Attachment 5 - Capital Expenditure

2025-30 Regulatory Proposal

January 2024

SA Power Networks

Empowering South Australia

Company information

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

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Disclaimer

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

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

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Note

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

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

Document	Description
	Regulatory Proposal overview
Attachment 0	Customer and stakeholder engagement program
Attachment 1	Annual revenue requirement and control mechanism
Attachment 2	Regulatory Asset Base
Attachment 3	Rate of Return
Attachment 4	Regulatory Depreciation
Attachment 5	**Capital expenditure**
Attachment 6	Operating expenditure
Attachment 7	Corporate income tax
Attachment 8	Efficiency Benefit Sharing Scheme
Attachment 9	Capital Expenditure Sharing Scheme
Attachment 10	Service Target Performance Incentive Scheme
Attachment 11	Customer Service Incentive Scheme
Attachment 12	Demand management incentives and allowance
Attachment 13	Classification of services
Attachment 14	Pass through events
Attachment 15	Alternative Control Services
Attachment 16	Negotiated services framework and criteria
Attachment 17	Connection Policy
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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[1]) to the standard our customers expect and in compliance with our 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

NETWORK

Augex
Augmentation/upgrades to network assets to ensure sufficient capacity and security of the network in meeting demand, and to manage reliability and bushfire risks.

Repex
Replacement of network assets in response to network condition – i.e. assets that need to be retired because they have either reached their end of technical life (i.e. failed) or reached the end of their economic life (i.e. risk costs > costs of replacement).

Connections
The cost of connecting customers to our distribution network (net of customer contributions toward their connection costs).

NON-NETWORK

ICT
Securing, refreshing and new investment in ICT (e.g. client devices, hardware, applications and data) used by our staff and customers, in support of our delivery of distribution service.

Property
Renewal, refurbishment and replacement of property assets (eg offices, depots, workshops) supporting the delivery of distribution services to customers.

Fleet
Replacement and purchase of additional vehicles, including passenger and commercial, forklifts, elevated work platforms, cranes, trucks and vans.

Other
Refreshing and replacing telecommunications systems, the distribution network management system, and operational telephony.

NETWORK / NON-NETWORK

CER
Augmentation/upgrades to the network to enable energy exports from Customer Energy Resources; enablement of flexible customer loads; and industry compliance improvement costs.

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1 Standard Control Services (**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 Overview

We forecast a capex requirement of $2.4 billion[2] for the 2025-30 Regulatory Control Period (**RCP, or period**), to deliver the service levels that our customers told us they prefer, that our analysis indicates is efficient and prudent, and otherwise allows us to comply with our obligations, in delivering reliable, safe and secure electricity distribution services to customers.[3] In aggregate, the new investments we propose to make by way of our forecast total capex and new opex, will deliver outcomes that are demonstrably efficient and in customers long term interests, producing an estimated **net benefit for consumers of over $0.5 billion** over a 20 year period in Net Present Value (**NPV**) terms.

This capex forecast responds to the circumstances of a time in which several significant challenges and opportunities facing our network and the services that we provide customers, are converging, including:

- **network demand** - resurgent and strong increases in demand, driven by electrification;
- **network asset condition** - managing an aged distribution network in deteriorating condition;
- **bushfire risk** - heightening bushfire risk across our rural network;
- **export service demand** - strong demand for network access / capacity to export renewable energy;
- **equity** - calls for more equity in service across a vast state-wide urban and rural network;
- **fit-for-purpose facilities** - need for more proactive updating of our property assets;
- **cyber threat** - increasing risk of cyber security threats;
- **ongoing needs** - other general and ongoing needs including to maintain adequate supporting assets across our vehicle fleet, properties and Information and Communications Technology (**ICT**) systems.

Addressing these challenges and opportunities at a time in which customers are also facing affordability challenges, requires a balance between service and price, and in striking that balance it is crucial that we are guided by multiple information sources as to which course of action will be in customers' long-term interests.

To understand our customers' preferences, we ran a comprehensive and multi-staged engagement program, that was outcomes focused and involved developing scenarios of service, expenditure and price to allow customers to make informed tradeoffs. We drew on the preferences of hard-to-reach communities in 'broad and diverse' engagement, consumer representatives and stakeholders via 'Focused Conversations', and ultimately everyday citizens via a 'People's Panel' charged with recommending an overall service / price balance that they considered to be in the interests of all South Australians. While consistently mindful of affordability, our consumers were clear that they do not want service to be compromised in 2025-30, and want us to achieve the following, that our capex forecast has aligned to:

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

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2 All financial figures in this document are expressed in June 2025 dollars unless otherwise specified.

3 The terms 'customers' and 'consumers' are used interchangeably throughout 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.

While our forecast represents a 21.5 percent increase on our estimated actual spend in 2020-25, it arises as the product of a balance that we have determined between considering:

1. **service outcomes** - that our customers have shaped while being mindful of tradeoffs in service, expenditure, and price impacts;
2. **obligations** - our legislative and regulatory obligations and requirements; and
3. **efficiency** - analysis of efficiency for customers, and other indicators of customer value and willingness to pay.

In summary, and as this attachment outlines, our capex forecast was developed as the product of a rigorous process to ensure that it will promote outcomes that are in consumers' long-term interests. Key features of our approach are that we have:

- **aligned to Australian Energy Regulator (AER) expectations** - applied a forecasting methodology aligned to AER expectations set out in the Better Resets Handbook, and which was subject to review and feedback via the AER Early Signal Pathway process that we volunteered to participate in;
- **applied a rigorous forecasting methodology** – forecasts were developed via a comprehensive methodology taking stock of challenges and opportunities facing our network and the services we provide, and identifying investment responses guided by alignment to regulation and consumer preferences on service outcomes;
- **internally and externally challenged forecasts** - applied multiple tiers of internal challenge within our business, and external challenge via expert review and our multi-staged consumer engagement program;
- **iteratively refined and customer shaped forecasts** - our expenditure forecast results from an iterative process of refinement over five key iterations undertaken together with our customers, as customer preferences were obtained across each key stage of our engagement program;
- **considered interactions in outputs and inputs** – we accounted for interactions (potential or real) between different expenditure areas, and optimised to choose the most efficient solutions to meet customer service needs;
- **investment actions guided by service objectives** – our programs and projects propose investments driven by identified needs that address the service objectives in the National Electricity Rules (**NER**); and
- **balanced preferences with efficiency** – our proposed programs and projects were guided by multiple information sources. This was to ensure that the service level preferences of our consumer representatives and stakeholders were considered alongside preferences of everyday citizens (People's Panel). Further, this was also to ensure that these preferences were supported by efficiency analysis of consumer benefits, as well as broader willingness to pay indicators particularly where costs are imposed across the general customer base but benefits are realised by a subset of customers.

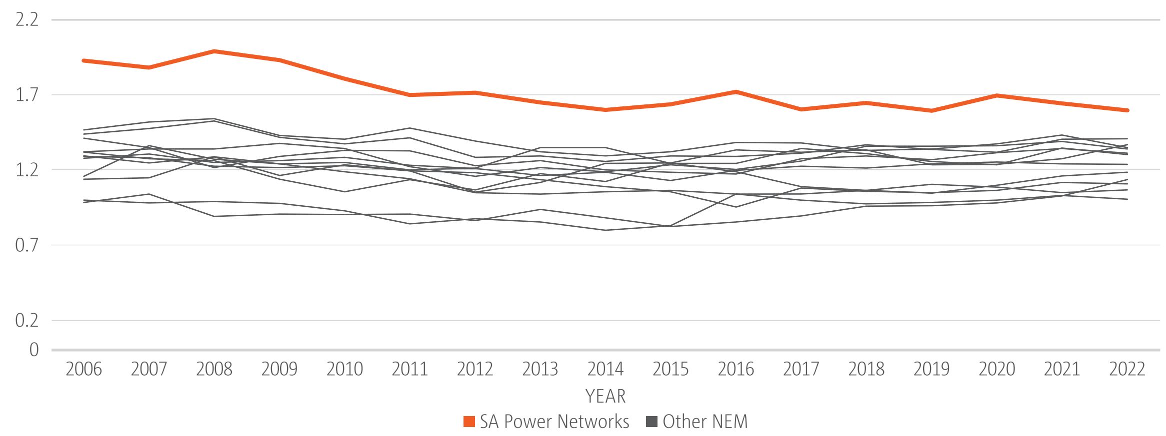
3 We have delivered long term sound performance for customers

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 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.

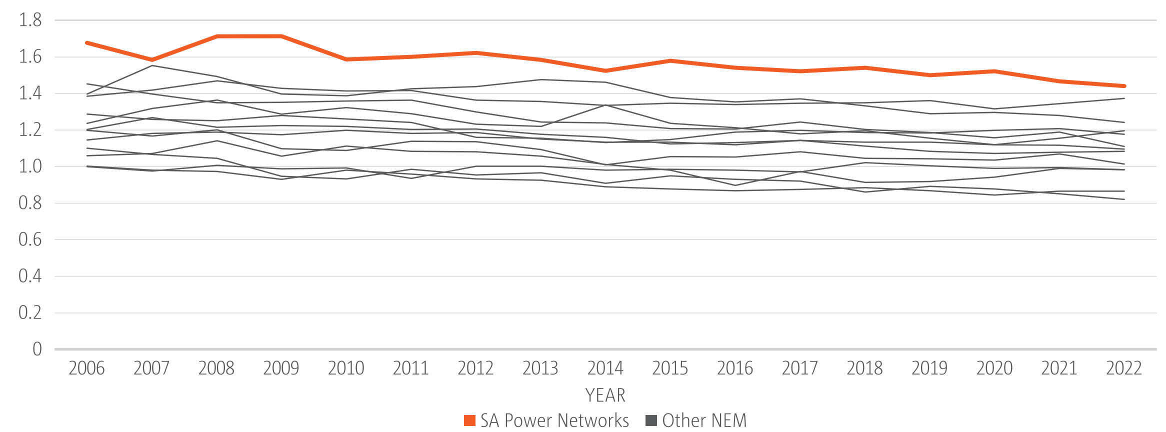
We retain strong relative performance far exceeding any other distribution network, notwithstanding significant challenges of managing a network with the oldest asset fleet in the NEM and being at the forefront of the renewable energy transition. We are the most efficient distribution network on Multilateral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

Figure 2: Electricity distribution multilateral total factor productivity indexes by distributor, 2006-22[4] [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 3: Capital multilateral partial factor productivity indexes by distributor, 2006-22[6] [7]



[4] AER, *Annual Benchmarking Report – Electricity Distribution Network Service Providers*, November 2023, P.34.

[5] The MTFP under the AER preferred approach to address capitalisation differences in the AER's 2023 benchmarking report has been updated using a preliminary, fit for purpose, method for data adjustment. The AER intends to undertake further consultation on this method in preparation for its 2024 benchmarking report.

[6] AER, *Annual Benchmarking Report – Electricity Distribution Network Service Providers*, November 2023, P.38.

[7] As above, this figure displays results using the AER's preferred approach to addressing capitalisation differences.

South Australians have benefited from consistently reliable service

In the process of 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 improved over the long term, in respect to both the frequency and duration of interruptions, as displayed in Figure 4 and Figure 5.

Figure 4: Distribution system unplanned system average interruption duration index normalised (USAIDIn) and implied jurisdictional target[8]

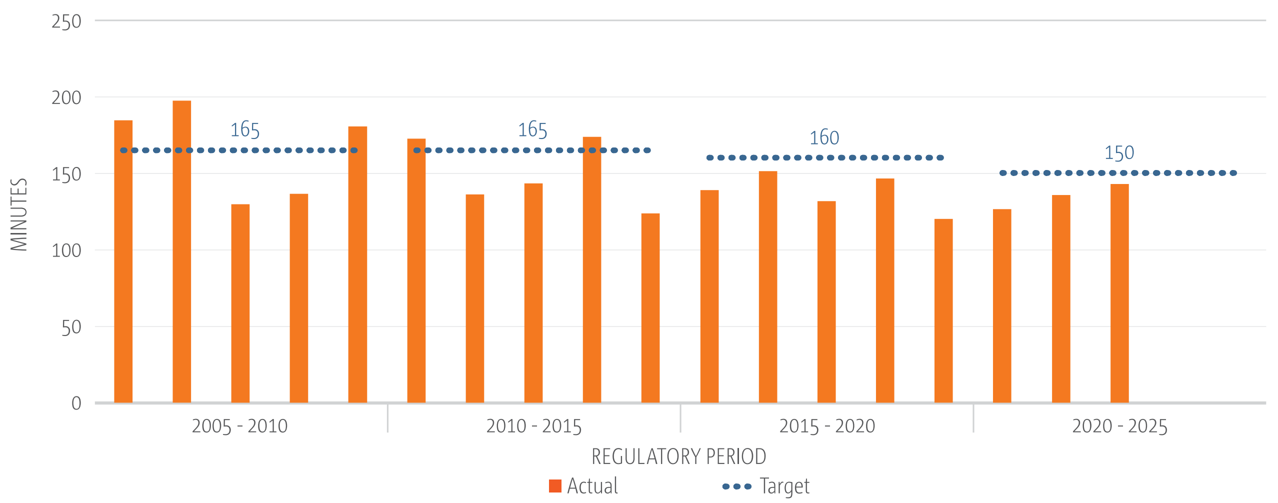
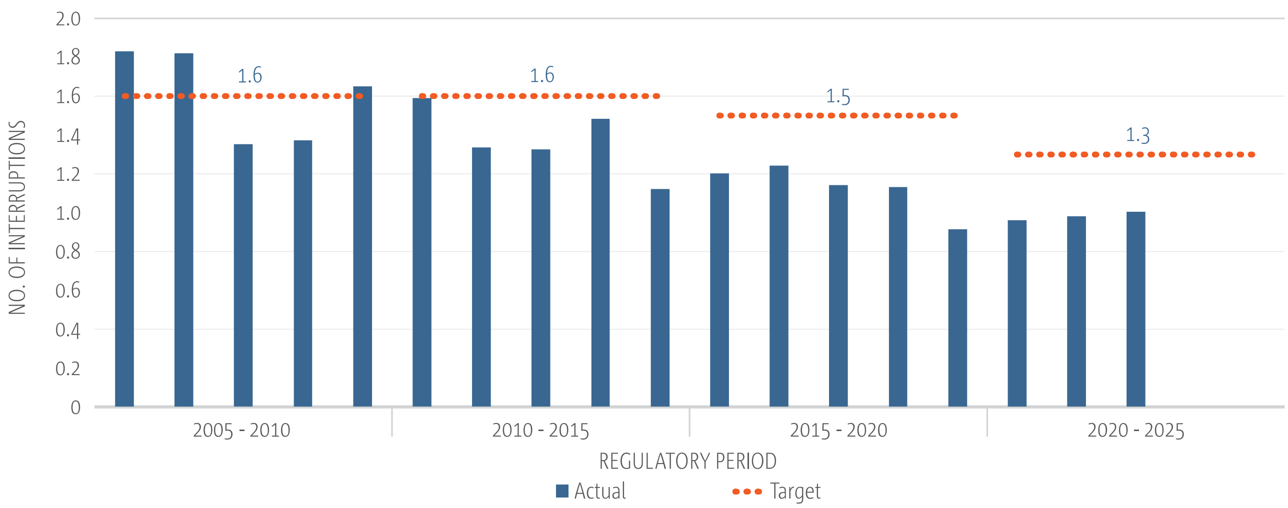


Figure 5: Distribution system unplanned system average interruption frequency index normalised (USAIFIn) and implied jurisdictional target



Further, over the past decade, South Australia has 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.

[8] The Electricity Distribution Code (EDC) sets reliability targets on a feeder category basis. The 'Implied jurisdictional target' refers to the implied target for overall distribution system reliability, if each of the feeder level targets were summed.

4 We have delivered on our plans for 2020-25

Over the current RCP we have demonstrated the reasonableness of our expenditure needs by having incurred expenditure that we expect to be in-line with the AER's forecast for 2020-25.

Differences between actuals and forecasts for 2020-25 are expected to be minor

We expect our actual capex differences to be immaterial and only 0.7 percent below the AER's forecast, having been driven predominantly by the following:[9]

- **external drivers** – lower economic activity and a higher rate of return (driving greater customer contributions on connections expenditure), had the effect of lowering our net connections expenditure;
- **external drivers** – altered decisions by Electranet drove augex on connection point upgrades to be $1.6 million, which was 88.2 percent lower than forecast. These were excluded from our capital expenditure sharing scheme **(CESS)** calculations so that we do not financially benefit from these deferred projects;[10]
- **external drivers** – general delays in field work due to covid restrictions in the first two years of this period;
- **internal efficiency** – decisions on choice of fleet vehicles allowed us to incur lower than forecast spend but procure more vehicles than reflected in the AER forecast;
- **internal cost attribution improvement** – changes to better attribute general costs to specific expenditure categories and program areas so that each more accurately reflects service delivery costs, leaving capitalised overheads to comprise general costs not easily attributed to specific activities; and
- **internal efficiency** – improved bundling in delivery of bushfire risk management work, and optimised repex and augex solutions, allowed us to incur lower augex on bushfire risk management ($11.5 million, which was 11.6 percent lower than forecast) while removing the same level of risk that we had forecast.

There are also no material deferrals from the current period included in forecast expenditure for 2025-30.[11]

Table 1: 2020-25 actuals / estimates versus AER forecast (allowance)

	actuals/ estimates	AER allowance	$ variance	% variance
Repex	706.0	681.0	25.0	3.7%
Augex	350.5	346.6	3.9	1.1%
Connections Net	268.5	336.9	-68.3	-20.3%
Cust. Connect (gross)	704.0	718.4	-14.4	-2.0%
Cust. Contributions - Connections	-435.5	-381.6	-53.9	14.1%
CER	41.0	36.1	4.9	13.5%
ICT	366.2	331.6	34.6	10.4%
Fleet	113.7	117.9	-4.2	-3.6%
Property	73.3	55.8	17.5	31.3%
Other Non-Network	29.8	9.9	20.0	202.8%
Capitalised network overheads	27.5	75.2	-47.8	-63.5%
Total Capex	**1,976.6**	**1,991.1**	**-14.4**	**-0.7%**

9 The expenditure categories listed in table 1 for which expenditure is estimated to exceed the AER forecast are discussed in Section 9. The exception pertains to the increase in 'other non-network' which mainly results from a need over the period to undertake additional investment in relation to our Advanced Distribution Management System – to improve our integrated test environment to enhance cyber security controls and procedures in response to increased threats.

10 These are detailed in Attachment 9 Capital Expenditure Savings Scheme, to this Regulatory Proposal.

11 As detailed in Attachment 9, there are two minor Augex connection point deferrals that have been included in our 2025-30 capex forecast, and accordingly, these were excluded from our CESS calculations to avoid customer impacts.

We delivered significant and transformational projects that have materially benefited customers

Consistent with our proposed plans, we delivered significant projects underpinning much of our operations, and continued to balance and re-prioritise how we manage our distribution network in the face of significant changes and challenges in our operating environment. Table 2 provides some key examples.

Table 2: Keystone initiatives delivered in 2020-25

Area	Achievement	Effect on customers
Repex	Increased repex above the AER forecast to manage significant risks arising from an aged and deteriorating network. We also rebalanced spend between repex asset classes based on their risk criticality at the time, directing more spend to assets such as overhead conductors, where we experienced increased failures, supply outages and safety risks.	Assets posing highest condition-based risk to safety and reliability were prioritised.
Augex	Continued to deploy feeder automation to reduce the escalating reliability impact of deteriorating asset condition and grey headed flying foxes (i.e. bats) by segmenting the network and re-routing supply to reduce the number of customers interrupted (i.e. reducing consequences of outages).	Minimised the number of customers affected by network outages.
CER	Continued to invest in transitioning to a truly 'two-way' distribution network able to support a 100% renewable electricity system – this includes developing our world leading capability to efficiently integrate very high levels of roof-top solar and other CER using DOEs, voltage management enhancements, tariffs and new emergency measures to help support system security at times of minimum demand. These measures have enabled greater utilisation of existing export capacity.	Significantly increased the amount of renewable energy customers could fit onto our grid, increasing individual and collective customer benefits from CER and improving environmental outcomes.
ICT	Delivered our comprehensive works portfolio as intended. This includes major changes to ICT infrastructure including our new billing system, and upgrading our SAP Enterprise Resource Planning system which underpins most of our key customer and business processes. We implemented technologies to facilitate flexible grid management, completed consolidation of Geographic Information Systems, invested to meet cyber security requirements / obligations, and improved our network data collection and analytics underpinning our ability to more accurately forecast risk and service level effects of network asset condition.	Network services continued to be supported by effective ICT deployment. ICT has also increased confidence in network asset risk forecasting for 2025-30. Consumer benefits of $134.5m were realised in 2020-25.

5 Underlying concerns for service performance are beginning to manifest

While long-term service performance has been sound, we are concerned for the impact on service in coming years if inadequate action is taken. This is in particular regard to the service risk posed by the condition of our network assets, as the oldest asset fleet in the NEM faces a critical time in which assets reach the end of their economic service life.

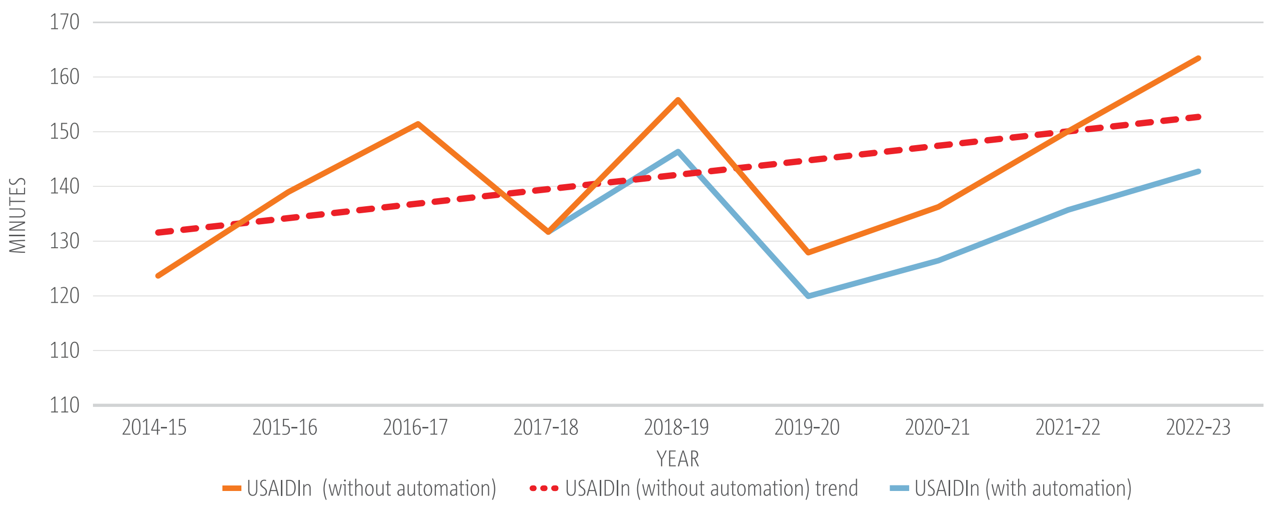
Our underlying concern arises from us considering:

1. **backward indicators**: recent service performance indicators and how they should be interpreted; and
2. **forward risk indicators**: our detailed and vastly improved modelling of the probability, likelihood and monetised cost for customers of poorer service outcomes in relation to reliability and safety (including bushfire risks) arising from:
   - asset condition based failures across our entire network asset fleet; and
   - ongoing trends in non-asset condition effects on reliability such as weather and animal contact, and ongoing bushfire safety risk.

Looking backward across our overall distribution network service performance, we see that underlying reliability has gradually deteriorated since the start of 2020-25 as shown in Figure 6, via a combination of: more frequent and severe weather and outages caused by grey-headed flying foxes (i.e. bats), which our 2025-30 forecast augex reliability programs address; and network asset failures, which forecast repex addresses.

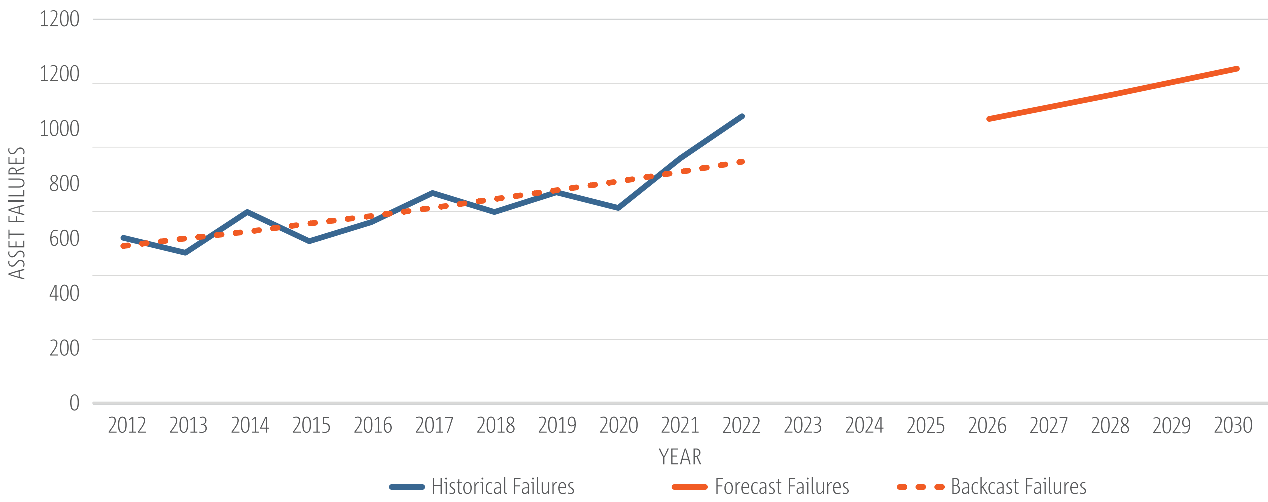
This effect has been masked by the implementation of Distribution Feeder Automation (**DFA),** implemented and expanded since 2018/19, which reduces the number of customers affected by network outages by segmenting the network and automatically re-routing supply in meshed areas of our network where feasible. Were it not for this program, out-turn reliability would have been materially worse – a decline of more than 20 minutes or 14 percent at 30 June 2023, or an average annual decline of four minutes or three percent).

Figure 6: Distribution system interruption duration (USAIDIn)—with and without DFA



A key driver of the deterioration in underlying performance is increasing asset failures across asset classes, such as displayed in Figure 7 for our overhead conductors, demonstrating a material worsening of asset condition, and supporting anecdotal feedback from our staff that condition related asset failures are significantly increasing. This actual failure data has also been used to ground and validate our view of forecast risk underpinning our proposed repex, by back-casting our forecasts against actual failures where data permits.

Figure 7: Historical and forecast asset failures - overhead conductors[12]



This data is of particular concern as we approach the 2025-30 period as we have now deployed DFA solutions in the vast majority of meshed parts of the network, with higher customer densities, for which it is most valuable and efficient. Further, DFA cannot address bushfire safety risk.

Nonetheless, in our modelling we have identified where it is more efficient to address the underlying cause of an outage rather than just mitigate its impact. A key example is our CBD reliability improvement program (section 9.3), where relying solely on automation is a higher cost option than a combined and optimised program of replacing deteriorated underground cables with some targeted automation.

[12] Overhead conductors are assets that transmit electricity between substations, and from substations to customers. We have approximately 175,000km of conductors across our network over a route length of approximately 70,000.

6 Our forecasting methodology was rigorous, guided by customers, and complies with regulation

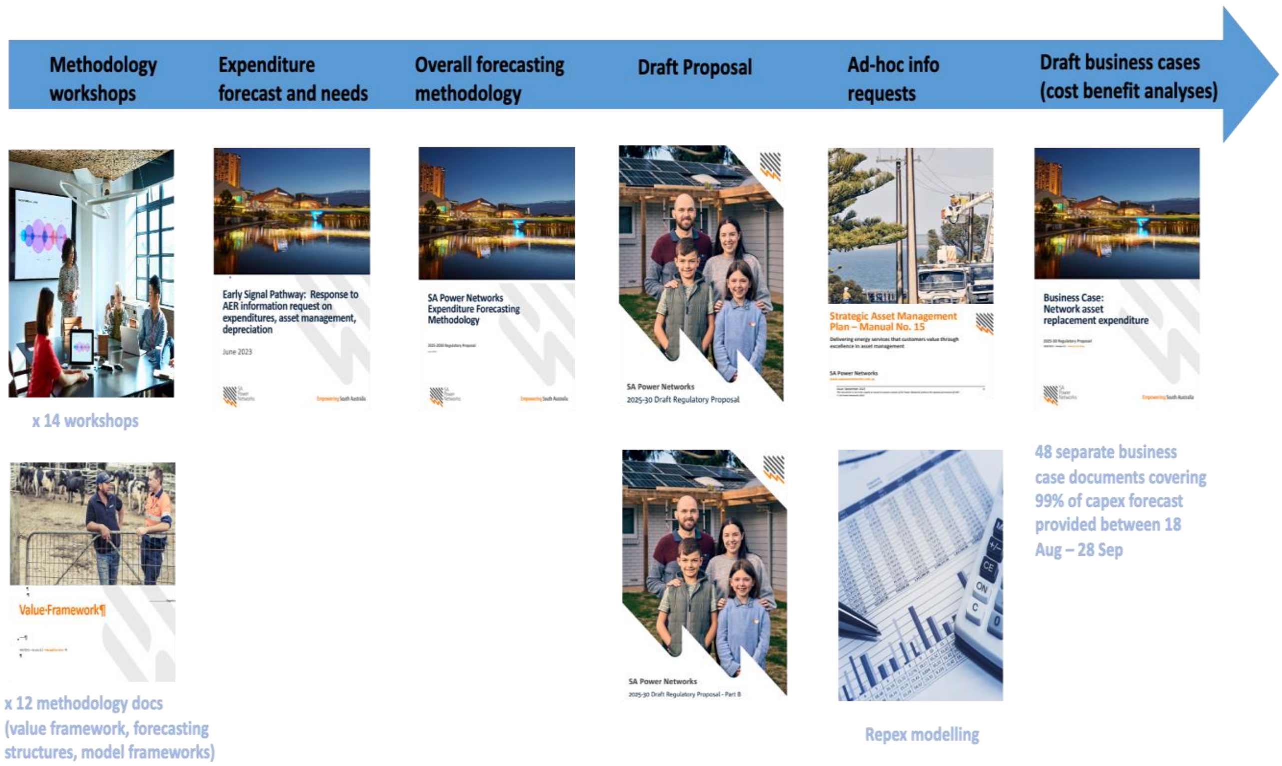
Our capex forecast results from a comprehensive forecasting methodology driven by two primary objectives:

1. **alignment to customer preferences**: we developed our expenditure forecast by closely aligning it with the expectations of our customers regarding the services and service levels we offer and corresponding pricing outcomes; and
2. **alignment to regulatory expectations**: we aligned our forecast to the AER's expectations and guidance in its Better Resets handbook, and related expenditure guidelines and guidance notes. We also aligned to the National Electricity Objective (**NEO**) and Revenue and Pricing Principles in the National Electricity Law (**NEL**), and the capex objectives, factors, and criteria in the National Electricity Rules (**NER**).

