Attachment 5 - Capital Expenditure

2025-30 Revised Regulatory Proposal

December 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' Revised Regulatory Proposal to the Australian Energy Regulator for the 1 July 2025 to 30 June 2030 Regulatory Control Period (**Revised Proposal**). The Revised 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 Revised Proposal includes documents and data that are part of SA Power Networks' normal business processes and are therefore subject to ongoing change and development.

Whilst care was taken in the preparation of the information in this Revised Proposal, 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.

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Note

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

Our Revised Proposal comprises the Overview document and Attachments listed below, and the supporting documents that are listed in Attachment 20. The light grey listed attachments below were submitted in our January 2024 Proposal and are not being resubmitted with our Revised Proposal.

Document	Description
	Revised Regulatory Proposal overview document
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

Capital expenditure **(capex)** refers to investments in the assets that we need to deliver electricity distribution network services, more precisely, our Standard Control Services **(SCS)**[1] to the standard our customers[2] expect and in compliance with regulatory obligations. Under the regulatory framework, SA Power Networks must self-fund all capital investment, however, we receive income throughout the life of these assets to compensate us for the cost of raising finance to acquire the assets and to recover their value over the period that they are in use.

Capex is grouped into expenditure categories, as described in Figure 1.

Figure 1: Categories comprising capex

1 SCS are our core regulated monopoly services, that utilise distribution network assets that are commonly shared by customers, and the expenditure for which is bundled together to form Distribution Use Of System charges **(DUoS).**

2 The terms 'customers' and 'consumers' are used interchangeably in this attachment to refer to all parties (residential or business) that receive distribution services provided by SA Power Networks, irrespective of whether the services comprise the consumption or export of energy via our distribution network.

2 Overview

We forecast a revised total capex requirement of **$2.3 billion**[3] for the 2025-30 Regulatory Control Period **(RCP)**, to deliver the service levels that our customers told us that they prefer, that our analysis indicates is prudent, efficient, and allows us to comply with regulatory obligations, in delivering reliable, safe and secure electricity distribution network services to customers.

We have been measured and balanced through our engagement and proposal development

This forecast responds to the circumstances of a time in which significant challenges and opportunities facing our network and the services that we provide customers, are converging as listed in Figure 2.

Figure 2 Key challenges we need to respond to in 2025-30

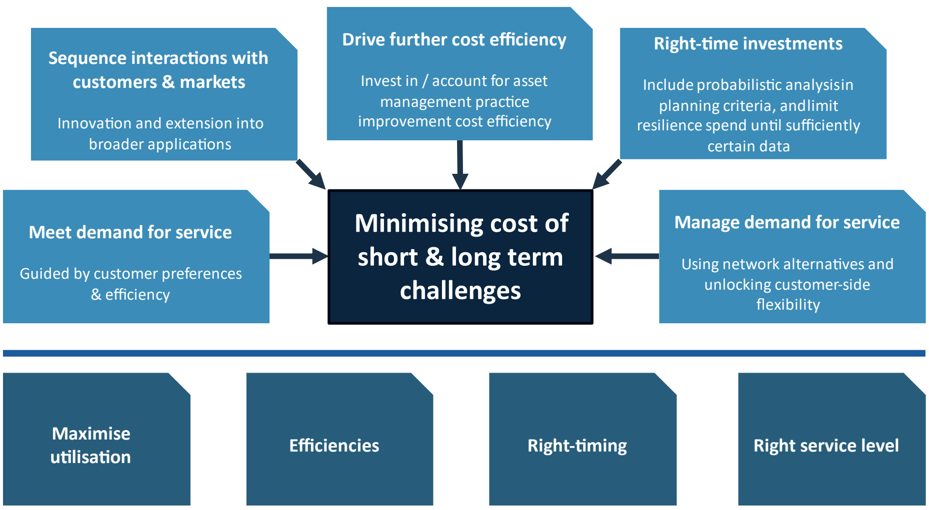
Network asset condition	**Cyber threat**
Managing an ageing network in deteriorating condition	Increased risk of cyber attacks
Network demand	**Fit-for-purpose facilities**
Resurgent & strong increases in demand driven by electrification	Need for more proactive updating of property assets
Export service demand	**Equity**
Strong demand for network access / capacity for renewables	Desire for more equity in service across the state-wide network
Bushfire risk	**Climate change**
Heightened bushfire risk across our rural network	Increased frequency and severity of extreme weather
	Ongoing needs
	Incl. to maintain supporting vehicles, properties, ICT

While consistently mindful of affordability, our customers were clear in our engagement, having considered outcomes-based scenarios and trade-offs, that they do not want service compromised, and want us to achieve the following, which our forecast aligns to:

- maintain overall service – maintain service levels, particularly network safety, reliability, export service, and with recognition of the supporting spends to achieve this;
- make modest targeted improvements – in reliability for worst served customers, and bushfire risk management;
- enable the energy transition – continue supporting the transition by enabling Customer Energy Resources **(CER)**, flexibility in customer loads, and efficiently greening our fleet; and
- prudency and efficiency – only invest where prudent and efficient for customers, and examine ways of doing more for less, by being as productive and efficient as possible.

Taking a longer-term strategic view, we saw that the most significant challenges facing the network and the services we provide, will likely manifest across several RCPs and can potentially drive significant costs to customers. Therefore, we considered how to make best use of our existing network and minimise building network were possible, applying several strategies to this end as displayed in Figure 3.

Figure 3 How we will 'meet' and 'manage' key challenges



[3] All financial figures in this document are expressed in June 2025 dollars.

These strategies are reflected throughout our capex forecast, and in other aspects of our plans, including our Tariff Structure Statement **(TSS)**, and Connections Policy, and involved:

- meeting demand for service by only forecasting expenditure to achieve service outcomes that our customers prefer and which are efficient, guided by multiple information sources to provide assurance:
  - customer preferences – via multi-staged and outcomes (service/price trade-offs) focused engagement with: 'broad and diverse' communities, representatives via 'Focused Conversations', everyday citizens via a 'People's Panel, and a Draft Proposal reaching all stakeholders. In engagement subsequent to our Proposal and Draft Decision, we observed no change in customers' preferences however, they expressed a continued desire for prudency and efficiency in delivering the desired outcomes;
  - efficiency - guided by economic analysis of monetary value metrics used in regulatory practice, as well as broader willingness-to-pay customer surveys;
- managing demand for service by proposing a varied 'tool-kit' to minimise network build/costs, including: time-varying load and now export tariffs; flexible load and export connections and network management; non-network alternatives; investing to unlock flexibility in customers' loads; and innovation pilots to open new opportunities from the inherent flexibility in customer-side devices;
- sequencing interactions with customers and markets, by proposing investments we proved via previous innovation, and proposing a new Innovation Fund to unlock an expanded 'tool-kit' that we can use to minimise costs into the subsequent RCP;
- driving further cost efficiencies, focusing on key areas of future challenge, mainly by proposing investment to improve network asset management practices to lower network costs; and
- right-timing investment and risk decisions, proposing only minor spend on resilience to historic weather until there is a greater evidentiary basis and regulatory reform to support material ex-ante expenditure in response to climate change, and adding probabilistic forecasting on network capacity upgrades into our long-standing planning criteria.

Our revisions have prudently and efficiently addressed the concerns of the AER Draft Decision

We are pleased, having assessed our proposal over many years, including via the 'Early Signal Pathway', that the Draft Decision found our proposal was largely prudent and efficient. The AER commented favourably on the combined strong consumer engagement, governance and forecasting methods, and comprehensive / in-depth business cases. The decision to accept all of our forecast opex, almost 90 percent of forecast capex, and all of our identified investment needs (i.e. outcomes of service levels, new efficiencies, and compliance needs), has left only largely technical issues to address in this Revised Proposal.

Our revised capex forecast responds explicitly to each specific concern in the Draft Decision. We acknowledged these concerns, incorporated most suggestions and improved modelling including by:

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

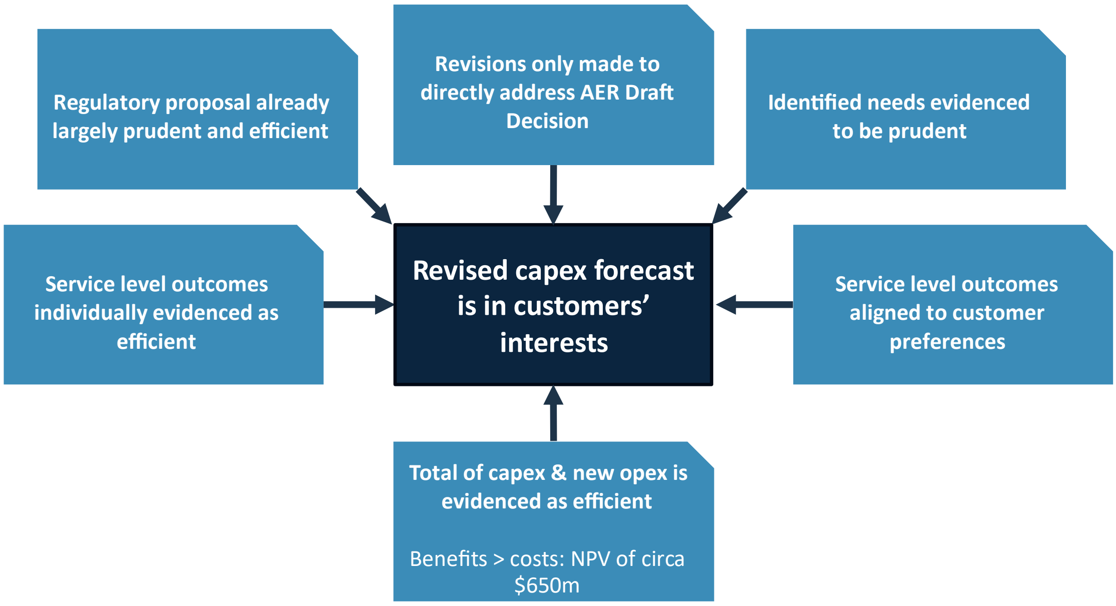
Addressing the Draft Decision's concerns resulted in our revised capex forecast being $41.4m lower and 1.7% lower than our original forecast.

Our revised capex forecast is evidenced to be in customers' interests

Our Revised Proposal evidences why we firmly consider that our revised capex forecast is in customers' interests and should be capable of AER acceptance. In summary:

- the Draft Decision already approved circa 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) align to customer preferences;
- the expenditure to achieve our proposed service outcomes are individually evidenced as efficient, being either least cost or having quantified customer benefits exceeding costs; and
- the total sum of our capex forecast and new opex, as a further top-down assurance on efficiency, is evidenced to be materially efficient, with customer benefits significantly exceeding costs and a Net Present Value **(NPV)** result of circa $650 million.

Figure 4 Factors explaining the prudency and efficiency of our revised capex forecast



3 Summary of key revisions to our original proposal

The Draft Decision accepted the vast majority of our proposed capex (close to 90 percent), and accepted all of the identified needs for capex by way of the customer service outcomes and compliance needs that we proposed to achieve. Therefore, our Revised Proposal:

- focuses only on the aspects of the Draft Decision that we do not accept, being the discrete subset of our Original Proposal for which the AER identified, largely technical, concerns leading it to substitute our proposal with a forecast that was 10.3 percent lower – key revisions are summarised below; and
- accepts and leaves unchanged, all other areas which were not adjusted in the Draft Decision.

Table 1 Summary of revisions to our capex forecast

Draft Decision	Expenditure area	Proposal	Revised Proposal $m	change v Proposal	
772.6	Repex (incl. CBD repex)	909.4	879.6	3.3%	Addressed AER concerns with modelled repex by revising / updating risk input assumptions and model calibrations with consistent use of actual data averaging periods.
12.2	CBD reliability program (repex & augex)	90.6	61.4	32.2%	AER forecast was a placeholder. Addressed concerns by better calculating the baseline service level, and a more granular/locational analysis to select an investment option optimising on least cost across all available solutions including network topology alterations.
204.5	Augex capacity	240.9	203.5	15.5%	Addressed AER concerns with demand driven projects by updating demand forecast inputs and improving project selection using economic timing.
50.1	Augex maintain underlying reliability prog	72.1	74.0	2.6%	Addressed AER concerns via additional / updated analysis of continued worsening reliability and the drivers which remain unabated, and adjusted the forecast to maintain to the latest 5 year actual spend.
2.4	ICT AEMO changes	2.4	15.3	549.2%	AER forecast was a placeholder. Revised options analysis and costings based on clearer indication of requirements from AEMO's work program.
0	ICT metering transition	0	7.2	n/a	AER accepted forecast would be revised. Costings revised based on the now clear implications of market reforms.
0	Innovation fund	16	16.1	0.3%	AER forecast was a placeholder. Addressed AER concerns by justifying projects vs AER assessment criteria, and explained costs, benefits, governance, and reconciled project costs to the proposed expenditure.
140.7	Fleet	154.9	150.4	2.9%	Reversed AER adjustment reflecting the level of network expenditure of our Revised Proposal.
29.5	Network overheads	33.5	32.3	3.6%	Reversed AER adjustment reflecting the level of network expenditure of our Revised Proposal.
944.8	Unchanged areas	944.8	944.8	0%	Expenditures that the AER did not adjust and which therefore remain unchanged.
(8.7)	Repex part of CBD reliability	(63.6)	(35.5)	n/a	Included in both the Repex and CBD reliability figures above. Subtracted to avoid double counting in this table.
9.0	Modelling adjustments	0	10.4	n/a	Applied the AER Draft Decision CPI, and revised real labour price escalators using latest forecasts.
2,135.2	**TOTAL NET CAPEX**[4]	2,379.1	2,337.7	1.7%	

[4] Total net capex, after disposals. We use the Original Proposal economic terms (CPI and labour escalation) in comparing actual and forecast expenditures by category, but Revised Proposal terms for total capex comparisons.

4 The updated performance trends

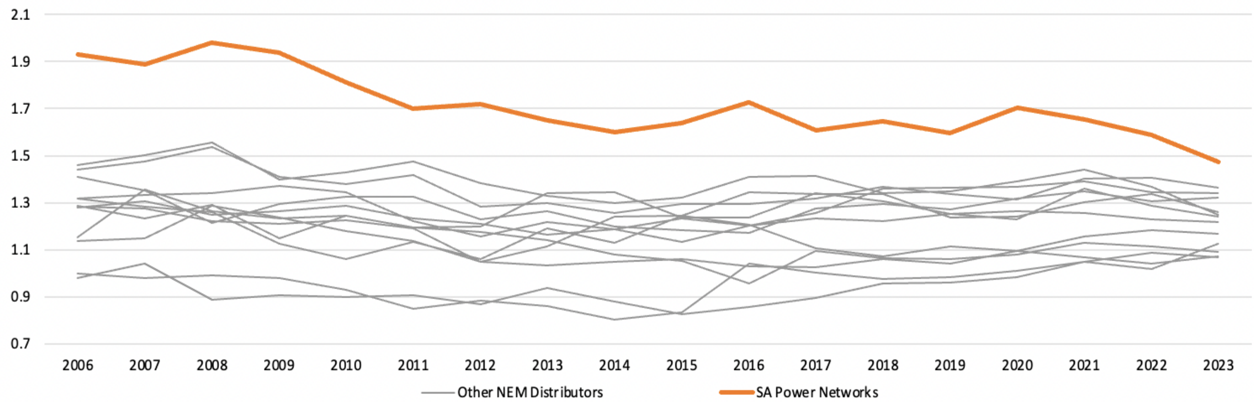
4.1 We have delivered long term sound performance to customers

AER benchmarks confirm we lead the nation in relative efficiency

Throughout the entire period that the AER has economically regulated our service provision and revenue allowances, the AER has consistently considered us to be among the most efficient electricity distribution networks in the National Electricity Market **(NEM)**. This is the product of our ongoing focus on managing our assets as efficiently as possible to deliver the services that our customers expect and value, as guided by incentive regulation which drives us to continually find opportunities for efficient savings.

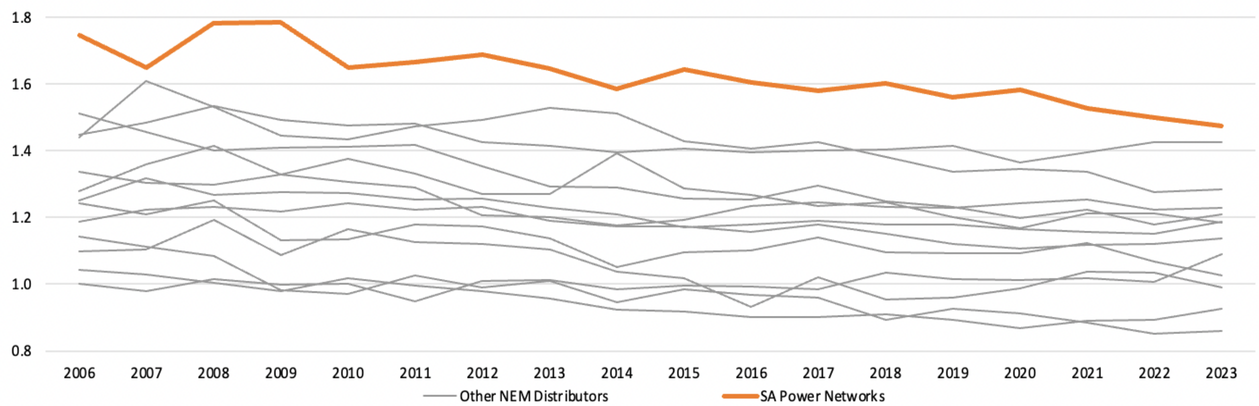
We retain strong relative performance far exceeding any other distribution network, notwithstanding significant challenges of managing a network with the oldest asset fleet in the NEM and being at the forefront of the renewable energy transition. We are the most efficient electricity distribution network on Multilateral Total Factor Productivity **(MTFP)**, which accounts for all capital and operating inputs and outputs.

Figure 5: Electricity distribution Multilateral Total Factor Productivity indexes by distributor, 2006-23[5]



We also rank as the most efficient distribution network in specific reference to capital performance, under the measure of capital Multilateral Partial Factor Productivity, which accounts for capital inputs and outputs.

