allows us to manage risks for today's level of cyber threat. However, given the continued increase in threat levels observed around the world and the increased legislative obligations, there is a need to significantly enhance our cyber security capabilities in coming years. This is to ensure adequate protections to limit the impact of compromise or damage to our assets and to ensure continuation of critical services, as expected by our customers.

We engaged with our customers on their desired service-level outcomes balanced against price outcomes and considered our regulatory requirements under the NER, the NEL and jurisdictional regulations. A significant focus of the ICT component of our engagement program related to cyber security, with both the Focused Conversations and People's Panel recommending an uplift in investment relative to the current expenditure level. The People's Panel recommended that we invest in a more significant program of cyber security, on the basis that the consequences of a cyber-attack could be catastrophic.

Further, in response to feedback on our Draft Proposal encouraging us to ensure our ICT proposal is indeed prudent and efficient, we have revised our investment option in line with business practice. Our forecast assumes a risk prioritised approach to identifying cyber security controls rather than assuming a requirement to comply with the AESCSF.

The preferred investment option was selected because it represents the most efficient option considered with benefits outweighing costs and delivers a prudent reduction in cyber security risk to an acceptable 'Medium' level, incorporating appropriate practices from both the AESCSF and other relevant cyber security frameworks.

Further details are provided in **Supporting Document 5.12.9 - Cyber Security Uplift** as well as **Attachment 5 - Capital expenditure**.

[31] $18.0 million in recurrent opex and $29.7 million in non-recurrent opex.

6.3.1.2 Smart meter rollout – ICT upgrades

This step change forecasts opex of $4.8 million over 2025–30 to store and secure greater volumes of data from the increasing number of smart meters, which is used for network billing and servicing customer queries.

The AEMC's Metering Contestability Review, completed in August 2023, aimed to address key shortcomings in the current contestable metering framework, including the failure to achieve the intended benefits of network visibility. This review has proposed changes to the NER and National Energy Retail Rules to accelerate the pace of the smart meter rollout, with a target completion by 2030 to enable greater access to good quality power related information to assist customer and network decision-making.

The proposed changes are expected to become a compliance obligation for SA Power Networks in 2024, as we will be required to store and secure more data from the increasing number of smart meters. This will require an upgrade to our current ICT storage capabilities and since the billing and customer analytics systems are now cloud based, the required ICT upgrades will be opex. There are also likely other system changes required to enable a larger number of smart meters. The proposed increase in opex is to ensure that we can prudently and efficiently meet this new regulatory obligation.

This is an initial cost estimate based on the expected growth rate in smart meters under the accelerated rollout, as well as expected system changes that need to be made during the next RCP to accommodate the accelerated growth. A final cost estimate will be shared with the AER during the Proposal review process, or incorporated into our Revised Regulatory Proposal, should one be required as the specific details become clearer during 2024.

Our ICT infrastructure refresh step change also includes expenditure for increased data storage requirements pertaining to the rollout of smart meters. This, however, relates to the business-as-usual growth in smart meter storage requirements, as opposed to the forecast growth under the accelerated rollout. We have ensured that there is no double counting of costs across these step changes.

Further details are provided in **Supporting Document 19.4 – Legacy Metering Transition – Towards 2030.**

6.3.1.3 Enactment of the small compensation claims regime

We forecast opex of $20.0 million over 2025–30 to meet an expected new regulatory obligation relating to claims and damages that will apply to us from 1 July 2025.

The SA Government has been consulting with us about enacting the Part 7—Small compensation claims regime of the NERL which would increase the amount of claims and damages that we would have to pay customers. Based on indications from the SA Government we expect it will be enacted from 1 July 2025 and made retroactive from 1 July 2022. The proposed small compensation claims regime will not replace the current regime that we currently operate under, but operate alongside and in addition to it as a new regulatory obligation.

Given this is a new regime, there is a degree of uncertainty as to the forecast number or value of claims that we would expect to receive over 2025–30. Therefore, we are proposing this as a category specific forecast with estimates for the required expenditure, which will provide greater transparency for our 2030-35 Distribution Determination. This is an initial cost estimate that we will continue to refine as more information becomes available in 2024. A final cost estimate will be shared with the AER during the Proposal review process, or incorporated into our Revised Regulatory Proposal, should one be required.

While the deep-dive Focused Conversation recommended that SA Power Networks should itself institute a new claims regime ahead of being formally obligated to do so, the People's Panel did not achieve consensus on this topic, and instead urged us to engage in discussions with the SA Government in relation to an expanded claims and damages regime as a matter of government policy.