6.1 We have aligned to regulatory expectations

We proactively sought alignment with regulatory expectations by voluntarily participating in the new **AER Early Signal Pathway** process. Over a two-year period, we developed and tested our forecasting approaches, forecasts, and business cases (encompassing our entire expenditure program), via a combination of collaboration, workshops, and scrutiny by AER expenditure assessment teams and technical advisors.

Figure 8: Engagement with AER via Early Signal Pathway process



We complied with AER expectations of capex forecasting set out in the Better Resets Handbook as summarised in Table 3. A key focus for us was to deliver comprehensive analysis, workshops, and documentation in business cases to justify that our forecast increase in capex is a prudent and efficient response to the risks posed to customer services arising from challenges facing our network.

Table 3: Assessment against AER capex expectations in the Better Resets Handbook

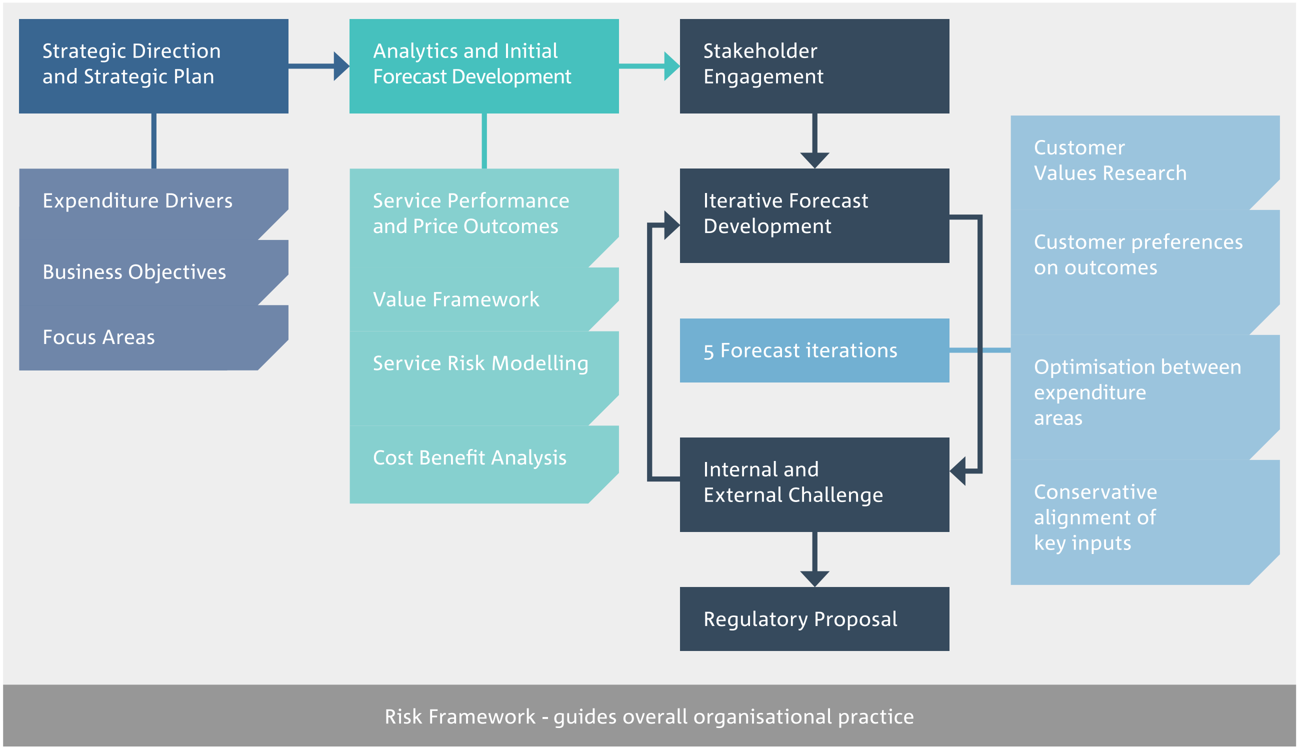
AER expectation		Explanation
Top-down testing	Total capex not materially above current actual spend, and if it is, justify with cost benefit analyses and service level risk analysis.	Recognising our forecast 21.5 percent increase on our expected actual spend, we underpinned our entire forecast with detailed business cases and cost benefit analyses. Each business case outlines a preferred option in comparison to a base-case counterfactual to identify service level outcomes and associated benefits.
	Recurrent expenditures not materially different from current expenditures unless reasons provided.	Forecast recurrent ICT capex is 7.8 percent below expected actuals, and augex on maintaining underlying reliability 0.5 percent below expected actuals. Forecast increases in recurrent repex, fleet and property are justified in business cases and cost benefit analyses.
	Non-recurrent expenditures supported by cost benefit analyses.	All non-recurrent expenditures are supported by cost benefit analyses, with base case counterfactuals and options analyses.
	Modelled forecast repex is not materially higher than AER repex model threshold unless reasoned.	For asset categories for which the AER repex model applies, our forecast is 4.46% below the AER repex model (lives basis).
	New categories explained.	We have no new primary categories. CER Integration is a category recently included in accordance with AER capex model.
Prudent and efficient decision making	Identification of the need in relation to the capex objectives.	Our entire capex forecast is substantiated with standardised business cases. Each case describes the identified need within the framework of the NER capex objectives.
	Quantitative cost benefit analyses, assessing feasible options, showing preferred option maximises net benefits.	Every business case includes quantified costs and benefits, presenting the preferred option. This option is either the least cost means of achieving the capex objectives or offers the highest positive net benefits while meeting customer-desired service level outcomes.
	Accounting for tradeoffs between capex and opex.	We traded off new investments in ICT to improve asset management efficiency, investment in acquiring a limited number of Electric Vehicles, and investment to improve supply restoration times, by accounting for opex savings or future cost avoidance.
Alignment with standards	Evidence of alignment to good asset and risk management standards.	We committed to aligning our processes with ISO 55000:2014 Asset Management framework via our Assets and Work Phase 3 program (i.e Asset Management Transformation). We have also had external consultants review key components of our forecast to ensure that our approaches align to and lead good industry practice.
Genuine customer engagement	Engagement on the service outcome need and options available.	Conducted an engagement program with a focus on outcomes. We engaged on service needs by presenting three alternative scenarios of expenditure, service level, and price tradeoffs. Via multiple engagement stages—'Broad and Diverse' discussions, 'Focused Conversation' workshops, a 'People's Panel' deliberation, and a Draft Proposal—we iteratively refined the scenarios. This resulted in an expenditure forecast that was iteratively shaped by our customers' preferences.
	Explanation of short and long term implications including on the Regulatory Asset Base and long-term price outcomes	At every engagement stage, we transparently communicated potential total expenditure (capex and opex) of various scenarios. This enabled customers to make informed recommendations. We also presented long-term network price implications of different actions.

6.2 Our overall forecasting approach has been rigorous

Our expenditure forecasting approach was rigorous, incorporating our governance framework, comprehensive analytics, a multi-staged engagement program, and multiple tiers of challenge. The key elements of our process are displayed in Figure 9, encompassing:

- **governance** – we applied a robust organisational governance framework. This framework continuously assesses long-term investment drivers, considering challenges and opportunities for our customers, community, and network, and implications for customer services;
- **analytics** – we developed comprehensive analytics to assess the impact of various investment drivers on the services we provide to customers. This includes forming scenarios of alternative outcomes, especially in assessing the effects of network asset condition and customer load demand / export on service levels at highly precise and granular levels;
- **engagement** – following a multi-staged program, we engaged with our customers through five iterations to develop and refine our expenditure forecasts. This ensured that customers played a central role in materially shaping our forecasts and resultant service and price outcomes. The process was conducted in a transparent, objective and outcomes-focused manner; and
- **challenge** – we applied multiple tiers of external challenge by engaging with customers, and internal challenge within our business. This ensured alignment of our forecasts with customer preferences, reasonable cost estimation, and optimal efficiency.

Figure 9: Overview of expenditure forecasting process



6.3 Our forecast was subject to external and internal challenge

Our capex forecast intends to deliver the service outcomes that our customers prefer and expect, and was developed via multiple tiers of internal and external challenge as summarised in Figure 10 and detailed in Table 4.

Figure 10: Tiers of internal and external challenge to expenditure forecast

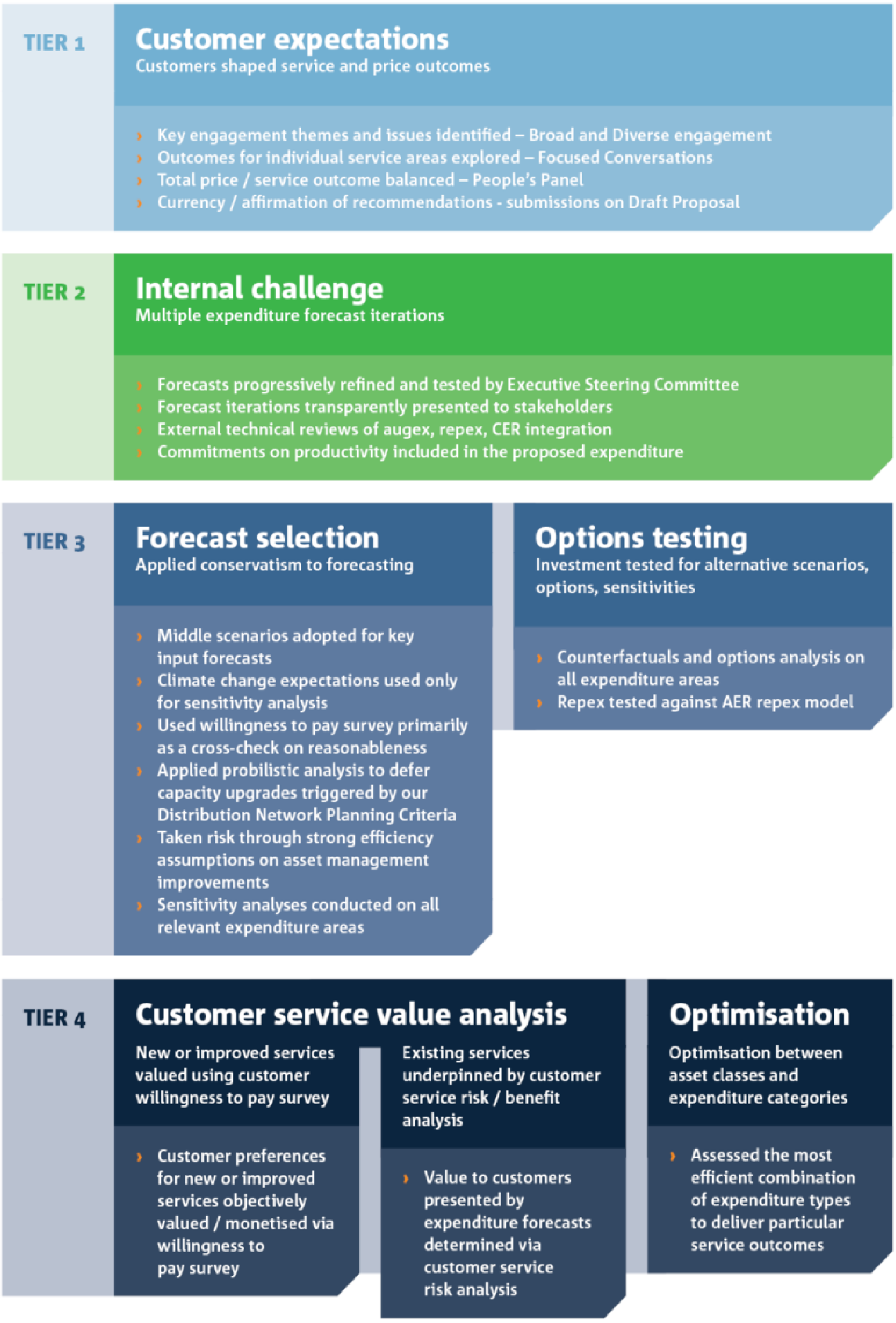


Table 4: Tiers of internal and external challenge of expenditure forecasts

Challenge tier 1 - Customer expectations

As the key challenge, our forecast was shaped by customers to reflect the service and price outcomes they value:

- **multi-staged engagement program** - conducted a comprehensive multi-staged engagement program spanning five forecast iterations. This afforded customers the opportunity to actively participate in shaping the service and price outcomes derived from our forecast total expenditure;
- **outcomes-focused engagement** - our engagement focused on services and service level outcomes, articulating individual and total expenditure, as well as price impacts. This empowered customers to make informed recommendations by understanding inherent tradeoffs. Using a scenario-based approach, we progressively refined options based on customer preferences via the various stages of our engagement program, ultimately converging on our proposed forecast; and
- **Draft Proposal** - as a final step, we invited submissions on our Draft Proposal, encouraging customers and stakeholders to validate the currency of their recommendations on service outcome preferences, especially given ongoing cost-of-living concerns. This step also sought confirmation that our proposed means of delivering these preferences remained appropriate in the evolving economic landscape.

Challenge tier 2 - Internal challenge

Internal scrutiny and refinement was integral to each forecast iteration, with a dual top-down and bottom-up challenge within our business, involving:

- **Executive Management Reset Steering Committee** - our forecast iterations were evaluated and approved by our Steering Committee. This included a top-down 'sanity-check', offering direction to explore optimisation between initiatives, and testing justifications against the NER;
- **business-wide coordination group** - led by our Regulation Team, a business-wide group reviewed the forecasts. This ensured consideration of interactions and opportunities to optimise between expenditure areas, alignment of key forecast inputs, and adherence to regulatory expectations in methodologies and business cases;
- **external technical review** - our forecasts and methodologies underwent external technical review, focusing on key areas of augex for reliability and bushfire management, augex capacity, CER integration, and property expenditure. This external scrutiny refined costings and scope, and ensured that customer-preferred outcomes aligned to efficiency; and
- **top-down productivity commitments** - we made substantial commitments by lowering forecasts below potential levels. This included taking on more risk via strong assumptions on direct efficiency gains from our proposed Assets and Work (Phase 3) ICT program. We factored these efficiencies into the forecast additional resourcing requirements supporting the increase in network capex. We included the AER assumption on opex productivity. Notably, we also decided to pursue but not propose new expenditure for some scope increases including: programs consistent with customer preferences - a new vulnerable customer assistance program, and an expanded 'Knock before you disconnect'; and the South Australian Government-mandated increase in our annual distribution licence fee.

Challenge tier 3 – forecast selection and options testing

We also challenged our business toward downward conservatism in selecting forecasts. Examples include:

- **repex forecast scenario** - choosing a repex forecast scenario that, while efficient (with benefits of risk avoidance outweighing repex costs), requires less expenditure than alternative scenarios our analysis also deemed efficient. We opted against higher cost scenarios, as they did not deliver the service level outcome (maintaining historic reliability by geographic region) and price balance (mindful of affordability concerns) our customers told us they prefer;
- **climate change projections** - opting for conservatism by not incorporating climate change projections into forecasts. While projections suggested increasing network risks from more frequent and extreme weather events, we erred on the side of caution. Climate change projections were only used to test the sensitivity and reasonableness of our network expenditure forecasts, which are primarily based on historic weather patterns;
- **network capacity augex** - temporarily taking on more risk by deferring some works triggered by our Network Planning Criteria, accomplished by incorporating probabilistic analysis - addressing affordability prudently and efficiently while monitoring the trajectory of demand increases and the potential for mitigation by investing in flexible load management.
- **sensitivity analyses -** applied to all relevant expenditure areas to consider potential variations and impacts; and
- **alignment with AEMO scenarios -** aligning all network repex and augex on load and CER to middle forecast scenarios developed by the Australian Energy Market Operator (**AEMO**), ensuring consistency with industry wide projections.

We also challenged our business to test forecasts / initiatives against alternative options as well as non-network alternatives:

- developing three scenarios with a base-case counterfactual across all key expenditure areas to engage and determine the service outcomes valued by our customers;
- ensuring all business cases include a base-case counterfactual ('do nothing' or 'business-as-usual') and multiple investment options (if credible) to ascertain the preferred option, and justify why some options are non-credible; and
- for relevant asset classes, comparing our network repex forecasts against the AER's Repex Model.

Challenge tier 4 – customer service value analysis and expenditure optimisation

To enhance our capability in identifying customer service value and risk, we undertook substantial measures to objectively ensure that our forecasts were reasonable and in customers' interests, including:

- **alignment with AER guidance -** documenting and aligning forecasting methodologies across all areas to AER guidance;
- **bilateral challenge by AER staff -** engaging in extensive bilateral challenge sessions with AER staff on our forecasting methodologies, which influenced our approaches and materially reduced our forecasts particularly for repex;
- **network asset risk analysis** - significantly improving our analysis to objectively quantify (in monetary terms) customer benefits of reliability and safety outcomes resulting from network repex and augex. This enabled us to align expenditures to achieve specific / targeted service outcomes and provide confidence that our forecasts are not only customer-supported but also efficient and prudent;
- **CER integration modelling** – our NEM-leading modeling capabilities for CER integration enabled us to precisely quantify customer benefits and assess the effects on service levels from our expenditure forecast on export service;
- **risk analysis for non-network expenditure** - implementing risk analysis for all non-network expenditure, including a comprehensive asset condition/risk register for property assets. This ensured that quantified risks and customer service benefits are identified for all non-recurrent initiatives, particularly where these are new or aim to improve outcomes.
- **willingness to pay survey** - surveying willingness to pay (Customer Values Research) across seven key areas to objectively value, in monetary terms, new or improved services recommended by customers. Survey results provided an additional reference point, confirming underlying analyses of quantified customer benefits and gauging broader customer support for specific initiatives;
- **cyber security risk quantification -** responding to significant customer concern as well as evidence of our increasing cyber threats, we improved our risk prioritisation and monetisation to target the development of cyber capabilities that manage the most risk; and
- **probabilistic risk analysis for network capacity** - incorporating probabilistic analysis to forecasts to ensure that investments for contingent events triggered by our network planning criteria are economically justified.

Our enhanced risk analysis capability has also enabled us to explicitly optimise expenditures, including:

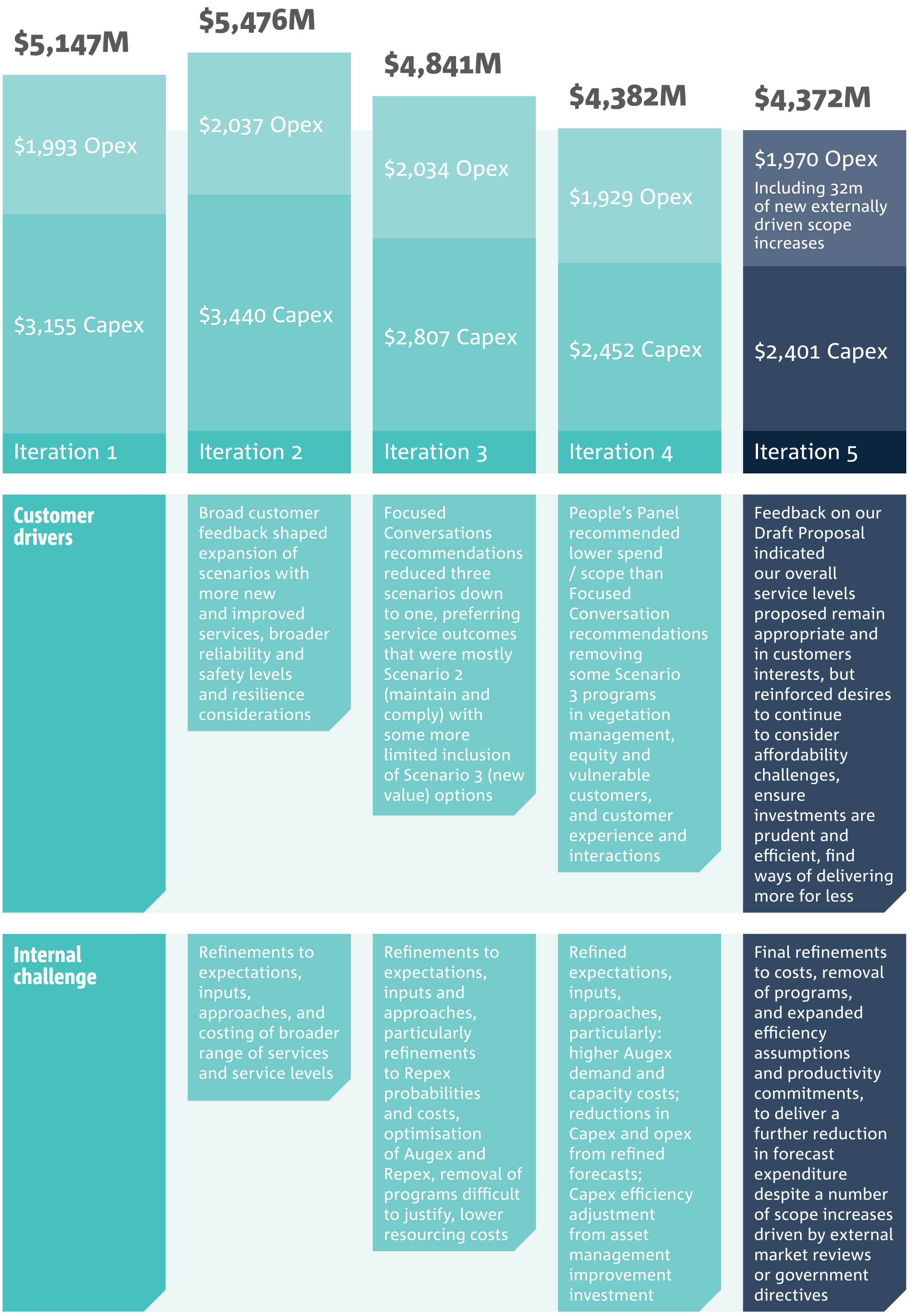
- **between repex asset classes** - choosing the most efficient combination of repex asset classes to achieve targeted service level outcomes, i.e. maintaining reliability by geographic region and safety in aggregate; and
- **across expenditure types** - optimising the most efficient combination of repex and augex to achieve targeted service level outcomes, particularly to improve CBD reliability to meet service standards (combining cable repex and feeder automation augex).

6.4 Our forecast was iteratively refined and shaped by customers

Our forecast capex for 2025-30 is the ultimate product of internal and external challenge processes. This forecast was refined with our customers over five forecast iterations aligned to each key stage of our consumer engagement program. The quantitative highlights are that:

- **capex was continuously and materially reduced** - the capex 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 with the forecast being required to give effect to the service outcomes recommended to us via our engagement process.

Figure 11: Expenditure forecast iterations mapped to engagement program stages



7 Our forecast responds to multiple converging service needs

We forecast a total capex requirement of $2.4 billion, a 21.5 percent increase on our expected spend in 2020-25. This increase reflects the need to prudently and efficiently respond to the convergence of multiple challenges and opportunities facing our network and the services we provide over 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 to maintain safety in aggregate;
- **Augex** – the need to increase expenditure on network upgrades in order to:
  - meet forecast strong increases in load demand, driven by customer electrification, by ensuring sufficient capacity in our distribution network;
  - respond to non-asset condition impacts on reliability (including bats, weather, and other damage causes); make targeted and optimised upgrades alongside repex to improve reliability in the Adelaide CBD to meet jurisdictional standards; and make targeted improvements for regions and customers who repeatedly experience 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 expenditure 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 network loads; and to improve compliance to CER technical standards;
- **Property** – the need to increase expenditure 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 vehicle replacement cycles, while increasing volume to support increasing network capital work, and acquisition of Electric Vehicles **(EVs)** where efficient; 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 12: Historic and forecast capex by category

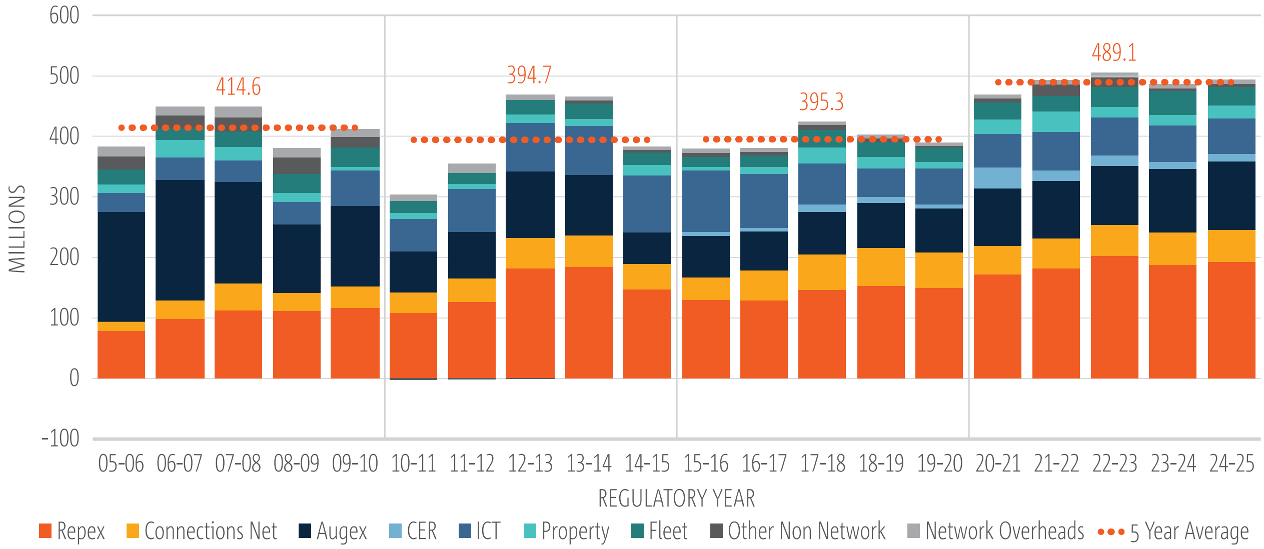


Figure 12 displays our forecast capex by expenditure category relative to our historic spend. Further, Table 5 outlines our forecast capex by expenditure category, relative to our expected actual spend in 2020-25.[13] In this figure and table, as well as in all data outlined in Section 9, the expenditure category expenditure forecasts are shown excluding our proposed efficiency adjustment.

We have proposed to apply our efficiency adjustment as a separate deduction to our capex forecast. This adjustment arises as the direct effect of our productivity commitment enabled by our proposed Assets and Work (Phase 3) ICT program to improve asset management efficiency (discussed in section 9.6).

Table 5: Capex forecast for 2025-30 - by category and totals ($ million, June 2025)

	2025/26	2026/27	2027/28	2028/29	2029/30	2025-30 RCP	2020-25 RCP	% change
Repex	171.8	181.9	202.0	188.1	192.6	936.4	706.0	32.6%
Augex	94.1	95.3	97.9	105.7	113.3	506.3	350.5	44.4%
Connections Net	48.1	49.3	51.5	53.2	53.1	255.2	268.5	-5.0%
CER	35.3	17.8	17.1	10.9	11.4	92.7	41.0	125.8%
ICT	55.0	62.7	63.0	60.5	59.5	300.8	366.2	-17.9%
Fleet	28.7	25.1	32.2	39.2	29.8	154.9	113.7	36.3%
Property	23.9	34.5	17.7	17.8	21.9	115.8	73.3	57.9%
Other Non-Network	6.1	18.9	16.4	3.6	5.3	50.4	29.8	68.8%
Network Overheads	6.5	6.6	7.0	6.6	6.9	33.5	27.5	21.9%
Total Capex	**469.6**	**492.3**	**504.8**	**485.5**	**493.7**	**2,445.9**	**1,976.6**	**23.7%**
Efficiency adjustment	-1.8	-9.0	-11.7	-10.9	-11.6	-45.0		
Total Capex (post adj)	**467.7**	**483.3**	**493.1**	**474.6**	**482.1**	**2,400.9**	**1976.6**	**21.5%**
Disposals	-2.7	-3.8	-6.4	-5.2	-3.7	-21.8		
Total Net Capex	**465.0**	**479.5**	**486.8**	**469.4**	**478.5**	**2,379.1**	**1976.6**	**20.4%**

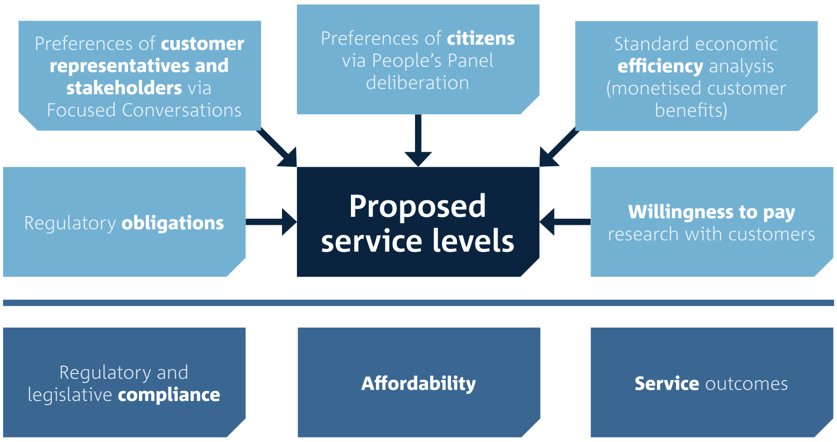
13 This forecast pertains to expenditure that relates to Standard Control Services (**SCS**) and which has been allocated in accordance with the principles and policies set out in SA Power Networks' Cost Allocation Method (**CAM**). SAPN, *Cost Allocation Method*, July 2020. Accessible on [https://www.sapowernetworks.com.au].