Figure 6: Capital Multilateral Partial Factor Productivity indexes by distributor, 2006-23[6]



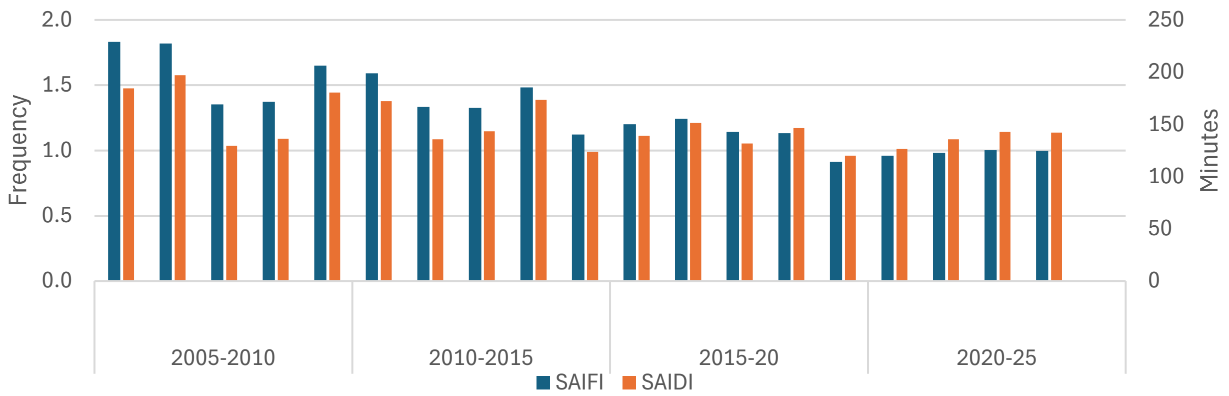
[5] AER, *Annual Benchmarking Report – Electricity Distribution Network Service Providers*, November 2024, P.27.

[6] AER, *Annual Benchmarking Report – Electricity Distribution Network Service Providers*, November 2024, P.28.

South Australians have benefited from reliable service over the long term

In efficiently minimising costs of service delivery over time, our service performance has not been compromised. Rather, since the AER commenced economic regulation, our overall reliability performance has continued to be sound and, in responding to the AER's Service Target Performance Incentive Scheme **(STPIS)** with targeted investments and enhanced supply restoration practices, performance has been improved from that experienced by customers in the early 2000s. However, as we discuss in Section 4.2, a worsening reliability trend has been manifesting for several years now as we enter the next RCP, due to outages from asset condition related failures and external causes.

Figure 7 Long-term network SAIDI and SAIFI performance

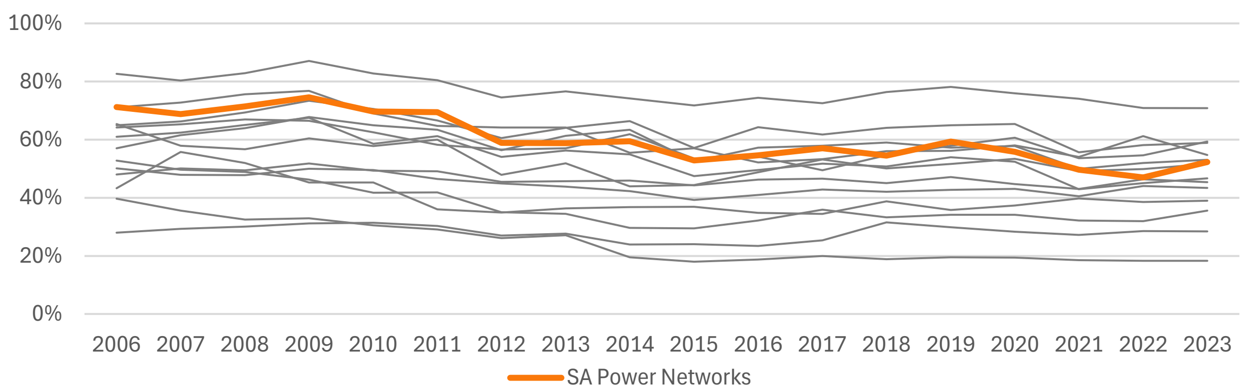


Over the past decade, South Australia has also been at the forefront of the transition to distributed energy. Our proactive and world-leading efforts in efficiently integrating CER via efficient tariffs, network interventions and flexible export management (Dynamic Operating Envelopes, **DOE**), have ensured that our customers have to date received a high grade of export service with minimal curtailment. We estimate that our CER customers typically receive an export service level of at least 95 percent today, meaning they are curtailed less than five percent of daylight hours throughout the year.

Network utilisation remains above average among NEM electricity distributors

Our sound performance for customers has also been achieved while maintaining network utilisation above the median, amongst NEM electricity distributors, based on AER metrics. The way that utilisation is measured by the AER will require refinement in future, particularly for our network, as it understates how much the network is being used by customers to both import and export electricity. Irrespective, maximising the use of existing network before building more, is rightly a key focus in regulation and engagement, and has / will remain a focus of ours, having shaped the design and range of our proposed investments for 2025-30 as discussed in Section 5.2.

Figure 8 Long-term network utilisation

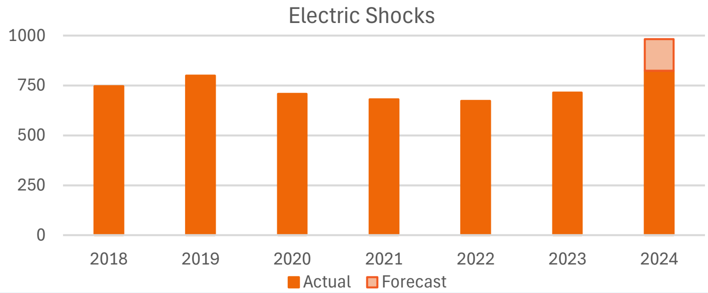


4.2 Underlying concerns for service performance continue to manifest

While long-term service performance has been sound, we have concern for service impacts in coming years if inadequate action is taken, mainly due to the deteriorating condition of our network as increasing numbers of assets exceed their economic service life. Our view of service risk, and the basis of our capex forecast, is reasonable based on forward indicators from our risk modelling which quantifies the service costs to customers of inadequate investment and resulting service levels. However, as the AER placed weight on backward indicators and queried how long-lived our concerns may be, we updated our trend analyses with an additional year's data. Updated data continues to evidence manifesting concerns for reliability and safety, with some examples outlined below and detailed in our business case addendums.

Safety incidents have continued to increase

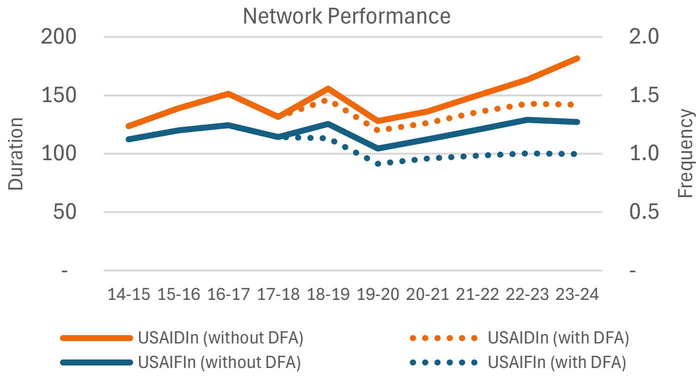
Reports of shocks continue to increase, with year-to-date figures (up to Oct) being higher than all prior years over 2018 to 2024.[7]



Reliability trends have continued to worsen

Worsening trends remain on the duration and frequency of interruptions.

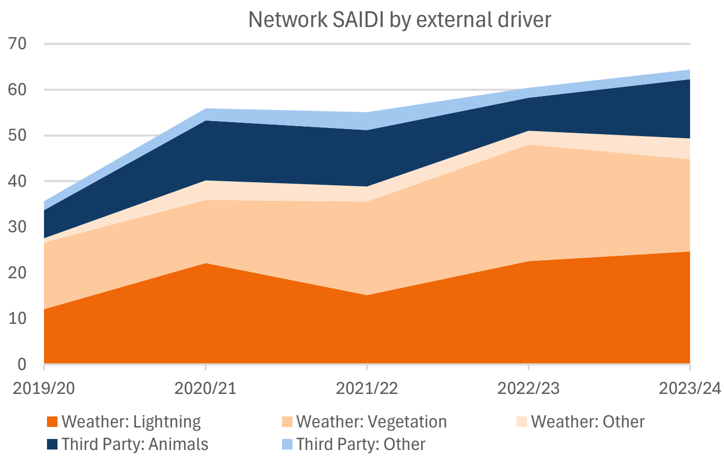
A more significant and underlying concern for the risk that asset condition is posing, can be seen by viewing reliability without the effect of Distribution Feeder Automation **(DFA)**, which has masked the full impact of recorded asset failure related outages.[8]



External impacts on reliability continue unabated

Trends in outages from external factors have also continued with:

- weather-related performance worsening, via continued increases in lightning strikes, and increasing vegetation-related outages resulting from greater vegetation cover in the vicinity of the network[9]; and
- animal-related outages continuing to increase, and the current rate of increase expected to continue based on the size and spread of flying-fox colonies; and
- third party caused outages increasing.



7 Data capture methods prior to 2018 were unreliable.

8 DFA has been implemented and expanded since 2018/19 and served to reduce the number of customers affected by network outages by segmenting the network and automatically re-routing supply in meshed areas where feasible.

9 Councils are pursuing 'urban canopy' strategies. However, many of these tree limbs, and particularly those above the powerlines, are outside of prescribed clearance zones and so cannot be cut under current legislation.

5 The approach to our forecast and its reasonableness

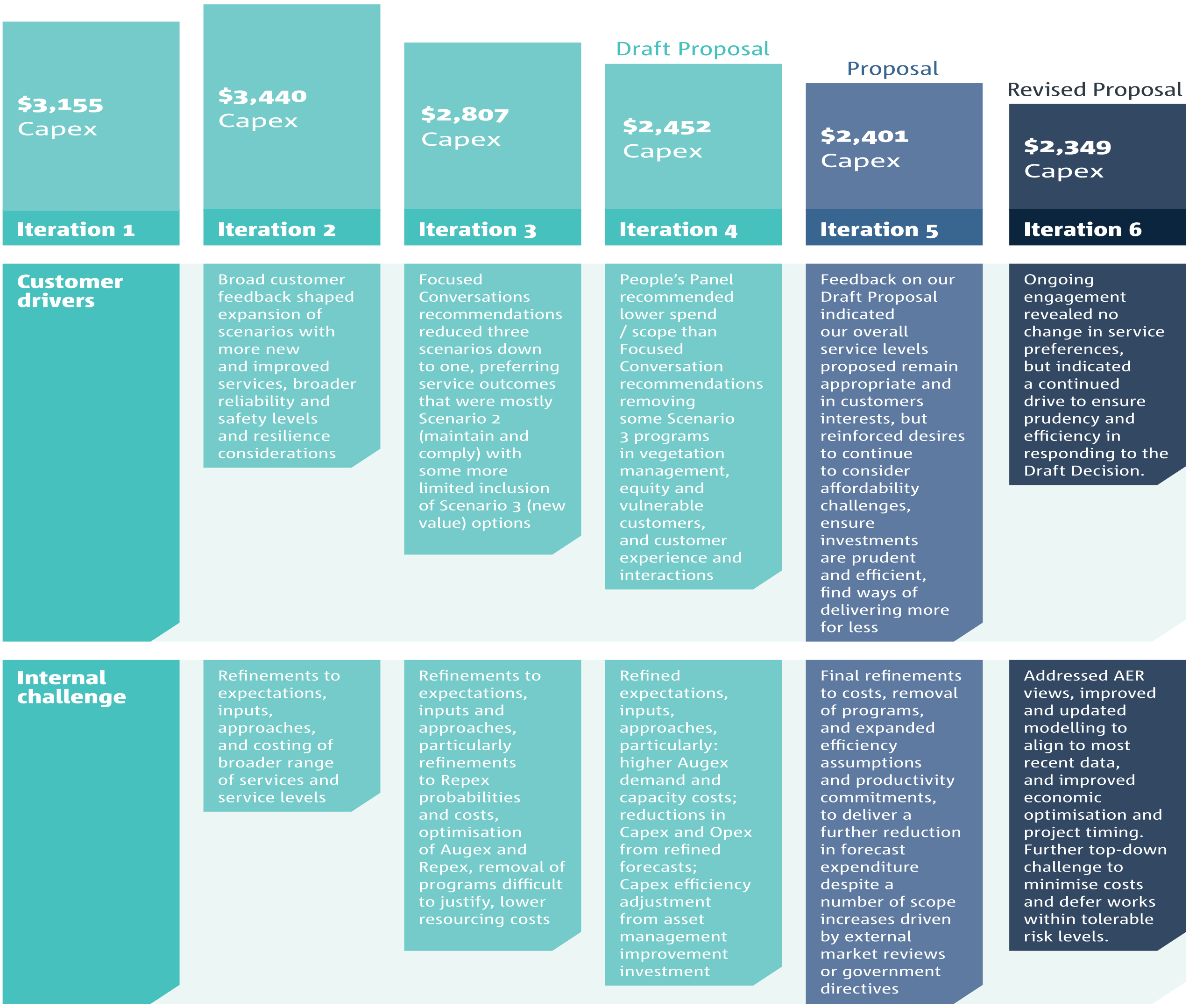
5.1 Our revised forecast reflects continued refinement internally and by customers

Our revised capex forecast for 2025-30 is the end-product of a process of internal and external challenge underway for four years. This forecast was refined with our customers via multiple iterations aligned to each key stage of our consumer engagement program. Key highlights were that:

- capex was continuously and materially reduced – the forecast reduced by over $1 billion relative to the potential forecast identified at earlier stages of the engagement program; and
- capex was materially shaped by customers – the majority of the forecast was shaped by our customers, being required to achieve the service outcomes recommended to us via our engagement.

Since our Proposal and in responding to the Draft Decision, we have continued engaging our customers and stakeholders. We focussed on resolving the largely technical matters the AER raised, with the exception of the Innovation Fund which needed substantive discussion. We have received no indication that the identified needs that our forecast responds to, and which the Draft Decision accepted, warrant any change.

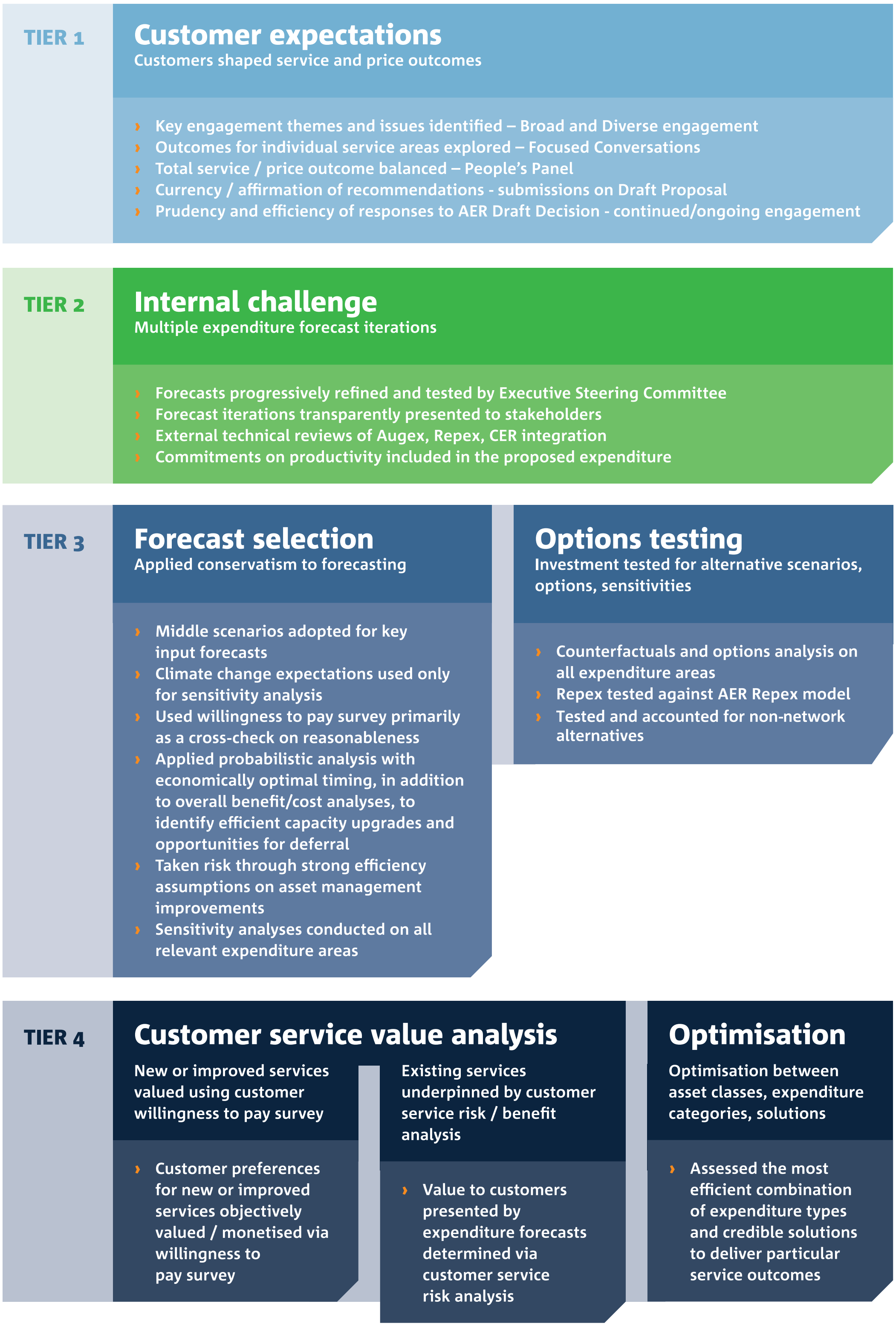
Figure 9 The iterative approach to developing our expenditure forecasts[10]



[10] This figure shows total net capex before disposals. For this figure to present a like-for-like comparison, we applied the same forecast inflation and real labour price escalators as those used in our Regulatory Proposal to all iterations.

We applied a multi-tiered challenge process to arrive at our Original Proposal, a process favourably reviewed by the AER and its consultants, EMCa, as reflecting good practice, governance and forecasting methods.[11] In revising our capex forecast, we continued and extended this challenge process as summarised in Figure 10, particularly in how we further tested options, selected forecasts and optimised.