We also directly engaged with the Energy and Water Ombudsman SA on this proposal, who strongly supported the regime including through feedback to our Draft Proposal.

Further details are provided in **Supporting Document 6.5 – National Energy Retail Law Claims Regime**.

6.3.2 Capex / opex tradeoffs

6.3.2.1 ICT infrastructure refresh

This step change forecasts opex of $9.9 million over 2025–30 to ensure our existing services continue to function with sufficient capacity for growth and efficiently managed storage, given the increasing use of ICT services.

Moving to cloud

The step change includes $2.0 million for a capex-opex shift, as we move more systems to the cloud. In 2020–25, we began shifting to cloud-hosted services – a journey we planned to undertake over multiple RCPs. We successfully implemented the required networks and security controls to enable secure connectivity to cloud services. We also implemented management systems and services to effectively monitor and manage these far more dynamic cloud-based services. In the 2025–30 RCP, we will continue our shift to cloud-based services, making prudent, opportunistic, system-by-system decisions when applications are required to be upgraded, refactored or replaced.

Increased capacity requirements

The step change includes $7.8 million to increase capacity requirements for the forecast growth in data, storage and processing capacity across our systems. The use of ICT systems and data collection has grown significantly in response to the need to manage a more dynamic grid and enable more data-driven decision-making. This in turn has increased demand for storage and compute power. This growth in capacity requirements is also being driven by current business as usual smart-meter rollout rates in South Australia, which are currently growing at 12 percent per year and are forecast to continue at this pace through the next RCP[32]. In previous RCPs this expenditure would have been capital but due to the Cloud transition is now classified as operating.

ICT infrastructure covers the hardware for servers, storage and ICT network equipment, underpinning the delivery of all ICT services critical to network operations and maintenance, management of network outages, and customer service provision. A failure or outage of ICT infrastructure negatively affects our service levels and our ability to provide efficient distribution services to customers.

The preferred option was selected because it maintains our existing systems and services at the current acceptable levels of using the least cost means of maintaining service provision.

[32] Costs associated with business-as-usual growth as opposed to the forecast growth under the accelerated rollout. We have ensured that there is no double counting of costs across these step changes.

Our ICT Infrastructure refresh program responds to customers' concerns, identified through our consumer and stakeholder engagement process, regarding their explicit service level recommendations that we maintain reliability and safety service performance.

Further details are provided in **Supporting Document 5.12.7 - ICT Infrastructure Refresh** as well as **Attachment 5 - Capital expenditure**.

6.3.3 Major external factors

The AER's EFAG[33] states that:

- step changes may be added (or subtracted) for any other costs not captured in base opex or the rate of change that are required for forecast opex to meet the opex criteria; and
- the AER will only approve step changes in costs if they demonstrably do not reflect the historic 'average' change in costs associated with regulatory obligations.

Additionally, the Better Resets Handbook includes major external factors as an acceptable category of step change providing that (among other things):

- it will have an impact on the costs of providing prescribed network services and where it can be demonstrated that it is not capable of being managed otherwise under forecast opex, including through inbuilt provisions under output, price and productivity growth[34].

The step changes we have identified as major external factors are listed in Table 11. These represent 3.47 percent of our total opex forecast[35] and 1.43 percent of our annual revenue requirement. This is a material cost impost on us, that is incapable of being managed otherwise under forecast opex, including via the rate of change provisions. That is, not accounting for these major external factors, would not provide a reasonable opportunity to recover at least our efficient costs, which would be inconsistent with the NEL and NER.

The following section summarises the step changes we propose as major external factors with further information provided in the associated business cases.

Table 11: Step changes being raised as major external factors ($ million, June 2025)

	2025/26	2026/27	2027/28	2028/29	2029/30	2025–30 RCP
Operationalising Cyber Security	3.5	3.5	3.5	3.5	3.5	17.4
CER Compliance	0.3	0.5	0.5	0.6	0.6	2.5
CER Integration	0.6	0.7	0.9	1.0	1.1	4.4
Demand Visibility	1.0	1.2	1.4	1.5	1.6	6.8
Insurance Premium Increases	2.2	3.3	4.1	4.6	5.1	19.4
Network Program Uplift	3.5	3.0	3.9	3.6	4.0	18.0
Total Step Changes	**11.2**	**12.3**	**14.2**	**14.8**	**15.9**	**68.4**

33 AER, *Better Regulation, Expenditure Forecast Assessment Guideline for Electricity Distribution*, August 2022, p 26.

34 AER, *Better Resets Handbook Towards Consumer Centric Network Proposals*, December 2021, p 28.

35 Excluding debt raising costs and legacy metering service costs.

6.3.3.1 Operationalising cyber security

This step change forecasts opex of $17.4 million over 2025–30 to maintain our existing cyber security and ICT resilience capabilities.