8 Multiple information sources indicate that our proposal is in customers' interests

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

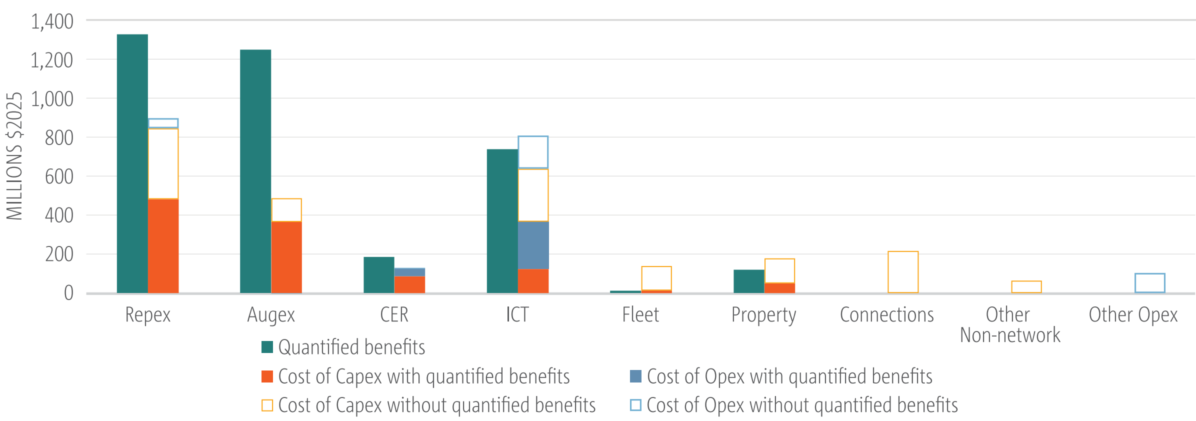
Addressing these competing considerations, requires a delicate balance of service and price. We considered that this was best managed by ensuring that the plans we put forward in this capex forecast, were not solely guided by any one consideration, and that we have had regard to multiple sources of customer preference information, economic efficiency, and other indicators of economic / customer value via willingness to pay analysis of our customers, as outlined in Figure 13 and detailed in Table 6.

Figure 13: Our approach to balancing service and price outcomes



The service levels we propose to achieve were shaped by engaging **consumer representatives and stakeholders** as well as **everyday citizens**. Each of the **service levels are efficient for customers**, with quantified (monetised) benefits exceeding investment costs. Our customer values research survey also indicates that the broader customer base is **willing to pay** for service levels that are experienced by specific customer cohorts. In sum, the new investments we propose (total capex and new opex) are overall demonstrably efficient with an estimated **net benefit of over $0.5 billion in NPV terms over 20 years**, arising from the investment areas shown in Figure 14.[14]

Figure 14: Areas contributing to overall positive NPV (20 years) of total capex and new opex – figures shown in PV terms



[14] This is a conservative estimate as, consistent with industry practice, several large expenditure areas (e.g. connections, fleet) lack an established regulatory approach to valuing benefits. The NPV covers all capex and new opex (step changes 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 6: The multiple sources evidencing our proposed service levels as being supported by customers and in their interests—key service levels and examples

Engagement with informed customer representatives and 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's Value of Customer Reliability (**VCR**)
Improve reliability for the CBD to comply to standard	**Supported**	**Adopted**	Optimised **least cost** to comply	The need is compliance driven, and evaluated using AER VCR
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 are 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 are 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 AER 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 and benefits of capex and new opex, derives a positive NPV result of circa $500m over 20 years.				

9 Our programs and projects reflect prudent and efficient responses to customer service needs

The total capex forecast for 2025-30 and the programs and projects that comprise each capex category, were developed and justified to meet the regulatory requirements of a Regulatory Proposal:

- **National Electricity Objective (NEO)** - the forecast is consistent with the NEO of the NEL, by promoting outcomes that are in customers' long-term interests with respect to the service performance and price outcomes that it affords, having been shaped by informed customer preferences and efficiency analysis;
- **Revenue and Pricing Principles** - the forecast is consistent with the NEL by ensuring that it provides us with a reasonable opportunity to recover at least our efficient costs of service provision;
- **capex objectives**[15] - each expenditure category and constituent projects and programs, are underpinned by detailed and standardised business cases and supporting analysis, that justifies each area of spend against the capex requirements in section 6.5.7 of the NER, including among other things:
  - a clear identified need for investment action to address the capex objectives in section 6.5.7(a) of the NER;
  - a base-case counterfactual to outline the detriment to service outcomes that would result; and
  - analysis of multiple options where credible (and information provided where deemed non-credible), with costs and benefits considered, to identify preferred options that represent the most prudent and efficient means of addressing the investment needs of the capex objectives, pursuant to section 6.5.7(c) of the NER;
- **customer preferences** - the capex forecast was materially shaped by customer preferences, with objective evidence provided in support of our programs and projects, consistent with the Better Resets Handbook expectations; and
- **forecasting methodologies** - our methodologies in forecasting each expenditure area supported by detailed documentation, outlining how these methodologies align to AER guidance by way of the Better Resets Handbook and various supporting guidance documents.

The following sections summarise the key features of our capex forecast for each capex category and constituent programs and projects.

The primary detail justifying these forecasts is contained in supporting documents to our proposal, including principally our **business cases**, and a series of expenditure **forecasting methodology documents**. Appendix A provides references to the supporting documents to all expenditure areas covered in this capex attachment.

15 Further, and pursuant to the capex factor in NER clause 6.5.7(e)(9), **supporting document 20.6** discusses our arrangements in relation to outsourcing activities.

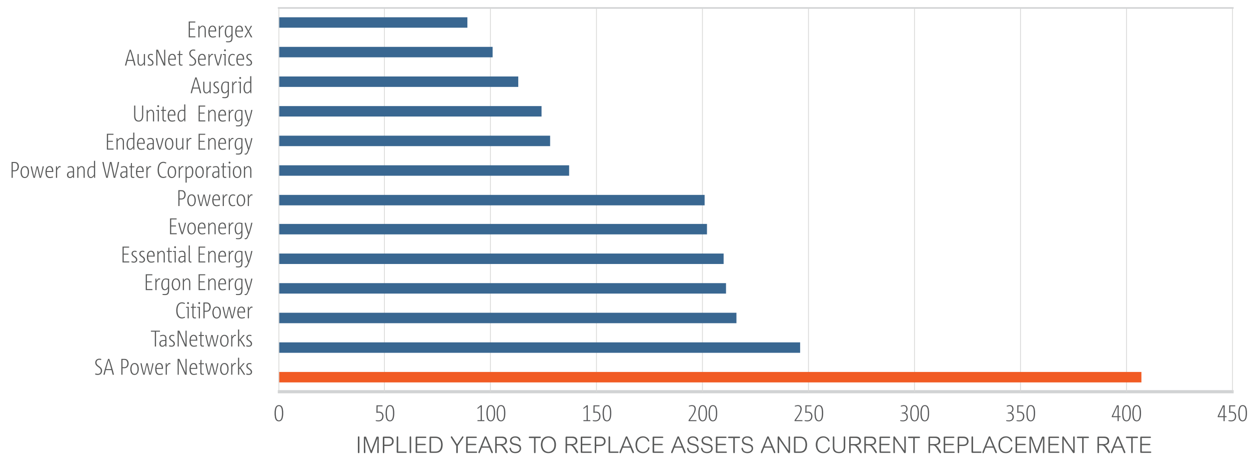
9.1 Network asset replacement expenditure (repex)

Capex $936.4 million

38.3% of total capex

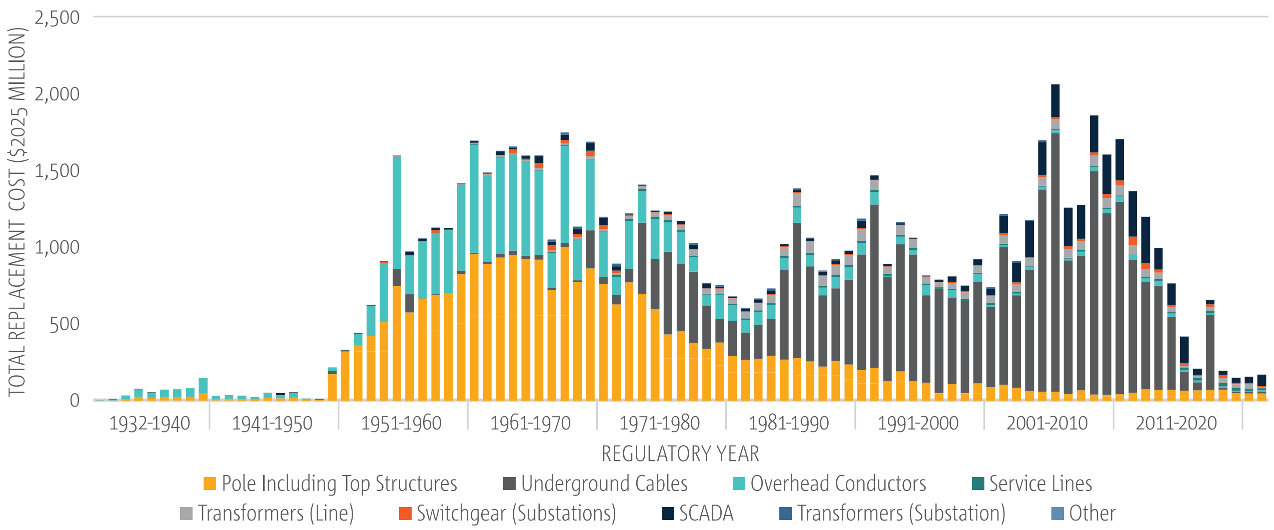
Our repex forecast of $936.4 million responds to the need to retire distribution network assets that are in poor condition, by replacing assets across several asset classes and through some discrete projects, with a view to maintaining reliability service performance and safety (including bushfire risk), across our network.

Figure 15: Implied asset lives – years implied to replace assets and current replacement rate



The risk that deteriorating asset condition is posing to safety and reliability is manifesting more significantly now as a product of our unique network asset age profile. We have one of the oldest distribution networks in Australia as Figure 15 shows, with a large proportion constructed in a confined period in the 1950s and 1960s as seen in Figure 16.

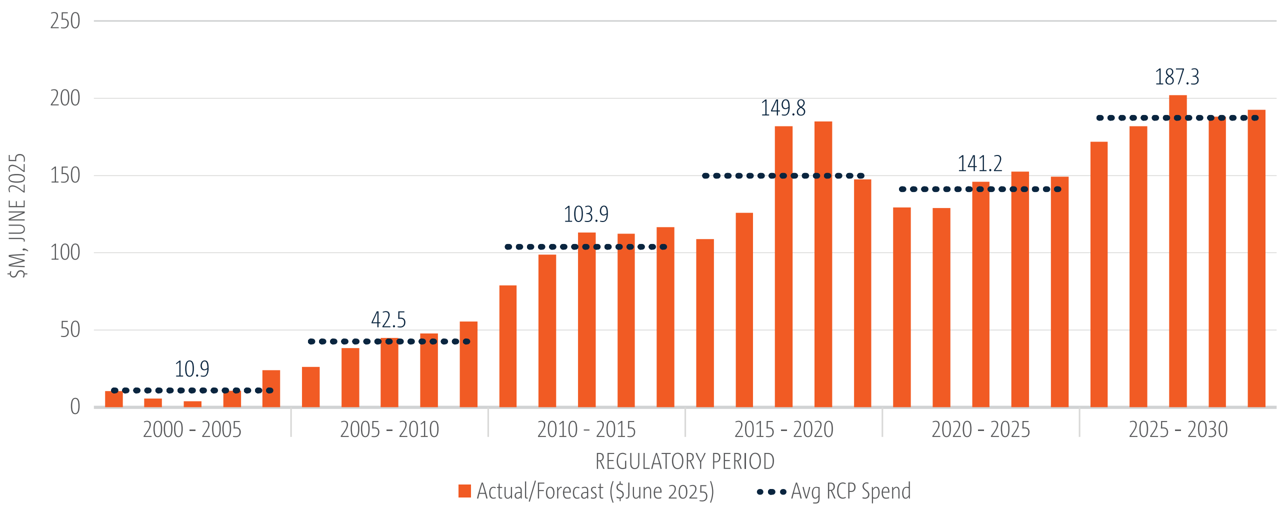
Figure 16: Age profile of our network assets



Acting prudently and efficiently, we replaced relatively little network in past periods when the age profile was lower. Over time, as the age profile has increased and asset condition deteriorated causing escalating service risk, acting prudently and efficiently, our repex levels have followed a consistent upward trend, as Figure 17 shows. This long-term repex increase, combined with increased augex on reliability and bushfire mitigation, have been crucial in keeping long-term service performance steady despite escalating risk.

In 2020-25, our repex levels continued the long-term trend, and we forecast spending $706.0 million, which is 3.7 percent higher than the AER forecast. Despite this increase in repex (and augex) overall distribution system reliability has declined over this more recent period as shown earlier in section 5.

Figure 17: Long term replacement expenditure profile



Our visibility of risk in 2020-25 vastly improved via analytics in quantifying in monetary terms, customer service risk posed by our assets, capitalising on enabling investments such as our Assets and Work ICT program from our 2020-25 Regulatory Proposal. With this information, we reprioritised expenditure within our repex asset classes, to reasonably endeavour to manage overall service performance within our total capex allowance.

Table 7: Repex - key achievements in 2020-25

	What we achieved in 2020-25	Benefits to customers in 2025-30
Risk cost modelling	Built a sophisticated model to better understand and forecast asset risk including detailed modelling of bushfire risk across our network.	Allowed objective engagement on outcomes – considering varying repex levels and resulting service and consumer benefits.
Improved repex investment decision making	With better risk visibility we refined decision making in repex allowing spend deferral that would have otherwise been made prematurely.	Reduced costs to customers by deferring low-value asset replacement that would otherwise have occurred.
Invested in line with 2020-25 AER forecast	Invested $706 million in repex to maintain safety and reliability of the network.	Minimised the spend now required in order to maintain reliability and safety performance.
Implemented new asset assessment tools	Built new systems to inspect assets and gather condition data, to better inform repex decisions.	Improved repex targeting, reducing risk of in-service asset failures.

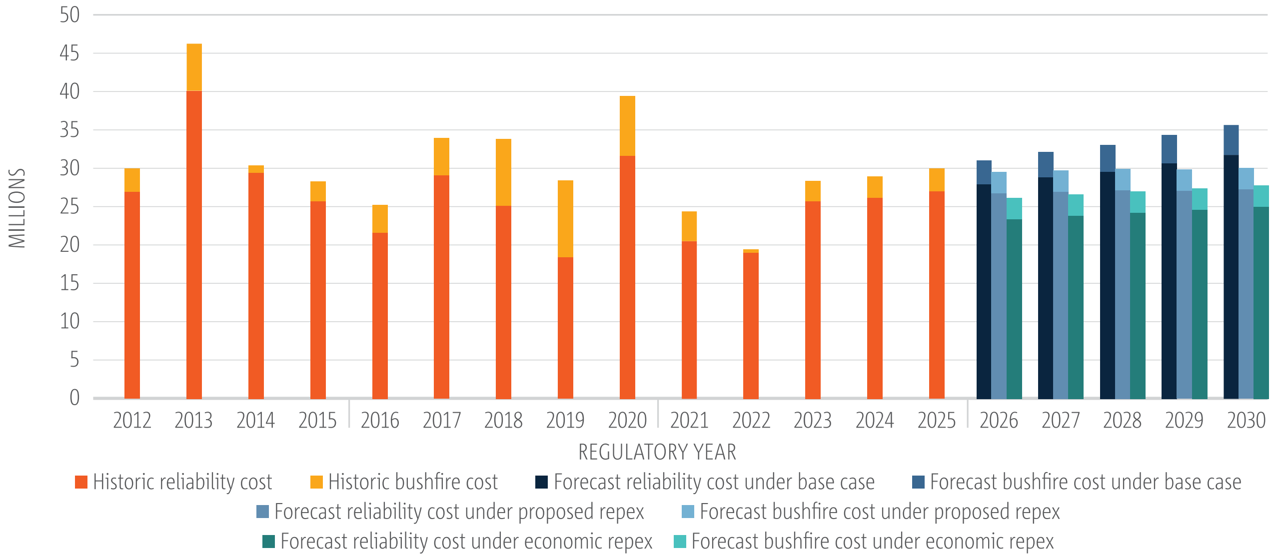
Our 2025-30 forecast is a 32.6 percent increase on our estimated 2020-25 spend, and follows our long-term upward trend in repex as Figure 17 shows, to continue to counter escalating customer service risk posed by deteriorating asset condition. Drawing on improved service risk modelling, our forecast has:

1. **aligned repex inputs to target a service level outcome** – combining all repex asset classes and projects to target the service levels our customers prefer, quantitatively shown in Figure 18; and
2. **achieved a service and spend level that is efficient** – the repex forecast is efficient and will generate substantial consumer benefits (in monetary terms), relative to alternative scenarios we considered. Overall, benefits will outweigh costs, with a **NPV outcome of $364.6 million over 20-years**.[16]

[16] This estimate is intentionally conservative, encompassing all costs associated with modelled and unmodelled assets, but not encompassing the entirety of expected benefits.

Figure 18 displays the results of our repex forecast and the outcomes it achieves, relative to our counterfactual ('base-case') of maintaining current spend and to an alternative scenario ('economic') of undertaking repex solely where total benefits outweigh costs irrespective of the service level effect.

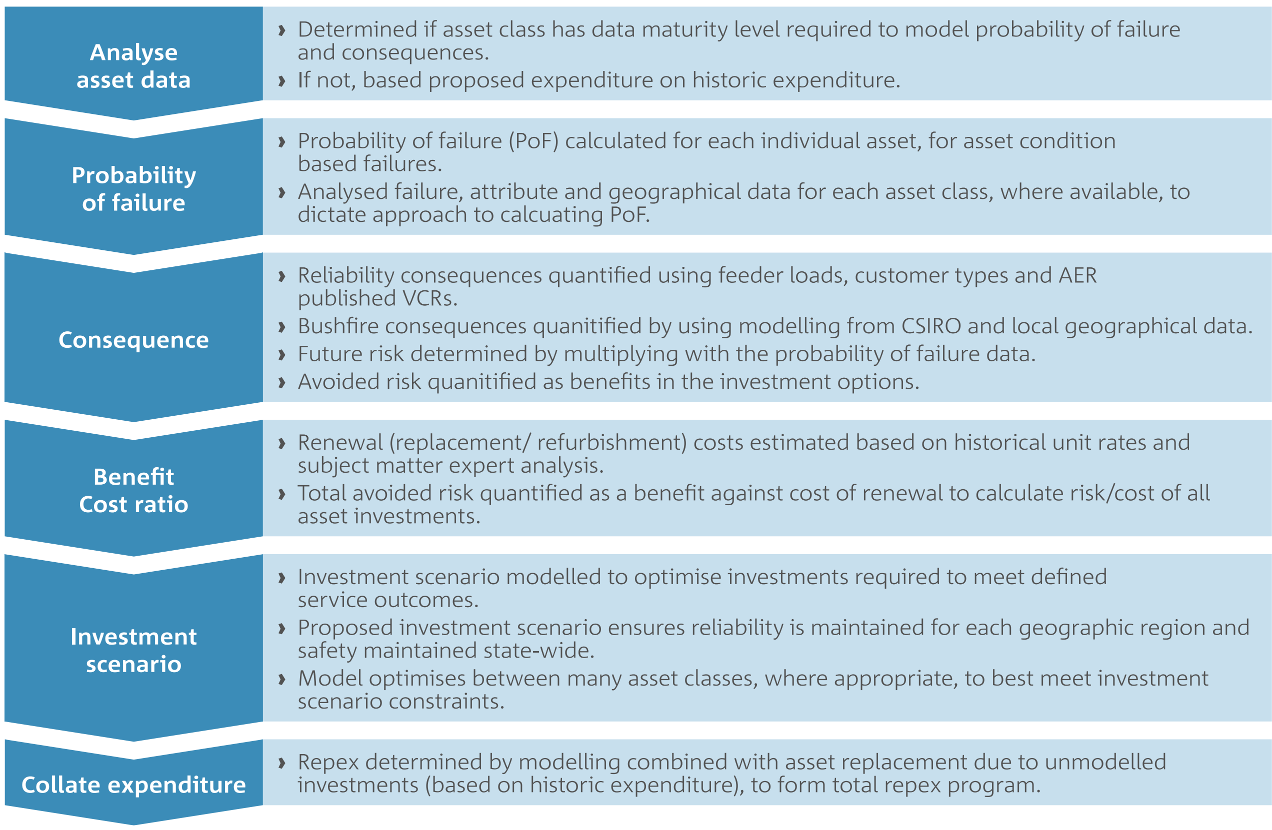
Figure 18: Repex reliability risk cost - historic vs forecast (base case vs proposal) ($ million, June 2025)



Expenditure forecasting approach

Repex was forecast with detailed bottom-up modelling and top-down trend analysis for some asset classes where obtaining condition information is difficult. The AER Repex model was used as a top-down comparator for our modelled assets.

Figure 19: Repex forecasting methodology



The identified customer service needs

Forecast repex responds to the risk posed by deteriorating asset condition and the need to retire and replace assets. If we continued with a counterfactual of our business-as-usual (**BAU**) approach and maintained only historic spend levels, we would not maintain safety (mainly bushfire risk) and not comply with jurisdictional service standards. In response, we configured all asset class and project inputs comprising repex, to target the overall service level outcome recommended by customers. Key repex inputs are summarised below.

Overhead conductors

Our historic, overhead conductors BAU approach of 'fixing on fail' with little proactive replacement, would deteriorate reliability and safety:

- continuing our current average spend over the last five years implies that our conductors would need to last approximately 2,500 years on average which is unrealistic;
- there are increasing trends of conductor failures impacting reliability and safety risks (bushfire); and
- we forecast in 2025-30 a risk of further deteriorating reliability and safety.

Underground cables

Our historic, underground cable BAU approach of 'fixing on fail' with little proactive replacement, would deteriorate reliability and safety:

- continuing our current spend level averaged over the last five years implies that our cables would need to last approximately 3,500 years on average which is unrealistic;
- we observe trends of increasing cable failures impacting reliability, particularly in the Adelaide CBD; and
- we forecast in 2025-30 a risk of deteriorating reliability levels, particularly in the Adelaide CBD.

With most of the deteriorating reliability due to underground cable condition is forecast to occur in the CBD, a specific reliability management program has been developed (discussed in section 9.3).

Pole replacements

Our historic BAU approach to pole management is to proactively replace based on condition and risk, or where efficient, extend the life of poles via 'plating' refurbishment (welding steel plates onto corroded poles). However, maintaining spend at current levels risks deteriorating reliability and safety service levels given:

- it implies our poles would last on average more than 300 years which is unrealistic, with the expected life averaging circa 100 years depending on location; and
- the need for pole repex in 2025-30 is insufficiently reflected in our 2020-25 spend noting that we had to reprioritise repex away from poles in order to address higher risk / consequence underground cable and conductors – a prudent short term measure noting we had previously proactively replaced more poles.

Circuit breakers

Our historic circuit breakers BAU approach has been to proactively manage based on condition and risk and where efficient we continue to extend life via refurbishment. We assess that maintaining our BAU approach and our 2020-25 repex spend level is likely sufficient. The alternative of 'run-to-fail', would degrade service.

Pole top structures

Our BAU approach to pole top structures is to replace or refurbish on a benefits versus costs approach where we identify a defective asset, as well as replacing on failure. The large volume and variety of pole top structures makes detailed modelling impractical so our forecast relied on historic spend.

Hindley Street substation 66kV switchgear

A do-nothing option (no capex investment) presents a reliability risk, with the deteriorated condition of circuit breakers posing risk of catastrophic failure at this key CBD substation, and resulting safety risk.

Mobile substations project

A base case of only doing minor refurbishment and regular maintenance of our mobile substations poses risks that defects in these substations will increase the risk to reliability.

Other repex programs

These comprise a broad range of asset classes each of which contribute less than 10 percent to total forecast repex. They include high volume assets, with the forecast based on: volumetric risk-based modelling for work that is condition-based; historic spend for reactive work; and historic spend for high volume assets for which there is insufficient data for modelling.

The preferences of our customers[17]

Preferences recommended up to Draft Proposal

We engaged on the need, expenditure, and price impacts via Focused Conversations by discussing scenarios:

1. a BAU counterfactual of historic spend;
2. maintaining reliability and safety in aggregate; and
3. maintaining reliability and safety by geographic region.

Focused Conversations recommended to the People's Panel that we invest sufficiently in repex in order to:

- maintain reliability by geographic region – highlighting the need to consider equity between regions;
- improve reliability of the Adelaide CBD – given the importance of complying with jurisdictional service standards, and of the CBD to economic / customers' prosperity; and
- maintain safety in aggregate across our network – given a desire to not see rising risks of harm to persons and damage to property and assets, particularly in the face of rising climate change risks.

The People's Panel then affirmed these recommendations in their formal recommendation to us, having deliberated on the overall service and price balance of our whole proposal.

Preferences recommended post Draft Proposal

Submissions confirmed the People's Panel recommendations as valid, despite cost-of-living pressures:

- members of the People's Panel affirmed that their recommendations, including on repex remain current;
- the South Australian Council of Social Services **(SACOSS)** supported maintaining current reliability levels (urging us to propose no more reliability expenditure than necessary to maintain current levels), and expenditure to comply with regulatory obligations – our repex forecast seeks only to maintain current reliability and safety risk;
- the SA Government's Department for Energy and Mining **(DEM)** supported investing to maintain reliability, while urging us to consider the timing of our repex and if some can be pushed beyond 2030 – our business case responds by: demonstrating the imprudence and inefficiency of not undertaking our forecast repex (by quantifying customer reliability and safety risk); and also by removing our substation disconnector program from our Draft Proposal having assessed this project could not be supported as efficient in 2025-30;
- the Asset Condition and Risk Sub-Committee of our Community Advisory Board (**CAB**) who has been engaging with us over the long term on the need for repex, noted it supports our forecast and the service outcomes it achieves. It considered our forecasting methodology was rigorous, scientific and meets industry standards, and supported our forecast, while also encouraging the AER to assess if it is the most economic outcome;
- the Small Business Commissioner of South Australia supported the repex forecast, noting its importance for reliable service and safety outcomes for small businesses and their customers; and
- the Energy and Water Ombudsman of South Australia **(EWOSA)** supported our proposed expenditure service levels for reliability, resilience, and safety, as being in the best interests of the South Australian community.

[17] 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 supporting documents listed in Appendix A, and out talkingpower website, accessible on: [https://www.talkingpower.com.au]

Our proposal and its efficiency for customers

OUR FORECAST	SERVICE LEVEL OUTCOME	EFFICIENCY FOR CUSTOMERS
OVERALL REPEX: $936.4M IN TOTAL		

› **Overhead conductor:** $80.2m, a 85.0% increase on 2020-25 to replace 1700 kms (replacing less than 1% of our population)
› **Underground cable:** $97.0m, a 76.8% increase on 2020-25 to replace 30 kms (replacing less than 0.4% of our population)
› **Pole replacements:** $155.9m, a 40.9% increase on 2020-25 to refurbish 21,000 units and replace 6000 units (replacing approximately 1% of our population)
› **Circuit breakers:** $83.3m, a 0.3% decrease on 2020-25 to replace 129 units (replacing approximately 7.5% of our population)
› **Pole top structures:** $161.6m, a 10.6% increase on 2020-25
› **Mobile substations:** $11.0m
› **Hindley Street switchgear:** $32.2m
› **Other repex programs:** $315.2m, a 18.0% increase on 2020-25:
  › replace or refurbish 81 zone substation power transformers, a 25.4% increase on 2020-25 (replacing or refurbishing approximately 13.5% of our population)
  › replace 2,090 distribution transformers, a 39.7% increase on 2020-25 (replacing less than 3% of our population)
	› Reliability maintained by geographic region
	› Safety (including bushfire risk) maintained in aggregate
	› Reliability in Adelaide CBD restored to jurisdictional service standard
		› **Overall benefits exceed costs** with NPV result of $364.6m over a 20 year period.
		› Forecast is lower than comparator AER repex model for AER modelled asset classes.

9.2 Network asset augmentation expenditure (augex)

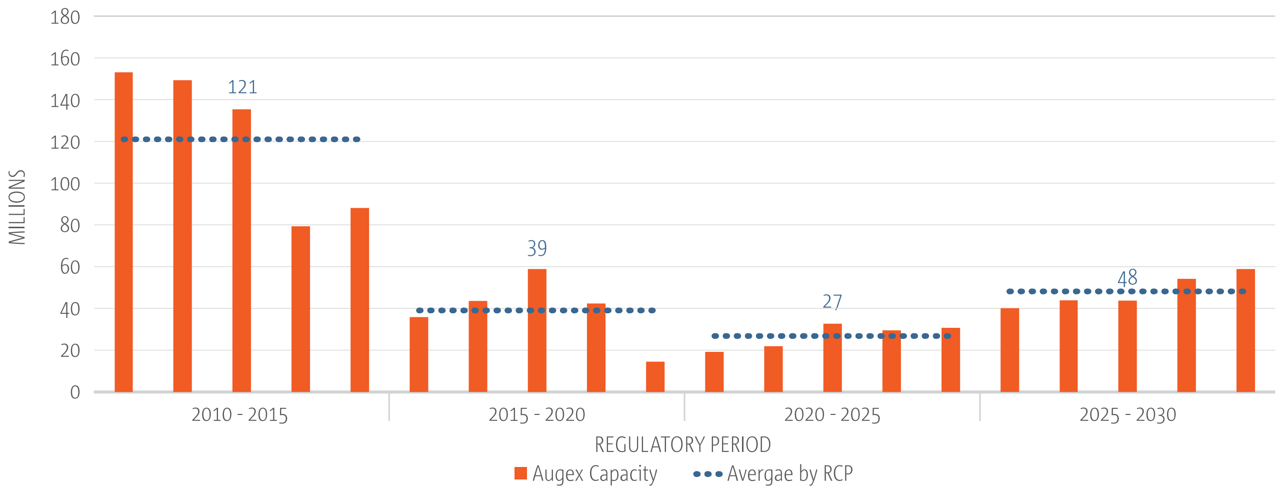
9.2.1 Network capacity

Capex $240.9 million

9.8% of total capex

Our forecast of $240.9 million is 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.