Figure 10 Tiers of internal and external challenge to expenditure forecasts



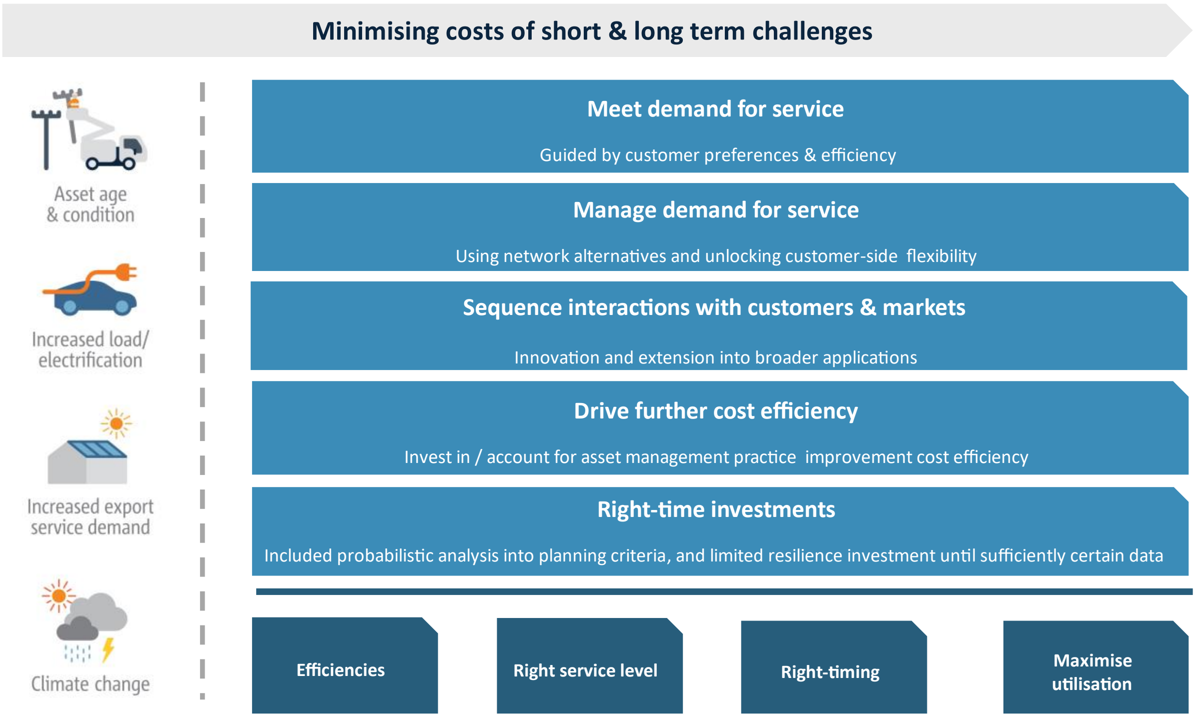
11 AER, *Draft Decision – SA Power Networks Electricity Distribution Determination 2025-2030: Overview*, September 2024, pp.vi-vii.

5.2 We plan to 'manage' service demands and costs and not just 'meet' them

In planning for 2025-30, we saw it crucial to strategically 'look-ahead'. We expect the energy sector transition, as well as the need to continue increasing our repex, will likely manifest over several future RCPs. These issues can potentially drive significant costs and impacts on customers if managed poorly, and likewise, the transition can, and should, increase the value customers obtain from electricity services and the devices they are investing in. Taking a strategic long-term view, we developed a varied 'tool-kit' of strategies to minimise how much we need to build now and in future, reflected throughout our forecast expenditure and involving:

- **meeting demands for service**[12] – only proposing expenditure to build network[13], where prudent and efficient and aligned to customer preferences on service levels, or otherwise for compliance;
- **managing coming demands for service** – proposing to use a broad 'tool-kit' to minimise required network build, by: proposing the use of time varying tariff signals on load and now on exports from 1 July 2025, flexible network management and related connection offers and policy, using non-network alternatives to defer builds, investing to enable flexibility in customer loads, and innovation in trials and pilots to expand the took-kit by unlocking responses from the inherent flexibility in customer-devices;
- **staging our interactions with customers and markets** – taking a multi-RCP view of efficiently sequenced actions including flexibly managing existing network capacity (load and export) to utilise current capacity before considering upgrades, and investing in innovation to prove new solutions that can become business as usual practice in subsequent RCPs;
- **driving further cost efficiencies** – proposing to invest to improve asset management efficiency to reduce the costs of responding to the multi-RCP challenges of network renewal / expansion; and
- **right-timing investments** – forecasting spend, and where possible deferring, by adding probabilistic planning and optimal economic timing into our long-standing planning criteria, and relying mainly on ex-post responses to climate change until there is a greater evidentiary basis and regulatory reforms, to support climate change resilience.

Figure 11 How we will 'meet' and 'manage' key challenges



12 We refer to demands for service from customers as including both the use of the network to import and export electricity.

13 We refer here generally to 'network build' as entailing all expenditure to replace assets and upgrade / expand asset capacity.

Table 2 The approaches we have used to minimise costs of addressing key long-term challenges – multi-RCP view

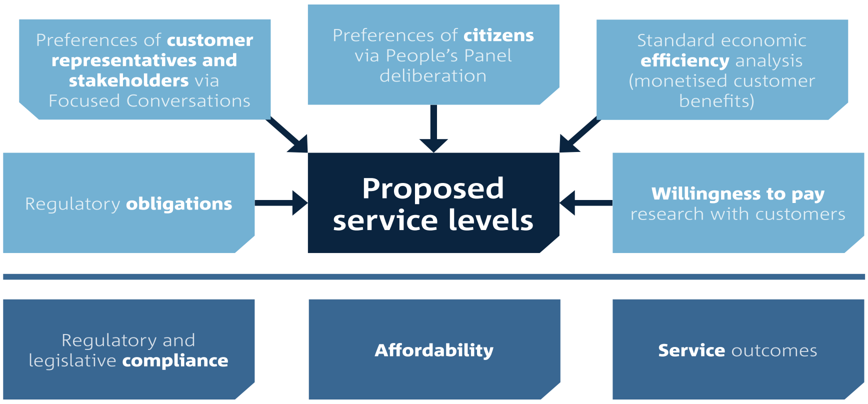
CHALLENGE	CURRENT 2020-25 RCP		PROPOSED PLAN FOR 2025-30		PLAN FOR 2030-35
	MEETING	MANAGING	MEETING	MANAGING	
Network asset age & condition	Ramped-up repex.	Invested to improve work selection effectiveness and bundling. Optimised assets.	Ramp-up repex to achieve customer aligned, compliant, and efficient service levels. **[Repex forecast]**	Invest to improve asset management to reduce cost of delivering network work. **[ICT Assets & Works program]**	Continue repex ramp; find more efficiency sources.
Increased demand & electrification	Record low demand. Spend increased through the RCP as demand increased.	Some non-network alternatives identified.	Increased capacity program (accounted for non-network options). **[Augex capacity forecast]**	Invest in systems and offers for flexible connections: large customers. **[Demand Flexibility program; Connections Policy]** Invest to expand our residential Flexible Exports offer to reward-based flexible imports. **[Demand Flexibility program]** Pilot using existing network capacity to automate assessments for cheaper/faster connections. Also pilot flexibility marketplace to procure non-network solutions from CER as an alternative to network augex. **[Innovation Fund]**	Produce / deploy flexibility services via Innovation Fund, offer incentives to customers/industry to increase network utilisation. Flexibility procurement becomes genuine alternative to network augex to manage demand.
Increased demand for export services	Improved visibility of hosting capacity and provided fixed export services within current capacity.	Invested in Flexible Exports systems (DOEs) and offered flexible connections for exporting customers, to optimise network utilisation.	Invest in suite of non-network solutions and targeted augex to increase network hosting capacity and deliver efficient and customer-aligned export service level. **[CER integration program; Demand Flexibility Program; CER compliance program; Network visibility program]**	Propose to offer Flexible Exports as default connection offer for all new exporting CER. **[CER integration program; Connection Policy]** Propose piloting systems to increase service levels, incl. improved reactive power support, planning tools to optimise for efficient service levels and integrate flexible market-active CER. **[Innovation Fund]**	Produce / deploy solutions to further increase export service levels, as piloted in Innovation Fund. Export service levels co-optimised with NEM benefits.
		Tariff signals for use in peak export periods (solar sponge). Assigned interval meter customers to time varying tariff with no op-out to increase uptake.		Propose to apply export tariffs (all customers) from July 2025 to signal/recover costs efficiently. Also, apply flexible tariff solutions for Large Business customers to complement flexible connection offers. **[Tariff Structure Statement]**	
Climate change	Ex-post spend (e.g. floods cost pass through)	Improving data and analytics on exposure and risk.	Not factored in ex-ante expenditure – rely on ex-post response until better evidence and regulatory valuation. Small-scale investment in mobile generation for network resilience. **[Augex resilience program]**	Propose to develop advanced data sharing capabilities with emergency service providers, enhancing coordination of emergency response **[Innovation Fund]**	Re-examine risk based on greater evidentiary base

5.3 Multiple sources evidence that our Revised Proposal is in customers' interests

Our expenditure forecast addresses a broad variety of challenges and opportunities to the services that we provide our customers, in regard to asset condition, changing customer use of the network via electrification and renewables integration, and changes in the operating environment with increasing cyber risks and NEM reforms. This has been overlaid by general affordability concerns facing South Australians.

Addressing competing considerations required a delicate balance of service and price. This was managed by ensuring our plans and capex forecast were not solely guided by any one consideration, and considered multiple sources of customer preference information, economic efficiency, and other indicators of customer value via a willingness to pay survey of customers, as outlined in Figure 12 and detailed in Table 3.

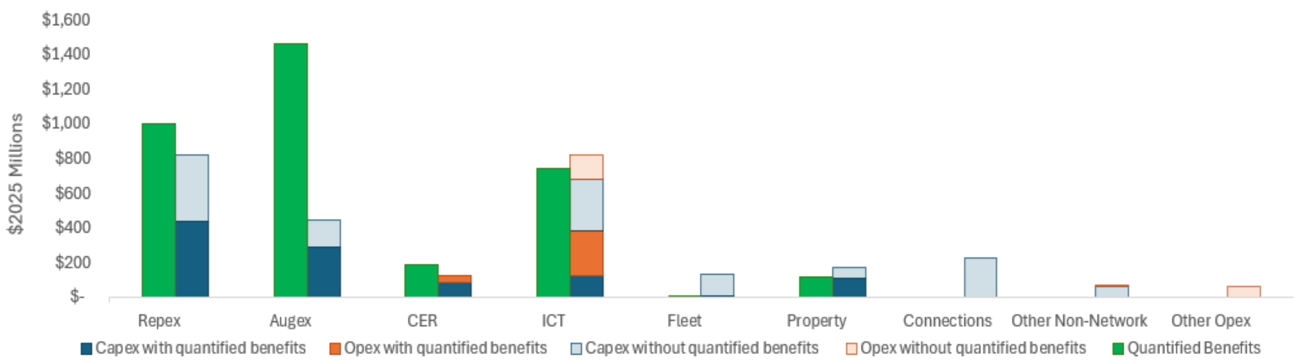
Figure 12: Our approach to balancing service and price outcomes



The refinements we made to our analysis to address the Draft Decision reinforced the prudency and efficiency of our capex forecast, and in summary:

- **service outcomes are aligned to customer preferences** – having been shaped by multiple sources of customer input (workshops with customer representatives, stakeholders and everyday citizens);
- **expenditure proposed to achieve customer service outcomes is efficient** – individually being either least cost for compliance needs, or having consumer benefits exceeding costs; and
- **the aggregate forecast is efficient** – as a further top-down assurance, the total sum of forecast capex and new opex for 2025-30 is also evidenced as efficient with significant net benefits to consumers of circa $650 million in NPV terms over 20 years – arising from the investment areas in Figure 13.

Figure 13: Areas contributing to overall positive NPV (2O years) of total capex and new opex - shown in PV terms[14]



[14] This is a conservative estimate. As per industry practice, some large areas (e.g. connections, fleet) lack a regulatory approach to valuing benefits. The NPV covers all capex and new opex (step changes, category specific forecasts, and base year adjustments) forecast for 2025-30. Costs and benefits beyond 2025-30 are considered, as covered in our business cases. The analysis period was normalised to 20 years including terminal values in the final year for programs with long asset lives. For some IT projects, the benefits period was extended beyond the 10 year period set out in respective business cases.

Table 3 The multiple evidence sources of our proposed service levels being supported by customers and in their interests – key service levels and examples

Engagement with customer representatives & stakeholders	Deliberation with People's Panel	Our proposal	Efficiency analysis via monetised consumer benefits	Willingness to pay survey (customer values research)
Maintain overall reliability by geographic region	**Supported**	**Adopted**	Repex is **NPV positive** overall	Benefits are quantified using the AER Value of Customer Reliability **(VCR)**
Improve CBD reliability to comply to standard	**Supported**	**Adopted**	Optimised **least cost** to comply	The need is compliance driven, evaluated on cost per SAIDI and SAIFI contribution
Improve reliability for worst-served customers	**Supported**	**Adopted**	Augex programs are **NPV positive**	General customer base is **willing to subsidise** the improvements for worst-served customers
Maintain overall safety risk posed by asset condition	**Supported**	**Adopted**	Repex is **NPV positive** overall	Benefits valued using disability weighted value of life, and value of property and buildings damage risk
Minimise bushfire risk via network upgrades	**Supported**	**Adopted**	Augex programs are **NPV positive**	Benefits valued using disability weighted value of life, and value of property and buildings damage risk
Maintain network security and capacity to meet demand	**Supported**	**Adopted**	Augex capacity program is **NPV positive**, excluding compliance work.	Customers **willing to pay** for investments to minimise long-duration outages
Improve resilience to long-duration outages in regional areas	**Supported**	**Adopted**	Augex mobile generation program is **NPV positive**	Customers **willing to pay** for investments to minimise long-duration outages
Maintain cyber security via stronger controls to meet compliance expectations	**Not supported**. Panel wanted us to invest more to exceed expected compliance	Revised option to take a risk-prioritised approach to increasing security controls	ICT program is **NPV positive**	Benefits are valued using VCR, and effects impacting on capex and opex
Improve personalised and on demand digital service capabilities	**Non-consensus**	Revised option to focus on service improvements that save network and customer costs	ICT program is **NPV positive**	General customer base is **willing to pay** for improvements
Maintain export service to achieve 95% export for 95% of customers	**Supported**	**Adopted**	CER integration program is **NPV positive**	Customers are **willing to pay** for proposed service level
Sum total of costs & benefits of capex + new opex = positive NPV of $645m over 20 years.				

5.4 Interactions in expenditure inputs were considered and aligned to service outputs

Our Proposal assessed multiple actual and potential interactions between the various areas of our forecast. We then expanded this to address the assurances the Draft Decision sought, particularly for the 'maintain underlying reliability performance' and 'CBD reliability improvement' programs. Our evidence indicates we have:

1. **no double counting –** of costs contained throughout our revised forecasts; and
2. **optimised –** considered the most efficient combination of investment actions to achieve the service needs.

Table 4: The Interactions between expenditure areas that we considered

Proposed outcome	Programs / projects to achieve outcome	Interactions with other programs	How we avoided double counting	How we optimised
Maintain overall network reliability by geographic region	[REPEX] – to maintain reliability risk posed by network asset condition	[CER INTEGRATION] program	Programs cross-checked. Transformers replaced in repex are incorporated in base case of CER augex model.	Where transformers are to be replaced via repex, only incremental costs to upgrade export capacity (if required) are included in CER integration augex.
		[AUGEX RELIABILITY] programs	Cross-checked. Reliability improvement via augex considered in repex model – no material impact.	
		[CBD RELIABILITY IMPROVEMENT] program	CBD reliability program combines augex and repex. Cable replacement repex is detailed in the CBD business case and referenced in the Repex case.	Assessed all available solutions as sought by AER Draft Decision to optimise selection of solutions on least cost basis across: cable repex, feeder automation augex, and topology changes augex.
	[AUGEX MAINTAIN UNDERLYING RELIABILITY PROGRAM] – maintain by addressing non asset condition effects	As above re repex, and extended to respond to Draft Decision by evidencing the service level effects of repex & augex. Also, considered opex solutions in response to Draft Decision.	As above re repex. Identified opex solutions (vegetation management) as infeasible due to impacts of vegetation outside of prescribed clearance zones. Cross-checked / confirmed no double counting with Augex capacity.	
Improve CBD reliability	[CBD RELIABILITY IMPROVEMENT PROGRAM] (REPEX & AUGEX)	[REPEX HINDLEY STREET SWITCHGEAR] project	CBD program replaces underground cables, installs automated switches, and topology changes – no overlap with Hindley Street zone substation assets.	Hindley Street repex addresses future service risk of specific CBD asset, while CBD reliability program considers drivers of poor reliability and performance over entire CBD.
		As above re [REPEX]		

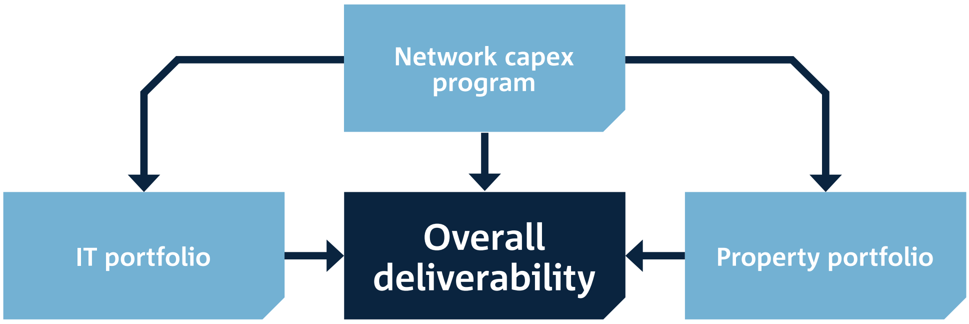
Proposed outcome	Programs / projects to achieve outcome	Interactions with other programs	How we avoided double counting	How we optimised
Improve reliability for worst served customers	[AUGEX WORST SERVED CUSTOMERS RELIABILITY IMPROVEMENT PROGRAMS]	Between [AUGEX WORST SERVED CUSTOMERS RELIABILITY IMPROVEMENT] programs. [OPEX]: addressed Draft Decision by accounting for emergency response and GSL opex savings.	Table cataloguing upgrades across reliability improvement programs used to identify and eliminate duplicated / related upgrades. Opex saving counted as negative step change, with a higher opex reduction than Original Proposal.	Catalogued avoided potential duplication of upgrades, and optimised, so each program is efficient with a positive NPV result.
Maintain overall network safety risk	[REPEX] – maintain safety risk from asset condition.	[AUGEX BUSHFIRE RISK MITIGATION] programs.	Bushfire risk reduction via augex bushfire risk mitigation program included in repex risk modelling.	Bushfire risk reduction via augex has positive net benefit, repex maintains the bushfire risk.
	[AUGEX BUSHFIRE RISK MITIGATION] programs to mininise bushfire risk.	[AUGEX RELIABILITY IMPROVEMENT] programs	Reliability improvement not quantified in bushfire analysis as not material vs bushfire risk reduction.	
Achieve CER export service level of 95% for 95% of customers	[CER INTEGRATION]	[CER COMPLIANCE] program increases export hosting capacity reducing the need for CER augex. [NETWORK VISIBILITY PROGRAM] increases flexible export efficacy. [AUGEX CAPACITY] component addressing LV quality of supply	Hosting capacity benefits from compliance included in base case for CER augex program, so not included in CECV benefits of CER augex. Effect considered in the base case for CER augex model, as above. Combined modelling tools used between programs.	CER augex model assumes underlying annual increase in export capacity from compliance program, before considering augex. Benefit modelled, reducing future export curtailment, before any augex investment. Transformers replaced in CER augex & flexible exports prevent growth in export driven supply quality issues.
Reduced network capital works delivery costs	[ICT ASSETS & WORK] - improves asset management efficiency to reduce cost of work.	[TOTAL NETWORK CAPEX]	A cost reduction was applied as an adjustment across repex, augex, and CER programs – as per Draft Decision.	
Maintain supply security & ability to meet demand	[AUGEX CAPACITY]	As above re [CER INTEGRATION DEMAND FLEXIBILITY] program R[EPEX]	Demand flexibility targets part of residual VCR risk remaining from augex capacity program - no overlap. Programs cross-checked. HV assets covered in HV capacity augex not included in repex.	Augex capacity doesn't resolve all forecast VCR risk. Demand flexibility reduces customer impact of the residual risk.
Reduced emissions	[FLEET] – replacing ICE vehicles with EVs.	[OPEX]	Efficiencies relative to ICE vehicles on total cost of ownership counted as negative opex step change.	ICE vehicles will be replaced with EVs where these are more cost effective.