In 2020–25, we are completing development of the capability and systems for our recurrent ICT cyber security, to manage an ever-increasing cyber security risk and regulatory requirements. Moving forward, the focus shifts to ongoing maintenance of these technologies, processes and information assets. As these activities are operational in nature, the appropriate accounting treatment is opex. We therefore propose to reclassify the majority of this expenditure from capex to opex from the start of the 2025–30 period. The proposed treatment is supported by an independent assessment from BDO Australia.

A significant focus of the ICT component of our engagement program related to cyber security, with both the Focused Conversations and People's Panel recommending an uplift in investment relative to the current expenditure level. The People's Panel recommended that we invest sufficiently to exceed expected legislated obligations in the 2025–30 RCP, highlighting the high importance our customers attribute to mitigating cyber security risks particularly as their dependency on electricity increases through greater electrification.

Further details are provided in **Supporting Document 5.12.6** - **Cyber Security Refresh.**

6.3.3.2 CER compliance

This step change forecasts opex of $2.5 million over 2025–30 to execute the second phase of the long-term CER compliance program set out in our Compliance Strategy, building on our 2020–25 program.

Our CER compliance program aims to improve compliance by installers and customers with technical standards, connection rules, and regulatory requirements for CER installations in South Australia in 2025–30. From 2025 onwards, we propose to continue to build out our suite of supporting systems and there is an associated small increase in the number of dedicated staff resources to support the broadening scope of compliance activities. As the additional staffing requirement arises from the impacts of CER and this is not included in the AER's standard opex growth factors we consider this a major external factor not capable of being managed under forecast opex, including through inbuilt provisions under output, price and productivity growth.

Stakeholders strongly supported our CER integration program, including the need for a compliance program at the earlier stages of our engagement program. In addition, AEMO and the AEMC are aligned on the urgent need to improve levels of compliance to CER technical standards to address system security risks and improve CER hosting capacity and customer quality of supply.

Further details are provided in **Supporting Document 5.7.3 - CER Compliance** as well as **Attachment 5 - Capital expenditure**.

6.3.3.3 CER integration

This step change forecasts opex of $4.4 million over 2025–30 to continue the scaling and maintenance of ICT systems to enable our flexible exports program.

South Australia has the highest ratio of rooftop photo-voltaic (**PV**) generation to operational consumption of all the NEM regions. In June 2023 installed rooftop PV capacity stands at 2.3 gigawatt (**GW**) and continues to grow strongly as homes and businesses respond to high energy prices.

Our primary operational tool to manage reverse power flows and maintain reliability and quality of supply in the 2025–30 RCP will be our flexible exports capability, which can dynamically reduce customer export limits in specific locations during times when the network is constrained. This curtails solar output to maintain the net reverse power flow at the local low voltage transformer within limits.

In addition to the investment we are proposing to make in new export capacity in the 2025–30 RCP, there is additional capex and opex associated with CER integration and the delivery of the export service that are not associated with the provision of extra export capacity for customers. These costs are unavoidable and are driven by factors outside our control and relate to the continuation and scaling of the ICT systems developed in 2020–25. These systems enable our flexible exports program and are needed to support the SA Government Smarter Homes requirements, which require all new rooftop solar installations in South Australia to support flexible exports, and this will be the standard connection method for rooftop solar in all areas of the network by the end of 2024.

These costs are required to comply with applicable regulatory obligations in relation to providing export services and otherwise maintaining the quality, reliability, security and safety of supply of the export services currently being provided by the intrinsic hosting capacity of our network. Given these requirements arise from the impacts of CER and this is not included in output growth factor of the trend component[36] we consider this a major external factor not capable of being managed under forecast opex, including through inbuilt provisions under output, price and productivity growth.

Throughout our engagement process customers across all demographics indicated strong support for prudent investment in the distribution network to facilitate greater levels of rooftop solar, enable the transition to electric vehicles, and support the state government goal of reaching net 100% renewable electricity system by 2030, the end of our next RCP.

Further details are provided in **Supporting Document 5.7.4 - CER Integration** as well as **Attachment 5 - Capital expenditure**.