Figure 20: Long term profile of augmentation expenditure on capacity



In 2020-25, we estimate spending a historically low $134.0 million on capacity augex (largely aligned to the AER forecast of $138.4 million). This reflects what had been the lowest demand driven capacity forecast in over 15 years as Figure 20 shows, resulting from largely flat or declining demand in the period.[18]

Table 8: Augex capacity - key achievements in 2020-25

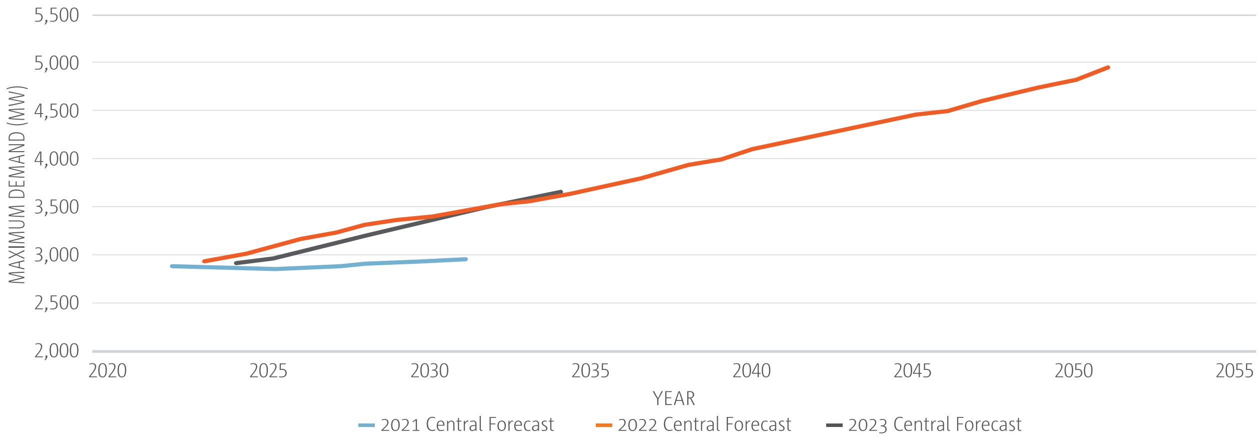
	What we achieved in 2020-25	Benefits to customers in 2025-30
Visibility & model	Developed method to use power quality data from smart meters and Low Voltage monitoring devices, extrapolating to network areas with limited / no visibility. Improved cost benefit analyses based on lost energy, service level and risk metrics vs costs of various solutions.	Minimised spend with holistic understanding of network constraints and efficient solutions. Improved customer experience and efficiency by proactively identifying / resolving network issues without customers making prior enquiries. Improved reliability by minimising outages from asset overload in LV networks.

Our forecast is 79.8 percent above our expected 2020-25 spend. This is driven by a material resurgence in forecast demand growth as Figure 21 shows, resulting from macro factors such as electrification in business, transport and residential sectors, EV up-take, renewable targets, and localised factors such as in-fill housing, residential developments and commercial and industrial loads. Our forecast is distinguished between:

1. **base costs** – projects for compliance or to relieve constraints at a 50% Probability of Exceedance (POE) level under normal operating conditions; and
2. **additional hybrid planning costs** – investment in sub-transmission, substations and distribution feeders identified by a hybrid approach using probabilistic (N-1) and deterministic planning (10% POE for N).

[18] Previously unidentified augmentations driven by changes in demand over the period were offset by deferrals driven externally by decisions of ElectraNet at joint connection points, and a cancelled large sub-transmission line upgrade due to changes in demand over the period and re-prioritisation of work.

Figure 21: SA operational demand forecast (summer 50% POE central, step change, scenario)

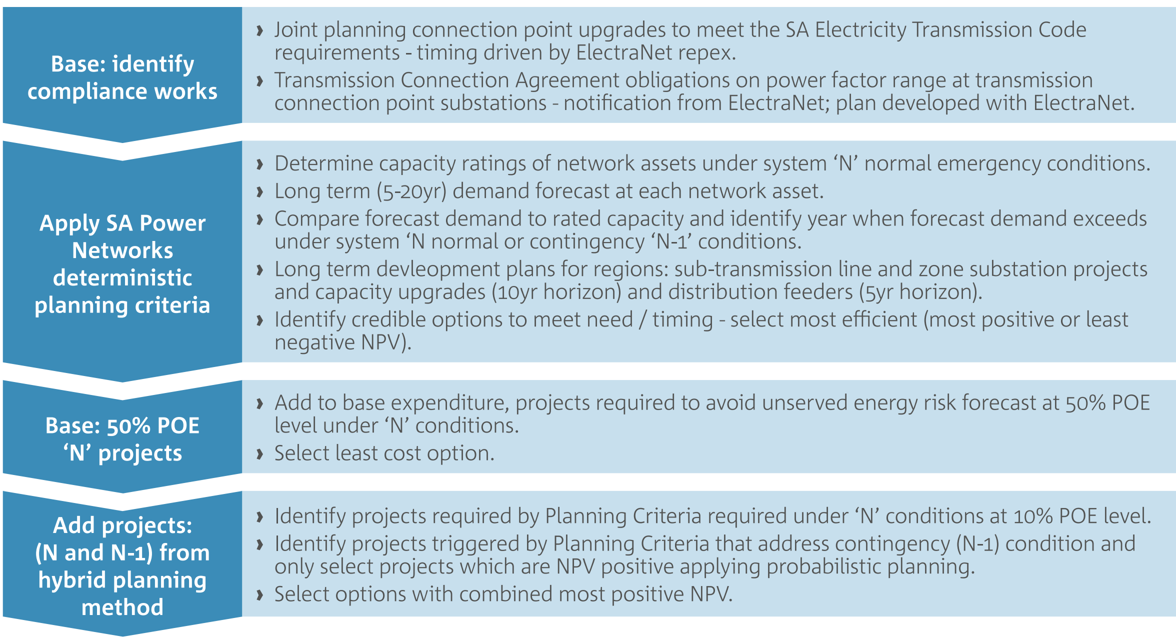


Expenditure forecasting approach

We typically apply our long-standing Distribution Network Planning Criteria to comply with service obligations in the SA Electricity Distribution Code, Distribution Licence, and NER. This planning approach considers when forecast network demand will breach capacity, requiring augmentation (network or non-network solutions). However, while we consider that this approach provides optimal long-term consumer outcomes, balancing service risk and cost, through top-down challenge we decided to apply an additional layer of economic / probabilistic analysis[19] to our expenditure forecast for 2025-30, with a view to:

- responding to the general affordability concerns expressed by our customers;
- erring on the side of conservatism, while we evaluate the significant demand growth now forecast by AEMO for South Australia, and the potential for non-network alternatives and flexible load connections to manage this demand; and
- to reduce the rate of workforce scale-up required to deliver our overall capital program in 2025-30.

Figure 22: Expenditure forecasting methodology



[19] This is a balanced but cautious approach for 2025-30 that we will re-evaluate longer term, given we retain concerns that the current regulatory framework and regulatory practice inadequately deals with and values High Impact Low Probability **(HILP)** events and Wide Area Long Duration Outages **(WALDO)** – noting that no WALDO VCR currently exists, nor agreement on the priority that should be given to projects that address HILPs and WALDOs.

The identified customer service needs

Base expenditure: Compliance – connection point upgrades

The need is to comply with regulatory requirements on joint planning with ElectraNet, to meet and manage customer demand and maintain security of supply of our services and system. Neither a BAU option of maintaining 2020-25 spend levels nor a 'do-nothing' option is sufficient to meet the need in 2025-30 noting:

- in 2020-25 we will spend less (upgrade less sites) than expected due to ElectraNet deferring some works;
- the need for increased expenditure in 2025-30 is forecast 'bottom-up', directly driven by information concerning our joint planning obligations and connection point agreements with ElectraNet; and
- under these scenarios we will not comply with the Transmission Connection Agreement (**TCA**), due to changing network load causing transmission over-voltage and compromising system security – driven by changing customer in-house appliances.

Base expenditure: Compliance – LV quality of supply

The need is to remediate LV supply to address non-compliant supply points driven via reactive response to customer enquiries, to progressively address existing areas of non-compliant overvoltage attributed to current levels of CER up-take, and expenditure to maintain thermal limits of distribution transformers.

We need to continue to address trends of reactive customer enquiries and maintain reliability of distribution transformers. Continuing current expenditure will be insufficient to address all existing areas of non-compliant overvoltage attributed to current CER up-take, but it ensures ongoing progress to compliance expected to sufficiently avoid increases in reactive customer enquiry volumes.

Base expenditure:	Hybrid planning expenditure:	Hybrid planning expenditure:
'N' projects justified at 50 POE;	Deterministic planning: 10% POE projects under normal operating conditions	Probabilistic planning: N-1 contingency projects

All these projects serve the same identified need, but at different operating conditions. The underlying investment driver is a forecast strong increase in customer demand that will exceed the intended operating conditions of our assets, triggering the need to upgrade or extend our network, to accommodate demand.

Undertaking only base and largely compliance expenditure, will degrade service levels, resulting from: increasing periods and quantity of customers load-shed (increasing unserved energy); decreasing capacity to maintain supply security during contingencies or planned maintenance; and compromising between asset condition and supply security (i.e. avoiding load shedding by operating assets outside their design ratings).

The preferences of our customers

Preferences recommended up to Draft Proposal

We engaged on the needs, expenditure, and price impacts with customers via Focused Conversations where we presented three scenarios of varying expenditure and resulting service effects.

Focused Conversations recommended to the People's Panel that we invest to achieve service outcomes that: maintain current emergency network backup capability (for HILPs), use the same established approach since before privatisation to identify investment needs with increasing demand; and maintain long term security of supply to current standards.

The People's Panel deliberated on and affirmed the Focused Conversation recommendation in its formal recommendation to us.

Preferences recommended post Draft Proposal

Submissions confirmed the People's Panel recommendations as valid, despite continued cost of living pressures, noting:

- members of the People's Panel affirmed that their recommendations, including in respect of security of supply / capacity expenditure remain current; and
- SACOSS noted that it supports maintaining current reliability levels and efforts driven by compliance.

The SA Government's DEM considered that we should identify savings on our capacity expenditure and sought further information on why these needs should apply in 2025-30 – our business case now evidences the prudency and efficiency of undertaking our forecast expenditure.

Our proposal and its efficiency for customers

OUR FORECAST	SERVICE LEVEL OUTCOME	EFFICIENCY FOR CUSTOMERS
Overall: $240.9m		
BASE EXPENDITURE		
	Maintain compliance with regulatory obligations, and maintain quality of supply.	**Least cost** solutions
HYBRID PLANNING EXPENDITURE		
While committing to adopt the People's Panel recommendation, we have also been mindful through engagement and feedback on our Draft Proposal, of the affordability concerns of customers and their general expectation that proposed expenditures are efficient and prudent and supported with analysis to justify their necessity in 2025-30. Therefore, we adopted a hybrid approach to our forecast, incorporating probabilistic analysis. With this analysis we removed several projects addressing single contingency (N-1) network conditions, that would otherwise have been required to comply with our Planning Criteria.	Maintains supply reliability, security, quality, and compliance with regulatory requirements.	**Benefits outweigh costs** with an NPV result of $717.3m over 20 years. Option is preferred to alternatives: › the base expenditure only; and › undertaking all projects triggered by our deterministic planning criteria (with a lower NPV).

9.2.2 Powerline Environment Committee Program (PLEC)

Capex $38.4 million

1.6% of total capex

We forecast $38.4 million to continue to deliver 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.[20] The program is part of our long-standing jurisdictional government obligations stipulated in legislation and a PLEC Charter.

Over the last two RCPs, we have forecast PLEC capex based on historic expenditure, and we forecast to spend $36.7 million in 2020-25.

For 2025-30, our forecast continues to be based on historic expenditure, applying an annual forecasting method prescribed in regulation, which results in our forecast being slightly below our expected actual 2020-25 spend.

Expenditure forecasting approach

Expenditure is forecast on a top-down basis as summarised in Figure 23.

Figure 23: PLEC expenditure forecasting methodology

OTR direction	› Each year the SA Office of the Technical Reguator (OTR) specifies the prescribed amount of PLEC expenditure that we must spend. › Calculation is based on historic expenditure adjusted according to a formula prescribed in regulations.
Identify total works and SA Power Networks portion	› PLEC expenditure forecast is based on historic expenditure. › We are required to undertake works equivalent to two thirds of the total OTR specified annual PLEC budget, with local Councils providing for the remaining third of the budget.
Estimate contributions	› During the RCP, works undertaken by SA Power Networks on behalf of Councils, will receive a capital contribution from Councils. › Forecast contributions have been based on historic contributions.

The identified customer service needs

PLEC program

The need is to continue to comply with our jurisdictional obligations and requirements under the PLEC Charter. The PLEC program is an 'un-scoped' allowance, and projects are approved by an independent committee convened by the SA Government's Office of the Technical Regulator **(OTR).** Construction will be completed via a competitive tender process.

[20] This forecast is net of forecast contributions, following the methodology set out in Figure 23.

9.2.3 Network resilience

Capex $8.2 million

0.3% of total capex

Our forecast of $8.2 million comprises a small-scale program of procuring and deploying 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.

During 2020-25, recent and escalating extreme weather events, both locally and interstate raised stakeholder concerns about the resilience of various communities to these events and have made the issue of long-duration supply interruptions of central importance to our customers. Customers also observe that increased electrification, particularly transportation, will make network resilience increasingly important.

Figure 24: Key weather factors of concern for South Australia[21]

Heat

The number of hot days increasing

No. of very hot days (>40°C) increase from **2 to 6 days/year** in Adelaide between now and 2050, leading to potential:

- Increase in peak electricity demand
- Increase risk of network fire starts
- Increased health impacts of power outages, including form coincident storm or bushfire events

Bushfire

Longer, riskier fire seasons

Longer fire seasons, with **~40%** more 'very high' fire danger days between now and 2050, leading to potential:

- Increase risk of network fire starts
- Increased risk of prolonged power outages (due to Public Safety Power Shutoffs, bushfire damage, and delayed access for repairs)

Rainfall and flood

Lower total rainfall projected, but extreme rainfall to increase

By 2030 total annual rainfall across SA projected to decline by **4.4-9.0%** - but the amount of rain falling in extreme rainfall events will increase and the frequency of extreme rainfall will increase between now and 2050, leading to potential:

- Increased risk of prolonged power outages (due to asset damage and delayed access for repairs)

Apart from managing risks of bushfires and extreme heat via our ongoing programs, we currently lack sufficient confidence in climate change model forecasts to accurately predict specific impacts on our network and customers. Consequently, we believe it is prudent to be cautious in 2025-30, refraining from substantial upfront spending on network resilience[22] and community resilience until we gain greater certainty and justification based on more reliable climate change information.

Our approach to resilience in our overall Regulatory Proposal is to propose:

- **conservatism on climate** - not use climate change forecasts to justify proposed expenditure, and instead err toward conservatism by using these forecasts exclusively as a sensitivity test of the assumptions supporting our network expenditure;
- **a modest resilience program** - investing in additional mobile generators, to address customer concerns on existing issues regarding long duration power outages in regional and remote areas based on historic network performance – a program that is also likely to provide additional flexibility should climate change lead to increased frequency of extreme weather events; and
- **an Innovation Fund** - which may consider resilience expenditure to trial alternative solutions and partnerships with third-parties, to improve the customer experience during extreme weather and other events that may cause long duration outages.

21 Rainfall and flood data from Climate Change Australia (CSIRO) summary of weather for South Australia – forecasts are for 2050, and data from SA Climate Ready Initiative – using a baseline period of 1981 to 2010. Heat data draw on examples of common climate risk and their impacts (NSW/ACT/TAS/NT Electricity Distributors Network Resilience: Collaboration Paper 2022).

22 Network Resilience refers to enhancing the network's ability to withstand or recover from major weather events.

Expenditure forecasting approach

Expenditure was forecast 'bottom-up' as detailed in our business case, with Figure 25 summarising key steps.

Figure 25: Network resilience expenditure forecasting methodology

Historic outages	Conducted high level review of historical outages over past 12 years to identify sample set of past outages where mobile generation could have been used to reduce extent of the customer interruptions.
Assigning areas	Outages were assigned to seven areas, based on the separate areas where a mobile generator could be located to manage long-duration outages in that area.
Frequency and consequence	Outages assigned to each area were used to estimate average frequency and consequences of customer interruptions in each of the seven areas.
Annual usage	This information was used to estimate the average annual mobile generation usages for these seven areas.
Expenditure and benefits	For each of the 7 areas, capex and opex (including maintenance and average usage) costs of the generation and the benefit of this usage in terms of economic value of avoided interruption to customer supply, using the AER VCR were calculated.
CBA	Costs and benefits of using the mobile generator in each of these areas was applied to identify the locactions where there will be a net benefit in using mobile generation and this was tested with sensitivity analysis

The identified customer service needs

The need is to address concerns raised by customers in relation to long-duration outages in regional and remote areas and the downstream impact of these outages on other critical services.

We acknowledge community resilience is the responsibility of many stakeholders and that SA Power Networks is only one part of this. While we focus this program on earlier restoration for towns and regional centres where many critical services are located, we assessed the costs and customer benefits and put forward an investment option that provides a net benefit.

This program may be complemented by using our proposed Innovation Fund to trial alternative solutions and partnerships, to improve the customer experience with regards to long duration outages in these areas.

The preferences of our customers

Preferences recommended up to Draft Proposal

The program's identified need, expenditure and price impacts were discussed with customers in Focused Conversations where we engaged on three scenarios of varying spend and effects on service.

The Focused Conversation recommended to the People's Panel that we invest sufficiently to: reduce the impact of long-duration outages on regional and remote communities; and investigate innovation and partnerships to build network and community resilience.

The People's Panel then deliberated and affirmed this recommendation in its formal recommendation to us.

Preferences recommended post Draft Proposal

Submissions confirmed the People's Panel recommendations as valid, despite continued cost of living pressures:

- members of the People's Panel affirmed that their recommendations, including in respect of resilience expenditure, remain current;
- several submissions supported the program in order to assist exposed regional customers, including: the Regional and Remote Customers CAB Sub-Committee who oversaw regular engagement with us on resilience; the SA Government DEM; the Small Business Commissioner; and
- an individual's submission, wanted greater action on climate change and resilience than we propose.

Our proposal and its efficiency for customers

OUR FORECAST	SERVICE LEVEL OUTCOME	EFFICIENCY FOR CUSTOMERS

\$8.2m to procure 3 mobile generators, with 2 located in key regional areas (Upper North, South East) and one to provide capacity to regional areas closer to Adelaide – combined capacity of 9MVA.	Improves average outages of 6.58 per annum, covering 10,050 customers on average per annum.	• **Benefits outweigh costs**, with an NPV outcome of \$13.4m over a 20 year period. It is preferred to alternatives including:
		  • doing nothing; and
		  • investing in generators to cover all 7 of the regional areas considered – with a lower NPV.
		• Customer Values Research also indicates the broader customer base is on average **willing to pay** for improved resilience to long duration outages (i.e, willing to subsidise service for regional customers).

9.2.4 Reliability management programs

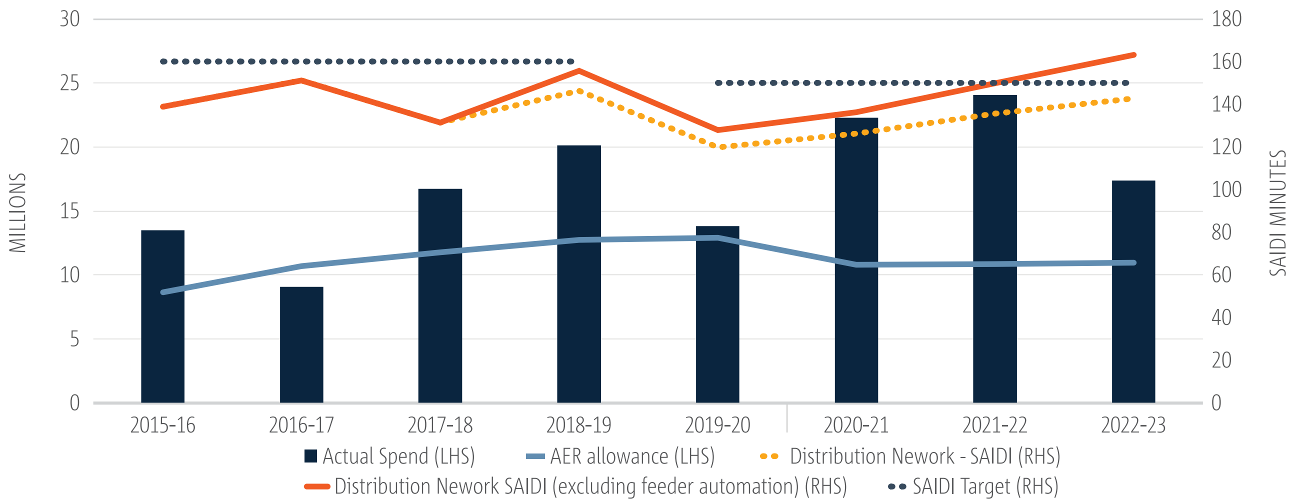
Capex $103.1 million

4.2% of total capex

Our reliability augex forecast of $103.1 million seeks to manage reliability via network upgrades. It comprises several programs responding to non-asset condition related causes of outages (as distinct from repex) such as weather, vegetation, and animal contact, via network upgrades to reduce outage causes and customer interruptions, and thereby maintain or improve reliability where needed for compliance, or efficient for customers.

In 2020-25 we forecast spending $87.0 million, a 58.9 percent increase on the AER forecast, driven mainly by our recurrent maintaining underlying reliability program, which we directed to address escalating outage causes. Despite increasing spend, overall duration of interruptions continued to increase as Figure 26 shows.

Figure 26: Distribution system reliability performance (excluding Major Event Days) vs actual expenditure[23]



The 2025-30 forecast mainly continues our recurrent program to maintain underlying reliability and thereby offset service degradation from trends of weather and third-party causes, with analysis indicating that these trends will continue. The forecast is an 18.6 percent increase on 2020-25, reflecting our intent to now also respond to declining performance on our jurisdictional supply restoration targets, and strong customer preferences for targeted and efficient improvements for worst served customers. This comprises:

- a recurrent program to 'Maintain Underlying Reliability' on the network; and
- targeted programs within a 'Reliability Integrated Worst Served Customers Improvement Programs' case:
    1. Rural Long Feeders Supply Restoration Improvement;
    2. Regional Reliability Improvement; and
    3. Low Reliability Feeders Improvement.

Table 9: Augex reliability - key achievements in 2020-25

	What we achieved in 2020-25	Benefits to customers in 2025-30
Grey Headed Flying fox (bat) review	Commissioned review of bat colonies in SA which indicates the colonies' population and that the number of colonies is likely to increase.	Confidence the 'maintain underlying reliability' program will address recent service decline and maintain rather than improve reliability.
Jurisdictional service standards	Complied with standards (spending above the AER forecast) via our Underlying Reliability Program, except in the CBD where asset condition is degrading service.	Minimises expenditure required to bring service back up to standard.

[23] Figure displays the implied jurisdictional SAIDI target for the distribution system overall, if each of the feeder level targets were summed – noting jurisdictional targets are set at a feeder category level.

Expenditure forecasting approach

The Maintain Underlying Reliability program is forecast top-down, as detailed in our business case and as summarised in Figure 27.

Figure 27: Forecasting methodology - Maintain underlying reliability program

Historic outages	Analysed historical outages relative to reliability expenditure undertaken in aggregate (excluding MEDs) to understand if current outage causes will persist going forward or if they are being mitigated.
Outage drivers	Engaged experts to undertake assessment of grey-headed flying foxes to understand if populations are expected to persist and grow in 2025-30.
Top down assess	Relationship between historic reliability expenditure and network performance projected forward to determine if on-going expenditure is required to maintain reliability at historical levels (consistent with STPIS target in 2025-30 and jurisdcitional service standard feeder category targets).

Reliability improvement programs were forecast bottom-up via detailed review of historical outages and cost benefit analyses, as covered in our business case and as summarised in Figure 28.

Figure 28: forecasting methodology – worst served customers reliability improvement programs

Historical Analysis	Analysed historical reliability performance to identify worst served customers and those vulnerable to extended outages, recurrent outage causes affecting these customers, the reliability impact of these outages, and the improvements in reliability achieved via previous reliability projects
Options	Developed options to address specific recurrent outage causes and/or reduce customer numbers interrupted - and/or interruption duration, including the scoping of these options, the development of a cost estimate for the option, and the estimate of the expected improvement in reliability that will be achieved by that option.
Evaluation	The evaluation of the options using formal cost-benefit analysis techniques to develop a preferred solution and program that maximises the net-customer benefit of the program.
STPIS and Opex	The analysis of the STPIS and supply restoration Opex implications of the preferred program to determine the proportion of the program expenditure that could be covered by these mechanisms and the relevant adjustments to the settings of these mechanisms.
Interaction	The preferred program and benefits are cross-checked with other programs to ensure there is no double counting of program elements and the expected benefits of the program or the other programs have been allowed for.

The identified customer service needs

Maintaining underlying reliability program

We need to maintain underlying reliability at historic levels and to continue to meet jurisdictional standards, in line with AER service incentives and jurisdictional requirements for 2025-30. Our BAU approach and expenditure broadly equivalent to 2020-25, is sufficient to maintain underlying reliability. Our analysis considers historic reliability spend versus service levels and trends, suggesting our historic spend would reasonably reflect ongoing needs to maintain reliability on average:

- our augex has increased historically, and in 2015-20 this saw improvement in underlying reliability;
- more recently in 2020-25, reliability has been worsening, partly due to increasing animal (bats) and weather related outages; and
- without continuing the underlying reliability program at historic levels, the duration of interruptions (measured on SAIDI) Is forecast to worsen by 20 to 30 minutes over the 2025-30.

Rural long feeders supply restoration improvement program

We need to respond efficiently to customers' concerns on extended duration outages in remote network areas and to meet jurisdictional supply restoration targets for Rural Long Feeders **(RLFs).** If we do nothing, a long term decline would continue in average restoration times of customers on RLFs, and jurisdictional targets for these feeders would continue to not be meet due to several factors:

- increasing network asset condition related failures;
- damage to assets caused by third parties; and
- these fault types (repairing fallen poles and wires) taking longer to repair than weather related outages (which may involve replacing lightning damaged insulators).

Low reliability feeders improvement program

We need to efficiently respond to customers' concerns on the consistently low reliability experienced by worst served customers supplied by our network. If we do nothing, customers on low reliability feeders **(LRFs)** (mainly in rural / remote areas) in 2025-30 will continue to experience repeatedly poorer reliability, more than double their regional average. We expect to have 81 feeders consistently classified as 'low reliability feeders' under jurisdictional regulation, at the start of 2025-30, feeders with an average SAIDI 142 percent worse than their regional average.

Regional reliability improvement program

We need to efficiently respond to customers' concerns for improving reliability in our worst served regions. If we do nothing, three regions (South East, Eyre Peninsula, Upper North) would continue to experience reliability significantly worse than the other seven regions (excluding Adelaide CBD and metropolitan) that we report to the Essential Services Commission of South Australia (**ESCoSA**) on.

The preferences of our customers

Preferences recommended up to Draft Proposal

We engaged customers on the identified needs, expenditure, and price impacts in Focused Conversations, and presented three scenarios with higher/lower spend and forecast reliability impacts. Focused Conversations recommended to the People's Panel that we pursue all programs. While mindful of affordability, customers wanted service to not degrade, and some targeted improvements for greater equity in service provision across our network.

The People's Panel deliberated on and affirmed the Focused Conversation recommendation to us.

Preferences recommended post Draft Proposal

Submissions confirmed the People's Panel recommendations as valid, despite cost of living pressures:

- members of the People's Panel affirmed that their recommendations, including on reliability augex programs remain current;
- SACOSS noted that it supports maintaining current reliability levels, and the SA Government's DEM specifically noted that it supports expenditure on the Maintaining Underlying Reliability Performance program;
- the Small Business Commissioner of SA supported all reliability programs noting the importance of reliable service outcomes for small businesses and their customers; and EWOSA supported our proposed service levels and expenditure to support a reliable, resilient and safe network, which include the reliability programs, as being in the best interests of the South Australian community.

Our proposal and its efficiency for customers

OUR FORECAST	SERVICE LEVEL OUTCOME	EFFICIENCY FOR CUSTOMERS
MAINTAINING UNDERLYING RELIABILITY		
$72.1m to continue recurrent program of network upgrades	Maintain underling reliability at historic levels and comply with regulatory obligations.	**Benefits outweigh costs.** Program is preferred to doing nothing which would decline reliability costing customers $225-280m.
LOW RELIABILITY FEEDERS IMPROVEMENT PROGRAM		
$10.5m on remediations specific to each feeder and outage causes on 67 of the 81 feeders expected to be 'LRFs'. Program selects 'optimal feeder improvements' being 67 feeders where improvements can be efficiently applied.	Improve reliability by 31% (average feeder USAIDI). Improve reliability for 67 low reliability feeders and 35,360 customers.	**Benefits outweigh costs,** with NPV result of $17.7m. Option is preferred to alternatives: › doing nothing; › improving all LRFs (lower NPV result).
REGIONAL RELIABILITY IMPROVEMENT PROGRAM		
$15.6m to bring performance for worst served regions more in line with similar regions via remediations specific to outage causes on feeders most impacting those regions – addressing current outage causes or reducing customer numbers interrupted when outages occur. Target 'optimal feeder improvements of 3 regions' being 52 feeders where it is efficient.	Improve reliability to 23,530 customers in three regions: › Eyre Peninsula – 10% SAIDI and 10% SAIFI improvement; › Upper north: 10% SAIDI, and 5% SAIFI improvement › South East: 5% SAIDI and 6% SAIFI.	**Benefits outweigh costs** with NPV outcome of $43.4m. Option is preferred to alternatives: › doing nothing; › undertaking optimal feeder improvements of only Eyre Peninsula and Upper North which (lower NPV result).
RURAL LONG FEEDERS SUPPLY RESTORATION IMPROVEMENT PROGRAM		
Forecast $5.0m, to make efficient and prudent progress to meeting SA EDC targets for RLFs, feeders where it is efficient to improve supply restoration times.	Improve reliability (15% average CAIDI improvement) for 44 feeders supplying 10,230 customers.	**Benefits outweigh costs** with NPV outcome of $6.7m. Option is preferred to alternatives: › doing nothing; › undertaking all feasible feeder improvements (lower NPV).

