2024–29 Regulatory Proposal

For submission to the Australian Energy Regulator

31 January 2023

Empowering communities for a resilient, affordable and net zero future

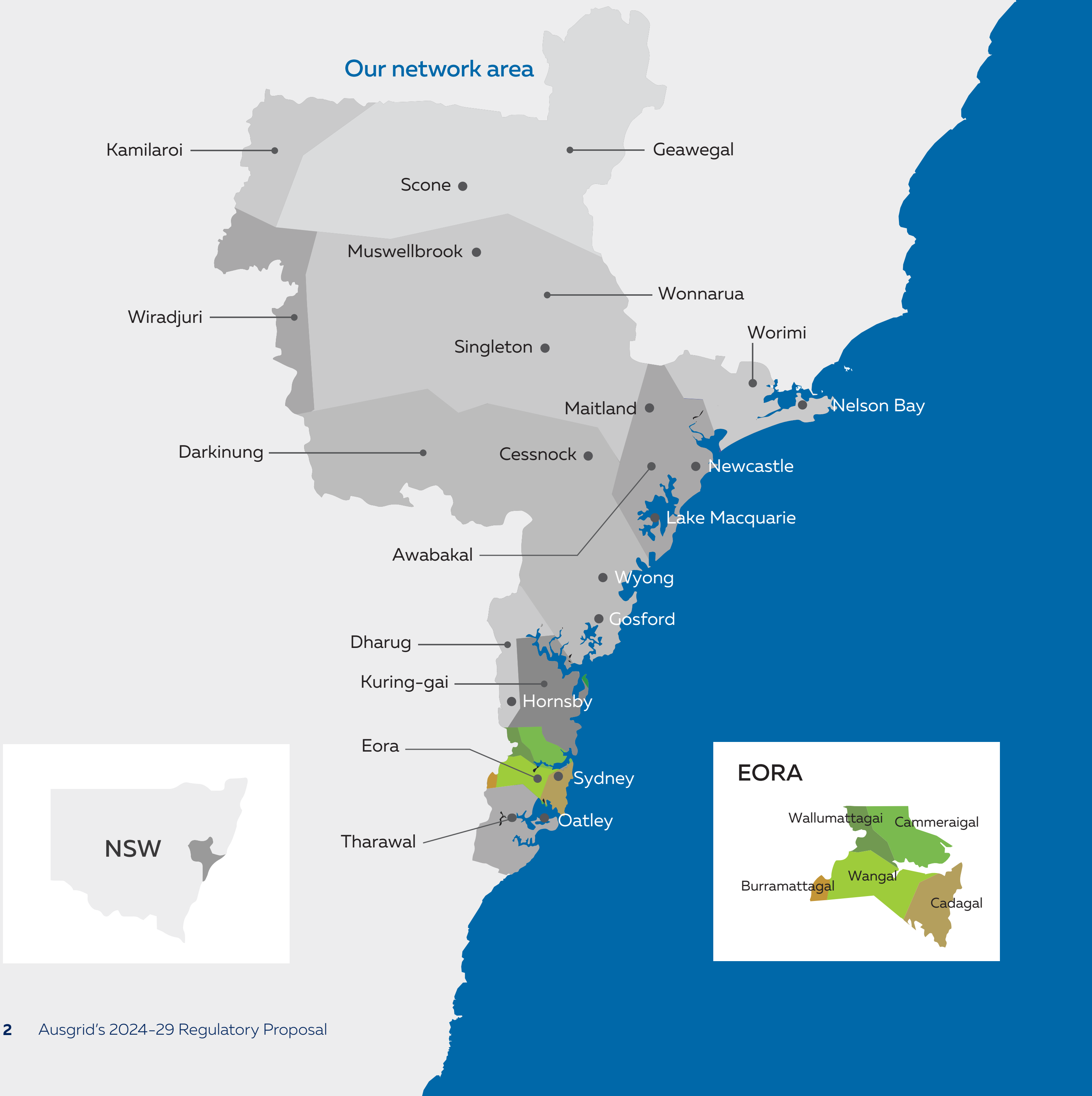
Ausgrid

Acknowledgment of Country

We acknowledge the Traditional Custodians of the lands where the Ausgrid distribution network is located, and we pay our respects to the elders past, present and emerging.

As set out in our Reconciliation Action Plan, it is important that this recognition leads to industry wide support and understanding of the knowledge, stories, languages and experiences of Aboriginal and Torres Strait Islander peoples, as our way of paying respect, and contributing to, some of the oldest continuous cultures of the world.

Our network and operations span the traditional country of 17 languages, tribal and nation groups in Sydney, the Central Coast and Hunter regions of New South Wales. We want to lead and foster a workforce, and approach to our operations, that embraces the learnings, voices, cultures and histories of these Traditional Owners into our own organisation.