6.3.3.4 Network visibility

This step change proposes opex of $6.8 million over 2025–30 to build on the foundations established in the current RCP to significantly enhance our Network visibility capability.

Our Network visibility program is to enhance our visibility of the network via investments in acquiring and processing data predominantly from smart meters that will increasingly be more readily accessible to us, as a result of the accelerated smart meter roll out reforms currently underway through a fast-tracked rule change process.

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36 The AER's benchmarking and productivity factors which are used to set the uplifts allowed for output growth currently do not account for growth in CER.

This will require expenditure in the 2025–30 RCP to develop the systems to receive, store and process this basic Power Quality (**PQ**) data and to implement the data analytics and business processes to enable the various customer benefits that smart meter data is intended to provide.

Note that our proposed expenditure does not include costs to procure basic PQ data as we assume that this data will become available at no direct cost from mid-2025, as per the AEMC's recommendations. As this outcome is still subject to a rule change process we have also modelled the case where this data is procured at current market rates as part of our sensitivity analysis. Should it eventuate that the rule change does not include provision of basic PQ data at no cost to the DNSP, if required our Revised Regulatory Proposal would need to be amended to ensure that we are provided with a reasonable opportunity to recover our forecast costs.

Given these requirements arise from the impacts of CER and are not included in the output growth factor of the trend component, we consider this a major external factor not capable of being managed under forecast opex, including through inbuilt provisions under output, price and productivity growth.

The three key use-cases for which we have quantified future benefits in this business case, neutral integrity fault detection, improving our understanding of network hosting capacity and the reduction of average network voltage are those that align most with the recurring themes raised in our engagement with our customers and with other industry stakeholders.

Further details are provided in **Supporting Document 5.7.6 – Network Visibility** as well as **Attachment 5 - Capital expenditure**.

6.3.3.5 Increases to insurance premiums

This step change forecasts opex of $19.4 million over 2025–30, to reflect significant market driven increases that are expected to apply to our insurance premiums.

We procure insurance across multiple classes as a means of mitigating the financial risk which may arise due to claims linked to our operations. Insurance obligations are imposed on us as part of our Distribution Network Lease Agreement with the Distribution Lessor Corporation. These obligations include specific limits and types of insurance to be in place and adhering to these obligations is not only necessary to ensure regulatory compliance but is also part of responsible business practices and robust governance. In addition, we also have distribution licence conditions imposed by ESCoSA, who require annual assurance that the bushfire liability insurance we acquire is adequate and appropriate, given the nature of the operations carried out under the licence and the risks associated with those activities.

Our insurance brokers have cautioned, that the upward pressure we have seen in recent years on insurance premiums, will continue into the next RCP. In regard to bushfire insurance[37], we are likely to face significant challenges in securing the same level of insurance cover on reasonable commercial and economic terms during the 2025–30 RCP, particularly given the continuation of extreme events and the resulting tightening of insurance capacity.

We engaged our insurance broker, Marsh, to prepare a forecast for any likely increases in premiums during the 2025–30 RCP. The Marsh Report (**supporting document 6.5**) addresses the current and likely insurance market conditions and explains how those market conditions will lead to continued increases in insurance

[37] Bushfire insurance falls under the combined liability premium.

premiums over the period. Given these forecasts, we forecast a step change to reflect the expected increase in insurance premiums for our combined liability and property premiums.

Our build-up of costs for this step change also considers the effect of the rate of change, which is applied to the opex base year to account for changes in output growth, price growth and productivity. When calculating the expected increase in insurance premiums over base year costs, we applied the rate of change (see section 6.2.1) to base year insurance costs to avoid double counting. The property premium forecast provided by Marsh also assumes no future increases in asset bases which form premium forecasts, noting that any increase in the value of the asset base will result in higher premiums than those reflected in the forecasts. Given the magnitude of the expected increases and the fact they are outside our control, we consider this a major external factor that is material and not capable of being managed under forecast opex, including through inbuilt provisions under output, price and productivity growth.

Further details are provided in **Supporting Document 6.4 - Insurance Premium Increase**[38].

6.3.3.6 Network program uplift

This step change forecasts opex of $18.0 million to support the proposed uplift in our total network capital program due to the additional support services and ICT costs required, in order to ensure that we have a reasonable opportunity to recover at least our efficient costs of providing standard control services (**SCS**).