9.2.5 Bushfire risk management programs

Capex $25.6 million

1.0% of total capex

Our forecast of $25.6 million seeks to manage bushfire risk by upgrading assets. These comprise: a program to **mitigate risk of our assets starting bushfires** – as distinct from management of bushfire risk achieved via our repex program which maintains risk posed by condition based asset failures to current levels; and a program to **reduce customer supply interruptions** arising from our public safety power shutoffs at bushfire risk times.

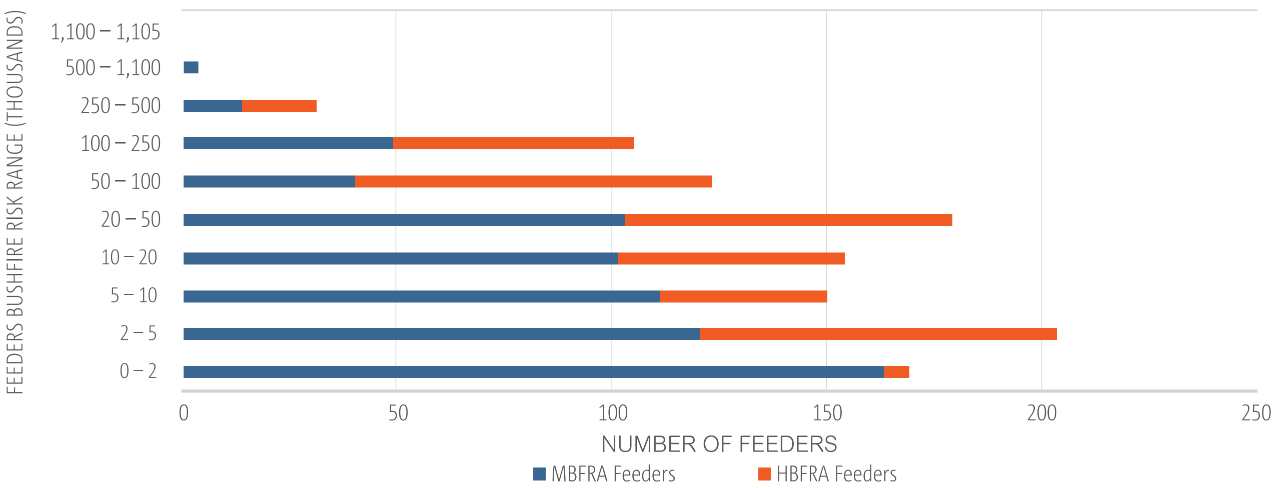
In managing bushfire risk in 2020-25, we expect to spend $11.5 million, broadly aligned to the AER forecast. The saving (circa $1.5 million) relative to the AER forecast arose from efficiencies in sequencing and bundling works and optimisation between repex and augex solutions, while still achieving the same level of bushfire risk reduction we had planned. Our expenditure covered programs to mitigate bushfire risk by implementing ultra-fast fault clearance and replacing fire-prone surge arrestors, and focused on feeders in designated High Bushfire Risk Areas, being the areas for which we had risk modelling available.

Table 10: Augex bushfire - key achievements in 2020-25

	What we achieved in 2020-25	Benefits to customers in 2025-30
Risk mitigation coverage	Achieved proposed level of risk reduction with lower spend.	Confidence we can efficiently target risk, and trust we use best endeavours to deliver our plans. Also, avoids pushing higher costs or underlying safety risk onto customers in 2025-30.
Risk modelling enhancements	Extended our risk modelling into Medium Bushfire Risk Areas and re-evaluated risk across High and Medium Bushfire Risk Areas with updated data.	Allows a more accurate view of risk that can be prudently and efficiently minimised for customers.

For 2025-30, our forecast 121.9 percent increase in expenditure is mainly driven by the need to extend our bushfire risk mitigation efforts into Medium Bushfire Risk Areas, for which analysis indicates there are significant opportunities to prudently and efficiently mitigate safety risk.

Figure 29: Distribution of bushfire risk across modelled feeders



Expenditure forecasting approach

Expenditure was forecast bottom-up, as detailed in our business case and summarised in Figure 30 and Figure 31.

Figure 30: Bushire risk mitigation expenditure forecasting methodology

Feeder risk	Calculate bushfire risk of individual feeders (undertaken by the CSIRO).
Costs and benefits	Calculate each feeder's upgrade option cost and benefit in terms of bushfire risk reduction.
Total C&B	Calculate the total option cost and benefits across all feeders, only including feeder upgrades with a net benefit
Option selection	Select option that maximises the net benefit and aligns with customer preferences.

Figure 31: Public safety power shutoff mitigation expenditure forecasting methodology

Exposed segments	Identify communities and network segments susceptible to service interruptions caused by Public Safety Power Shutoffs to reduce bushfire risk.
Value	Quantify economic value of the foregone reliability of each community's potential interruptions.
NPV analysis	Evaluate costs and benefits associated with upgrades to prevent or reduce service interruptions in each community and perform cost-benefit analysis. Exclude upgrades which do not have a positive net benefit.
Select option	Select preferred level of investment consistent with customer preferences

The identified customer service needs

Bushfire risk mitigation program

We need to address customers' concerns and reduce the risk of our network assets starting bushfires, where efficient. To date, we have only undertaken bushfire mitigation programs targeting High Bushfire Risk Areas. However, recent analysis undertaken for us by the CSIRO indicates the opportunity exists to further reduce risk, largely in Medium Bushfire Risk Areas, and it would be prudent and efficient to do so – avoiding risk of property damage, crop loss and personal harm.

Public safety power shutoff mitigation program

We need to address customers' concerns, and reduce customer impacts of Public Safety Power Shutoffs, where power is disconnected on the highest bushfire risk days. Currently, our BAU approach is that at times of high bushfire risk, we have authority to switch off power to feeders. While this mitigates risks during bushfire risk times, it costs customers via reduced reliability. If we do nothing, there would continue to be lost value / negative benefits to customers via poorer reliability outcomes than would otherwise be the case.

The preferences of our customers

Preferences recommended up to Draft Proposal

We engaged customers on the needs, expenditure, and price impacts in Focused Conversations, presenting three scenarios with higher/lower expenditure and resulting safety risk outcomes. Focused Conversations recommended to the People's Panel that we invest sufficiently to further mitigate bushfire risk where efficient for customers, and to minimise reliability impacts when bushfire safety power shutoffs are enacted.

The People's Panel endorsed the recommendation in its formal recommendation to us.

Preferences recommended post Draft Proposal

Submissions confirmed the People's Panel recommendations as valid, despite cost of living pressures:

- members of the People's Panel affirmed that their recommendations, including on bushfire risk mitigation expenditure, remain current;
- the SA Government's DEM noted that it specifically supported the Bushfire Risk Mitigation Programs where these are suitably targeted and efficient – our proposal justifies both programs as being efficient;
- members of the Regional and Remote Customers Sub-Committee of the CAB affirmed that we struck a reasonable balance of affordability and service, and it supported the Bushfire Risk Mitigation Programs;
- EWOSA believes all of our proposed service levels and expenditure to support a reliable, resilient and safe network (including Bushfire Risk Mitigation Programs) are in consumers' best interests; and
- the Arborists Reference Group indicated the Public Safety Power Shutoff Mitigation program was an appropriate alternative to undergrounding and that this reflected a good focus on customer service.

Our proposal and its efficiency for customers

OUR FORECAST	SERVICE LEVEL OUTCOME	EFFICIENCY FOR CUSTOMERS
BUSHFIRE RISK MITIGATION PROGRAM		
$21.6m to mitigate bushfire risk where efficient, by implementing ultra-fast sensitive protection on 239 feeders to reduce the risk of a fire start.	Manage / maintain network safety risk, and comply with regulatory obligations / requirements	**Benefits outweigh costs,** with NPV result of $322.6m over the life of the assets involved in the program. Option is preferred to alternatives: › doing nothing – increases bushfire start likelihood; and › alternative investments which either have a lower NPV or higher NPV but higher capex.
PUBLIC SAFETY POWER SHUTOFF MITIGATION PROGRAM		
Forecast $4.0m, to target an efficient level of consequence mitigation, (i.e. 'optimal program' option). Implement remote operated switchgear and targeted powerline upgrades / undergrounding to maintain supply to high risk regions.	Maintain safety, regulatory compliance, and efficient reliability improvement. Reduces customers interrupted by 11,250.	**Benefits outweigh costs** with an NPV result of $10.5m over the life of the assets involved in the program. Option is preferred to alternatives: › doing noting – with no reliability improvement; and › a 'full program' with extended coverage – higher cost and lower NPV.

9.2.6 Augex - other

Capex $63.0 million

2.6% of total capex

Our forecast of $63.0 million for 'augex- other' comprises a diversity of small scale initiatives largely driven by compliance requirements.

These include:

- 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.

Expenditure forecasting approach

Expenditures are largely recurrent and based on a mix of top-down and bottom-up analysis, as per Table 11.

Table 11: Expenditure forecasting approach: augex - other

Program	Forecasting method
Safety	
Substation lighting program	Top-down based on historic expenditure, with regard to the number of sites required to complete the long term program of remediating risk assessed sites.
Substation security and fencing program	Top-down based on historic expenditure, with regard had to the expenditure level needed to continue to address identified highest risk sites.
Substation infrastructure – earthing systems program	Top-down based on historic expenditure, with adjustment to account for new cost sharing agreements with ElectraNet on shared sites.
CBD site safety program	Top-down based on historic expenditure, with regard to higher costs of addressing sites with more complexity and safety risk.
Protection systems compliance program	Top-down and bottom-up modelling with regard to increasing complexity to address compliance on remaining known parts of the network and deliver the program over the next two RCPs.
Environment	
Oil containment program	Top-down based on historic costs, with regard to the site scope coverage required to achieve construction of compliant oil containment systems at all sites by 2030.
Strategic	
Under Frequency Load Shedding Standards Program	Bottom up based on the identification of 30 additional feeder exits needing protection relay replacement in 2025-30 to meet requirements of the Voltage Management & Under Frequency Load Shedding Emergency Standard expected to be required by the South Australian Office of Technical Regulator.

The identified customer service needs

Safety

Substation lighting program

We must ensure that substations have sufficient egress lighting so personnel can safely exit if primary lighting fails. Not all of substations have sufficient emergency lighting and this poses risk of physical harm.

Substation security and fencing program

There is an ongoing need to progressively respond to the assessment that circa 220 substation sites have insufficient security with respect to fencing and surveillance, and that this is a public safety risk (via break-in or inadvertent entry) as well as a risk of theft of electrical assets.

Substation infrastructure – earthing systems program

There is an ongoing need to ensure our network contains functioning / appropriate earthing systems, to avoid harm to workers and the public and risks of maloperation of protection schemes, and to comply with obligations. Earth Potential Rise and associated step and touch potentials are not only a risk within substation boundaries, but include nearby publicly accessible areas and adjacent telecommunication infrastructure. To ensure earth grids meet safety requirements, ongoing condition monitoring and remediation is needed.

CBD site safety program

This program addresses safety and compliance risk from inadequate electrical clearances, poor access in substations, absence of emergency exits, inadequate ventilation and other hazards. 33kV substations in the CBD are typically in tight spaces and/or building basements, with many installed in high-rise CBD commercial and office areas, typically in consumers' premises. These sites are typically inadequate to house modern 33kV transformers and switchgear. The larger size of 33kV vs 11kV assets means clearance needs often cannot be met with modern 33kV assets. Converting sites to 11kV addresses safety risk for personnel. Where site hazards can be addressed with modern 33kV assets, sites may be retained on the 33kV network if efficient.

Protection systems compliance program

We need to invest in backup protection due to inadequacies in several network areas (particularly rural) that have no backup protection systems. Having backup protection is an obligation. These systems clear electrical faults when primary protection systems fail to. The inadequacy of backup protection was identified via a system assessment. If primary protection fails, conductors and / or distribution transformers beyond these locations will be destroyed because no backup protection exists to clear the initial fault, causing outages and repairs to the impacted network area. Failure to have / insufficient backup protection, poses a damage risk to other parts of the network (beyond where a fault occurs), a safety risk to personnel, the public, and livestock.

Environment

Most zone substations in our network contain assets with oil filled equipment, a standard feature historically and likely to remain so in the foreseeable future. The ongoing action required is to ensure reasonable steps are taken to avoid oil leaks leading to environmental pollution, in compliance with environmental regulations.

Strategic – under frequency load shedding standards program

We must comply with requirements stipulated by the OTR in its Voltage Management & Under Frequency Load Shedding Emergency Standard. The OTR is expected to update this Standard in 2024 to reflect the continued increase in CER since 2021, triggering the need for us to undertake further augmentation to our network by installing additional relays at specific points.

The preferences of our customers

Preferences recommended up to Draft Proposal

The identified needs of these programs were not specifically deliberated on in our engagement process given that, together with our CAB, they were considered to not be priority topics, under a desire to 'focus on what matters' most to consumers.

However, in our engagement program, our customers were consistently concerned with the need to comply with regulatory obligations and ensure that the distribution network and system remains stable and secure as a foundation for the future, and remains safe to our workers and the public.

Further, all program costs were included in the total expenditure stack presented to consumers in each engagement stage to enable transparency on the totality of the service, expenditure and price trade-offs being deliberated.

Preferences recommended post Draft Proposal

Submissions on our Draft Proposal did not comment on the needs of these programs. However, SACOSS outlined support for expenditure to maintain current core reliability and service levels and to meet our regulatory obligations.

Our proposal and its efficiency for customers

OUR FORECAST	SERVICE LEVEL OUTCOME	EFFICIENCY FOR CUSTOMERS
SAFETY		
› **Substation lighting program:** $0.4m to continue program › **Substation security & fencing program:** $14.9m to continue program › **Substation earthing systems program:** $7.3m to continue program › **CBD site safety:** $10.3m to continue program › **Protection systems compliance program:** $16.3m to continue program	Maintain safety levels and compliance	**Least cost** solution
ENVIRONMENT		
Oil containment program: $8.5m to continue compliance program	Maintain compliance	**Least cost** solution
STRATEGIC		
Under Frequency Load Shedding Program: $3.5m to target 30 feeders identified in load shedding technical regulatory requirements	Comply with obligation	**Least cost** solution

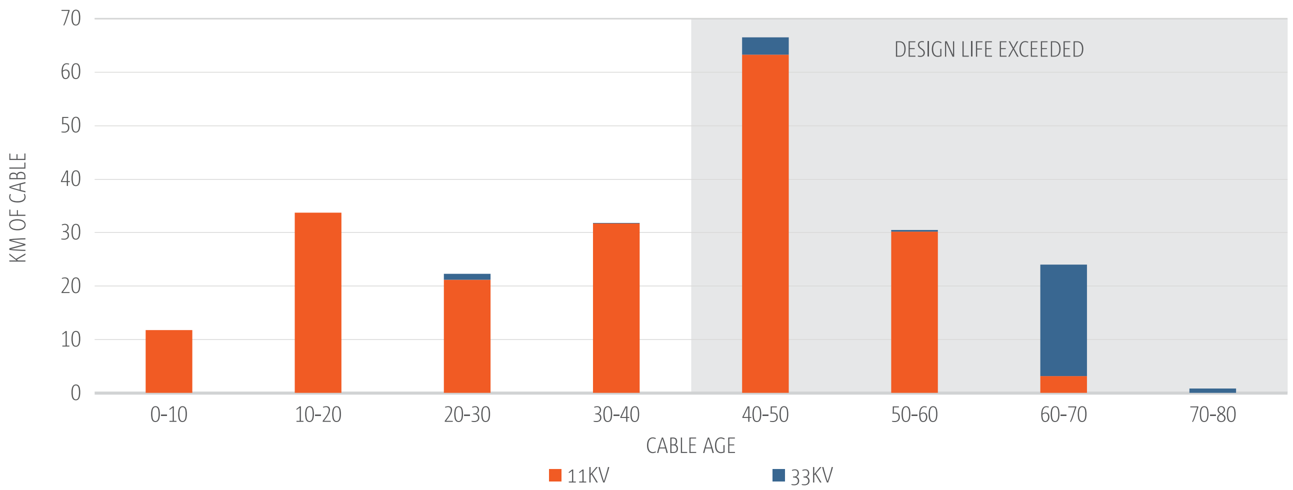
9.3 CBD reliability improvement program

Capex $90.5 million

3.7% of total capex

This program is not an expenditure category, and comprises repex and augex. It is summarised here as it was a material topic for customers in our engagement. We forecast $90.5 million to replace underground cables ($63.5 million repex) and install automated load switches ($27.0 million augex), to improve CBD network reliability to comply with jurisdictional service standard targets set by ESCoSA.

Figure 32: Adelaide CBD cable network - age profile



Our practice has been to run underground CBD cables to failure with minimal proactive investment, which was prudent and efficient when assets had a lower age. The CBD now has our oldest underground network, with the age profile shown in Figure 32. In 2020-25 we spent to improve risk visibility and enable automation, and increased proactive cable replacement in response to increasing failures. However, despite forecasting to spend $46.5 million on CBD assets, we failed to meet jurisdictional targets (as shown in Figure 33), due to cable failures.

Figure 33: Historical SAIDI performance of Adelaide CBD vs ESCoSA target

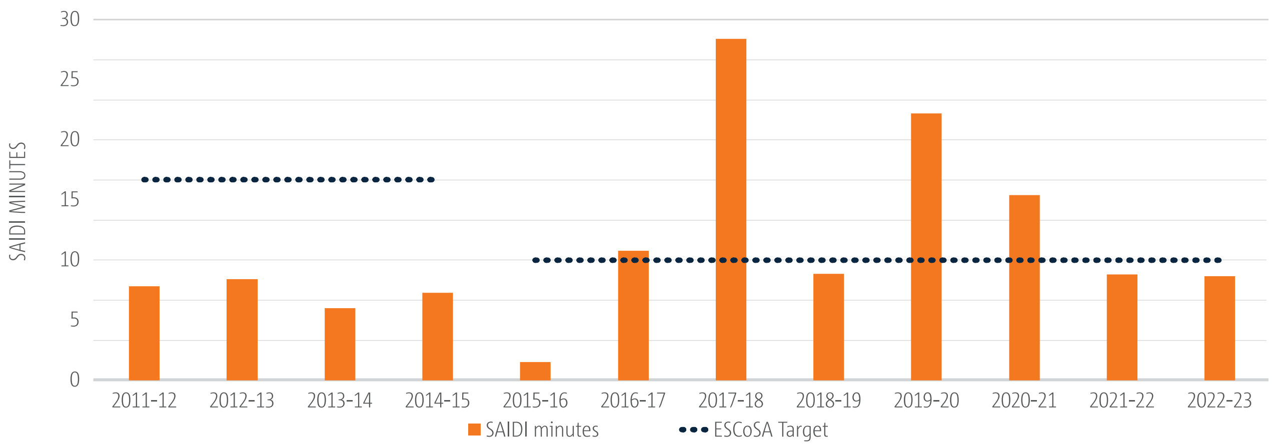


Table 12: CBD reliability - key achievements

	What we achieved in 2020-25	Benefits to customers in 2025-30
Understanding CBD network risk	Improved analytics to understand cable risk: probability of failure for cable sections; and reliability and financial consequences of failure.	Enhanced ability to manage reliability efficiently by targeting work that eliminates the most risk.
CBD Automation	Commissioned an automation scheme.	Scheme provides reliability benefits to customers and is a foundation that will be expanded on in 2025-30.

Our forecast for 2025-30 seeks to implement a program that efficiently optimises deployment of underground cable repex and automated switches in augex, in order to meet the jurisdictional standard target which is set at a SAIDI of 15 minutes for 2025-30.

Expenditure forecasting approach

Expenditure was forecast 'bottom up', as detailed in our business case and summarised in Figure 34.

Figure 34: CBD reliability improvement expenditure forecasting methodology

Probability of failure	› Probability of failure over time for each CBD cable calculated by analysing failure, attribute, and geographical data
Reliablity risk	› Reliablity consequences quantified by using feeder loads, customer types and AER published VCR › Future reliability risk determined by multiplying with probability of failure data › Avoided unserved energy quantified as benefits in the investment options
Financial risk	› Financial consequence quantified using a historical unit rate for unplanned fault response › Future financial risk determined by multiplying with the probability of failure data › Avoided financial risk was quantified as benefits in the investment options
Automation benefits	› Benefits of installing automated switches calculated by reducing the reliability risk by a factor of the number of sections a feeder could be divided into › Number of sections estimated by reviewing the number of existing switching positions available for automation
SAIDI target	› Percentage reduction in SAIDI minutes required to comply with ESCoSA targets applied to the reliability risk to determine extent of cable replacements and automated cubicle installations
Costs	› Cost of cable replacements estimated based on historical unit rates and subject matter expert analysis of the complexities of CBD replacements › Costs for installation of automated cubicles estimated by a subject matter expert

The identified customer service needs

The need is to correct a non-compliance issue in the most efficient way for customers. A large portion of network assets used to supply customers via CBD feeders are ageing and deteriorating in condition. This is in part triggering the need to retire assets. The condition of CBD supply assets has been driving poor reliability levels relative to the jurisdictional standard, and we must ensure compliance over 2025-30.

The preferences of our customers

Preferences recommended up to Draft Proposal

We engaged customers and stakeholders on the CBD program's need as a key Focused Conversation, presenting alternative options and trade-offs including: (1) a base case counterfactual of BAU practice (2) a compliance scenario and (3) an improve beyond compliance scenario.

Focused Conversations recommended to the People's Panel that we invest to bring CBD reliability in line with jurisdictional targets by the end of 2025-30.

The People's Panel deliberated on and affirmed the results of the Focused Conversations in their formal recommendation, on the basis that the CBD is vital as the state's business hub and has critical infrastructure that supports the lives of many residents.

Preferences recommended post Draft Proposal

Submissions confirmed the recommendations of the People's Panel as valid, despite cost of living pressures:

- People's Panel members affirmed their recommendations, including on CBD reliability, remain current;
- the SA Government's DEM supported improving CBD reliability;
- SACOSS supported meeting compliance obligations and noted support for ESCoSA's expectations that we make sufficient investment to deliver the minimum network performance standards for CBD feeders;
- the Asset Condition and Risk Sub-Committee of our CAB who engaged with us over the long term on these issues, supported our repex forecast and the service outcomes it achieves including for the CBD;
- the Small Business Commissioner of SA supported the CBD program and its combination of repex and augex upgrade inputs, which it deemed critical to small business stability and growth; and
- EWOSA supported the CBD program to meet jurisdictional standards.

Our proposal and its efficiency for customers

OUR FORECAST	SERVICE LEVEL OUTCOME	EFFICIENCY FOR CUSTOMERS
$90.5m to replace 15 km of 11kV cable and 2km of 33kV cable, and install 39 automated switches.	Achieve SAIDI of 15 minutes by 2030	**Least cost solution** to meet compliance need, with the least negative NPV. Option optimises between cable repex and automated switches augex while achieving compliance, and is preferred to alternatives which also achieve compliance but at higher cost (more negative NPV): › only undertaking cable replacements; and › only undertaking automated switches.

9.4 Connections expenditure

Capex $255.2 million

10.4% of total capex

Our forecast of $255.2 million in net connections expenditure is to enable customers to connect to and access the distribution network in 2025-30, consistent with obligations and our Connection Policy. This comprises works to connect new customers, upgrade existing customer connections or alter customer connections where required.

In 2020-25, we expect to have incurred net connections expenditure of $268.5 million, 20.3 percent lower than the AER forecast. This resulted from external factors, including lower than forecast construction activity[24], and a higher Weighted Average Cost of Capital (**WACC**) driving higher customer contributions (via a lower Incremental Revenue Rebate via our Connection Policy) and therefore lower net expenditure.[25]

For 2025-30, a key change in our forecasting is the addition of a new connections category of Large Embedded Generation (**LEG**) connections – we are seeing increasing demand and complexity for CER connection services and large load connections such as firm and flexible load / export combinations. These loads include battery energy storage systems, solar farms and fast EV chargers or a combination. LEGs include NEM scheduled generators (greater than 30 MW) which previously have not connected to our distribution network.

We forecast a five percent decrease in net connections expenditure relative to 2020-25. Overall connections works are forecast to increase as reflected in gross connections expenditure of $745.2 million (5.9 percent higher), driven by economic recovery and strong growth particularly in major customer and embedded generation connections. However, an expected stronger financial environment contributing to a higher WACC, will again drive higher contributions ($490.1 million or 12.5 percent higher), and lower net expenditure.

Expenditure forecasting approach

Expenditure is forecast via a top-down and bottom-up approach, as detailed in our methodology, business case, and as summarised in Figure 35.

Figure 35: Net connections expenditure forecasting methodology

Categorisation	› Categorise connections into: major customer connections (less than $30k); medium customer connections ($30k to $100k); major customer connections (great than $100k); underground residential developments; large embedded generation (LEGs)
Forecast gross connections	› Obtained independent forecast from Oxford Economics Australia › Key drivers: historic expenditure, committed major projects (government schemes and commercial developments in defence / infrastructure); Australian Bureau of Statistics building activity data; population growth; major project developments; real estate developments › Top-down econometric and statistical modelling to predict connection volumes › Bottom-up assessment of known probable projects - use for part of major customer connections
Forecast customer contributions	› Apply incremental revenue rebate formula in SA Power Networks Connection Policy, using forecast WACC › Estimate forecast customer contributions for each connection category by applying the Incremental Revenue Rebate, with regard to recent historical contribution levels, to gross connections forecast
Calculate net expenditure	› Determine net expenditure as gross expenditure minus customer contributions

24 Particularly in the minor and medium categories due to subdued South Australian economic activity.

25 SA Power Networks' Connection Policy for 2025-30 is contained in Attachment 17 to our Proposal.

The identified customer service needs

Connections expenditure is a core requirement of our regulatory obligations under the NER to provide an offer to connect customers to the distribution network, consistent with the open access nature of the regulatory framework.

The preferences of our customers

Preferences recommended up to Draft Proposal

We considered, together with our CAB, that this topic did not warrant deliberative engagement via Focused Conversations nor the People's Panel, in keeping with a desire to 'focus on what matters' most to customers. This was on the basis that connections expenditure is pursuant to a core regulatory obligation, is driven by expectations of external factors in the economy, and poses no service level options for customers.

However, forecast net connections expenditure was included in the total expenditure stack communicated to customers at each engagement stage as they evaluated options and trade-offs on other engagement topics. The forecast was also more regularly discussed with our CAB.

Further, the changes proposed to our Connection Policy discussed above, and Connection Policy, procedures and charges, were subject to engagement in Focused Conversations and via our Connection Working Group. The key recommendation was that the Connection Policy be updated to introduce flexible load and export arrangements.

Preferences recommended post Draft Proposal

No submissions were received on our connections expenditure.

A submission from EWOSA commented on our proposed changes to the Connection Policy, outlining that it supports the policy being updated to accommodate the increasing take up of clean energy and CER, but that the policy may be complex for some customers to understand.

Subsequent engagement with our Connections Working Group resolved the remaining issues with proposed amendments to our Connection Policy and received endorsement.

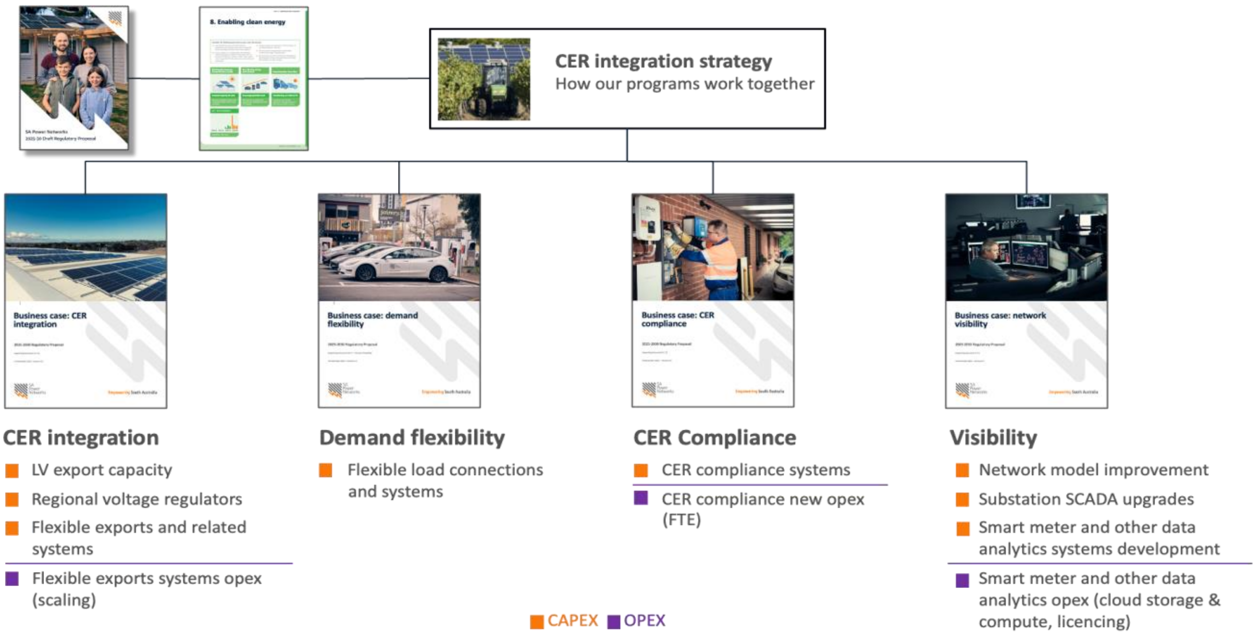
9.5 Customer Energy Resources integration expenditure

Capex $92.7 million

3.8% of total capex

Our CER expenditure forecast of $92.7 million covers several customer and industry facing programs to efficiently support forecast CER growth. It is a strategic and balanced suite of four initiatives (see Figure 36), broader than just enabling export service, seeking to also improve load utilisation via flexibility, improve industry compliance, and utilise more readily available smart meter data to improve operations and safety.