5.5 Our capex program remains deliverable

Our Original Proposal demonstrated that a key consideration in forecasting an increase in our overall capex for 2025-30 was to ensure that our plans were deliverable, having regard to the timing of practical implementation and required supporting staff and other resources. This was an important topic for customers that we proactively engaged on.

Deliverability was considered throughout our Regulatory Proposal, with each of our business cases outlining how this was considered in specific contexts. Our overall approach focused on the three largest portfolios / programs of work, by considering deliverability individually as well as interdependencies between the portfolios.

Figure 14 Key considerations in overall deliverability



The topic of deliverability was examined by the AER and its external engineering consultants, EMCa, and no concerns were identified in the Draft Decision.

There has been no change in the deliverability assurance that we have, with respect to our Revised Proposal, noting that our revised capex forecast has:

- not introduced any new programs of work that were not already foreseen and planned for; and
- forecast a reduction in the expenditure and work than we had originally forecast.

6 Our revised expenditure forecast

6.1 The total capex forecast and its drivers

Our revised total capex requirement is $2.3 billion, a 18.5% increase on our expected 2020-25 spend. This forecast is $41.4m and 1.7 percent lower than in our Original Proposal which had represented a higher 21.5 percent increase on 2020-25. Our forecast reflects the need to prudently and efficiently respond to the convergence of multiple challenges and opportunities for our network and our services in 2025-30, including:

- **Repex** – the need to increase repex rates to levels commensurate with the risk posed by our network age profile and asset condition in order to maintain overall reliability by geographic region, improve reliability in the Adelaide CBD to meet jurisdictional service standards, and maintain safety in aggregate;
- **Augex** – the need to increase spend on network upgrades in order to:
  - meet forecast strong increases in load demand, driven by customer electrification, by ensuring sufficient distribution network capacity;
  - respond to non-asset condition impacts on reliability (ie. bats, weather, third parties); make targeted and optimised upgrades alongside repex to improve reliability in the CBD to comply to standards; and make targeted improvements for regions and customers repeatedly experiencing poor reliability performance; and
  - to mitigate the risk of our assets starting bushfires and minimise customer impacts when we must initiate public safety power shutoffs during bushfire risk times;
- **CER integration** – the need to increase spend to: meet and manage demand for export services by increasing hosting capacity to provide an efficient service level that customers prefer; invest in capabilities to enable flexibility in customer loads; and improve compliance to CER technical standards;
- **Property** – the need to increase spend due to deteriorating condition, capacity limitations, and opportunities for activity consolidation, by refurbishing, renewing, and rebuilding properties;
- **Fleet** – the need to increase spend due to the timing of replacement cycles, while increasing volume to support increasing network capital work, and efficient acquisition of Electric Vehicles **(EVs)**; and
- **ICT** – while we forecast a decrease for recurrent and non-recurrent expenditure, we need to replace existing systems to maintain services and functionality, invest in new capabilities for more personalised and on demand services via digital channels, and to improve the efficiency of asset management practices, while also enhancing our cyber security in response to increased threats.

Figure 15 Total capex profile – historic and forecast, by expenditure category

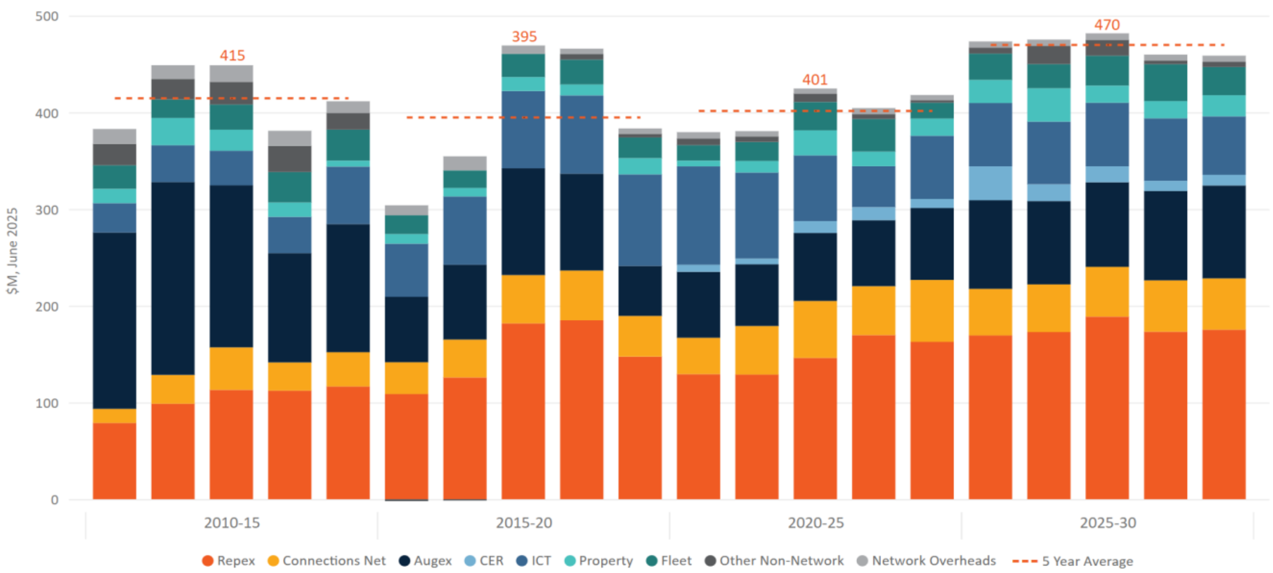


Figure 15 displays our forecast capex by category, relative to our historic spend.[15] Further, Table 5 outlines our revised capex forecast by category, relative to our actual spend in 2020-25 and to our Original Proposal.

Table 5 Revised capex forecast for 2025-30 - by category and totals ($million 2025)

	25/26	26/27	27/28	28/29	29/30	25-30 Total	20-25	% change vs 20-25	Proposal	% change vs Proposal
Repex	169.4	172.9	188.8	173.2	175.3	879.6	736.8	19.4%	909.4	-3.3%
Augex	91.6	86.2	87.5	92.4	96.1	453.7	344.9	31.6%	490.3	-7.5%
CER	35.1	17.4	16.5	10.6	11.1	90.7	48.5	87.1%	90.7	0.0%
Connections net	48.1	49.3	51.5	53.2	53.1	255.2	261.5	-2.4%	255.2	0.0%
ICT	65.4	64.7	65.8	64.6	60.4	321.0	366.2	-12.3%	300.8	6.7%
Fleet	27.2	25.0	30.9	38.2	29.2	150.4	115.1	30.6%	154.9	-2.9%
Property	23.9	34.5	17.7	17.8	21.9	115.8	76.8	50.8%	115.8	0.0%
Other non-network capex	6.1	19.0	16.4	3.7	5.3	50.4	28.9	74.3%	50.4	0.1%
Capitalised overheads	6.4	6.4	6.8	6.3	6.4	32.3	28.8	12.3%	33.5	-3.6%
TOTAL NET CAPEX (before disposals)	473.4	475.4	481.8	459.8	458.7	2,349.1	2,007.5	17.0%	2,400.9	-2.2%
less disposals	-2.7	-3.8	-6.4	-5.2	-3.7	-21.8	-28.3	-22.8%	-21.8	0.0%
TOTAL NET CAPEX (after disposals)	**470.7**	**471.5**	**475.4**	**454.6**	**455.0**	**2,327.2**	**1,979.2**	**17.6%**	**2,379.1**	**-2.2%**
Modelling adjustments[16]	1.0	1.4	2.1	2.6	3.4	10.4	-6.7	n/a	-	n/a
TOTAL NET CAPEX (after modelling adjustments)	**471.6**	**472.9**	**477.5**	**457.2**	**458.4**	**2,337.7**	**1,972.5**	**18.5%**	**2,379.1**[17]	**-1.7%**

15 Expenditures displayed in this figure are shown before disposals and before modelling adjustments.

16 Modelling adjustments consist of the revised inflation using the AER Draft Decision CPI forecast, and revised real labour price escalators using latest forecasts – using the same escalators used for opex forecasting.

17 Modelling adjustment was not applied to the Original Proposal. It is part of the overall change between the Revised Proposal and the Original Proposal ($41.4m and 1.7 percent reduction).

6.2 The revisions made to prudently and efficiently address the Draft Decision

6.2.1 Network asset replacement expenditure (repex)

Capex $879.6 million

37.4% of total capex

Our revised repex forecast of $879.6 million[18] responds to the need to retire distribution network assets that are in poor condition, by replacing assets across several asset classes, with view to maintaining reliability performance and safety (including to bushfire risk) for customers.

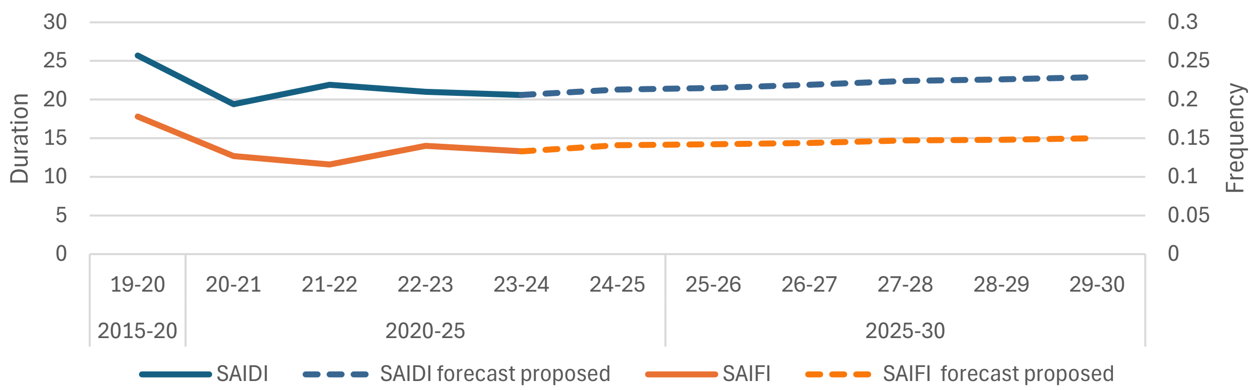
Our Regulatory Proposal originally forecast repex of $909.4 million.[19] The forecast applied risk modelling aligned with AER guidelines, for asset classes with sufficient data. This modelling quantified service outcomes for customers and the community from various counterfactual levels of repex. The forecast sought to achieve an overall identified need, consistent with the service outcomes preferences of our customers.

We do not accept the Draft Decision to reduce forecast repex to $772.6m, as our modelling indicates that this would deteriorate customer service outcomes, via failure of in-service assets, degrading reliability (more outages) and increasing safety risks to customers and communities. However, we accept that our justifications may have been insufficient, and that the Draft Decision raised some legitimate concerns. We therefore revised our modelling to address each individual concern in the Draft Decision, resulting in our revised repex forecast being $29.8 million lower than our original forecast.

Our revised forecast represents a prudent and efficient level of repex on the basis that:

- **service outcomes align to customer preferences** – achieves a target service outcome (maintaining safety, improving CBD reliability to standard, maintaining reliability by geographic region) aligned to our customers' preferences, which have remained unchanged;
- **the value of service outcomes to customers is maintained** – maintains service outcomes in 2025-30 to current levels, in monetised risk terms, that is, quantifying the risk posed by asset condition to reliability and safety to customers in dollar impact terms – in contrast, a counterfactual of maintaining only our current rates of repex would deteriorate reliability and increase safety risk;
- **the service level outcomes are maintained for customers** – maintains outcomes in terms of actual service levels measured as SAIDI and SAIFI – that is, forecast repex will only maintain current / historic service levels rather than improve; and
- **expenditure to achieve these service outcomes is efficient for customers** – the forecast repex to achieve the target service outcomes is efficient, with total customer benefits outweighing costs and an NPV result of $171m over a 20-year period, and the AER's own repex model shows our forecast to be comparatively lower cost (for applicable asset classes).

Figure 16 Evidence of service levels maintained by our forecast repex



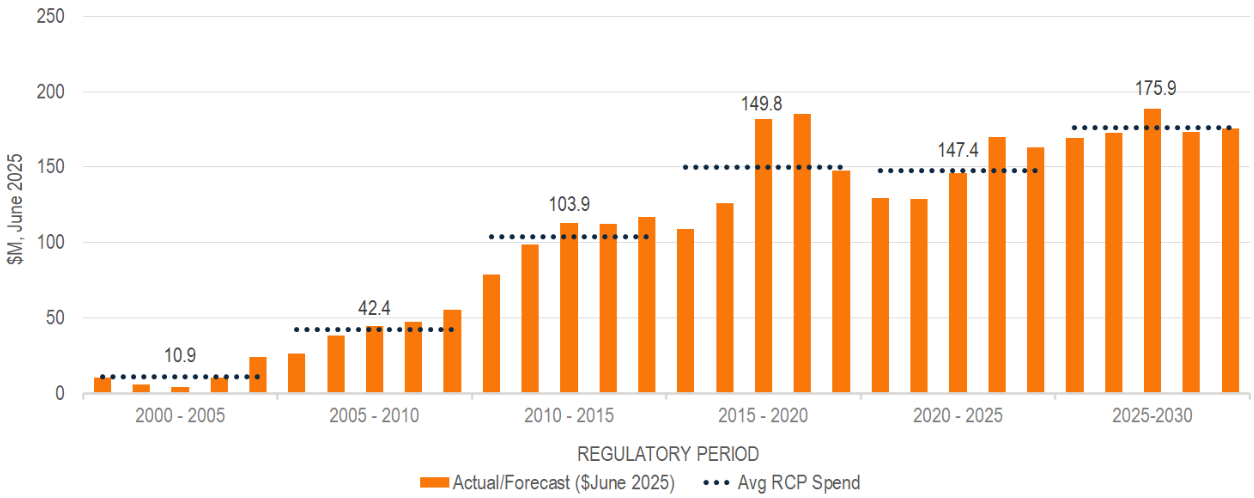
18 Includes $27.1 million efficiency adjustment from our Assets and Works program for 2025-30, approved in the Draft Decision.

19 Our original forecast was $936.4m excluding the $27.1m efficiency adjustment, or $909.4 including the efficiency adjustment (totals do not add up due to rounding).

Despite being a 19.4 percent increase on our 2020-25 spend, our revised forecast for 2025-30 simply continues our steady long-term upward trend in repex as displayed in Figure 17. This trend is explained by the following:

- acting prudently and efficiently, we replaced relatively little network in past periods when the age profile of our network assets was lower;
- over time, as the age profile has increased and asset condition deteriorated, acting prudently and efficiently our repex levels have followed a consistent upward trend – this long term repex increase, combined with increased augex on reliability and bushfire mitigation, have been crucial in keeping long term service performance steady;
- in 2020-25, despite increasing repex (and increasing augex), distribution system reliability has declined over this more recent period as shown earlier in Section 4.2; and
- now, to maintain service over the 2025-30 RCP, our forecast repex needs to continue to steadily increase. Our modelling suggests this will likely need to continue until at least 2050 before stabilising – given the age and condition profile of our assets.

Figure 17 Long-term repex profile



Key revisions to our approach

The Draft Decision reduced our forecast repex on asset types with expenditure forecast on the basis of our risk-cost modelling, substituting our forecast with historical expenditure. Our revised proposal has focused on the components of our repex for which the AER raised concerns.

	AER DRAFT DECISION CONSIDERATIONS	HOW WE HAVE RESPONDED[20]
Modelling input assumptions	**Outage duration**	
	a. Using a 12-year average likely overstates risk as it does not consider changes in asset condition or response to practices that may impact frequency or duration of events.	a. Updated our average duration to reflect a 5-year average – incorporated into our revised modelling.
	b. Calculating an entire asset population's outage duration by voltage alone is not reflective of the actual restoration experience for urban vs rural customers.	b. Updated our average outage duration to account for network characteristics using feeder type (urban, rural long, rural short and CBD) – incorporated into our revised modelling.
	c. Large weather events may be skewing outage duration data adjacent to these events (in last 2 years).	c. Undertook analysis of the impact of large weather events on average restoration times – analysis showed a negligible difference and so we have not adjusted our modelling.
	Likelihood of consequence	
	a. Assumption of a 100% chance of outage in event of a failure likely overstates risk and is not supported by actual data.	a. Updated our likelihood of consequence to reflect actual observed likelihoods based on our failure data.
Model calibration	**Probability of failure**	
	a. Predicted increasing failure trends are inconsistent with actual failure data for HV and LV conductors.	a. Recalibrated our probability of failure models for cables and conductors to align with actual failures over a 5-year average.
	b. Calibration of failure model should better reflect observed overall network risk values.	b. Audited our asset failure data, identifying a systemic issue resulting in under-reporting of failures in some asset classes and over-reporting in others. Corrected failure data is now used to calibrate our model as well as in Regulatory Information Notice (RIN) reporting.
Target service level	**Baseline service level**	
	a. An average of 3 to 5 years should be used to set the baseline service level that the proposal seeks to maintain, rather than a single year (2021-22).	a. Clarified an AER misinterpretation. Our service outcome forecasting approach calibrates the model using historical observations (over a period) and uses this as the target service level - the baseline service level maintained is not 2021/22 but the average service level of the 5 years used to calibrate the model.
	Link between expenditure forecast and target service level	
	a. Better demonstrate the effect of the proposed expenditure (and counterfactuals) on service level outcomes by way of SAIDI and SAIFI.	a. Updated modelling to reflect reliability service performance in SAIDI and SAIFI performance (in addition to our modelled monetary service risk to customers).