To deliver the uplift that we have proposed in relation to our network expenditure in the areas of replacement expenditure (**repex**), augmentation expenditure (**augex**) and CER integration, we require a corresponding uplift in our resources across corporate support (ie training, procurement, human resources, fleet maintenance and health, safety and environment) and ICT. These costs are material and our ability to recover our costs will not be sufficiently provided via the opex base and trend components.

Our build-up of costs for this step change also considers the effect of the rate of change, which is applied to the opex base year to account for changes in output growth, price growth and productivity. When calculating the expected increase in support and ICT costs over base year costs, we have applied the rate of change (see section 6.2.1) to base year costs to remove any possibility of double counting.

Given the magnitude of the expected increases and the fact they are outside our control, we consider this a major external factor that is material and not capable of being managed under forecast opex, including through inbuilt provisions under output, price and productivity growth.

The underlying identified need of this change (achieving the reliability, safety and security service levels provided by our capex forecast) was supported by customers as reflected in the People's Panel recommendations. The need for and magnitude of resourcing costs was also discussed in Focused Conversations.

Further details are provided in **Supporting Document 5.2 Resourcing Plan for Delivering the Network Program** as well as **Attachment 5 - Capital expenditure**.

[38] The Marsh Report was completed before the 2023/24 premiums were available, as such, the 2025–30 forecast premiums included in that report are based on an estimate of the 2023/24 premiums. The 2025–30 forecast premiums included in supporting document 6.4 are based on the actual premiums for 2023/24.

6.3.4 Negative step changes

6.3.4.1 Reliability improvements

This negative step change of $0.7 million in opex arises from reductions in network interruptions and associated reduced emergency response costs achieved by our proposed augex on our reliability programs to improve reliability for worst served customers.

We expect that in aggregate, our programs specifically on Low Reliability Feeder Improvement and Regional Reliability Improvement, should provide a small overall reduction in the current level of opex, due to a reduction in network interruptions and associated reduced emergency response costs achieved by these programs. The changes in opex due to the implementation of these programs will occur incrementally over the next five-year regulatory period as the programs are rolled out over this period.

Further details are provided in **Supporting Document 5.9.5 - Worst Served Customers Reliability Improvement Programs** as well as **Attachment 5 - Capital expenditure**.

6.3.4.2 Transitioning to electric vehicles

This negative step change of $1.3 million in opex arises from reductions in fuel and maintenance that is expected to occur as a result of our proposed EV transition program.

As the automotive industry evolves, we continue to assess the feasibility of transitioning from Internal Combustion Engine (**ICE**) vehicles to EVs. The drivers behind this transition are both economic and environmental (ie to reduce emissions). We propose to transition to EVs where, on a total cost of ownership basis, an EV represents the lowest overall cost when compared to an ICE vehicle and is therefore a more cost-efficient choice.

Further details are provided in **Supporting Document 5.10.1 – Fleet Business Case** as well as **Attachment 5 - Capital expenditure**.

7 Relationship with Efficiency Benefit Sharing Scheme

The Efficiency Benefit Sharing Scheme (**EBSS**) provides a continuous incentive for DNSPs to pursue efficiency improvements in opex and provides for a fair sharing of savings between DNSPs and customers. Customers benefit from improved efficiencies through lower network prices in future RCPs.

The EBSS allows for the exclusion of categories of operating costs that have not been derived using a single revealed year cost forecasting approach. These categories are outlined in **Attachment 8 - Efficiency benefit sharing scheme** and include costs such as debt raising costs and legacy metering costs.

SA Power Networks proposes that the EBSS continue to operate and be applied for the 2025–30 RCP.

Glossary

Acronym / term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
Augex	Augmentation expenditure
CAB	Community Advisory Board
Capex	Capital expenditure
CER	Customer Energy Resources
CPI	Consumer Price Index
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme
EFAG	Expenditure Forecast Assessment Guideline
ESCoSA	Essential Services Commission of South Australia
ESOO	Electricity Statement of Opportunities
EV	Electric vehicle
GSL	Guaranteed Service Level
GW	Gigawatt
ICE	Internal combustion engine
ICT	Information and Communication Technology
MPFP	Multilateral Partial Factor Productivity
MTFP	Multilateral Total Factor Productivity
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NERL	National Energy Retail Law
Opex	Operating expenditure
PQ	Power quality
PV	Photo voltaic
RCP	Regulatory Control Period
Repex	Replacement expenditure
RIN	Regulatory Information Notice
SaaS	Software as a service
SA Government	Government of South Australia
SGI	Superannuation guaranteed increases