Figure 36: CER integration strategy and investment programs



In 2020-25 we forecast spending $41.0 million, 13.5 percent above the AER forecast, in executing plans from our Regulatory Proposal, to flexibly manage the network and maximise utilisation of existing hosting capacity. Most of the spend was to develop the capability to enable flexible exports (DOEs) for solar customers.[26] This capability is now in place and forms the foundation of our forward CER integration approach.

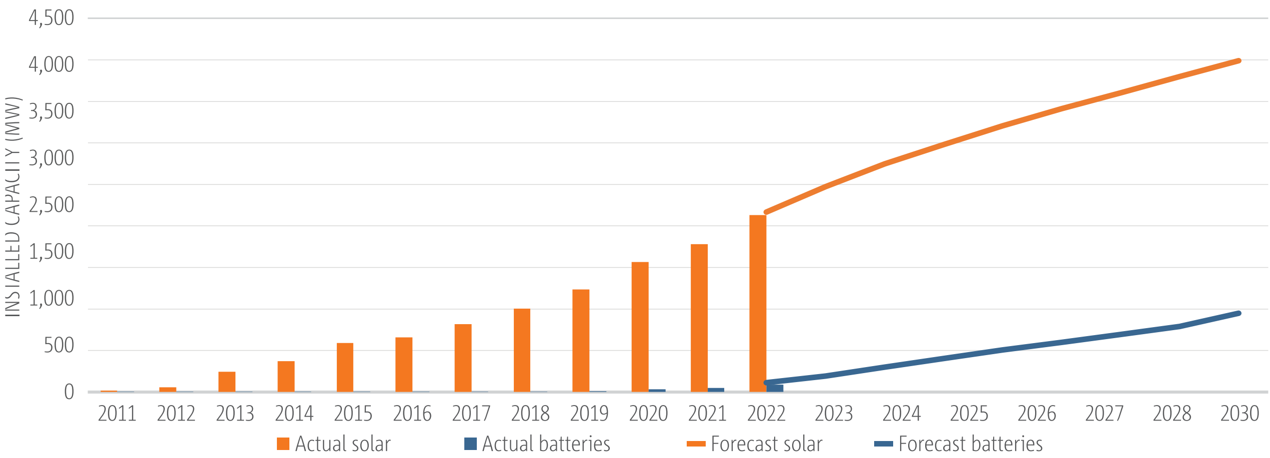
Table 13: CER integration - key achievements in 2020-25

	What we achieved in 2020-25	Benefits to customers in 2025-30
CER integration & flexible exports	Transitioned from static limits to flexible exports for rooftop solar – delivering the key goal of our planned 2020-25 CER strategy. Flexible exports is now rolling out across our network. By end 2024 it will be the standard connection for new small-scale solar in SA.	This is a step change in service for solar customers in congested areas, enabling them to continue to connect new solar and have an export limit of up to 10kW, double our previous limit, with a high level of access to full export capacity year-round.
Tariffs	Introduced Australia's first 'solar sponge' time-of-use tariffs as standard for small customers.	Customers save by shifting load to the day. Improves utilisation, and enables more solar with less augex.
Demand flexibility	Gave control of off-peak controlled load to retailers and moved to a Time of Use tariff to create opportunity and incentive to shift hot water loads to the daytime.	Retailers are shifting overnight hot water loads to benefit from our tariff: increasing utilisation, reducing congestion, driving lower retail prices.
Voltage management	Improved across the network via upgrades at more than 140 zone substations (EVM).	Reduced customer daytime over-voltage issues in high solar areas and increased hosting capacity.

26 We also spent $10m on an enhanced voltage management **(EVM)** program in our strategic augex. A key driver was to establish an emergency solar curtailment capability to mitigate system security risks at times of minimum demand. But this also improved CER hosting capacity, and our 2025-30 CER integration expenditure includes expanding this capability to more substations.

	What we achieved in 2020-25	Benefits to customers in 2025-30
Emergency backstops – solar shedding	An Australia-first capability. Protects SA system in emergencies - used in 2022 for AEMO when transmission was severely damaged causing instability.	Protects from the risk of a state-wide blackout, particularly as SA is now the first / only jurisdiction to operate close to zero operational demand
Network visibility	Rolled out ~1,500 new LV transformer monitors, as planned in our 2020-25 Proposal, and a new visibility software platform for future smart meter data.	Visibility allows better load forecasting, reducing outage likelihood at peaks, enabling better voltage management, and increasing solar hosting capacity.

Figure 37: SA CER forecasts, AEMO ISP 2022 Step Change scenario



Our expenditure forecast for 2025-30 is 125.8 percent higher than 2020-25.[27] This reflects continued growth in customer demand for export service and changes in the scope of our CER integration activities as we progress to the next stage of our long-term CER integration strategy. While the current period focused on maximising utilisation of existing hosting capacity, our forecast includes investments in:

- **flexibility** - systems and capabilities to enable flexibility in customer energy loads (the demand side) and facilitate load shifting to the daytime, building on our flexible export capabilities;
- **compliance** - continuing proactive work with industry to improve compliance with standards for CER, and developing new systems to leverage smart meter data to improve compliance;
- **network visibility** - acquiring and processing voltage and other power quality data now more readily accessible from a faster smart meter rollout, to efficiently manage network operations, increase CER hosting capacity and improve safety; and
- **hosting capacity** - targeted upgrades to network capacity and the systems to flexibly manage capacity, to enable customers to export energy from CER at service levels they expect and value.

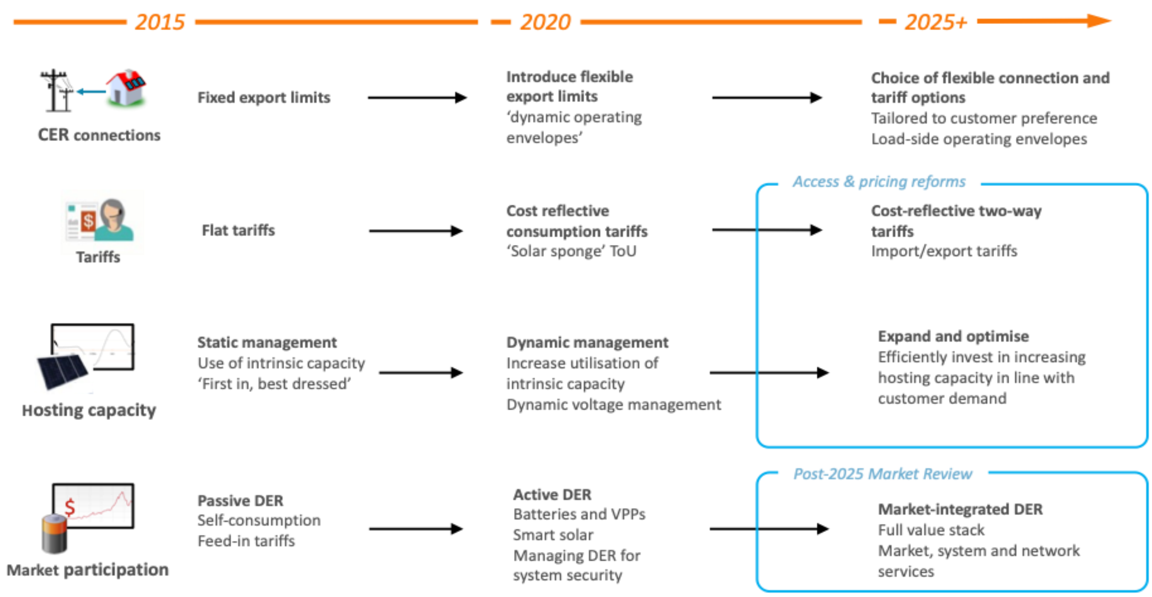
We also propose new export tariffs for 2025-30 to continue transitioning to cost-reflective pricing for all customers – signalling efficient long-term network costs of enabling more export service capacity and avoiding cross-subsidies from non-solar customers by recovering costs from those using the service.

Our 2025-30 CER integration program, continues our long-term strategy as illustrated in Figure 38, balancing all levers and only investing in physical network as a last resort, to maintain service and integrate CER via:

1. **non-network solutions** - shifting and shaping load and generation via efficient combinations of non-network solutions, cost-reflective price signals and flexible exports; and
2. **network solutions** – where non-network solutions are insufficient, then making targeted and efficient network investments in additional export capacity

[27] Noting that our 2020-25 figure excludes the $10 million EVM program.

Figure 38: The staged sequence of our holistic CER integration strategy

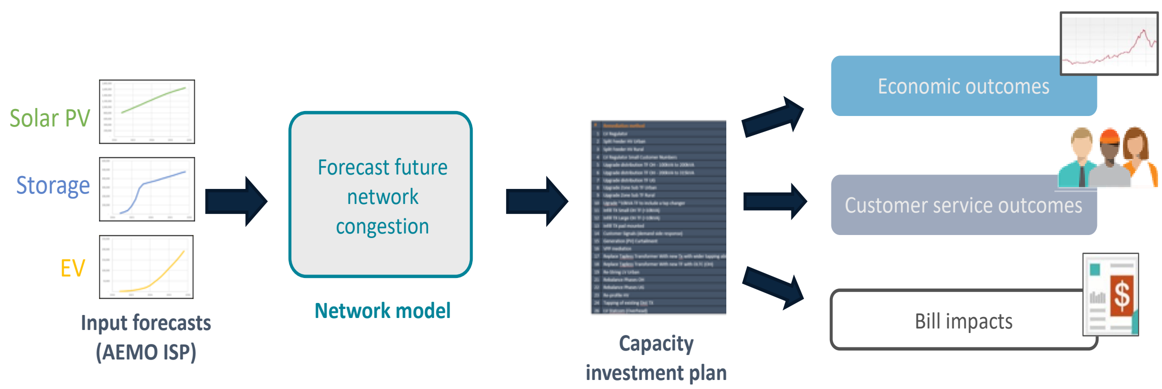


Expenditure forecasting approach

The four programs were forecast bottom-up, as detailed in our CER integration strategy and respective business cases, with key features outlined below and in Figure 39:

- AEMO's Integrated System Plan 2022 Step Change scenario is the main source for South Australia CER uptake forecasts;
- spend is forecast via a network model, 'LV Planning Engine' **(LVPE)**, forecasting reverse power flows for all LV transformers in 30-min intervals from 2025-2050 using postcode forecasts of service growth from AEMO scenarios, and considers changes in customer load profiles from tariff response and other factors;
- identifying areas and future 30-minute time intervals where reverse power flow will exceed local capacity, the LVPE calculates future export service levels (e.g. '95% export access') and potential lost NEM value due to curtailment, and identifies the most efficient investments to maintain service levels; and
- in determining the minimum network investments required, the LVPE also considers benefits (in alleviated curtailment) expected from flexible exports and our Demand Flexibility, CER Compliance and Network Visibility program, as well as any hosting capacity benefits from other programs such as repex.

Figure 39: Methodology used to forecast future export capacity investment using our LV Planning Engine



Our CER integration expenditure forecasting process is summarised in Figure 40.

Figure 40: CER integration forecasting methodology

Hosting capacity	› Assess hosting capacity individually for each of the 70,000+ LV transformers on the network › Account for efficient network voltage management planned for completion prior to 2025
Forecast service demand	› Forecast CER network connection and export service demand, using AEMO ISP as the primary source for CER uptake (solar, batteries, EVs), then mapped to postcode level, aggregated up to provide individual CER updtake forecasts for each LV transformer area
Curtailment profile	› Use LV planning engine to calculate net load flow for every LV transformer for every 30 minute interval from 2025-50 › Calculate alleviation profile in congested areas assuming dynamic curtailment using flexible exports
Solution: demand and supply side	› Demand side: consider behavioural remediation activities incorporating: SA Power Networks solar sponge TOU tariffs; hot water shifting; ev charge profiles; impact of proposed demand flexibility program › adjust curtailment profile taking into account modelling outcomes from behavioural remediations › Supply side: analysis of network and non-network options (flexible exports; TOU tariffs; CER compliance program, demand flexibility program) › Create alleviation profiles for each option
Costs and benefits	› Apply value stack to alleviation profiles including relevant CECV: 30 min CECV values; value of avoided generation capacity investment as additional 30 min value stream) › Select option with the highest economic value
Consumer engagement	› Engage with consumers and stakeholders on options, tradeoffs and outcomes regarding expected service level › Run modelling to achieve customer desired service level

The identified customer service needs

Demand flexibility

We need to minimise the costs of managing customer demand by enhancing our ability to provide/encourage flexible services for loads and generation, to increase utilisation, avoid network asset investments and reduce long term costs. Our BAU approach (as with all NEM networks) is to manage demand by building capacity or interacting with the demand-side such as paying third-parties to reduce demand or draw on energy storage. Having successfully implemented DOEs for Flexible Exports, we can now apply the same approaches to load - mitigating peak demand growth, shifting load with greater flexibility, minimising costs to integrate uses such as EV charging, and further facilitating day-time load shifting to ‘soak-up’ surplus solar.

CER compliance

The need is to meet and manage demand for export services, maintain security of our distribution services and system and ensure compliance. Network connected generators must conform to technical standards and regulatory requirements, to ensure the network and broader system are safe and reliable at high levels of CER penetration. AEMO studies reveal high non-compliance with standards across installed equipment in South Australia, findings confirmed in our investigations. We aim to improve compliance to standards, connection rules, and regulation for CER installations.

CER integration

The need is to meet and manage forecast demand for export services. Our customers in 2020-25 receive a high grade of export service. A sample of customers on our flexible exports program indicates circa 98% of solar customers currently receive an export service of at least 95%, with exports curtailed fewer than 5% of daylight hours through the year.

We forecast under a counterfactual scenario where we make no new investments in increasing hosting capacity in 2025-30, our network will be increasingly unable to meet service demand due to voltage and thermal constraints. This will require increased curtailment of customer exports using DOEs, degrading service levels, foregoing economic value to exporting customers and ultimately to all customers as a result of energy not being available to the NEM.

Network visibility

We need to enhance visibility by acquiring and processing data mainly from smart meters that will now be more readily accessible to us as a result of the accelerated smart meter roll out reforms underway via a rule change process actioning the recommendations in the Australian Energy Market Commission **(AEMC)** review of metering.

Visibility is key to several operational, safety, CER integration and network planning functions. In 2020-25, we undertook several measures to improve visibility: deploying a third-party time series data analytics platform with an in-house database; rolling out monitors to target a subset of our LV transformers; and establishing contracts with two key Metering Coordinators to procure a small sample of smart meter data. However, our dynamic visibility, particularly of the LV network is limited, and we need to build on our foundations and enhance this capability, using the expected greater access to meter data beyond 2025.

The preferences of our customers

Preferences recommended up to Draft Proposal

CER integration – export service

We engaged customers in Focused Conversations, on several investment scenarios with higher / lower expenditure and corresponding service levels, to determine the outcome that customers valued and expected. Focused Conversations recommended to the People's Panel that we invest in sufficient capacity to maintain current service levels, preferring a target service level of at least 95% for most customers.

The People's Panel deliberated and affirmed this recommendation, to continue enabling solar users to export excess energy for a green, sustainable and reliable future, and enable the network to keep pace with demand.

Demand flexibility

We considered and engaged customers on several alternative investment scenarios with higher / lower expenditure and resulting differences in expected benefits to consumers and the market. Focused Conversations recommended to the People's Panel that the program be supported.

The People's Panel deliberated and affirmed this recommendation, to make the network smarter, more efficient and flexible – reducing costs to all customers.

Preferences recommended post Draft Proposal

Submissions focused on the CER integration program, confirming the recommendations of the People's Panel as valid, despite continued cost of living / affordability pressures:

- members of the People's Panel affirmed that their recommendations, including in respect of the CER Integration program and the Demand Flexibility program remain current;
- EWOSA along with survey respondents outlined support for the CER Integration program and the proposed service level; and some parties such as SACOSS and EWOSA noted that support for this program was contingent on introducing export tariffs in 2050-30 to ensure that non-solar customers do not pay for the costs of the proposed export service level—our 2025-30 Proposal introduces export tariffs.

Our proposal and its efficiency for customers

OUR FORECAST	SERVICE LEVEL OUTCOME	EFFICIENCY FOR CUSTOMERS
CER INTEGRATION – EXPORT SERVICE		
› $16.6m capex and $4.4m opex to maintain and scale flexible exports and other systems necessary for the ongoing provision of the export service. › $53.5m capex on upgrades to address emerging constraints on the LV network, improve voltage and increase available export capacity in targeted areas to maintain customer preferred service level	Maintain service level of 95% for 95% of customers.	**Benefits outweigh costs** with an NPV result of $21.9m over a 25-year period. Option is preferred, having the most positive NPV vs alternatives including: › a base case of no new capacity increase; › a lower 90% service level; and › a higher 98% service level The spend on the proposed service level is materially less than what Customer Values Research Survey indicates our customers are **willing to pay** for this outcome.
DEMAND FLEXIBILITY		
$7.7m to develop: › 'flexible load' connections for small and large customers – extend ICT systems, technical standards, network capacity models and business processes to enable a full 'DOE' for import and export; and › new customer services and operational capabilities to help customers activate smart devices (home batteries, smart EV chargers, hot water and smart appliances).	Assists in meeting and managing demand for SCS	**Benefits outweigh costs,** with an NPV outcome of $7.7m over a 20-year period. Option is preferred, having the most positive NPV to alternatives including: › doing nothing to flexibly manage capacity; and › advanced services – additional investments in advanced data publication services for market participants including near real time interfaces for network state data.
CER COMPLIANCE		
$5.7m capex and $2.5m opex to extend the scope of our ongoing compliance program to include data analytics for non-compliance detection. Includes new compliance analytics applications and business rules to respond to detected non-compliance.	Assist meeting and managing demand for SCS; maintaining service performance; and compliance with obligations.	**Benefits outweigh costs,** with an NPV outcome of $5.5m over a 20-year period. Option is preferred to the alternative of discontinuing our compliance program. Option is also consistent with recommendations of the AEMO and AEMC that distributors should address poor industry compliance to CER technical standards.
NETWORK VISIBILITY		
$9.1m capex, and $6.8m opex on: › procedures and infrastructure to receive basic PQ data from MCs, and licensing and hosting to support higher volume data from a 100% smart meter penetration; › analytics to support data use cases: network hosting capacity, improved voltage management, neutral integrity fault detection and others; and › commercially procuring small volume of higher-frequency (non-basic) data.	Assist in meeting and managing demand for SCS; maintaining safety; improving network voltage management and enabling compliance with all obligations	**Benefits outweigh costs,** with an NPV result of $67.6m over a 15-year period. Option is preferred having the highest NPV vs alternatives including: › continuing as is, with only limited smart meter data acquired; and › receiving and processing only 30 percent of basic power quality data.

9.6 Information and Communications Technology

Capex $300.8 million

12.3% of total capex

Our forecast ICT expenditure of $300.8 million supports delivery of distribution services across the full spectrum of our operations. This includes our customer service delivery and communications, management of business activities and field resource deployment, capture and use of data on network condition / capacity, cyber security, among other activities.

In 2020-25 we expect to spend $366.2 million, realising consumer benefits of $134.5 million. We delivered several large and complex projects, including replacing our billing system and upgrading our SAP Enterprise Resource Planning system **(ERP)**. We also invested to comply with cyber requirements, and improve network data capture / analytics enabling more accurate forecasting of risk and service levels posed by network asset condition.[28] We expect our expenditure to be 10.4 percent above the AER forecast, as we also had to respond to emergent needs including: more condition driven replacements and updates to mid-sized systems, more client devices from changes to hybrid working arrangements and in response to cyber requirements.

Table 14: ICT - key achievements in 2020-25

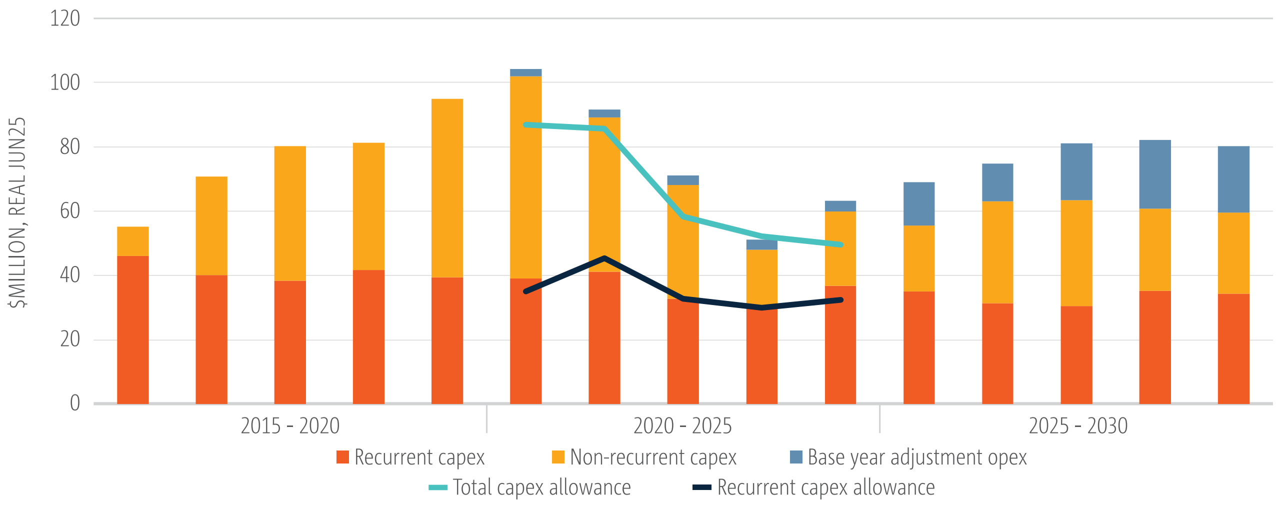
	What we achieved in 2020-25	Benefits to customers in 2025-30
Benefits to customers	Delivered over $134.5m in consumer benefits to keep distribution services costs down.	Benefits realised by customers long term via lower network expenditure.
Benchmarking	Performed at NEM average in IT recurrent totex per customer, and one of the lowest opex in the NEM on recurrent IT opex per customer.	Unit costs among most efficient.
Large Replacements & Upgrades	Replaced our billing system and upgraded our ERP on time and budget.	Kept long-term costs down and data secure.
Cyber security	Improved incident detect / response, as per maturity obligations – ensuring no network incidents.	We are targeting the cyber investment for maximum impact in 2025-30.
Moving services to the Cloud	Shifting data centres to Cloud, secured network connections and financial management capabilities.	Secure access to cost-effective systems.
GIS Consolidation	Consolidated our Geographic Information System (**GIS**) onto a single platform.	Ensures most efficient long-term costs for this increasingly important capability.
Assets & Work	Improved asset data collection / models to optimise on the basis of highest value network work.	Confidence our network spend is based on accurate risk and efficiency data.

Our 2025-30 forecast is 17.9 percent lower than spend in 2020-25, due to systems that are, or transitioning to Software-As-A-Service **(SAAS)**, being accounted as opex. Forecast capex responds mainly to investment cycle timing to refresh and replace systems in order to maintain functionality and services, as we come off a period of lower replacements and upgrades. Drivers also include an increasing dependence on ICT in our operations and customer services, higher cyber risk, and opportunities to improve digital customer interactions as well as asset management efficiency.[29] In total, our forecast is estimated to deliver material consumer benefits of circa $613.0 million over 10 years, mainly by avoiding cost increases, cyber risk management and more efficient network asset management.

[28] The AER requires that we undertake a Post Implementation Review of our 10 largest completed projects. Across these 10 largest completed projects, 60% were completed on or below budget with a total cost overrun of less than 1 percent across all projects.

[29] Improving asset management efficiency is particularly important as we approach a required long-term uplift in network spend.

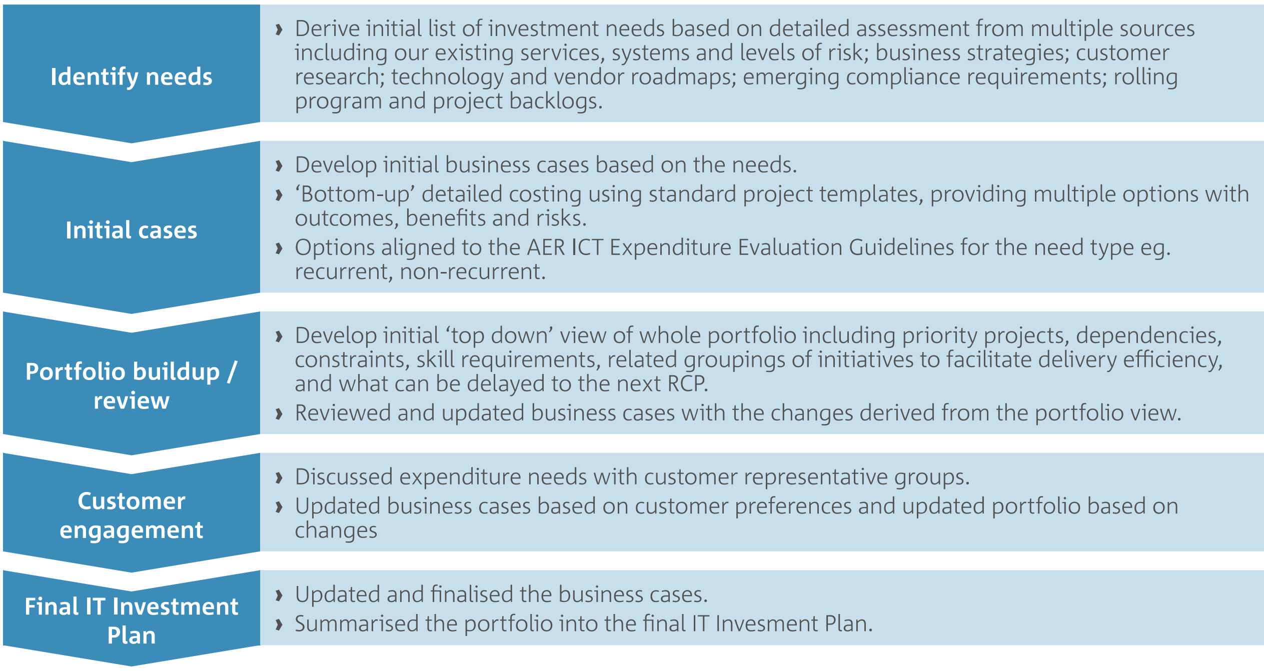
Figure 41: ICT forecast capex vs historic spend by AER category, plus 2025-30 SaaS capex to opex adjustments



Expenditure forecasting approach

We apply a range of techniques in forecasting ICT expenditure as detailed in our IT investment plan and business cases, and as summarised in Figure 42.

Figure 42: ICT expenditure forecasting methodology



The identified customer service needs

Expenditure is categorised by the overall need, and programs and projects then respond to specific needs.

Recurrent IT expenditure

This comprises various programs with a need to maintain existing ICT systems, services, functions, capabilities and / or benefits and manage technology risk, and sub-categorised by asset class as set out below.

- **Client devices[30]:** periodic refresh to mitigate risk of declining performance as devices age, need more maintenance and ultimately fail;
- **ICT infrastructure:** periodic refresh of hardware[31] enabling delivery of all ICT services critical to network and outage management and customer service, to manage the risk of failure and service degradation;
- **ICT applications:** refresh to ensure our expanding portfolio of systems maintain functionality, are secure and evolve with customer, business and network changes; and
- Smaller programs cover refreshes for **Data, Analytics and Intelligent Systems** and to enable our recurrent **Cyber Security** capability, by maintaining functionality and security for systems growing in importance in the energy transition as we seek to maximise use and value of data for network and customer decisions.

Large upgrades and replacements

Comprises programs needed to maintain existing systems and services and manage risk. Several large and critical systems will reach 'end of useful life' in 2025-30 arising from an announced end of vendor / supplier support, and / or legacy systems that are legacy and no longer 'fit-for-purpose' nor cost effective.

Customer technology replacement program

We need to meet rising customer demand for power supply information via digital channels. If we did nothing new, high-volume customer communications will increase and drive costs (to us and customers) in responding and managing resolution, and due to ageing technology. We need to refresh core systems[32], given growing energy sector complexity with CER uptake driving more and longer calls to us, and customer demand for information on outages, planned jobs, claims and complaints. Aged technology also currently impedes online services meeting good accessibility practice.

Other large upgrades and replacements

These comprise initiatives needing to:[33]

- replace our customer and national market critical Service Order Management Module when the vendor ceases (already extended) support in 2030, to ensure customer data security and systems functionality;
- replace our core integration platform before extended support ceases in 2030, to avoid leaving many services vulnerable from both a security and a reliability perspective;
- consolidate our existing data warehouse onto our Enterprise Data Platform when extended support ends in 2030, to managing our risk and simplifying our systems;
- replace our Click field management and scheduling system so that customer services and field force remain operational and safe; and
- make smaller investments to maintain existing service and risk across several SAP small modules.

New or altered compliance requirements and obligations

This comprises programs responding to new requirements on cyber security and market interaction systems.

Cyber Security

This covers controls to protect critical infrastructure and supporting systems from attack. We need additional controls, to respond to increasing cyber threats on networks, and to meet increasing compliance obligations.

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30 Includes computers, mobile phones, tablets and other devices our staff use to in customer service and field operations.

31 This includes servers, storage and ICT network equipment.

32 Legacy Customer Relationship Management, website / portal software, customer notification system and analytics engine.

33 While we 'sweat' assets and extend support where possible / practical, support and security patching options will run out before 2030 as suppliers decommission systems.

*AEMO Energy Security Board (**ESB**) Post 2025 roadmap initiatives*

AEMO is reviewing reforms via roadmap initiatives under the ESB Post 2025 work, that we expect to drive several market enablement changes on distributors requiring initiatives with material costs.[34]

New or expanded capability

Comprises programs for new systems and capabilities to create new operational and customer value.