[20] We also corrected two errors found in the course of responding to AER Information Requests, and to the Draft Decision: (1) the omission of recurrent 'car-hit-pole' expenditure, and (2) omission of some non-CBD cable expenditure.

The preferences of our customers[21]

We continued our ongoing engagement with our Community Advisory Forum **(CAF)** and Reset Advisory Group **(RAG)** subsequent to our Proposal and the Draft Decision. No new perspectives emerged to suggest any change in customers' preferences with respect to the need that repex responds to.

That is, the service outcome preferences of our customers remain as to:

- maintain reliability by geographic region – to avoid further inequity emerging between regions;
- improve reliability of the Adelaide CBD to comply with our jurisdictional standard – given the importance of compliance, and of the CBD's importance to South Australians;
- maintain safety in aggregate across our network – given a desire to not see rising risks of harm to persons and damage to property / assets, particularly given rising climate change concerns; and
- ensure that our proposed repex is efficient for customers.

Revised proposal and its efficiency for customers

REPEX FORECAST	Proposal	AER Draft Decision	Revised forecast
Modelled	$532.0m	$426.6m	$492.0m
Unmodelled	$404.4m	$373.1m	$414.6m
Less Repex efficiency adjustment[22]	-$27.1m	-$27.1m	-$27.1m
TOTAL REPEX	**$909.4m**	**$772.6m**	**$879.6m**

SERVICE LEVEL OUTCOMES

Service levels maintained in monetary terms – risk posed by asset condition to reliability and safety maintained in monetary risk terms.

Reliability service levels maintained: SAIDI and SAIFI risk from asset condition maintained to current levels, and maintained by geographic region.

Safety risk maintained – risk posed by asset condition to safety (including bushfire risk) maintained in aggregate.

EFFICIENCY FOR CUSTOMERS

Positive net benefits: total benefits outweigh costs with NPV result of $171m[23] over a 20 year period.

Least cost vs AER comparators: lower cost than the top-down comparator forecast of the AER's own repex model (for applicable asset classes).

21 Further information and source references for views provided by our customers and stakeholders through our engagement on all expenditure areas covered in this attachment, please see the relevant business case documents supporting our Original Proposal, and the business case addendums supporting our Revised Proposal which are listed in Appendix A, and our talkingpower website, accessible on: [https://www.talkingpower.com.au]

22 Efficiency adjustment from the Assets and Works program – the program was approved in the Draft Decision.

23 This NPV estimate is intentionally conservative, encompassing all costs associated with modelled and unmodelled assets, yet it does not encompass the entirety of the benefits.

6.2.2 Network capacity expenditure (augex)

Capex $203.5 million

8.7% of total capex

Our revised forecast of $203.5 million responds to the need to expand / upgrade assets to ensure network capacity and security to meet demand and maintain service quality, reliability and security, with some projects triggered by compliance. This comprises programs and projects extending or upgrading the sub-transmission, distribution and Low Voltage networks, and transmission connection points and substations.

Our Regulatory Proposal originally forecast $240.9 million, comprising several programs including: compliance driven connection point upgrades; compliance driven quality of supply upgrades; and demand driven projects. Demand driven projects were forecast by a 'hybrid planning' method, combining projects selected on both a 'deterministic' basis applying our long-standing distribution network planning criteria (10% POE projects under 'N' normal conditions), and 'probabilistic' planning for 'N-1' contingency conditions.

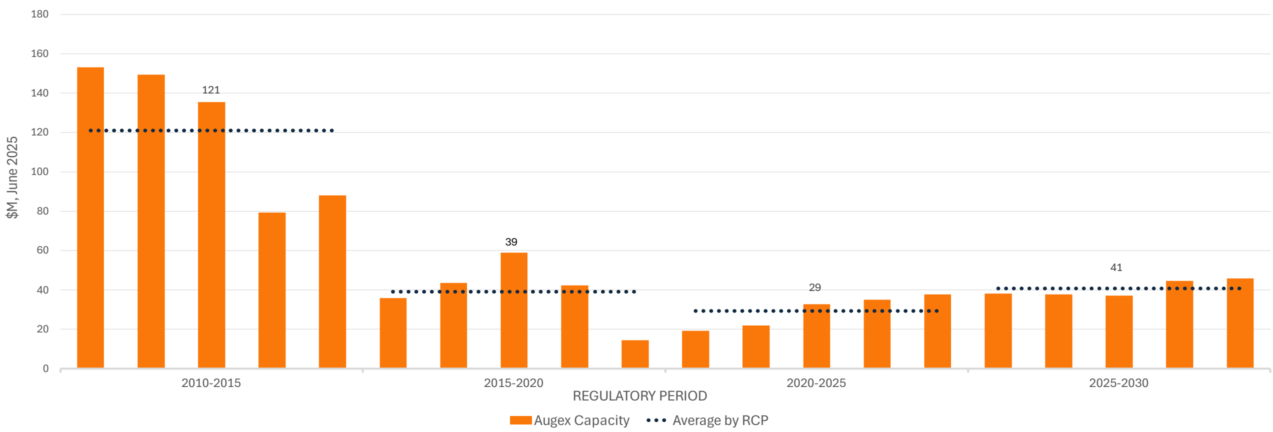
The Draft Decision substituted our forecast with $204.5 million which was $36.4 million lower than our forecast. In arriving at its substitute forecast, the AER identified several concerns that it wanted addressed. We acknowledge the insufficiency of our proposal with respect to the justification of our forecast's reasonableness and our approach to project selection and economically optimal timing. We have therefore revised our modelling and documentation to address each individual concern identified in the Draft Decision, resulting in our revised forecast being $37.3 million lower than our original forecast, and $0.9m lower than the Draft Decision.

Our revised capacity forecast represents a prudent and efficient level of expenditure on the basis that:

- **balanced considerations are applied** – our overall forecasting approach reflects a prudent balance between aligning regulatory expectations with those of our customers who seek sufficient network investment to meet future demand in order to maintain service and security;
- **demand forecast inputs are updated** – our forecast includes an updated demand forecast reflecting our best available expectations, incorporating latest data and prudently usable AEMO forecast;
- **efficient timing of projects** - our revised forecast only selected projects from an amended and structured selection process, applying Benefit-Cost-Ratio (BCR) analysis, and a new two-step deferral test so that only projects that are prudently and efficiently timed for 2025-30 are selected; and
- **total expenditure is efficient** – our total revised forecast is efficient for customers, with benefits outweighing costs and an NPV result of $812 million over a 20 year period.

This revised forecast level of expenditure represents only a modest increase on the historically low levels of capacity augex that we spent over the past decade while demand growth was negligible other than in localised areas of our network.

Figure 18 Long-term capacity augex profile



Key revisions to our approach

The Draft Decision reduced our forecast capacity augex by substituting our forecast with a lower expenditure forecast in relation to the 'demand driven' component of the overall capacity augex. The AER accepted the 'compliance driven' component of our capacity augex. Therefore, our Revised Proposal has focused on the components of our capacity augex for which the AER raised concerns.

The expenditure forecasting methodology presented in our Regulatory Proposal, replicated in Figure 19, has been adapted to address the Draft Decision, with our revised approach now assessing N and N-1 projects using a new 2-step process outlined in Figure 20.

Figure 19 Original / overall forecasting method

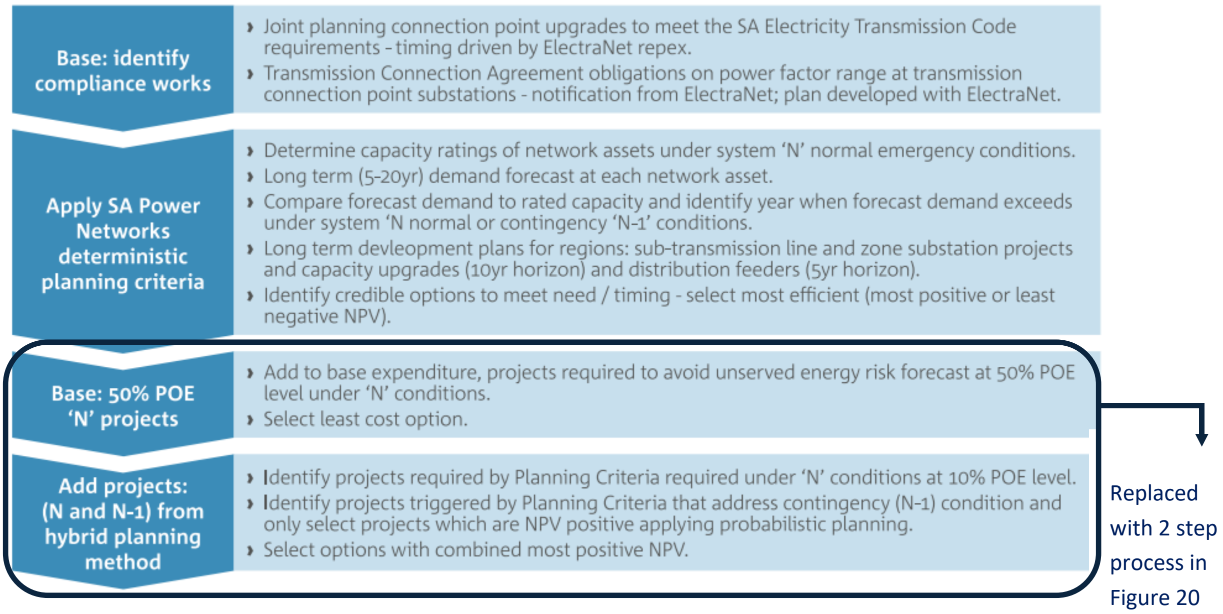
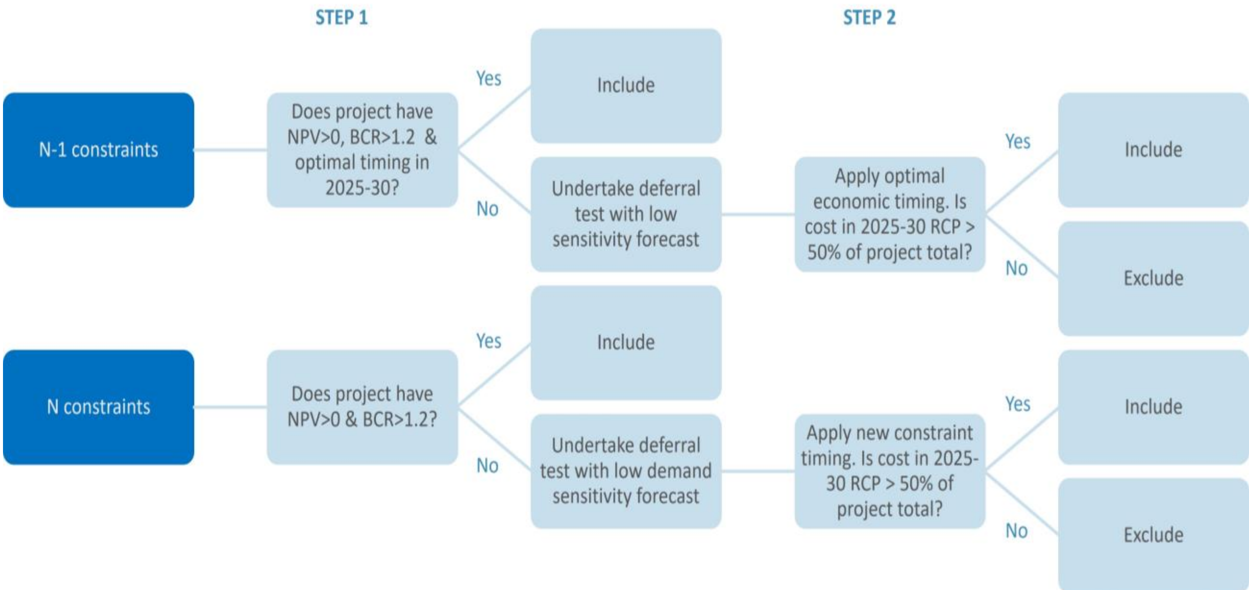


Figure 20 Additional two-step project selection process



	AER DRAFT DECISION CONSIDERATIONS	HOW WE HAVE RESPONDED
Demand forecast	**Forecast update**	
	a. Use the latest available information in the Revised Proposal.	a. Updated to latest / prudently usable information – using latest historic measurements and the AEMO ISP 2024 Central forecast. This is our most robust and complete forecast available for this Revised Proposal, a decision supported by analysis from independent forecasting experts, Endgame Economics.
	Block load adjustments	
	a. Demonstrate how AEMO and SAPN's forecasts reconcile and that block loads are not already accounted for in AEMO's forecast trend to avoid duplication / over-estimation.	a. Provided detailed reconciliation between AEMO's forecast and our adjustments, showing how we avoided duplication and overestimation using a method recommended by Endgame Economics.
	b. Exclude BESS from the forecast.	b. Removed BESS adjustments.
	c. Concerned with SAPN's application of its 5% materiality threshold for block load adjustments, which results in over-estimation.	c. Engaged Endgame Economics to review our demand forecasting approach and adapted our method to incorporate their recommendations on materiality thresholds, block load treatment and evaluation of potential overestimations.
	d. Need to evaluate potential over-estimation in customer requested loads, likelihood of projects not proceeding, impact of project loads on seasonal and system peak time.	d. Implemented an assumed 2-year lag in our forecasting and project selection method, based on the findings of Endgame Economics regarding the timing of customer requested loads.
Optimal project timing	**Demand forecasts mapped to projects**	
	a. Demand forecast must be clearly mapped to specific augmentation projects to demonstrate optimal timing.	a. Mapped demand forecasts to specific projects to show optimal timing, and implemented a clear audit trail in our Capacity Augex Tool, showing when the cost to customers (expressed in the Value of Customer Reliability) exceeds the annualised investment cost.
	Economically optimal timing of projects	
	a. SAPN's analysis does not inform economically optimal timing - BCR analysis is needed.	a. Selected projects based on economic optimal timing, aligned to the method in the AER 'Industry practice application note – asset replacement planning'.
	b. Concerned that some projects with low but positive NPVs are susceptible to variances in demand or costs.	b. In addition to NPV analysis proving benefits outweigh costs, also conducted benefit-cost ratio (BCR) analysis to guide the economic optimal timing of projects and introduced a two-step project selection approach for projects susceptible to small variances in key inputs.
	c. Projects cut had a BCR less than 1.2, with economic timing beyond the RCP, relatively low BCRs and mostly negative NPVs even over 20 years.	c. To ensure the robustness of forecast expenditure we completed deferral tests (step 2) on projects with a BCR less than 1.2.
	Sensitivity analysis	
	a. Need further sensitivity testing of project forecasts to ensure their robustness and necessity.	a. Completed sensitivity analysis on forecast expenditure. Applied the EMCa recommended 'BCR>1.2 test' to identify projects susceptible to small variances. Also, our deferral test incorporates a low demand sensitivity.
	Consideration of alternatives	
	a. Demonstrate identified needs cannot be addressed via other means than building more network.	a. Visibility of alternatives explored to minimise upgrades. Also manually deferred projects close to RCP end where network risks can be operationally managed.

The preferences of our customers

We continued our ongoing engagement with our CAF and RAG subsequent to our Proposal and Draft Decision. No new perspectives emerged that would suggest any change in the preferences of our customers with respect to the need that forecast capacity augex responds to.

That is, the service outcome preferences of our customers are to ensure sufficient investment in order to:

- meet expected customer demand for service over the 2025-30 RCP;
- maintain long term security of supply to current standards; and
- to achieve these outcomes in a manner that is mindful of energy affordability by ensuring prudency and efficiency in forecast expenditure.

Revised proposal and its efficiency for customers

CAPACITY FORECAST	Proposal	AER Draft Decision	Revised Forecast
Compliance – connection point upgrades	**$58.7m**	**$58.7m**	**$50.2m**
Compliance – LV quality of supply	**$41.3m**	**$41.3m**	Decision accepted
Compliance - other	**$24.8m**	**$24.1m**	**$27.7m**
Demand driven capacity	**$116.0m**	**$80.3m**	**$84.4m**
TOTAL CAPACITY	**$240.9m**	**$204.5m**	**$203.5m**

SERVICE LEVEL OUTCOMES

Maintain service: forecast meets / manages forecast demand, thereby maintaining supply reliability, security and quality

Maintains compliance: forecast maintains compliance with regulatory and licence obligations

EFFICIENCY FOR CUSTOMERS

Positive net benefits: total benefits outweigh costs with an NPV result of $811.6 over a 20-year period (modelled assets).

Projects timed efficiency: projects have economically optimal timing, ensuring capex is spend when most needed and efficient, evidenced by applying the BCR analysis and two-step project selection process.

Least cost compliance solutions: applied to compliance driven upgrades, focusing on maintaining service quality and reliability and considering non-network alternatives to defer/avoid augex where feasible and cost-effective.

6.2.3 Maintain underlying reliability performance program (augex)

Capex $74.0 million

3.1% of total capex

Our revised forecast of $74.0 million is to continue our long-standing program which seeks to maintain reliability service performance to customers using various network upgrade solutions to respond to factors impacting reliability but unrelated to network asset condition, including: weather effects (i.e. lightening and vegetation contact), animals (e.g. flying foxes) and third parties.

Our Regulatory Proposal originally forecast $72.1 million, using a top-down forecast based on historic costs, being our most recent 5 years of revealed costs at the time.

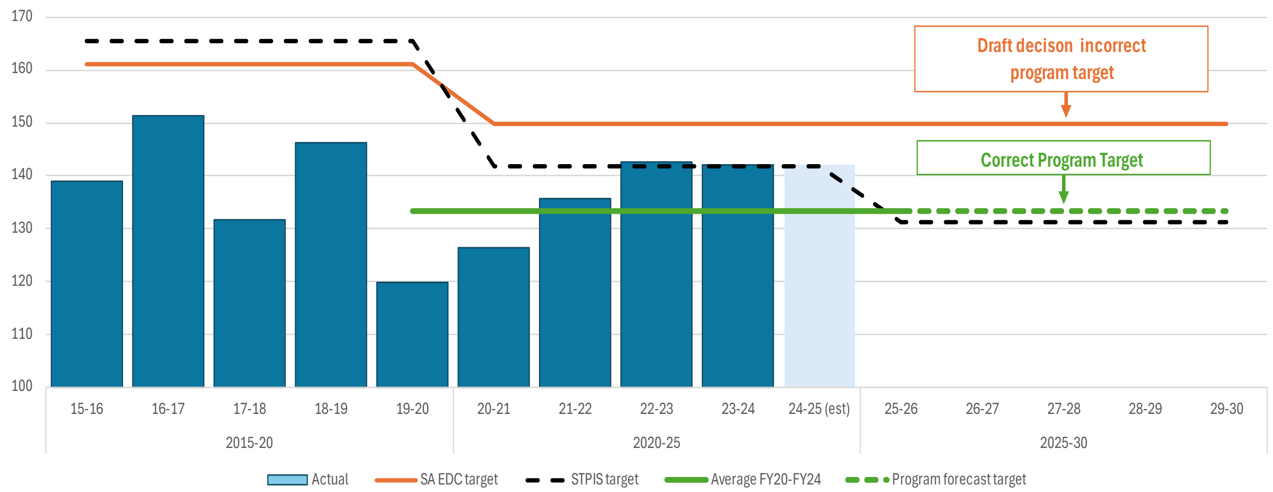
We do not accept the Draft Decision to reduce our forecast to $50.1 million (a $22.0m reduction), as this would materially reduce reliability for customers in 2025-30, inconsistent with our customers' preferences.

However, we acknowledge that our information was insufficiently clear, which led to a misinterpretation by the AER as to the target service level of the program's expenditure and why our forecast will only maintain and not improve service. We have therefore provided more analysis and updated data to address each Draft Decision concern, and revised our forecast to include an additional year of revealed expenditure. This has resulted in our revised forecast being $1.9m higher than our original forecast.

Our revised forecast for this program represents a prudent and efficient level of expenditure to meet the identified need of maintaining underlying distribution network reliability at historical levels, on the basis that:

- **service outcome aligns to customer preferences –** the forecast expenditure level aligns to our customers' preferences by maintaining reliability in 2025-30 to current levels, rather than only seeking to comply with our jurisdictional reliability targets, which would see reliability deteriorate;
- **reliability trends continue to worsen** – the forecast expenditure is needed to maintain reliability, in response to worsening reliability trends, and no evidenced abatement (and likely continued increases) in the factors that will continue to affect reliability (i.e. weather, animals, third-parties);
- **revealed 5-year expenditure is a reasonable basis for forecasting –** the most recent revealed period (2019/20 to 2023/24) aligns to the period the AER uses to set STPIS targets for 2025-30, and this period's revealed spend is shown to have not improved reliability nor contained material lag effects, providing therefore reasonable indication that the forecast will only maintain reliability; and
- **the Draft Decision expenditure would materially degrade service outcomes –** we estimate that reducing our forecast to the Draft Decision level would worsen SAIDI by 10 minutes (7% worse) and increase unserved energy costs to customers by circa $75-93 million over the investment life.

Figure 21 Network SAIDI performance



Key revisions to our approach

AER DRAFT DECISION CONSIDERATIONS	HOW WE HAVE RESPONDED
The target reliability outcome	
a. The level of proposed expenditure forecast is not required as performance against ESCoSA jurisdictional reliability targets have been met (except for CBD).	a. Explained that this is not the correct basis for defining the expenditure level required for this program in the 2025-30 RCP, and that this significantly understates the requirements of the program's forecast. The correct basis for the target reliability level is the level required to maintain reliability to the average of the most recent 5-year period, which is a far more onerous target than ESCOSA's targets.
Reliability performance	
a. The level of proposed expenditure forecast is not required as reliability is being maintained noting: SA Power Networks' recent public planning and performance reports do not support the proposal; normalised reliability is being maintained and any deterioration would likely be addressed via investments in the current period. The AER's consultant report by EMCA, noted some uncertainty in performance as 2023/24 data was not yet available.	a. Greater evidence that reliability has worsened and explained the drivers of these trends and how they affect future needs: i. updating results with 2023/34 reliability and expenditure data, showing the reliability trend is worsening; ii. further explaining our historical expenditure and showing there is unlikely significant further improvement via investments we made in this RCP – demonstrating we considered but observed no significant lag effects from investments to improvements; iii. further explanation and data on current and emerging issues driving performance that we need to manage over the 2025-30 RCP – explaining why factors driving weather-related performance (lightening, vegetation contact) and animal (flying foxes) and third-party caused outages are expected to at least continue if not worsen;
b. Weather related impacts are not increasing and may be more effectively addressed via opex solutions (i.e. vegetation management).	b. We explained why it is unlikely that there are more effective opex solutions, particularly further vegetation management – given planning / legislative limits in the use of these solutions.
Interactions with other programs	
a. Not evident that improvements in reliability resulting from other repex and augex programs had been accounted for.	a. The concern is not valid. We explained how we took account of other repex and augex programs in how we developed the program's target reliability level and forecast expenditure level.
Historic expenditure averaging period on which to base the forecast	
a. Top-down approach of forecasting expenditure is reasonable, but should be set to reflect the most recent 8-year period of revealed historic costs rather than the proposed 5-year period.	a. The basis for the AER's use of an 8-year average is not substantiated. Given the above-mentioned ways in which we have explained the need for the level of forecast expenditure and that it only seeks to maintain reliability to that experienced in this period, we have set the forecast to maintain to the level of historic spend in the most recent 5-year period

The preferences of our customers

We continued our ongoing engagement with our CAF and RAG subsequent to our Proposal and Draft Decision. No new perspectives emerged to suggest any change in the preferences of our customers with respect to the need that the maintain underlying reliability program responds to.

That is, the service outcome preference of our customers is to:

- maintain reliability service performance in the 2025-30 RCP to the performance level that customers currently experience; and
- ensure that the expenditure forecast is prudent and efficient.

Revised proposal and its efficiency for customers

EXPENDITURE FORECAST	Proposal	AER Draft Decision	Revised Forecast
TOTAL	**$72.1m**	**$50.1m**	**$74.0m**

SERVICE LEVEL OUTCOMES

Maintain service reliability: reliability performance (in SAIDI and SAIFI metrics) maintained to average performance of the last 5-year period (2019/20 to 2023/24) consistent with the measurement period used by the AER to set STPIS targets for 2025-30.

Preferred to counterfactual: the expenditure forecast is preferred to the option of setting expenditure to the AER Draft Decision as this counterfactual would materially decrease reliability by 10 minutes over the RCP (7% worse SAIDI), and require an adjustment to the STPIS targets for 2025-30.

EFFICIENCY FOR CUSTOMERS

Program is preferred to counterfactual: program is preferred to the option of setting expenditure to the AER Draft Decision as this counterfactual would result in unserved energy costs to consumers of circa $75-93 million over a 15 year investment life.

6.2.4 CBD reliability improvement program (repex & augex)

Capex $61.4 million

2.6% of total capex

Our revised forecast of $61.4m is to improve reliability in the Adelaide CBD, to bring performance into line with our jurisdictional service standard set by ESCoSA. The program comprises several available solutions, optimised to meet the need on a least cost basis including: replacing cables ($35.5m repex); installing automated load switches and making topology changes ($26.0m augex)

Our Regulatory Proposal originally forecast $90.6m. We considered three options, cable replacement only, automation only, combined cable replacement and automation, and recommended the latter option.

The Draft Decision accepted the program's identified need, and so it remains unchanged from our Proposal. The identified need is to improve CBD reliability to bring it into line with the jurisdictional standard. We failed to comply with the standard's targets in multiple periods from 2017-18 to 2023-24, the targets are already exceeded in the first 4 months of this 2024/25 year, and without investment, we forecast to not comply with our targets in the next RCP. Underground cable failures are the main driver that we need to respond to.

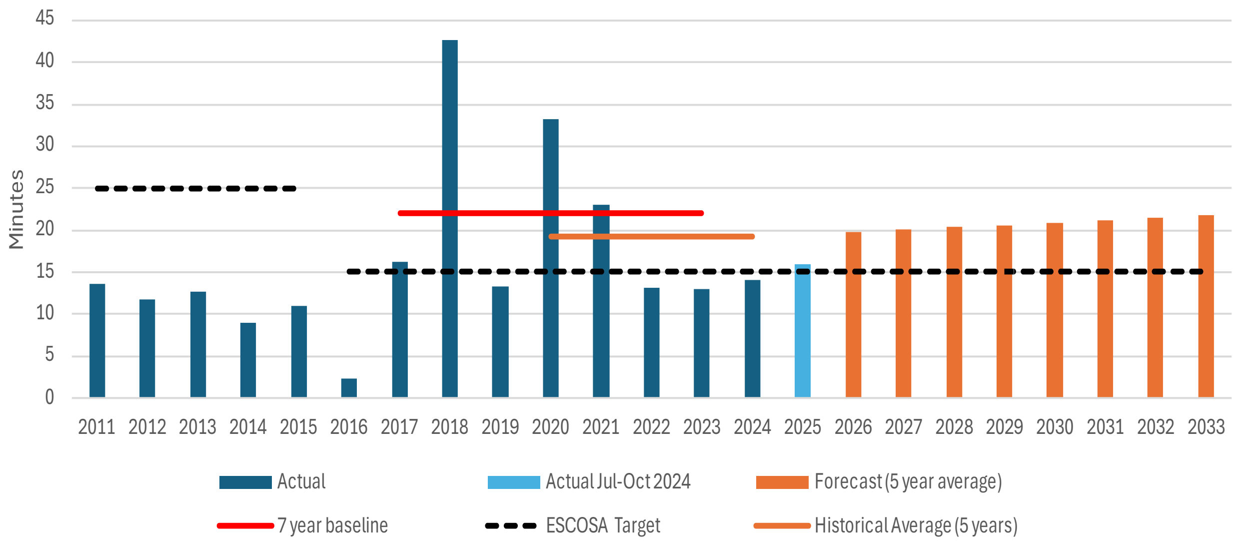
We do not accept the Draft Decision to apply a lower substitute forecast of $12.2m. This substitute was stated to be a 'placeholder' pending several concerns being addressed, including: the calculated gap to the target compliant service level, the measured forecast service risk, and the non-consideration of an additional solution involving changes in the CBD network's topology.

We recognised that some of our assumptions and our options analysis could be improved. Therefore, we revised our approach, addressing each specific Draft Decision concern by aligning to AER views on several assumptions and model inputs, and extending our analysis to all available solutions to address the need, enhancing our analysis to a more granular and locational basis. These changes to address the Draft Decision resulted in our revised forecast being $29.2m lower than we originally forecast.

Our revised forecast for this program represents a prudent and efficient level of expenditure to meet the identified need of improving CBD reliability to comply with standards, on the basis that:

- **achieves a compliant target service level –** the proposed solutions will bring CBD reliability into line with jurisdictional service standards by the end of the 2025-30 RCP;
- **target service level is aligned to customer preferences** – the forecast expenditure will improve CBD reliability to standard, consistent with our customers' recommendation given the importance of the CBD to South Australians;
- **optimised selection of credible solutions –** the recommended option selected a mix of all credible network solutions to address the need, optimised for least cost on a locational-specific basis, including: cable replacement (augex), automation (augex), and topology changes (augex);
- **highest NPV of the credible options –** the recommended option has the least negative result in NPV terms; and
- **measured approach to address the underlying cause** – the recommended option, while it does not over-rely on repex, reflects a level of repex that makes reasonably measured progress to address the key underlying cause of the CBD reliability problem (i.e. needing to retire poor condition cables).

Figure 22 CBD SAIDI performance and forecast



Key revisions to our approach

The revised expenditure forecasting methodology that we have applied is displayed in Figure 23.

Figure 23: CBD reliability improvement expenditure forecasting methodology

Current performance	➢ Calculated baseline CBD SAIDI and SAIFI performance over a 5-year period from 2019/20 to 2024/25.
Asset risk	➢ The probability of failure over time for each CBD cable was calculated by analysing cable attributes, failures, and geospatial data. ➢ Probability of failure data is forecast to understand future asset risk.
Assess improvement required	➢ The SAIDI and SAIFI drop required in the year 2029/30 to meet service standard targets is calculated
Priority areas for analysis	➢ Priority areas with the highest asset risk within the CBD were selected for detailed analysis of potential investment options.
Investment options	➢ Detailed analysis to determine investment options including cable replacement, automation and topology changes.
Optimisation of each area	➢ Benefits and costs calculated for each option and the most cost-efficient option selected.
Optimised program	➢ The minimum number of optimised investment options are selected to meet required SAIDI and SAIFI reductions

AER DRAFT DECISION CONSIDERATIONS	HOW WE HAVE RESPONDED
Baseline level of service	
Calculating the baseline reliability performance using a 7-year average (22.1 minute SAIDI) is insufficiently explained and likely overstates the gap to the compliant service level – a 5 year average baseline would likely be a more accurate assessment of performance.	Revised approach and calculated baseline performance using a 5-year average of the most recent performance data (2019/20 to 2023/24) also aligning to the STPIS target measurement period. This materially reduced the assumed current network risk by 2.8 minutes SAIDI and 0.025 SAIFI and so also materially reduced the expenditure forecast.
Likelihood of outage assumptions	
Assuming a 100% chance of an outage in the event of a cable failure likely overstates risk and is not supported by actual data which indicates a 64% likelihood.	Re-calibrated cable probability of failure (PoFs) rates, using actual data, and only on historical failures that caused a SAIDI and SAIFI impact, negating the need for the likelihood of consequence metric.
Outage duration	
There is a discrepancy in the assumed restoration time for CBD cables (296.82 minutes) compared to the 5-year historic average of 112.	Updated the average outage duration for 11kv CBD cables to the most recent 5-year average restoration times for 11kv cables in the CBD from 2019/20 to 2023/24, resulting in a 114 minute average.
Analysis of additional options	
Consider additional options, taking a broader system planning perspective and not assuming network topology is fixed – topology changes (e.g. additional feeder ties or feeder sections) should be considered alongside other options (repex, automation) to demonstrate the most efficient and effective solutions for the need.	Considered options that involve topology changes, via a bottom-up granular and locational analysis, allowing us to optimise between feeder ties, new feeders, feeder automation and cable replacement solutions. In most cases, topology changes necessitated investment in a new substation and this largely rendered these options to not be comparatively cost effective.
Performance measures	
In addition to the identified SAIDI need, SAIFI performance should also be considered in the options analysis.	Considered SAIDI and SAIFI performance to ensure both reliability targets are met. When optimising investments to achieve the required SAIDI improvement at least cost, we found no additional investment required to achieve SAIFI.

The preferences of our customers

We continued engagement with our CAF and RAG subsequent to our Proposal and Draft Decision. No new perspectives emerged suggesting a change in our customers' preferences on the program's need. That is, our customers' service outcome preferences are to ensure that CBD reliability can be improved to align with the jurisdictional service standard; and that the forecast expenditure is efficient.

Revised proposal and its efficiency for customers

EXPENDITURE FORECAST	Proposed	AER Draft Decision	Revised Forecast
Repex	$63.6m	$8.7m	$35.4m
Augex	$27.0m	$3.5m	$26.0m
TOTAL	$90.6m	$12.2m	$61.4m

SERVICE LEVEL OUTCOMES

Achieves compliant service level – the forecast improves CBD reliability to a compliant performance level of 15 minutes SAIDI and 0.15 SAIFI by the end of the 2025-30 RCP, aligning to customers' preferences.

EFFICIENCY FOR CUSTOMERS

Least cost investment option – selects from all available credible solutions (replacement, automation, topology changes) by optimising for comparative cost efficiency, and has the least negative NPV (being for compliance).[24]

[24] It is standard regulatory practice for business cases that respond to compliance driven identified needs to recommend the investment option that achieves the highest NPV which may be the least negative NPV.

6.2.5 ICT - ESB AEMO post 2025 roadmap changes

Capex $15.3 million

0.7% of total capex

Our revised forecast of $15.3 million in non-recurrent (compliance) ICT expenditure is to update our market-facing systems, and replace and upgrade market interfaces across our market and billing systems, to maintain existing energy market services and achieve compliance. The need is triggered by work being undertaken by AEMO in redesigning and replacing its own market systems as part of the Energy Security Board's **(ESB)** energy transition requirements and timelines.

At the time of our Regulatory Proposal we had insufficient certainty on the scope of AEMO's requirements and noted that cost implications could range from $2-21 million. We forecast $2.4 million as a placeholder only until we received further guidance.

We do not accept the Draft Decision forecast of $2.4 million on the basis that this forecast will not allow us to meet requirements in 2025-30, noting the AER recognised that this was only a 'placeholder' value to be amended in our Revised Proposal.

Having now obtaining sufficiently clearer indications from AEMO on the timing and obligations from the two phases of their work, we have now more reasonably forecast our requirements over the 2025-30 RCP:

- Phase 1 – is approved and requires replacement and upgrade of NEM cyber security identity management and access protocols and systems; replacement of portals to access NEM information; piloting replacement of core market integration systems with a data exchange; and piloting power quality data and CER data sharing exchanges and protocols.
- Phase 2 – is now detailed (to be approved circa end-2025), and will require us to start replacing and upgrading market integrations and systems piloted in Phase 1, and be involved in setup and testing when other market participants migrate their systems to the new environments to ensure market function integrity; and
- the AEMC flexible trading arrangements reforms now have a confirmed delivery date requiring us to implement changes by 2026 to enable customers to: engage different service providers for different loads via secondary service points;[25] and record consumption against new NMI types for streetlights and other street furniture.

Our revised forecast represents a prudent and efficient level of expenditure on the basis that it:

- **ensures compliance** – complies with the requirements that we expect to have in the 2025-30 RCP;
- **takes a measured approach** - addresses Phase 2 of AEMO's requirements by not seeking to achieve compliance with the whole phase (noting approval is pending), but making investments pursuant to Phase 2 that are 'no regrets' on the basis that:
  - we only targeted activities expected irrespective of AEMO's end-solution (i.e. initial planning, analysis, design for the end-solution), and not those dependent on the solution, (i.e. implementation activities);
  - other market participants will commence their migration ahead of us, based on their own drivers and/or opportunities, and as a DNSP we are required to be involved in setup and testing for South Australian customers to ensure market integrity; and
  - we reasonably expect that AEMO's timelines will be adhered to, as there is already a significant national effort to ensure this occurs.