*Assets and work Phase 3 (i.e. Asset Management Transformation Program, **AMTP**)*

We forecast increasing work volumes to 2035 and beyond as we continue our long-term increase in the level of repex to address deteriorating condition, and increase in capacity to meet rising service demand (load and export). We need to minimise the cost of delivering this increasing work volume in coming years, having identified the potential for ICT systems to improve asset management practice, and lower the delivery cost of network services (i.e. lower costs per job).

Personalised on-demand services improvements[35]

Our high-volume customer service processes (mainly manual and paper based) no longer meet customer expectations and will drive cost increases. We need capability for digital self-service to save customers' time in regard to enquiries, claims, connection status, and property access information, and to provide quick information on new energy initiatives, eliminating the need to consult multiple participants.

The preferences of our customers

Preferences recommended up to Draft Proposal

All ICT capex and opex was included in the expenditure stack presented to consumers, and was also subject to engagement with our CAB. Together with our CAB, and given a desire to 'focus on what matters' most to consumers, we decided to focus engagement on 'new compliance' and 'new or expanded capability'. Focused Conversations recommended to the People's Panel that we invest in: **Cyber security** to enable compliance with AESCSF SP-3 by 2030; in **Personalised On-demand Services** to improve digital service capabilities; and in **Assets and Work** to improve asset management efficiency as long as benefits exceed costs.

The People's Panel supported Assets and Work, but did not reach consensus on Personalised On-demand Services. They also recommended a larger cyber security program to exceed SP3 by 2030 as this maturity level was considered insufficient compared to overseas jurisdictions, and an attack would be catastrophic.

Preferences recommended post Draft Proposal

Submissions confirmed the People's Panel recommendations as valid, despite cost of living pressures. Members of the People's Panel affirmed that their recommendations, including in respect of the Cyber Security, Personalised On-demand Services, and Assets and Work (Phase 3) programs, remain current.

SACOSS wanted us to not exceed expected cyber maturity obligations, while the SA Government's DEM expected us to show the Cyber Security program is efficient and prudent. And, the Assets and Work (Phase 3) program was endorsed by the Small Business Commissioner, urging us to pursue improvements in works scheduling to minimise impacts on businesses.

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[34] Includes: new industry data exchange, energy market identity, access management to improve security and portal consolidation. As AEMO's review is still underway we cannot fully cost implications on us, which could be between $2-25 million, and therefore we forecast a placeholder that will likely require amendment.

[35] This initiative is dependent on our non-recurrent replacement expenditure proposal for ageing customer technologies and is an integrated work program under the title of the Customer Technology Program.

Our proposal and its efficiency for customers

OUR FORECAST	SERVICE LEVEL OUTCOME	EFFICIENCY FOR CUSTOMERS
RECURRENT		
$165.3m (7.8% lower vs 2020-25).	Maintain capabilities and functions supporting delivery of SCS.	**Least cost** option.
NON-RECURRENT: MAJOR REPLACEMENTS OR UPGRADES		
Overall: $93.8m (20.3% lower vs 2020-25)		
Customer technology program (excluding Personalised On-demand Services): $19.5m	Maintain capabilities and functions supporting delivery of SCS.	**Benefits outweigh costs** with NPV of $11.7m over 10 years.
Other large replacements or upgrades ($74.4m)		**Least cost** option.
NON-RECURRENT: NEW COMPLIANCE		
Overall: $5.4m (77.7% lower vs 2020-25)		
Cyber security uplift ($3m capex and $47.6m opex): increase maturity via customised controls to maintain security in response to increasing threats. Option revised in response to Draft Proposal feedback, by taking a risk prioritised option rather than assuming requirement to comply with AESCSF.	Maintain cyber security to increasing threats.	**Benefits outweigh costs** with NPV outcome of $124.1m over 10 years
AEMO ESB Post 2025 roadmap initiatives ($2.4m)	Comply with market requirements.	**Least cost** compliance option.
NON-RECURRENT: NEW OR EXPANDED CAPABILITY		
Overall: $36.3m (19.5% lower vs 2020-25)		
AMTP ($34.9m): we responded to Draft Proposal feedback urging us to continue our focus on affordability, efficiency, prudency and productivity, by revising the program to take on more self risk by assuming that higher estimated efficiency gains will result from the program – efficiencies which we have deducted from total capex and opex of our entire Regulatory Proposal.	Improves the efficiency of our delivery of SCS to customers.	**Benefits outweigh costs** with NPV of $34.1m over 10 years. $45m in direct benefits to accrue in 2025-30 via a reduction to total capex.
Customer technology program - Personalised and On-demand Services ($1.4m): option responds to the People's Panel's non-consensus, but the program having been supported at earlier engagement, by revising the program down to focus on communication improvements that save time and costs to us and customers.	Improves the efficiency of our delivery of SCS to customers.	**Benefits outweigh costs** with NPV of $9.5m. Also Customer Values Research indicates customers are willing to pay for digital service improvements

9.7 Fleet

Capex $154.9 million

6.3% of total capex

Our fleet forecast of $154.9 million supports our delivery of distribution services to customers by ensuring a sufficient and fit-for-purpose fleet of vehicles.

In 2020-25, we forecast to incur expenditure largely in line with the AER's forecast (3.6 percent lower), with minor savings achieved by efficiencies in the choice of vehicles procured and accessories included.

For 2025-30, our forecast expenditure increase of 36.3 percent relative to 2020-25 responds to the timing of our standard and unchanged vehicle replacement cycles, the need to increase our fleet volume to support a forecast increase in network capital work, and the opportunity to acquire EVs where it is efficient.

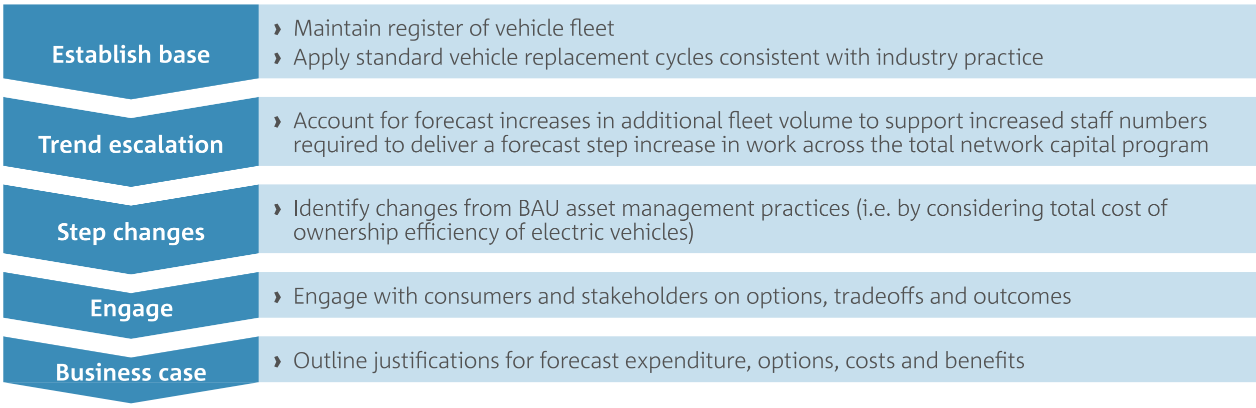
Table 15: Fleet - key achievements in 2020-25

	What we achieved in 2020-25	Benefits to customers in 2025-30
Replacement cycles	Managing our assets by maintaining all the vehicle replacement cycles reviewed and notionally approved by the AER.	Confidence the majority of fleet expenditure reflects recurrent BAU practices aligned to industry practice.

Expenditure forecasting approach

Expenditure is forecast bottom-up as detailed in our business case, and as summarised in Figure 43.

Figure 43: Fleet expenditure forecasting methodology



The identified customer service needs

Fleet does not comprise specific projects but accounts for incremental needs as summarised below.

Base expenditure

Maintains our existing fleet according to vehicle replacement cycles that accord to the AER decision for 2020-25, and practice of other networks. This covers only our existing fleet and does not address drivers over 2025-30 to increase the volume of fleet assets to support a work uplift nor to enable a transition to EVs.

Trend escalation

To increase the volume of fleet assets to support the increased volume of network work that we forecast for 2025-30.

Step change

EVs are lowering in cost and reaching parity with Internal Combustion Engine **(ICE)** vehicles for some fleet categories. While EVs generally have higher upfront capital costs of purchase, they drive lower comparative opex due to cost savings in fuel and maintenance – i.e. more efficient on a total cost of ownership basis.

The preferences of our customers

Preferences recommended up to Draft Proposal

The totality of our fleet expenditure was communicated to customers through each stage of our engagement program, being within the total expenditure stack as customers evaluated scenarios of expenditure, service and price. However, total fleet expenditure was not chosen as a topic that customers (and our CAB) wished to workshop in Focused Conversations, keeping with a desire to 'focus on what matters' most to customers.

The key aspect of our fleet forecast subject to engagement in Focused Conversations was the transition to EVs, where a recommendation was made to the People's Panel that we should only incur expenditure transitioning to EVs where this is more efficient than replacing ICE vehicles. The People's Panel deliberated and affirmed this recommendation.

Preferences recommended post Draft Proposal

Submissions confirmed the recommendations of the People's Panel as valid, despite cost of living pressures:

- members of the People's Panel affirmed that their recommendations, including in respect of investment in an EV fleet transition remain current; and
- no other submissions raised concerns or new information to warrant a change in approach.

Our proposal and its efficiency for customers

OUR FORECAST	SERVICE LEVEL OUTCOME	EFFICIENCY FOR CUSTOMERS
Base: $128.8m to maintain to existing replacement cycles.	Maintain effective / efficient fleet to support SCS delivery.	**Least cost** means of maintaining service provision, consistent with industry practice.
Trend escalation: $23.2m to increase fleet asset volume to support forecast increases in the volume of network work.	Sufficient resources to meet growth in SCS work.	**Least cost** means of maintaining service provision to customers.
Step change - $2.9m, to acquire 235 EVs instead of ICE vehicles, when due for replacement and more efficient than ICE vehicles.	More efficient delivery of SCS.	**Least cost** on total cost of ownership basis, versus alternative option of replacing with ICE vehicles.

9.8 Property

Capex $115.8 million

4.7% of total capex

Our forecast of $115.8 million is to provide a fit-for-purpose, safe, and compliant property asset portfolio that effectively and efficiently supports our delivery of services to customers.

In 2020-25, we significantly transformed our approach to property asset lifecycle management, underpinned for the first time by detailed and independent asset condition reports, asset replacement estimates and criticality and risk assessment across all properties down to the asset sub-system level. This more granular visibility of individual asset classes and risk, enabled more accurate and efficient prioritisation of refurbishment to properties that are in worst condition, at / or beyond end-of-life replacements, and of critical site importance. With a more accurate risk visibility, we prudently responded and forecast to have spent $73.3 million, being 31.3 percent more than the AER forecast.

For 2025-30, our overall forecast increase in expenditure of 57.9 percent, responds to the deteriorating condition and capacity limitations of our properties by increasing refurbishment, renewals, and rebuilds on some of our properties. The forecast is data driven, and risk / work optimised, to proactively manage our buildings and building asset maintenance and replacement lifecycles and to consolidate activity efficiently. Our forecast results from a three year process of improving our analytics as displayed in Figure 44.

Figure 44: Property asset management transformation and 2025-30 approach

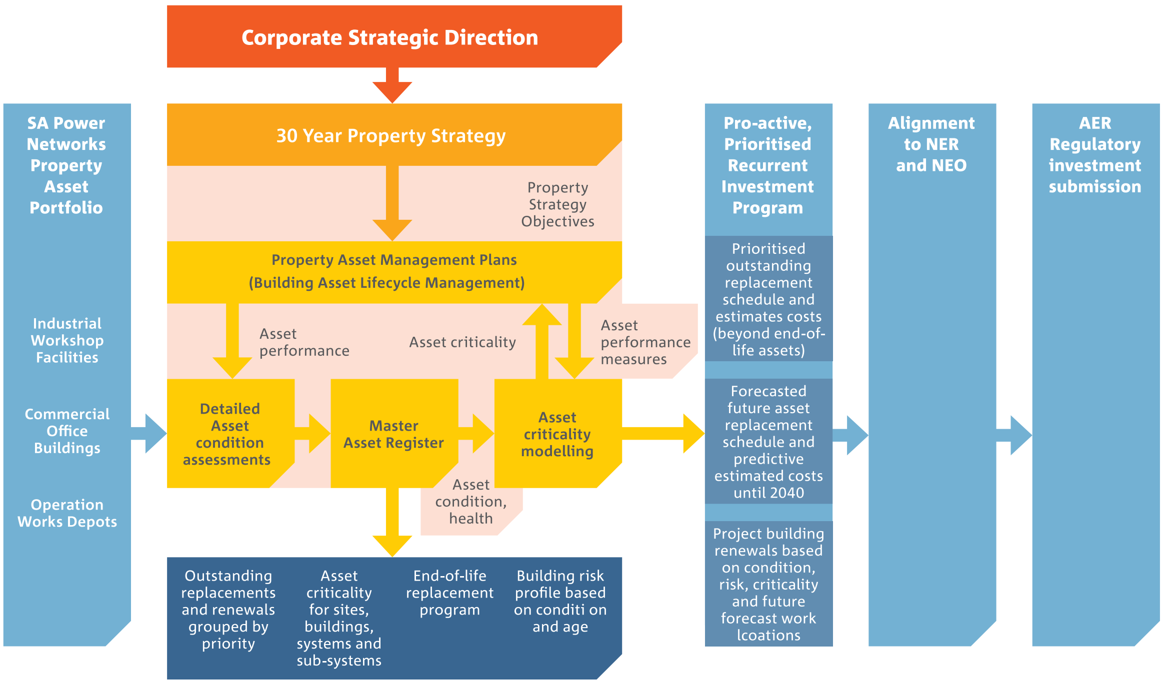


Table 16: Property - key achievements in 2020-25

	What we achieved in 2020-25	Benefits to customers in 2025-30
Asset Condition & Asset Management Plans	Improved asset management via capture and use of detailed asset condition and performance data, and risk assessment to baseline the importance profile of the property portfolio at site, building and asset level.	Forecast is based on an optimised replacement strategy to prioritise investments based on cost, risk, performance, and business need / importance.
Criticality risk assessments	Improved asset management enabled by a criticality and risk rating system to prioritise investment.	Greater confidence on the need for forecast spend, underpinned by risk and criticality view.
Investments	Spent more than the AER forecast, showing resolve in actioning on critical needs based on risk assessments.	Confidence on the need for forecast spend. Also, minimises the cost of replacement works needed.
Delivery of Large Projects	New Seaford depot and warehouse on track to complete in 2024. The largest depot we will have built.	Demonstrates ability to deliver large-scale construction projects.

Expenditure forecasting approach

We applied a bottom-up approach to forecasting expenditure as detailed in our respective business cases, following the sequence summarised in Figure 45.

Figure 45: Property expenditure forecasting methodology

Condition and capacity assess	› Assessed condition and capacity of each of our property assets (Commercial Offices, Operational Depots and Industrial Workshops)
Asset criticality and risk	› Identified the criticality of each property asset and therefore the failure risk posed to operations
Options	› Identified the options for assessment based on those that are most cost efficient, lowest risk, best optimised. Includes renewals replacements, rebuilds or refurbishments.
Segment expenditure type	› Recurrent – planned cyclical activities to retain functionality, capability and service on regular cycles set in Property Asset Register, incl. refurbishments and pro-active replacements and renewals to maintain existing services; or › Non recurrent – less frequent replacements and upgrades to provide more discernible benefits, generally large strategic projects not falling under planned cyclical works in recurrent expenditure
Consumer engagement	› Engaging on options, tradeoffs, and outcomes
Business cases	› Identify preferred option that is either least cost or maximises net benefits to consumers

The identified customer service needs

The forecast responds to specific identified needs detailed in business cases and summarised below.

Recurrent expenditure – replacements and refurbishments

These cover a broad range of cyclical activities with a need to maintain functionality, capability and service. They respond to the poor condition of a significant proportion of our property assets, with an independent property portfolio assessment finding 90 percent to be in the high-to-medium criticality range, due to poor-to-very-poor condition. Over 25 percent of our assets are reaching their end of useful life in 2025-30.

In 2020-25 we increased our capability to identify and assess asset condition and prioritise / optimise spend. In 2021 we engaged consultants to assess condition, risk and criticality of our property portfolio – via physical inspection, Asset Register cataloguing, and condition rating assignment to each asset.[36] Risk ratings of each asset were assessed based on criticality to operations, safety or compliance. Outputs were used to prioritise renewal and replacement investments to optimise costs while keeping to acceptable risk.

Recurrent expenditure – building renewals

These cover renewals of entire buildings, via major renovations or rebuilds.[37] The need is to address the risk posed by poor asset condition and to efficiently and prudently meet growing work volume and demand. Our 30 year renewal plan across our whole portfolio identifies two major depots as due for renewal in 2025-30, Port Augusta and Mount Barker, comprising 44 percent of the total depot renewal program.

[36] Ratings accorded with the Institute of Public Works Engineering Australia Guidelines.

[37] Asset Replacement / Refurbishment covers smaller-scale works in buildings, such as lighting, air conditioning or office furniture.

Mount Barker Depot

The need is to respond primarily to the current depot's capacity constraint:

- this is one of our highest utilised operational works depots, constructed in 1980, storing equipment and offices for field crews to meet operational and public safety needs of our network in delivering customer services – the depot is located in what has become a densely populated residential area experiencing rapid growth and highest bushfire risk zone; and
- if we continue to operate and maintain the existing site as current, it will have insufficient capacity for both current and future increasing work volumes. Further continuing to operate this depot in this location is presenting an increasing safety risk to the community given its proximity in the township.

Port Augusta Depot

The need is to respond to the current depot's impractical and unsafe environment and capacity constraints:

- our current operational works depot was built in 1970 and services 10,500 customers in an area covering more than 37,000 $km^{2.}$ Field crews operate from the site to provide planned and unplanned restoration and repair work in the Port Augusta and surrounding region – the depot is in the centre of Port Augusta CBD, with no option to expand; and
- under our current BAU approach of continuing to operate and maintain this depot, we forecast continued inadequacies in operational needs, constraints in location expansion to meet demand, and unsafe and inefficient movements of people and equipment to and from the site and within the surrounding area.

Non-recurrent expenditure – transformer workshop

The need is to respond to the workshop's poor condition, being past its useful life (built in the 1950s). This is a critical asset, enabling essential services on critical network assets, such as power and distribution transformers, and switching cubicles. This key industrial facility comprises a workshop, associated storage areas and an oil recycling plant.

If we maintain a BAU approach to operating and maintaining the existing site, we forecast needing significant ongoing capital upgrades and replacements due to its poor condition.

The preferences of our customers

Preferences recommended up to Draft Proposal

The identified needs of the property portfolio and expenditure and price impacts were discussed with customers via Focused Conversations, where the expenditure forecast was endorsed, and a recommendation made to the People's Panel to deliberate on the specific identified need of the 'transformer workshop'.

The People's Panel recommended that we respond to the need of the transformer workshop by building a new workshop, being the most effective long-term option, and highlighting the importance of having purpose built and properly maintained building facilities that provide safe and efficient workspaces.

Preferences recommended post Draft Proposal

Submissions confirmed the recommendations of the People's Panel as valid, despite cost of living pressures:

- members of the People's Panel affirmed the currency of their recommendations, including on property;
- the Asset Condition and Risk Sub-Committee to our CAB which lead engagement on property endorsed the property expenditure, on the basis that it reflects appropriate risk mitigation to deliver a fit-for-purpose, safe and compliant property portfolio that meets customer and staff needs.

Our proposal and its efficiency for customers

OUR FORECAST	SERVICE LEVEL OUTCOME	EFFICIENCY FOR CUSTOMERS
RECURRENT – REPLACEMENTS & REFURBISHMENTS, DEPOT RENEWALS		
$61.7m to maintain functions, capability, service.	Fit-for-purpose properties with capacity and capability to support delivery of SCS.	**Least cost** approach to maintaining existing assets. Pro-active replacement on lifecycle approach, minimises spikes in spend profile and minimises long term costs. Also Reduces risk of asset failure and down-time.
RECURRENT – RENEWALS (MOUNT BARKER)		
$16.9m to rebuild the depot on a new site, remediating and selling the existing site outside of the congested suburban area and constructing new buildings.	Fit-for-purpose properties with capacity and capability to support delivery of SCS	**Benefits exceed costs** with an NPV of $7.7m over a 30-year period. Option is preferred to alternatives including: › BAU – requires increasing intervention and external leasing to meet capacity constraints; › rebuilding on same site - requires demolition of existing depot and replacement via new buildings; and › leasing new site - requiring a site lease in Mount Barker to eliminate the existing capacity constraint.
RECURRENT – RENEWALS (PORT AUGUSTA)		
$10.1m to rebuild depot on a new site, remediating and selling the existing site, and buying an outer suburb site and constructing buildings.	Fit-for-purpose properties with capacity and capability to support delivery of SCS.	**Benefits exceed costs** with an NPV of $3.6m over a 30-year period. Option is preferred to alternatives including: › BAU – requiring increasing intervention and external leasing to meet capacity constraints; › rebuilding on same site – requiring demolition of the existing depot and replacement with new buildings; and › leasing suitable depot site and fitting with building offices and facilities.
NON-RECURRENT EXPENDITURE – TRANSFORMER WORKSHOP		
$27.1m to relocate and rebuild Transformer Workshop.	Fit-for-purpose properties with capacity and capability to support delivery of SCS.	**Benefits exceed costs** with an NPV of $91.1m over a 30-year period. Option is preferred to alternatives including: › rebuilding on same site – requiring demolition and rebuild with an interim strategy of replacing rather than repairing transformers; and › phasing out workshop and purchasing rather than repairing transformers.

9.9 Other non-network

Capex $50.4 million

2.1% of total capex

Our forecast of $50.4 million[38] covers several distinct and un-related areas, including establishing an 'innovation fund'; and operational technology systems for network management.[39]

9.9.1 Innovation fund

Our forecast of $16.0 million in capex and $4 million in opex is to establish an 'innovation fund'. This is to pursue initiatives likely to return long term consumer benefits, but which have not been fully scoped as the fund will seek to explore over the course of 2025-30, the optimal delivery methods, technologies, systems / processes, and partnering arrangements to use.

We have successfully delivered innovation in 2020-25. Our trials of technology, systems and processes via world-leading research yielded significant consumer and NEM benefits, and were adopted by other distributors. We developed world-first solutions to integrate CER including DOEs for exporting customers. We maximised use of the AER Demand Management Innovation Allowance Mechanism (**DMIAM**) and leveraged external funding sources to minimise costs on consumers.[40]

Figure 46: Innovation - Key achievements in 2020-25

	What we achieved in 2020-25	Benefits to customers in 2025-30
Flexible constraint management – solar PV customers	After an award-winning pilot with 1k Virtual Power Plant customers to trial flexible exports, we developed capabilities to offer flexible connections, a national standard (CSIP-AUS), via a trial of 150 customers, engaging SA Government and industry. Flexible exports was adopted by SA Government 'Smarter homes' and became a standard connection in 2023. The project won the SA Premier's Award for Innovation in the energy sector in 2023.	Met customer demand for new solar connections in congested areas in 2020-25 without static zero export limits. Improved utilisation of intrinsic hosting capacity and increased maximum customer export limits from 5kW to 10kW. Provided foundation for plans now proposed for export service, minimising the cost of network investment.
Market active solar trial	Trial on how flexible exports supports retailer provision of market-based solar management products, rewarding customers using solar to respond to market price.	Completes pillar of long-term CER integration, showing how flexible exports work with market-based solutions to maximise benefits.
LiDAR / Digital Twin project: River Murray Floods	Tested LiDAR to manage response - first use on extreme events. 3D model allowed view of power lines and poles vs water levels. Trillions of LiDAR data points collected over a 650km river, aided real-time flood modelling.	Despite significant inundation, LiDAR data delayed / avoided disconnections, expedited reconnections, and avoided shocks.

Our 2025-30 proposal responds to expected greater need for innovation than permitted within the DMIAM's small scope and funding cap – responding to the need to enable and leverage the rapidly evolving future energy market, work collaboratively with third parties in improving community resilience to climate change, and to drive greater environmental sustainability in our operations consistent with new objectives in the NEO.

[38] The gross 'other non-network' capex of $83.0 million, offset by $-32.6 million of superannuation costs.

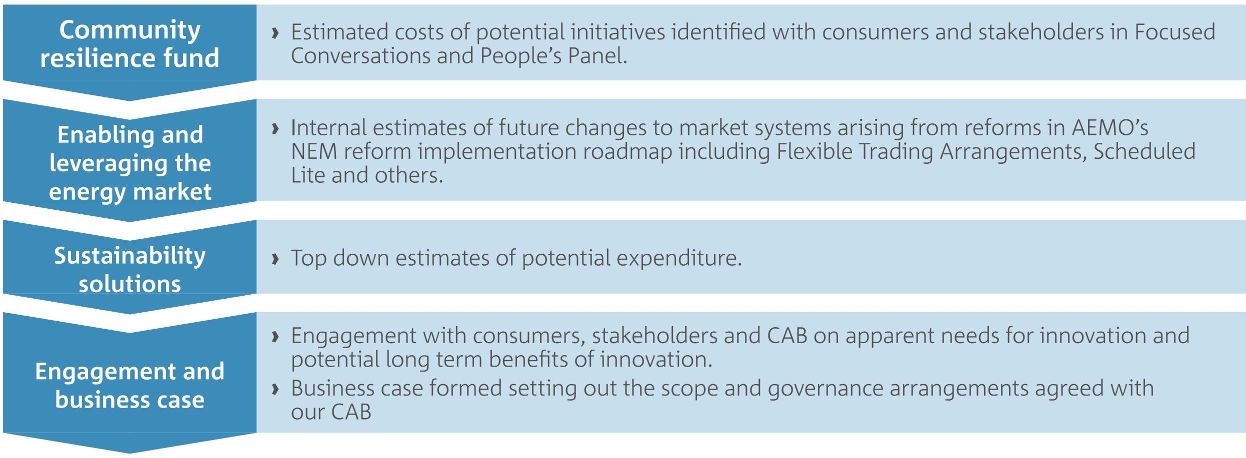
[39] Other non-network also includes other general cost items ($24.4 million) on new or replacement plant, tools and equipment to undertake a variety of network infrastructure work. As this does not pertain to specific initiatives but rather to generic resource costs, it is detailed in the respective business case rather than detailed in this attachment.

[40] Including via the Australian Renewable Energy Agency (ARENA) and the Reliable Affordable Clean Energy for 2030 program.

Expenditure forecasting approach

Expenditure was forecast top-down, considering our past innovation, the need for further innovation in 2025-30, and bottom-up cost estimates of potential initiatives. This led us to forecast a total $20 million cap, split 80 percent to capex and 20 percent opex.[41] The forecast considered three key themes agreed with our CAB (1) Enabling and leveraging the future market; (2) Community resilience; and (3) Sustainability solutions.

Figure 47: Innovation fund expenditure forecasting methodology



The identified customer service needs

Overall need for the Innovation fund

We need to respond to the DMIAM being typically exhausted and not addressing broader innovation opportunities,[42] and innovation investment not being supported by other AER incentive schemes. In a rapidly changing energy system we need innovation on a broader set of drivers facing our business and the services that we provide. This fund combines initiative areas that could drive long-term customer benefits, but which are difficult to scope and develop economic cases for due to initiatives being intentionally not fully scoped at this point. As agreed with our CAB, we propose three broad themes to address via the fund, as set out below.

Need underlying (1) the 'community resilience' theme

To enhance network and community resilience to extreme weather events, we need to explore joint funding opportunities with third parties - fostering information sharing collaboration with other utilities and emergency services agencies / communities to identify vulnerabilities and put in place solutions.

Need underlying (2) the 'enabling and leveraging the future market' theme

We need to test models to share real-time information on the dynamic status of the network with third parties, such as via location-based pricing models to procure network support via market interfaces. This can more efficiently utilise network support from third parties (VPPs, community batteries etc), while informing parties of market opportunities. This can also help us manage increasing challenges of system security and support future market reforms from the Energy Security Board's Post-2025 market review.

Need underlying (3) the 'Sustainability solutions' theme

We need to improve sustainability via innovation and partnering to explore heavy fleet electrification on a customised basis and model scheduling system changes needed to integrate EVs into our fleet en masse.

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41 We propose that the opex component be added via the revenue control formula, allowing transparency and facilitating our proposed 'use it or lose it' mechanism.

42 Noting the DMIAM focuses on managing network demand.

The preferences of our customers

Preferences recommended up to Draft Proposal

Topics on enabling and leveraging the future market, sustainability solutions concerning EVs and community resilience were explored in Focused Conversations, with customers and stakeholders encouraging us to progress these themes. Focused Conversations recommended to the People's Panel the establishment of a 'community resilience fund'. The People's Panel deliberated on and affirmed this recommendation to us.

Engagement with our CAB then considered inherent challenges of developing business cases for these topics involving monetised benefits, particularly in the realm of innovation where uncertainties exist on optimal delivery methods, partnering, or technology choice. The CAB endorsed advancing these investments by establishing an innovation fund that also contains consumer safeguards and oversight.

Preferences recommended post Draft Proposal

Submissions confirmed support for the innovation fund, despite continued cost of living pressures:

- the SA Government's DEM supported the Innovation Fund providing it is efficient to customers long term – our case outlines potential benefits from initiatives in the three proposed innovation themes. We also responded by including safeguards that funded initiatives be subject to assessment principles on the basis of likely benefits, and that any unspent funds be returned;
- EWOSA supported the innovation fund, while wanting us to consider directing some of the fund to a Vulnerable Customer Assistance Program or customer damages claim scheme. We consider the needs for the innovation fund are distinct from these initiatives, and have therefore proposed separate expenditure for our expected new claims scheme obligations; and
- the EV Council supported the fund, and wanted a portion to be used to provide public visibility of network capacity. In response, one of the fund's three themes, (2) 'enabling and leveraging the future energy market' will explore how to more readily expose dynamic network condition information to the market.