[25] For example, separate flexible Photo Voltaic (PV) loads from more 'passive' consumption.

Key revisions to our approach

Expenditure was forecast on a bottom-up basis, via the method described in Figure 24.

Figure 24 Expenditure forecasting method

Identify needs	➢ Derived list of required compliance changes, related to the ESB Post 2025 Project, with agreed / defined plans and dates in 2025-30, or where there are proposed dates and sufficient detail such that we reasonably expect that compliance will need to be achieved or commenced in 2025 -30.
Identify compliance changes	➢ Replacing: national market security systems and protocols (Industry Data and Access Management); national market access portals (portal consolidation); national market integration systems (Industry Data Exchange) ➢ Flexible Trading rule changes
Impact costing	➢ Derived internal process & system impacts based on published AEMO impact analysisand ongoing AEMO workshops for detailed design stages ➢ 'Bottom-up' detailed costing and risks for our response to each change, using standard project templates, on a resource by activity basis, and based on our experience of similar changes
Options analysis	➢ Derived options, consistent with AER ICT Expenditure Evaluation approach for compliance projects, to explore variations in timing and approach to ensure only doing what we believe is essential in the RCP.
Other considerations	➢ Reviewed changes for opportunities to deliver them efficiently together vs. individually ➢ Considered impact of changes in the context of the overall portfolio deliverability ➢ Ensured other participants can continue to meet their NEM compliance needs, even when drivers and timings differ to ours.
Recommended option	➢ Delivers on the compliance requirements we need to achieve during the RCP.

The preferences of our customers

In our engagement, our customers were consistent in their view that we must comply with our regulatory obligations, maintain service and risk, and manage assets prudently and cost-effectively, ensuring they are fit-for-purpose. This project was communicated to our customer groups, but not identified as warranting deep engagement, consistent with their desire to 'focus on what matters most' to customers.

Revised proposal and its efficiency for customers

EXPENDITURE FORECAST	Proposal	AER Draft Decision	Revised Forecast
TOTAL	**$2.4m**	**$2.4m**	**$15.3m**

SERVICE LEVEL OUTCOMES

Achieves compliance – enables our market facing systems to comply with AEMO requirements in the 2025-30 RCP.

EFFICIENCY FOR CUSTOMERS

Least cost investment option – the investment recommended is the least cost option to achieve compliance

6.2.6 Accelerated metering transition expenditure

Capex $7.2 million

0.3% of total capex

Our revised forecast of $7.2m in non-recurrent (compliance) ICT expenditure is to make process and system changes and upgrades to enable, and achieve compliance with, the accelerated metering transition requirements and timelines. This need is triggered by AEMC reforms to accelerate the rollout of smart meters to all customers by 2030 - coordinated by DNSPs, executed by Retailers, and adhering to an agreed 'legacy metering retirement plan'.

Our Regulatory Proposal originally forecast $0 ICT capex and $4.8 million ICT opex. This forecast was only a 'placeholder', as we had insufficient certainty at the time, on the timing of the reforms and the required business and process changes. Prior to the Draft Decision, we submitted to the AER (July 2024) a revised business case.[26] However, the AER stated that it had insufficient time to complete its analysis, and therefore decided on $0 capex.

We do not accept the Draft Decision of $0 forecast capex, on the basis that this will not allow us to meet our requirements in 2025-30, and noting that the Draft Decision recognised that its forecast was only a 'placeholder' value expected to be amended in our Revised Proposal.

The AEMC released its final rule change determination on 28 November 2024.[27] This resulted in the start of the accelerated rollout program being delayed by 5 months until 1 December 2025.

Our revised forecast[28] is now based on the final rule change determination and from the additional information we now have from the AEMC and AEMO (on the timing, obligations and impacts of the rule change), such that we can reasonably forecast our requirements over the 2025-30 RCP, which include:

- systems and process changes, including new business-to-business and business-to-market transaction types to enable the program itself, as well as systems changes to manage higher volumes of site defects, shared fuse arrangements and other expected customer issues and impacts;
- remediating our market and billing systems to maintain system stability and continue to achieve our existing service obligations and enable the increased volumes of data; and
- the incremental cost increase to store, manage, backup and consume increased volumes of data on an ongoing basis.

[26] At the time, we were forecasting $5.9 million capex and $1.5 million opex.

[27] AEMC, *Rule determination: National Electricity Amendment (Accelerating Smart Meter Deployment) Rule and National Energy Retail Amendments (Accelerating Smart Meter Deployment) Rule*, 29 November 2024.

[28] The slight increase in our forecast capex, from our July 2024 business case, reflects the 5-month delay in the start date – increasing the amount of work required in the latter half of 2025.

Key revisions to our approach

We have forecast expenditure on a bottom-up basis via the method outlined in Figure 25.

Figure 25 Expenditure forecasting method

Identify need	➢ Identified the required compliance change with defined plans and dates in the 202530 RCP.
Impact costing	➢ Derived internal process and system impacts based on published AEMO impact analysis and ongoing Metering Services Review Working Group workshops. ➢ 'Bottom-up' costing and risks for our response to each change, using standard project templates, on a resource by activity basis, and based on our experience of similar changes.
Options analysis	➢ Derived rollout options to explore variations in timing and approach to ensure we are only doing what we believe we absolutely need to do within the RCP. ➢ Assessed timing options based on different rollout scenarios, in collaboration with Retailers and Metering Businesses, and based on the planning principles laid out by the AEMC.
Recommended costs	➢ Proposed costs and timing reflect rollout scenario agreed with other market participants, including the 5 month adjustment to the start of the program.

The preferences of our customers

During our engagement, our customers were consistent in their view that we must comply with our regulatory obligations and generally maintain existing levels of service and risk, and manage our assets prudently and cost-effectively ensuring they are fit for purpose.

This project was communicated to our customer groups, but was not identified as a topic warranting deep engagement on trade-offs, consistent with their desire to 'focus on what matters most' to our customers.

Revised proposal and its efficiency for customers

ICT METERING FORECAST	Proposal	AER Draft Decision	Revised Forecast
TOTAL	$0m	$0m	$7.2m

SERVICE LEVEL OUTCOMES

Achieves compliance – expenditure enables our customer and market systems to comply with AEMC and AEMO requirements in the 2025-30 RCP.

EFFICIENCY FOR CUSTOMERS

Least cost investment option – to achieve compliance

6.2.7 Fleet

Capex $150.4 million

6.4% of total capex

Our revised forecast of $150.4m supports delivery of distribution services to customers by ensuring sufficient and fit-for-purpose vehicles.

We originally forecast $154.9m on the basis of incremental needs:

- base expenditure – to maintain our existing fleet according to vehicle replacement cycles that accord to the AER Decision for 2020-25, and practice of other networks. This covered only our existing fleet and did not address drivers over 2025-30 to increase the volume of fleet assets to support a work uplift nor to enable a transition to Electric Vehicles **(EVs)**;
- trend escalation – to increase the volume of fleet assets to support the increased volume of network work we forecast for 2025-30, by modelling the uplift in network capex and resourcing requirements;
- step change – to acquire EVs instead of Internal Combustion Engine **(ICE)** vehicles when these are flagged for replacement, and where EVs are more efficient on a total cost of ownership basis.[29]

The Draft Decision substantively accepted our forecasting method and the vast majority of our forecast, deciding on $140.7m. The AER only arrived at a substitute forecast that was $14.2m lower than ours, by adjusting one component, being the 'trend escalation'. The AER applied a simple downward modelling adjustment to this component, based on its lower substitute forecast for repex and augex, which lowered the extent of the forecast expenditure increase on our actual network spend in 2020-25.

Our Revised Proposal revised our forecast network capex relative to the Draft Decision. We therefore, replicated the AER modelling adjustment, resulting in our revised forecast being $4.5m lower than our original.[30]

Key revisions to our approach

The overall forcasting approach remains unchanged having been accepted in the Draft Decision. Our revised forecast for 'trend escalation' replicates the AER's approach by making an adjustment based on the size of the uplift in network expenditure proposed. Our revised forecast increase in network expenditure relative to current period expenditure was used to scale the trend escalation component.

Revised proposal and its efficiency for customers

EXPENDITURE FORECAST	Proposal	AER Draft Decision	Revised Forecast
TOTAL	**$154.9m**	**$140.3m**	**$150.4m**
SERVICE LEVEL OUTCOMES			
Our approach, retained from the proposal, **maintains service through supporting fleet assets.**			
EFFICIENCY FOR CUSTOMERS			
Least cost – least cost means of maintaining service, consistent with industry practice, and efficient vehicle choice.			

[29] EVs will generally have higher upfront capital costs of purchase, but drive lower comparative opex due to cost savings in fuel and maintenance.

[30] This was based on the increase quantum of our revised network expenditue forecast relative to our current expenditure – this quantum of increase was a 19.4% less than that forecast for our Original Proposal.

6.2.8 Innovation Fund

Capex $16.1 million

0.7% of total capex

Our revised forecast of $16.1 million in capex (and $4 million in opex) is to establish an Innovation Fund, to be governed together with our consumer/stakeholder groups to fund projects trialling transformative new solutions, capabilities and practices to assist in maximising the value, and minimising the costs to consumers, of opportunities and challenges arising from the energy transition.

Our Regulatory Proposal had originally forecast the same $20 million in total expenditure. We provided only an indicative description of potential projects, given our desire, and that of our customers, to maximise flexibility to respond in the RCP to changing needs, but pursuant to three innovation categories:

1. **Enabling a flexible future** – improving network utilisation via innovative pilots in network planning and operations for a CER heavy future, incentivising flexible use of existing network via new customer-facing demand flexibility products and integrating flexibility into wider system planning;
2. **Community resilience** – innovative solutions to managing network reliability in regional and remote communities, as well as during extreme weather events, working with community groups and emergency services to enhance community resilience; and
3. **Sustainability solutions** – accelerating our decarbonisation via innovative approaches to managing our field operations, including electrifying our heavy vehicle fleet and exploring solutions to best integrate heavy EVs into our outage management process.

The need to undertake innovation and establish an Innovation Fund arises from several factors:

- the energy transition is driving unprecedented change with the potential to materially increase costs on the distribution network if not managed effectively;
- the network will in coming years face ever increasing risks arising from climate change;
- technology change is opening new opportunities for how the distribution network can be managed and built in coming years, to minimise the extent of new investments needed in coming years; and
- while there are some existing funding sources for innovation projects, a separate Innovation Fund is still required, given that other sources such as Australian Renewable Energy Agency **(ARENA)** funds will likely need to be complementary to qualifying projects, and the AER Demand Management Innovation Allowance Mechanism **(DMIAM)** has an insufficient funding cap and a scope that is too narrow to cover the breadth of challenges that the Innovation Fund responds to.

We do not accept the Draft Decision forecast of $0, which was stated as only a 'placeholder' pending further information in our Revised Proposal. We accept that our Original Proposal reflected a level of project flexibility that did not accord with the AER, and lacked sufficient information and individual justifications for proposed projects. We addressed each Draft Decision concern, by significantly enhancing our case for the Innovation Fund and via subsequent engagement with our consumer groups. Having addressed the Draft Decision, our Revised Proposal maintains our original forecast capex and opex.

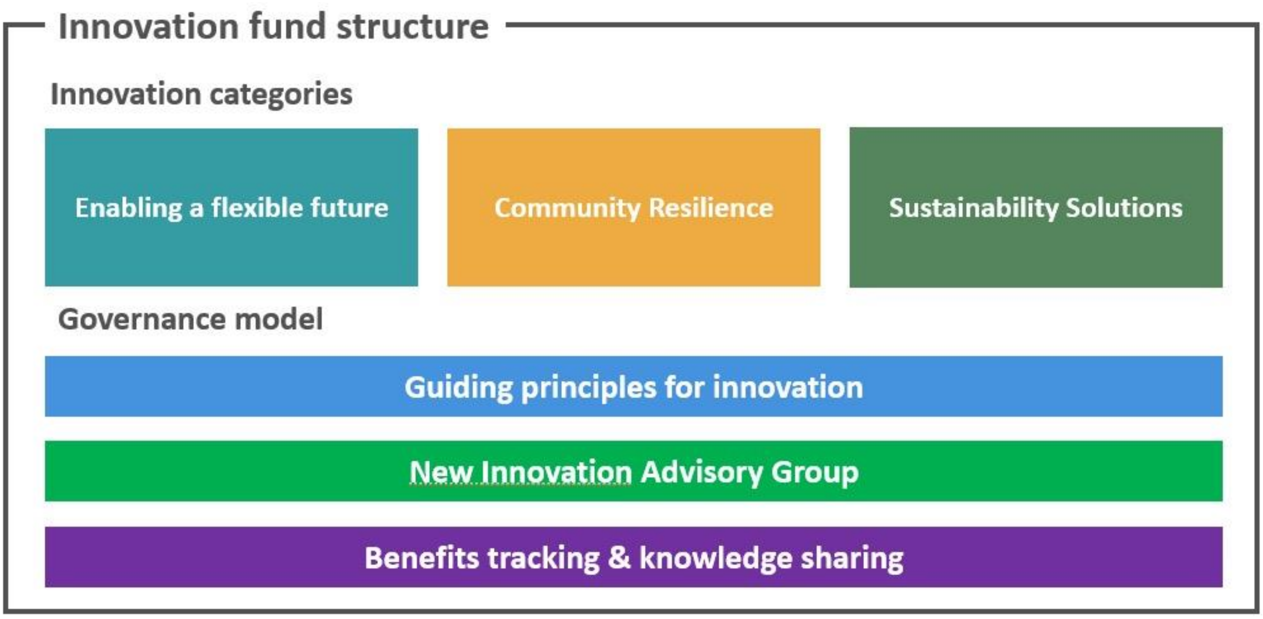
Our revised forecast represents a prudent and efficient level of expenditure to address the identified needs that the Innovation Fund responds to, on the basis that:

- **firm and customer-prioritised project list** – we have proposed a firm list of 9 projects (8 on 'enabling a flexible future' and 1 on 'community resilience') that reconcile to our forecast expenditure, and which reflect prioritisation by our customer groups;[31]

[31] We have no longer proposed projects within the 'sustainability solutions' innovation category. However, this theme will remain within our Innovation Fund structure, as a focus lens in our engagement with consumer groups on innovation.

- **compliance with AER assessment criteria** – proposed projects comply with the AER's new assessment criteria by: involving transformative innovation, having identified needs pursuant to the NER expenditure objectives, not duplicating other funding sources, having appropriate scaling for trials and clear pathways to broader implementation;
- **costs reasonably estimated** – the costs of the proposed projects are itemised and their basis justified
- **consumer benefits** –proposed projects aim to prove new functions, capabilities and services to unlock a range of sources of consumer benefits with respect to: utilisation; wholesale market costs; system security; emissions reduction, and climate resilience;
- **long term strategic view to maximise value and minimise costs –** projects arise from a long-term view of energy sector changes, potential impacts on services/costs, and options to interact with customers/markets to maximise value and minimise costs. A key focus is unlocking the flexibility in consumer demands (and their devices) to better meet and manage demands in coming years; and
- **customer-led governance model –** the Fund will be governed by a framework empowering customers via a new 'Innovation Advisory Group', guided by a new set of assessment principles to prioritise, monitor, and ensure projects are delivering in customers' interests, and that learnings are shared.

Figure 26 Proposed structure for the Innovation Fund



Key revisions to our approach

AER DRAFT DECISION CONSIDERATIONS	HOW WE HAVE RESPONDED
Application of AER assessment criteria	
a. Initial proposal was too conceptual and further information is needed on the scope and efficiency of intended projects.	a. Each project is now individually justified in terms of its identified need pursuant to the NER, why it's truly innovative, why it's prudently scaled for a trial, how success will be identified and the plan for broader implementation, the expected consumer benefits, and justified / itemised costings.
b. Justify projects against AER assessment criteria, including among other things: demonstrating why projects are transformative rather than core improvements and efficiency that should be normal business operations.	b. Each project is now individually evidenced to comply with new AER assessment criteria. Applying the criteria, and having regard to the assessment in the Draft Decision, we removed projects from our initially extended project list, as these could not be justified (i.e. co-funding community resilience programs, resilience batteries and heavy EV projects.).
Propose a firm project list	
a. A firm list of projects is required.	a. A firm list of prioritised projects has been proposed.
b. Total costs must reconcile to proposed expenditure forecast.	b. Itemised costings with assumptions have been prepared.
c. Projects should contain detail on expected type of consumer benefits.	c. The nature of consumer benefits that each project is expected to prove has been detailed in project specific justifications.
d. Project timelines are detailed.	d. An initial prioritisation sequence has been agreed with our consumer groups, with each project's start time to be subject to ongoing prioritisation with consumers via the IAG. Timelines are provided indicating project duration and activity sequence.
Knowledge sharing	
a. Explain how knowledge from innovation projects will be shared with industry, consumers and regulators.	a. Knowledge will be shared according to the governance and knowledge sharing framework that we have now developed together with our customer groups via subsequent engagement
b. Demonstrate how shared lessons have been considered and used to inform the proposed projects and the incremental benefit of the project.	b. We have detailed how industry knowledge has been leveraged in developing each individual project we proposed.
The role of the DNSP	
a. Explain if SA Power Networks is the appropriate party to undertake the proposed innovation compared to a contestable market, and any ring-fencing concerns.	a. We explained why we, as the DNSP, are the appropriate party to undertake the proposed projects – our proposed activities are firmly within the scope of our SCS.
How projects fit within a long-term view of energy sector changes, costs and value to customers	
Not raised.	a. We also explained how our proposed projects fit within a considered long-term view of how we can best respond to the profound energy transition in South Australia. Particularly, how innovation to unlock flexibility can assist in enabling the energy transition with minimal need for network upgrades, increasing utilisation, reducing emissions, and putting downward pressure on NEM costs and prices to all consumers.

The preferences of our customers

We continued our ongoing engagement with our CAF and RAG subsequent to our Proposal and AER Draft Decision. No new perspectives emerged suggesting any change in customers' preferences with respect to the overall need to establish an Innovation Fund.

However, to address the Draft Decision's concerns, we conducted subsequent detailed engagement specifically on the Innovation Fund with our CAF, RAG and sub-group chairs. Engagement focused on seeking their input and prioritisation on the firm list of innovation projects and the governance framework, and we:

1. engaged to outline the Draft Decision's concerns, discussing various options to refine our approach;
2. conducted 'deep dive' workshops to seek feedback on the project list and collaboratively designed governance arrangements for the Fund – project assessment principles reflect the shared view of what is important to our customers; and
3. surveyed CAF and RAG members on the final prioritisation of projects for the Revised Proposal.

Revised proposal and its efficiency for customers

FUND FORECAST	Proposal	AER Draft Decision	Revised Forecast
TOTAL	**16.0m capex**	**$0**	**$16.1m capex (and $4.0m opex)**

SERVICE LEVEL OUTCOMES

Applicable to all SCS - projects aim to prove the potential of new functions and capabilities to apply to the delivery of our Distribution Services and SCS, including in meeting/managing service demand (load and export), and management of reliability and security of services and the broader system.

EFFICIENCY FOR CUSTOMERS

Unlocking consumer benefits: the proposed projects aim to prove the potential for new solutions to address challenges in a way that can derive material long-term consumer benefits by way of:

- increased network utilisation and avoided network augmentation costs for all consumers;
- improving system security for all consumers;
- reduced wholesale electricity pricing for all consumers;
- reducing energy system emissions, increasing the value of emissions reduction for all consumers;
- improved community resilience and therefore reliability and safety outcomes for customers;
- expanded CER revenue streams for customers with CER;
- reduction in CER upfront costs for CER customers; and
- improved customer experience and benefits to consumers by way of customer value of time.

6.2.9 Capitalised network overheads

Capex $32.3 million

1.4% of total capex

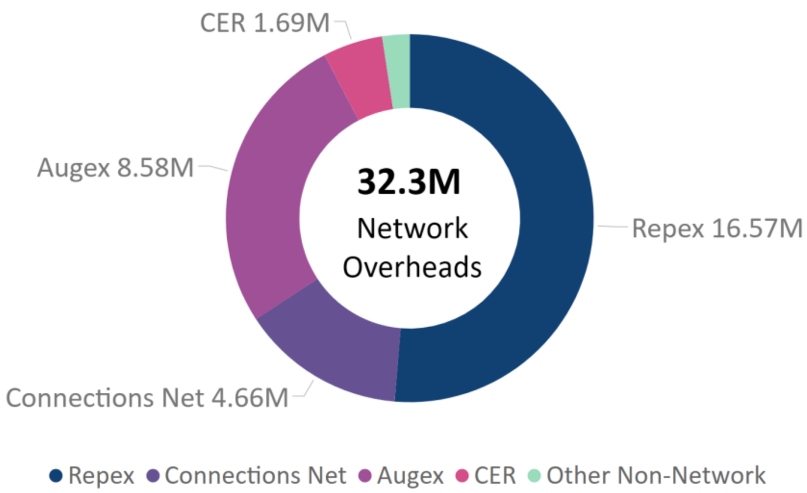
Our revised forecast of $32.3m covers the indirect costs that we incur in delivering network and non-network capex programs. This includes costs associated with our Network Management and Field Services department's general and senior management costs including asset services, works program, planning and engineering, customer solutions and others.[32]

While these costs support the delivery of the capex program, they cannot be directly attributed to specific projects or programs, being associated with the delivery of multiple programs. These costs are therefore bundled to form capitalised network overheads as reported in our RINs.

Our Regulatory Proposal had originally forecast $33.5m, applying an approach which was accepted in the Draft Decision. The Draft Decision only substituted our forecast with a lower forecast of $29.5m via a modelling adjustment to account for the lower forecast of total network expenditure decided in the Draft Decision.

We do not accept the Draft Decision, as our revised total network capex forecast is higher than the Draft Decision, and therefore we applied a commensurate upward modelling adjustment to our overheads forecast. The total forecast is split between the expenditure categories as displayed in Figure 27.

Figure 27 Capitalised network overheads by category split



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32 SA Power Networks expenses corporate overheads in opex. Further information on our practices are set out in the supporting document to our Regulatory Proposal, '5.1.6 – accounting practices and guidelines manual'.

6.3 Areas unchanged and found to be prudent and efficient in the Draft Decision

6.3.1 Augmentation expenditure (augex)

Powerline Environment Committee Program (PLEC)	$38.4m (1.6% of total capex)

Description

The forecast continues our regular program of undergrounding selected parts of the network, to improve aesthetics, having regard to road and electrical safety, for the community's benefit. The program is part of our long-standing jurisdictional government obligations stipulated in legislation and a PLEC Charter.

Draft Decision

We accept the Draft Decision forecast of $38.4m, as it is consistent with our Proposal.

Network resilience	$8.2m (0.4% of total capex)

Description

The forecast comprises a small-scale program to procure and deploy mobile generation to assist customers, who are in regional areas supplied by long radial networks, and are exposed to potential long duration outages typically arising from extreme weather. It responds to customer concerns on long-duration outages in regional/remote areas and the downstream impact of these on other critical services.

Customer service outcome and efficiency

- Improves reliability – improve average annual outages of 6.58 and 10,050 customers on average annually.
- Efficient - benefits outweigh cost with an NPV outcome of $13.4m over a 20 year period.

Draft Decision

We accept the Draft Decision forecast of $8.2m, as it is consistent with our Proposal.

Worst served customers reliability improvement programs	$31.0m (1.3% of total capex)

Description

The forecast comprises several targeted programs to improve reliability for customers with relatively poorest reliability, responding to factors unrelated to asset condition: Rural Long Feeders (RLF) Supply Restoration Improvement Program; Regional Reliability Program; and Low Reliability Feeders (LRF) Improvement Program. These respond to customers' concerns and only target efficient upgrades.

Customer service outcome and efficiency

Improves reliability and is efficient (benefits outweigh costs):

- RLF Supply Restoration Improvement: average of 15% improvement in CAIDI for 44 feeders supplying 10,230 customers, and an NPV of $6.7m.
- Regional reliability improvement: reliability improved to 23,530 customers in three regions (Eyre Peninsula, Upper North, South East), and an NPV of $43.4m
- LRF Improvement: reliability improved by 31% (average feeder USAIDI), improving reliability for 67 LRFs and 35,360 customers, and an NPV of $17.7m.

Draft Decision

We accept the Draft Decision forecast of $31.0m, as it is consistent with our Proposal.

Bushfire risk management programs	$25.6m (1.1% of total capex)

The need

The forecast manages bushfire risk by upgrading assets via two programs which respond to customers' concerns and seek to achieve the following:

1. bushfire risk mitigation program – mitigating the risk of assets starting bushfires, as distinct from managing bushfire risk posed by asset condition which is addressed via our forecast repex; and
2. public safety power shutoff program - reducing customer supply interruptions from our public safety power shutoffs at bushfire risk times.

Customer service outcome and efficiency

- Maintains safety – forecast addresses safety risk, and complies with regulatory requirements.
- Improves reliability – during bushfire risk times.
- Efficient – the programs are efficient with benefits outweighing costs and an NPV result of $322.6 (Bushfire Risk Mitigation program), and $10.5m (Public Safety Power Shutoff Mitigation program).

Draft Decision

We accept the Draft Decision forecast of $25.6m, as it is consistent with our Proposal.

Augex other (safety, environment, strategic)	$63.0m (2.7% of total capex)

Description

The forecast comprises of diverse small-scale initiatives largely driven by compliance needs, including:

- maintaining network safety, via largely recurrent spend on lighting, fencing and security for our substations, earthing systems, and continued implementation of rural network backup protection;
- managing our environmental compliance, particularly regarding oil containment; and
- meeting requirements regarding voltage management and under frequency load shedding.

Customer service outcome and efficiency

The investments maintain safety and compliance with obligations, and are all the least cost solutions.

Draft Decision

We accept the Draft Decision forecast of $63.0m, as it is consistent with our Proposal.

Augex efficiency adjustment	$-16.0m (-0.7% of total capex)

Draft Decision

We accept the Draft Decision forecast of $-16.0m, as it is consistent with our Proposal. This pertains to the efficiency adjustment we proposed to achieve as resulting from our Assets and Work ICT program which was approved in the Draft Decision.

6.3.2 Connections expenditure

Connections expenditure	$255.2m (10.9% of total capex)

Description

The net connections forecast enables customers to connect to and access the distribution network, consistent with obligations and our Connection Policy. This comprises works to connect new customers, upgrade existing customer connections or alter customer connections where required. Connections expenditure is a core requirement of our NER regulatory obligations to provide an offer to connect customers to the distribution network, consistent with the open access regulatory framework.

Draft Decision

We accept the Draft Decision forecast of $255.2m, as it is consistent with our Proposal.

6.3.3 CER integration expenditure

CER integration expenditure programs	$90.7m[33] (3.9% of total capex)

Description

The forecast covered several customer and industry facing programs to efficiently support forecast CER growth. It is a strategic and balanced suite of four programs, broader than just enabling export services:

1. Demand Flexibility – minimise costs of managing customer demand by enhancing our ability to provide/encourage flexible loads and generation, to increase utilisation, avoid network asset investments and reduce long term costs;
2. CER Compliance – meet and manage demand for export services, maintain security of our distribution services and system and ensure compliance, by improving industry compliance with standards, connection rules, and regulation for CER installations;
3. CER Integration – meet and manage forecast demand for export services by investing to enable a level of export service that customers prefer and which is efficient;
4. Network Visibility – enhance visibility by acquiring and processing data mainly from smart meters (now more accessible via metering acceleration reforms), to improve operations and safety.

Customer service outcome and efficiency

- Demand Flexibility – assists to meet and manage demand for SCS, and is efficient with benefits outweighing costs (NPV of $7.7m over 20 years).
- CER Compliance – assists meet/manage demand for SCS, maintain service performance, and comply with obligations, and is efficient with benefits outweighing costs (NPV of $5.5m over 20 years).
- CER Integration – maintains a service level of 95% for 95% of customers, and is efficient with benefits outweighing costs (NPV of $21.9m over 30 years).
- Network Visibility Program – assists in meeting and managing demand for SCS, and is efficient with benefits outweighing costs (NPV of $67.6m over a 20 years).

Draft Decision

We accept the Draft Decision forecast of $90.7m[34], as it is consistent with our Proposal.

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33 Including $2.0 million efficiency adjustment arising from the Assets and Works program for 2025-30.

34 $92.7 million excluding $2.0 million efficiency adjustment, or $90.7 million including $2.0 million efficiency adjustment.

6.3.4 Non-network expenditure

Property expenditure	$115.8m (4.9% of total capex)

Description

The forecast is to provide a fit-for-purpose, safe, and compliant property asset portfolio that effectively and efficiently supports our delivery of services to customers, comprising:

- recurrent expenditure on replacements and refurbishments – a broad range of cyclical activities with a need to maintain functionality, capability and service;
- recurrent expenditure on building renewals – renewals of entire buildings, via major renovations or rebuilds, with two major renewals being to the Mount Barker and Port Augusta depots; and
- non-recurrent expenditure on the transformer workshop – to relocate and rebuild the workshop

Customer service outcome and efficiency

- Support delivery of SCS: fit-for-purpose properties with capability/capacity to support SCS delivery.
- Efficient: recurrent expenditure (replacement & refurbishment) is least cost; recurrent expenditure (building renewals) has positive NPVs of 7.7m (Mount Barker), and 3.6m (Port Augusta); non-recurrent expenditure (Transformer Workshop) has positive NPV of $91.1m.

Draft Decision

We accept the Draft Decision forecast of $115.8m, as it is consistent with our Proposal.

Fleet expenditure	$131.7m (5.6% of total capex)

Description

The forecast supports our delivery of distribution services to customers by ensuring a sufficient and fit-for-purpose fleet of vehicles and comprised expenditure responding to incremental needs including:

- base expenditure – maintaining our existing fleet according to vehicle replacement cycles;
- trend escalation - to increase the volume of fleet assets to support the increased network work; and
- step change – to acquire EVs instead of ICE vehicles,

Customer service outcome and efficiency

Support delivery of SCS - the base maintains effective/efficient fleet to support SCS delivery, the trend enables sufficient resources to meet growth in SCS work, and the step change enables more efficient delivery of SCS.

Least cost - all components of the forecast represent the least cost solutions.

Draft Decision

The AER substantively accepted our forecasting approach and the majority of our forecast expenditure, deciding on $140.7m. The AER only substituted the 'trend escalation' component with a lower forecast, and therefore it is only this component that we have responded to and revised as covered earlier in Section 6.2.7

We accept the Draft Decision forecast of $131.7m, covering the 'base' and 'step change' components as they were consistent with our Proposal.

Other non-network: Operational Technology	$42.7m (1.8% of total capex)

Description

The forecast ensures ongoing performance, security and functionality of telecommunications systems to monitor and manage the network, comprising our Telecommunications Network Control Management Systems, Operational Network and Business Telephony, and Advanced Distribution Management System which is used to manage our distribution system in a safe and secure manner.

Customer service outcome and efficiency

- Main safety, reliability and compliance
- Efficient – least cost solutions.

Draft Decision

We accept the Draft Decision forecast of $42.7m, as it is consistent with our Proposal.

Information and communications technology (ICT)	$298.5m[35] (12.7% of total capex)

Description

The forecast supports distribution services across all of our operations, including: customer service delivery and communications, management of business activities and field resource deployment, capture and use of data on network condition/capacity, cyber security, and other activities. This comprised:

- recurrent expenditure: to maintain existing ICT systems, services, functions, capabilities and/or benefits and to manage technology risk across a number of sub-categories (client devices, ICT infrastructure, ICT applications, data analytics and intelligent systems);
- large upgrades and replacements: to maintain existing systems and services and manage risk, including to our customer technology systems, and other large systems (service order management module; integration platform; Enterprise Data Platform, Click field management and scheduling, and other smaller investments across several SAP modules;
- new or altered compliance requirements/obligations: responding to new requirements on cyber security and market interaction systems; and
- new or expanded capabilities: programs for new systems and capabilities to create new operational and customer value, including: the third phase to our 'Assets and Work' Program and the 'personalised on-demand services' improvements program.

Customer service outcome and efficiency

- Recurrent: maintains capabilities/functions supporting SCS delivery and were least cost options;
- Non-recurrent (major replacements or upgrades): maintains capabilities/functions supporting delivery of SCS, and is efficient with benefits outweighing costs (NPV of $11.7m over 10 years);
- Non-recurrent (new compliance): maintains cyber security, and is efficient with benefits outweighing costs (NPV of $124.1m over 10 years);
- non-recurrent (new or expanded capability): 'Assets and Work' program improves efficiency of our delivery of SCS and is efficient with benefits outweighing costs (NPV of $34.1m over 10 years with $45m in direct benefits accruing in 2025-30 via a reduction to total capex); and the 'Personalised and on demand services' program improves efficiency of our delivery of SCS and is efficient with benefits outweighing costs (NPV of $9.5m).

Draft Decision

[35] This amount excludes the 'ESB AEMO post 2025 roadmap changes' expenditure and 'Accelerated metering transition' expenditure covered in Sections 6.2.5 and 6.2.6.

The AER Draft Decision approved our entire forecast of $300.8m. However, the Draft Decision noted that the forecasts approved for two programs within the category of 'non-recurrent: new compliance' were only 'placeholders' pending updated information in our Revised Proposal, arising from reform processes by AEMO and the AEMC.

Therefore:

- our Revised Proposal has only responded to and revised the forecast for these two programs, as covered earlier in Sections 6.2.5 and 6.2.6; and
- we accept the Draft Decision with respect to all other components of the ICT expenditure forecast, as they were consistent with our Proposal.

Appendix A – References to supporting documentation

The table below lists all of the expenditure areas that have been subject to revision in our Revised Proposal as discussed in this capex attachment, and their supporting documents – including the business cases that provide the primary and detailed source of justification for our expenditure

discussed in this capex attachment, and the supporting documents. These include the business cases that provide the primary and detailed source of justification of our expenditure, and a series of expenditure forecasting methodology documents that further detail our approaches.

Table 6: List of references to supporting documents

Section of capex attachment	Business case addendums
6.2.1 Network asset replacement expenditure (repex)	5.3.1 – Repex – Business case addendum
6.2.2 Augex capacity	5.4.2 – Augex Capacity – Business case addendum 5.4.2.1 – End game economics report 5.4.2.2 – Mount Barker East new substation – Project Justification 5.4.2.3 – Salisbury South new substation – Project Justification 5.4.2.4 – Smithfield west substation upgrade – Project Justification
6.2.3 Maintain underlying reliability program (augex)	5.9.3 – Maintain underlying reliability performance program – Business case addendum 5.9.6 – Adelaide flying-fox population trend
6.2.4 CBD reliability improvement program (repex & augex)	5.3.12 – CBD Reliability – Business case addendum
6.2.5 ESB AEMO post 2025 roadmap changes to ICT	5.12.29 – ICT Non-Recurrent - ESB AEMO Post 2025 Roadmap Changes – Business case addendum
6.2.6 Accelerated metering transition expenditure	Attachment 19 – Legacy Metering 19.4 – Legacy metering transition – Towards 2030
6.2.8 Innovation Fund	5.13.4 – Innovation Fund – Business case addendum

Glossary

Acronym / term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMTP	Asset Management Transformation Program
Augex	Augmentation expenditure
BAU	Business as Usual
CAF	Community Advisory Forum
CAPEX	Capital expenditure
CBD	Central Business District
CER	Customer Energy Resources
CESS	Capital Expenditure Sharing Scheme
DFA	Distribution Feeder Automation
DMIAM	Demand Management Innovation Allowance Mechanism
DOE	Dynamic Operating Envelopes
EBSS	Efficiency Benefit Sharing Scheme
EDC	Electricity Distribution Code of South Australia
EDP	Enterprise Data Platform
ESB	Energy Security Board
ESCOSA	Essential Services Commission of South Australia
EV	Electric Vehicles
ICE	Internal Combustion Engine
ICT	Information and Communications Technology
ISP	Integrated System Plan
LRF	Low Reliability Feeder
MTFP	Multilateral Total Factor Productivity
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NPV	Net Present Value
OT	Operational Technology
OTR	Office of the Technical Regulator of South Australia
PLEC	Powerline Environmental Committee
POE	Probability of Exceedance
RCP	Regulatory Control Period
Repex	Replacement expenditure
RLF	Rural Long Feeders
SCS	Standard Control Services
STPIS	Service Target Performance Incentive Scheme
USAIDI	Unplanned System Average Interruption Duration Index
USAIFI	Unplanned System Average Interruption Frequency Index
VCR	Value of Customer Reliability