Our proposal and its efficiency for customers

OUR FORECAST	SERVICE LEVEL OUTCOME	EFFICIENCY FOR CUSTOMERS
The fund's scope covers the three themes agreed with our CAB: 1. Enabling and leveraging the future market; 2. Community resilience; and 3. Sustainability solutions. The fund's arrangements would be as follows: › a cap of $20 million, split 80% capex and 20% opex; › excluded from EBSS and CESS, providing no benefits from unspent funds; › a 'use it or lose it' fund with underspends returned next period, and opex excluded from the base year in future periods; › commitment to knowledge sharing to benefit the broader NEM and to seek opportunities to leverage government funding opportunities (e.g. via ARENA, government RACE for 2030); and › governance arrangements are still being defined with our CAB but could include the setting of innovation investment principles and oversight of project selection.	Meeting and managing demand for SCS, maintaining system security, and progress against NEO emissions reduction objective.	Unquantified - potential long term benefits via improved productivity resulting in reduced costs, higher output or enhancement of benefits received by all customers and NEM.

9.9.2 Operational Technology (OT)

Capex $42.7 million

1.7% of total capex

Our forecast of $42.7 million ensures the 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 (**ADMS**).[43]

In 2020-25, we forecast spending $40.9 million, 61.1 percent higher than the AER forecast, upgrading our existing ADMS version, to maintain vendor support and cyber security, and investing in Telecommunications Systems and more capabilities to provide ongoing and contemporary system management.

Our 2025-30 forecast is driven by largely recurrent costs of maintaining existing telecommunications systems, and the need to upgrade our ADMS as key components end support arrangements over 2025-30.

Table 17: OT - key achievements in 2020-25

	What we achieved in 2020-25	Benefits to customers in 2025-30
ADMS DERMS	New DER Management System (**DERMS**) capability to enable management of CER via ADMS.	Assists maintaining network / system safety, compliance, and reliability. Enables dynamic control of CER, and provides a foundational component to our ability to maximise hosting capacity and minimise network upgrades.

Expenditure forecasting approach

Telecommunications systems were forecast top-down, reflecting recurrent costs. The ADMS upgrade was forecast bottom-up, considering different combinations of application, database, and operating system supportability to ensure cyber security while maintaining current vendor support level.

The identified customer service needs

Telecommunications systems

There is a recurrent need to maintain existing telecommunications systems used to manage the network and to deliver operational and business telephony.

ADMS upgrade

We need to keep the ADMS operational, mitigate cyber risks and maintain compliance. We assess that under a BAU option of continuing to operate the existing system, cyber risks will increase to unacceptable levels due to the product vendor withdrawing support for key components of over 2025-30.

The preferences of our customers

Together with our CAB, it was deemed that this topic did not warrant consumer engagement. However, as noted in section 9.6 in relation to ICT, consumers via Focused Conversations and the People’s Panel have consistently communicated a strong preference for us to invest to mitigate cyber security risk – the proposed upgrade of our key operational system in the ADMS also actions on this preference.

[43] Our ADMS is used to manage our distribution system in a safe and secure manner.

Our proposal and its efficiency for customers[44]

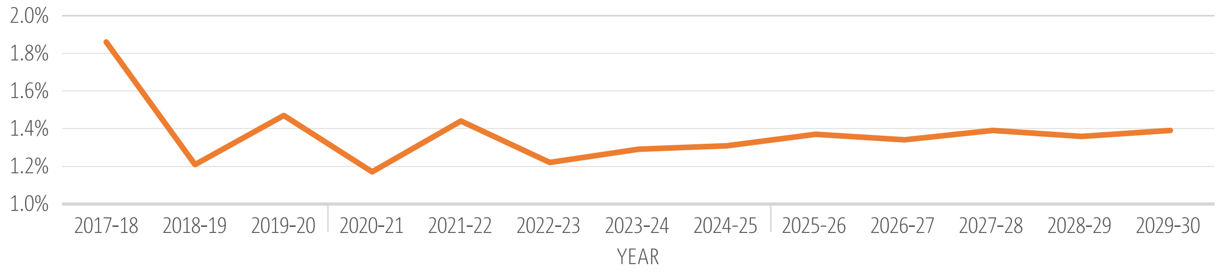
OUR FORECAST	SERVICE LEVEL OUTCOME	EFFICIENCY FOR CUSTOMERS
TELECOMMUNICATIONS SYSTEM		
$6.9m to continue to maintain our telecommunications systems.	Maintain safety, reliability and compliance.	**Least cost solution** to maintain service. Option preferred to higher cost alternative of upgrading / replacing systems no longer fit for purpose due to changing communications technology.
ADMS UPGRADE		
$32.4m to continue proactively refreshing systems and coverage	Maintain safety, reliability and compliance.	**Least cost solution** to maintain service. Preferred to doing-nothing, posing cyber security risk.

[44] Our forecast also includes $3.4 million of recurrent capex required to maintain our existing OT cyber security and resilience capabilities. Further detail on this component of OT expenditure is provided in the Supporting Document 5.12.6 - Cyber Security Refresh, which covers both ICT and OT capabilities.

9.10 Capitalised network overheads

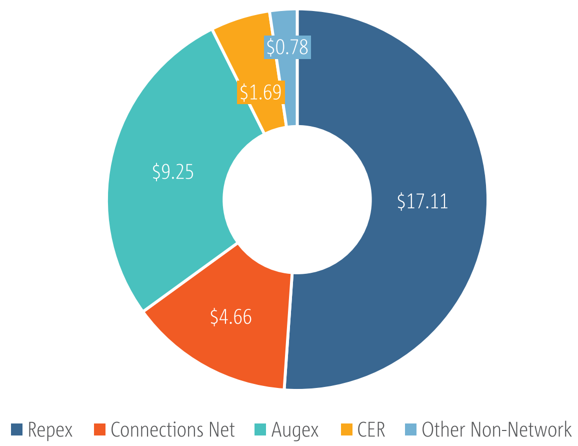
These include indirect costs that we incur in delivering network and non-network capex programs. This includes costs associated with our Network Management and Field Services department's general and senior management costs including asset services, works program, planning and engineering, customer solutions and others.[45] 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 network overheads as have been reported within our Regulatory Information Notices.

Figure 48: Network overheads as a percentage of total capex



Expenditure on capitalised network overheads is forecast to be $33.5 million and represent 1.4 percent of the total capex forecast for 2025-30. This forecast is based on the historically observed ratio of network overheads to direct costs of network projects experienced in 2020-25, as shown in Figure 48. Figure 49 displays how capitalised overheads are split between other expenditure categories.

Figure 49: Application of capitalised network overheads



[45] SA Power Networks expenses corporate overheads in opex. Further information on our practices are set out in **supporting document 5.1.6 – accounting practices and guidelines manual.**

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

In forecasting capex consistent with the Better Resets Handbook, we engaged consumers and configured the inputs (i.e capex programs and projects) to align to their preferred service outcomes. In doing so, we considered multiple actual and potential interactions between these inputs, as summarised in Table 18, to ensure:

1. **no double counting –** of costs contained throughout our Regulatory Proposal; and
2. **optimisation –** considering the most efficient combination of investment actions to achieve the desired service need.

Table 18: Interactions between expenditure areas that were considered

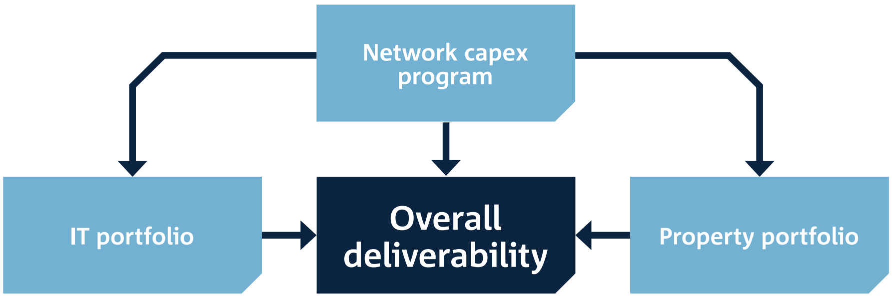
Service outcome proposed	Programs / projects to achieve outcome	Interactions with other programs	How we avoided double counting	How we optimised
Maintain overall network reliability by geographic region	REPEX – to maintain reliability risk exposure from network asset condition	CER INTEGRATION export service 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 is a combined augex / repex case.	Assessed repex and augex only solutions, and selected an optimised mix to meet compliance at least cost.
	AUGEX MAINTAIN UNDERLYING RELIABILITY PROGRAM – address non asset condition effects	As above re repex	As above re repex	
Improve CBD reliability	CBD RELIABILITY IMPROVEMENT PROGRAM (REPEX & AUGEX)	REPEX HINDLEY STREET SWITCHGEAR project	CBD program replaces underground cables and installs automated switches – no overlap with Hindley Street zone substation assets.	Hindley street repex addresses future service risk of specific CBD asset, while CBD reliability program considers current drivers of poor reliability and performance over entire CBD.
Improve reliability for worst served customers	AUGEX WORST SERVED CUSTOMERS RELIABILITY IMPROVEMENT programs	As above re REPEX		
		Between the AUGEX WORST SERVED CUSTOMERS RELIABILITY IMPROVEMENT programs	Table cataloguing upgrades across reliability improvement programs used to identify and eliminate duplicated / related upgrades.	Cataloguing avoided potential duplication of upgrades and optimised, so each program is efficient with a positive NPV result.

Service outcome proposed	Programs / projects to achieve outcome	Interactions with other programs	How we avoided double counting	How we optimised
		OPEX – emergency response	Opex saving counted as negative step change.	
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 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 expenditure program	CER COMPLIANCE program will increase export hosting capacity reducing the need for CER augex.	Hosting capacity benefits from compliance included in base case for CER augex program, so not included in CECV benefits of CER augex.	CER augex model assumes an underlying increase in export capacity year-on-year arising from compliance program, before considering any augex investment.
		NETWORK VISIBILITY PROGRAM increases flexible export efficacy.	Effect considered in the base case for CER augex model, as above.	Benefit is modelled and reduces forecast future export curtailment, before any augex investment.
		AUGEX CAPACITY program component addressing LV quality of supply	Combined modelling tools used between programs.	Transformers replaced via CER augex and use of flexible exports prevent growth in export driven quality of supply issues, keeping to historical spend.
Reduced network capital works delivery costs	ICT ASSETS & WORK - improves asset management efficiency to reduce cost of delivering network work	TOTAL NETWORK CAPEX	A cost reduction was applied as a post-model adjustment across repex, augex, and CER programs.	
Maintain network supply security and ability to meet demand	AUGEX CAPACITY program	As above re CER INTEGRATION		
		DEMAND FLEXIBILITY program	Demand flexibility targets portion of residual VCR risk remaining from augex capacity program, ensuring no overlap.	Augex capacity is based on hybrid probabilistic / deterministic planning that doesn't resolve all forecast VCR risk. Demand flexibility reduces customer impact of the residual risk.
		REPEX	Programs cross-checked. HV assets covered in HV capacity augex not included in repex.	
Reduced emissions	FLEET – replacing of 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.

11 Our capex program is deliverable

A key consideration in proposing an uplift in our overall capex for 2025-30, has been to ensure that our plans are deliverable, having regard to timing of practical implementation and required supporting staff and other resources. This was an important topic for customers that we proactively engaged on. Deliverability is 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.

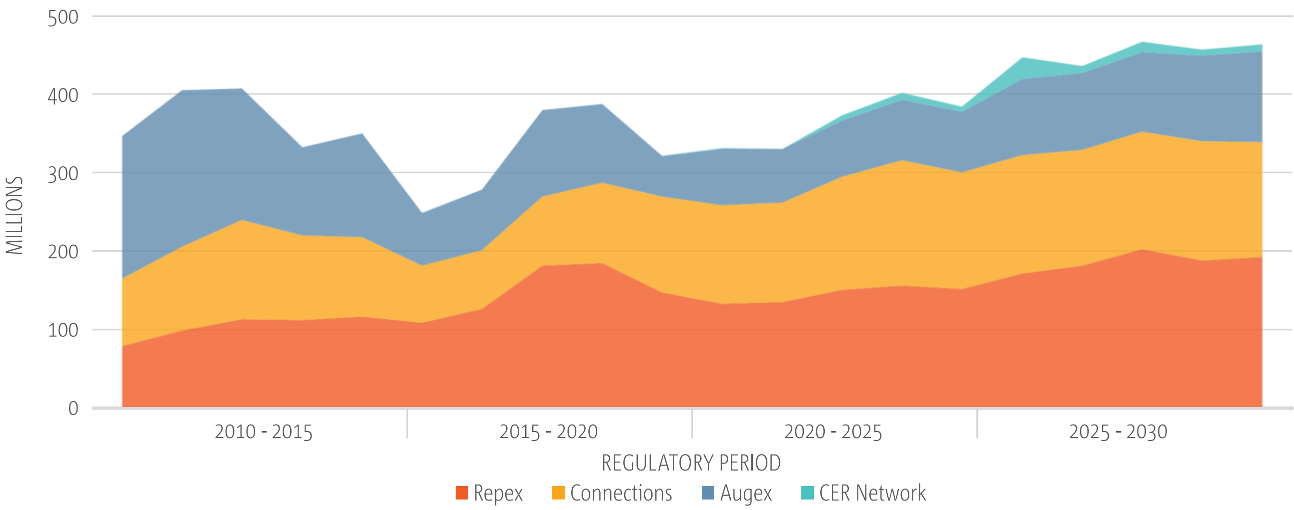
Figure 50: Key considerations in overall deliverability



Network capex program

The key deliverability assessment concerned our total network programs covering: repex, augex, CER integration and connections.[46] As displayed in Figure 51, we are forecasting an uplift on our 2020-25 spend, although we have ensured delivery of similar levels of network capex in past periods.

Figure 51: Actual and forecast gross network capex for 2010-2030



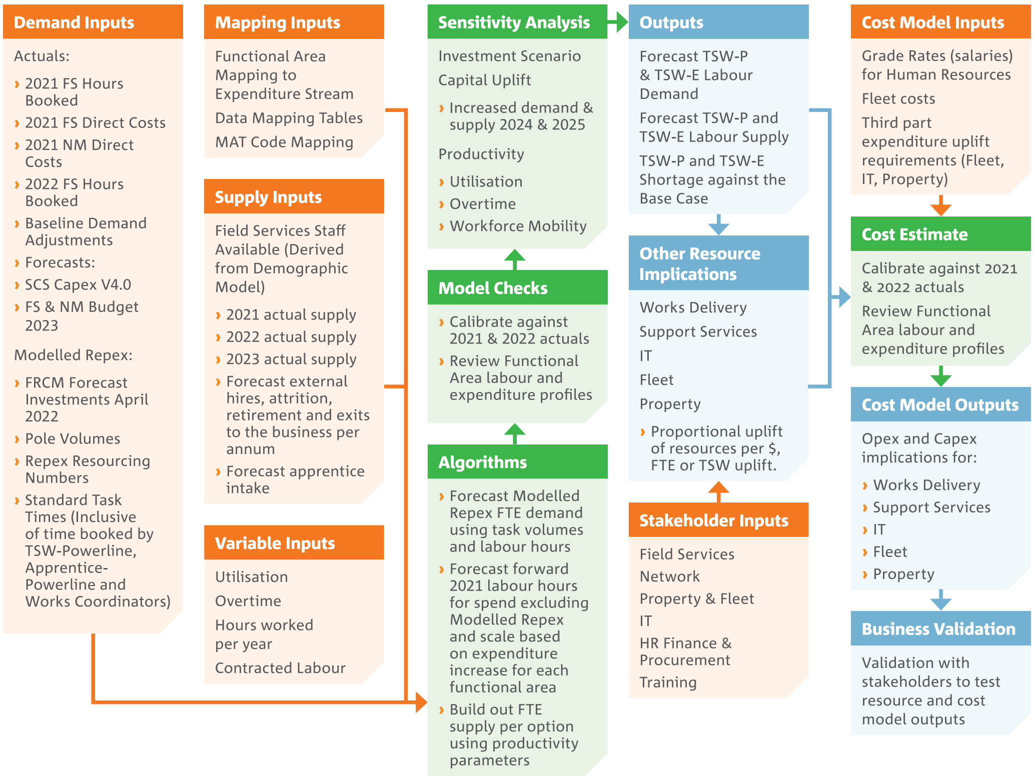
Recognising that an uplift in work requires additional staff and that this then triggers additional supporting resource requirements (e.g. IT equipment, fleet, parking spaces and workstations, corporate support etc), we undertook a business-wide program to model resourcing options and costs with key features including:

- **modelling:** building a robust resourcing and costing model to identify requirements and options;
- **resource constraints**: identifying primary constraints, being an uplift in field workers, and available options. Our demand for additional 'Trade Skilled Workers – Electrical' can be met by maximising our existing apprenticeship program capacity and recruitment and / or external contractors, and 'Trade Skilled Workers – Powerline' can be met by maximising our apprenticeship program capacity;

[46] This analysis considered gross connections rather than the 'net connections expenditure' included in our total capex forecast for our Regulatory Proposal, as gross connections more accurately reflects the total volume of actual work we will undertake.

- **supporting resources**: estimating supporting resources for additional staff to deliver their work, based on current correlations / utilisation between staff and resources, including additional: support services staff; vehicle fleet; office space; IT hardware and software to enable human and fleet resources;
- **expenditure:** calculating additional capex in relevant categories, and opex into a step change; and
- **adjusting for efficiencies**: modelling the effect of our proposed ICT 'Assets and Work Phase 3' program – as this reduces the work delivery cost by improving asset management processes, these efficiencies also reduce the additional resources needed to deliver the 2025-30 network program. This adjustment was included in our forecast resourcing capex and opex step change.

Figure 52: Resource and Cost Model Methodology



Property portfolio

We have forecast a comprehensive portfolio of property works with multiple small scale recurrent activities and a number of large depot rebuilds. Recognising this, our approach involved considering:

- **construction market**: having regard to current high demand, in scoping, costing and timeline setting;
- **integrated scheduling**: timing major works impacting multiple sites well in advance and with regard to overall resource availability, to ensure timelines are realistic, with continuous management put in place;
- **option deliverability**: investment options were assessed for relative deliverability implications[47]
- **market sourcing**: outsourcing delivery of capital construction and operational maintenance where required, drawing on existing building panel arrangements, and with assessment of market availability;
- **past practice**: examining lessons from our past success in building new depots to schedule and budget;[48]
- **bundling**: grouping works by region or project type and builder, for economies of scale – this was further examined based on advice from our CAB through our engagement.

47 For example, we considered the prudency and efficiency of replacing our transformer workshop within a short timeframe as a single project versus the higher resourcing implications of investing in ongoing capital maintenance and replacements.

48 The Angaston Depot as a recent example of a large industrial development.

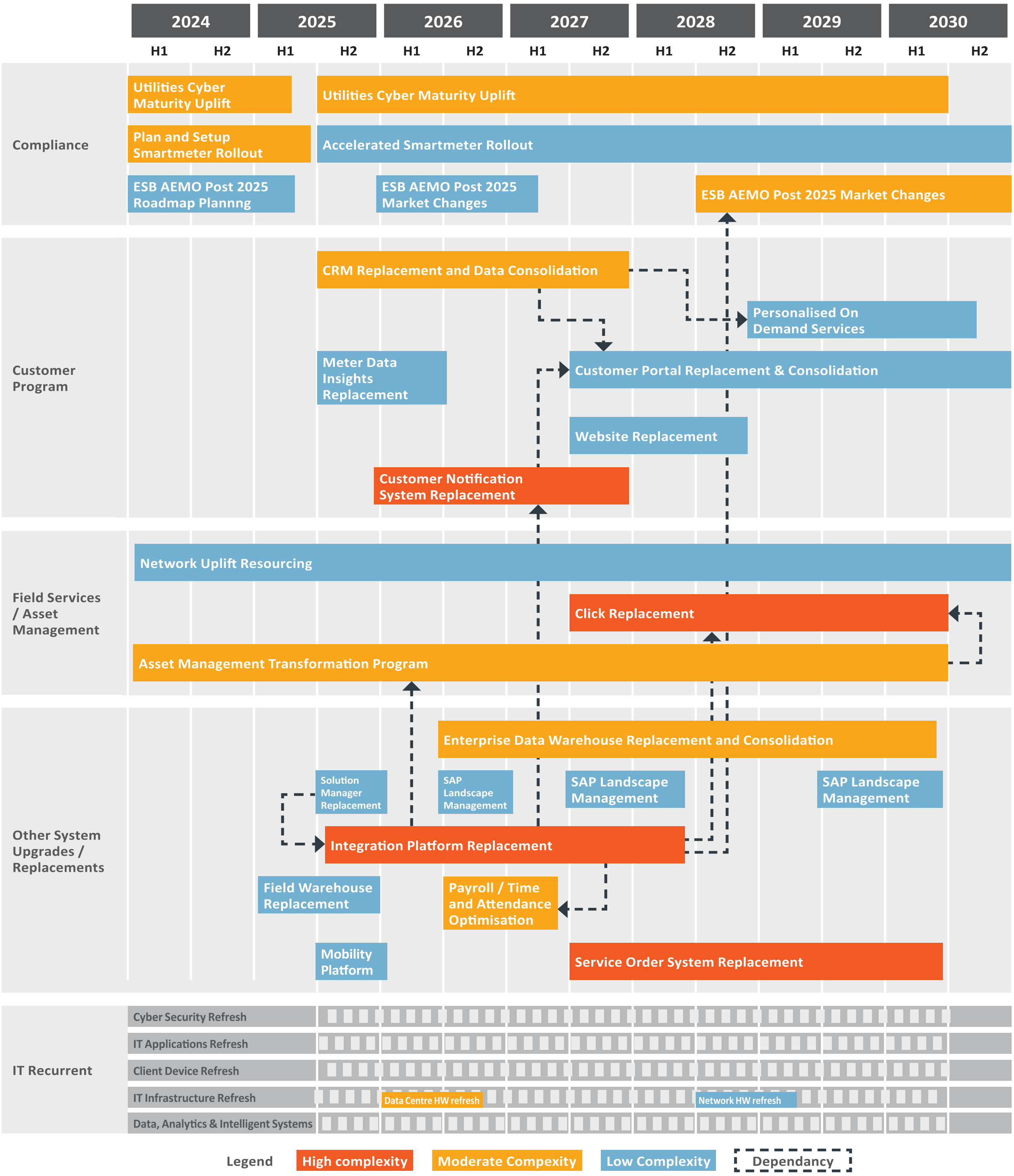
ICT portfolio

Our ICT portfolio comprises a high volume and variety of works as shown in Figure 53, consistent with past regulatory periods. We have delivered a portfolio of similar magnitude of works over the past 10 years (with more complex changes) without impacting customer service and while adapting to significant changes in services. We also have a long history of successfully estimating project costs and delivering on those estimates, as demonstrated in our ICT Post Implementation Reviews and in our IT investment Plan. The key features of our approach to deliverability for ICT included:

- considering the design of our whole portfolio to maximise positive customer outcomes:
  - grouping related projects into programs to efficiently share resources and minimise delivery cost;
  - accounting for the complexity and impacts of each change to ensure risks are spread across the RCP, to minimise the impact on customer services and the possibility of cost overruns;
  - leveraging key dependencies between programs and projects to ensure efficient long-term delivery, and accounting for impacts across programs (e.g. the network uplift and Assets and Work Phase 3 program);
  - delivering customer benefits / outcomes as early as possible within the portfolio;
- having a mature and flexible resourcing model with long term contractual arrangements with key suppliers across Australia, enabling efficient sourcing and ramp up / down as required; and
- having effective approaches to manage high demand skills such as on cyber security and advanced data science, which will be key issues in the next RCP. We built an ecosystem of partnerships that has allowed us to grow and ramp these skills internally, using tertiary education institutions and software supplier, complemented by national and international experts.

Overall, our ICT portfolio plan delivers on identified business and customer service needs, spreads delivery risk across the RCP, and minimises the cost and impact to normal operations and to customers.

Figure 53: ICT portfolio plan of investments through to 2030



Appendix A – References to supporting documentation

The table below lists all of the expenditure areas 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 19: List of references to supporting documents

Section of capex attachment	Business cases	Methodology Documents
9.1 Network asset replacement expenditure (repex)	5.3.1 - Network Asset Replacement expenditure - Business case 5.3.10 - Hindley Street Substation 66kV Replacement - Business case 5.3.11 - Mobile Substation Replacement - Business case	5.3.4 - Repex model framework – Methodology 5.3.2 - Repex Forecasting Approach - Methodology
9.2 Network asset augmentation expenditure (augex)		
9.2.1 Network Capacity	5.4.2 - Augex Capacity - Business case	5.4.1 - Capacity Methodology Document - Methodology
9.2.2 Powerline Environment Committee Program (PLEC)	5.8.9 - Powerline Environment Committee - Business case	
9.2.3 Network resilience	5.8.3 - Network Resilience mobile generation - Business case	5.8.4 - Network Resilience mobile generation forecasting Structure - Methodology
9.2.4 Reliability management programs	5.9.3 - Maintain underlying reliability performance program - Business case 5.9.5 - Worst Served Customers Reliability Improvement Programs - Business case	5.9.1 - Reliability forecasting structure – Methodology
9.2.5 Bushfire risk management programs	5.6.1 - Bushfire Risk Management - Business case	5.6.2 - Bushfire Risk Management forecasting approach – Methodology 5.6.3 - Bushfire Model Framework - Methodology
9.2.6 Augex - other	5.8.1 - Augex Environmental - Business case 5.8.2 - Augex Strategic - Business case 5.8.5 - Augex Network Safety - Business case	5.8.7 - Augex Reliability forecasting approach - Methodology
9.3 CBD reliability improvement program	5.3.12 - CBD Reliability - Business case	
9.4 Connections expenditure	5.5.1 - Justification Document: Connections Expenditure 2025-2030 Regulatory Proposal - Business Case	
9.5 Customer Energy Resources integration expenditure	5.7.3 - CER Compliance - Business case 5.7.4 - CER Integration - Business Case 5.7.5 - Demand Flexibility - Business Case 5.7.6 - Network Visibility - Business Case	5.7.2 - Compliance Strategy 5.7.9 - CER Integration Modelling Methodology 5.7.15 - CER Integration Strategy - Strategy

9.6 Information and Communications Technology		
9.6 ICT- Recurrent	5.12.4 - IT Applications Refresh - Business case 5.12.5 - Client Device Refresh - Business case 5.12.6 - Cyber Security Refresh - Business case 5.12.7 - IT Infrastructure Refresh - Business case 5.12.8 - Data, Analytics & Intelligent Systems Refresh - Business case	5.12.23 - ICT Forecast Methodology & Business Case Structure – Methodology 5.12.1 - IT Investment Plan 2025-30 - Asset Plan
9.6 ICT - Non-recurrent: major replacements or upgrades	5.12.17 - Customer Program: Website replacement - Business case 5.12.18 - Customer Program: Customer Portals Consolidation - Business case 5.12.19 - Customer Program: Customer Notification System Replacement - Business case 5.12.20 - Customer Program: Meter Data Insights System Replacement - Business case 5.12.21 - Customer Program: CRM Replacement & Data Consolidation - Business case 5.12.10 - Click Replacement - Business case 5.12.11 - Enterprise Data Warehouse Replacement & Consolidation - Business case 5.12.12 - Integration Platform Replacement - Business case 5.12.13 - Service Order Module Replacement - Business case 5.12.14 - SAP Small Module Lifecycle Management & Optimisation - Business case	
9.6 ICT - Non-recurrent: new compliance	5.12.9 - Cyber Security Uplift - Business case 5.12.29 - ESB AEMO Post 2025 Roadmap Changes - Business case	
9.6 ICT - Non-recurrent: new or expanded capability	5.12.15 - Assets & Work Phase 3 (Asset Management Transformation Program) - Business case 5.12.22 - Customer Program: Personalised on Demand Services - Business case	
9.7 Fleet	5.10.1 - Fleet Business Case	5.10.5 - Fleet Expenditure Forecasting Approach - Methodology
9.8 Property		
9.8 Property - Recurrent	5.11.7 - Recurrent property portfolio - Business case	5.11.1 - Property expenditure forecasting Methodology
9.8 Property - Recurrent - Renewals	5.11.10 - Pt Augusta Depot - Business case 5.11.12 - Mt Barker Depot - Business case	
9.8 Property - Non-Recurrent	5.11.8 - Transformer Workshop - Business case	
9.9 Other non-network	5.13.3 - Plant and tools - Business case	
9.9.1 Innovation fund	5.7.7 - Innovation Fund - Business case	
9.9.2 Operational Technology	5.13.1 - ADMS Version Upgrade - Business case 5.13.2 - Telecommunications Systems - Business case	

Glossary

Acronym / term	Definition
ADMS	Advanced Distribution Management System
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
ARENA	Australian Renewable Energy Agency
AMTP	Asset Management Transformation Program
Augex	Augmentation expenditure
BAU	Business as Usual
CAB	Community Advisory Board
CAM	Cost Allocation Method
CAPEX	Capital expenditure
CBD	Central Business District
CECV	Customer Export Curtailment Value
CER	Customer Energy Resources
CESS	Capital Expenditure Sharing Scheme
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DEM	The South Australian Government Department for Energy and Mining
DERMS	Distributed Energy Resources Management System
DFA	Distribution Feeder Automation
DMIAM	Demand Management Innovation Allowance Mechanism
DOE	Dynamic Operating Envelopes
DUoS	Distribution Use of System
EBSS	Efficiency Benefit Sharing Scheme
EDC	Electricity Distribution Code of South Australia
EDP	Enterprise Data Platform
ERP	Enterprise Resource Planning
ESB	Energy Security Board
ESCOSA	Essential Services Commission of South Australia
ETC	Electricity Transmission Code of South Australia
EV	Electric Vehicles
EVM	Enhanced Voltage Management
EWOSA	Energy and Water Ombudsman of South Australia
HILP	High Impact Low Probability event
ICE	Internal Combustion Engine
ICT	Information and Communications Technology
ISP	Integrated System Plan
LRF	Low Reliability Feeder
LV	Low Voltage
LVPE	Low Voltage Planning Engine
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
PQ	Power Quality
RCP	Regulatory Control Period
Repex	Replacement expenditure
RLF	Rural Long Feeders
SAAS	Software as a Service
SACOSS	South Australian Council of Social Services
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
WACC	Weighted Average Cost of Capital