About Ausgrid

Ausgrid owns and operates the network of substations, powerlines, underground cables, and power poles that delivers power to communities in large parts of Greater Sydney, the Central Coast and the Hunter.

We build, operate and maintain this distribution network with a focus on providing a safe, reliable and affordable energy supply to all electricity consumers in our network area, both now and over the long term.

Our vision is for communities to have the power in a resilient, affordable, net zero future.

The revenue we earn and the prices we charge for our distribution network services are regulated by the Australian Energy Regulator (**AER**) under the *National Electricity Rules* (**NER**).

About this Regulatory Proposal

This document and its supporting attachments form our Regulatory Proposal to the AER for the period 1 July 2024 to 30 June 2029 (**2024-29 period**). It provides the information the AER requires to make its determination on the revenue we can earn and the prices we can charge over this period to efficiently deliver a safe, reliable and affordable energy supply in the long-term interests of our customers.

It aligns with Ausgrid's vision that our communities have the power in a resilient, affordable and net zero future.

While our Regulatory Proposal is primarily designed to meet the AER's requirements, we welcome feedback on our proposal from our customers and stakeholders via the AER's consultation processes.

Our Regulatory Proposal has been shaped by extensive consultation with our residential and business customers, our delivery partners, and other stakeholders such as customer advocates and government agencies. It will allow us to respond to the key challenges and opportunities that face the communities we serve, our business and the energy system both now and into the future, in accordance with our customers' priorities and preferences.

We have also provided an easy-to-read **Overview** of this Regulatory Proposal which includes descriptions of how our customers influenced our thinking for the Regulatory Proposal and the benefits that it offers to our customers.[1]

1 The NER provide that a distribution network service provider's (**DNSP**) Regulatory Proposal must be accompanied by an overview paper in reasonably plain language which includes certain matters (NER, cl 6.8.2(c1)).

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Message from the Chairman and CEO

We are delighted to present our 2024-29 Regulatory Proposal to the AER. This moment represents a key milestone in delivering our communities' ambition, and our vision, for a resilient, affordable and net zero future.

We were exceptionally grateful for the submissions we received on our 2024-29 Draft Plan, Pricing Directions Paper, and draft Climate Resilience Framework.
This proposal acts on that feedback. It reflects the commitment of our customers and partners to support the transformation of the grid to facilitate a cleaner energy future.

When we last made a Regulatory Proposal to the AER in 2018, our customers were telling us that we were inefficient, we weren't customer centric, and we weren't innovative enough. We have spent much of the last 5 years responding to that feedback and we are pleased to say that we have made real progress.

We are now much more efficient, AER opex benchmarking shows that we are the most improved business in the National Electricity Market (**NEM**) over the last 5 years. We are much more customer centric, having made significant improvements in customer service outcomes and engagement and consultation. We are more innovative, with the help of our customers we have implemented electric vehicle (**EV**) charging, microgrid, community battery and pricing innovations.

There are significant challenges ahead. We all know that we must take steps now to deliver net zero. Our proposal reflects our commitment to supporting customers get the most out of their investments in rooftop solar, batteries and EVs in a way that supports lowest cost decarbonisation for all.

New technologies and ways of living and working are leading to new patterns of energy use and customers are expecting individualised and affordable, zero emissions energy solutions. These changes mean collaboration, engagement and customer focus have never been more important. They also create new opportunities for customers to be rewarded for using the network more flexibly.

Our communities have told us our plans must prepare the network for increasing external threats. In response we are proposing to invest in improving network and community resilience. This initiative is designed to address an increase in extreme weather events resulting from a changing climate. Our resilience investment must also ensure our network and operations are prepared to meet the cyber security challenges of an ever-increasing threat environment.

As we face these challenges, we do so in a context of increasing cost of living pressures. These are driven by rising energy bills and interest rates, while inflation is at levels not seen in decades. Those pressures challenge us all and directly impact this proposal. In response this proposal includes several measures designed to offset some of the upward pressure on prices.

So as we face these challenges together, we have looked to our customers for help in balancing these competing priorities of resilience, affordability and pursuing net zero. We thank all who have engaged with us, most notably the Reset Customer Panel (**RCP**) who have challenged us every step of the way to ensure we have got that balance right. We are confident this proposal reflects the communities' views and aspirations for our future energy system.

Yours sincerely,

Dr Helen Nugent AC
Chairman, Ausgrid

Marc England
CEO, Ausgrid

Executive summary

1

Over the past decade, Ausgrid has taken significant steps to transform our business and better meet our customers' expectations. This has included reducing our costs, delivering more affordable services, and working to better understand and respond to our customers' expectations.

Figure 1.0.1

Our recent achievements

Taking bold steps forward, with the support of our customers, has prepared us to meet the challenges of our changing climate and the transition to a low carbon economy.

Ausgrid's journey: Progressively moving towards a community-focused business by acting on feedback

Improved reliability
Since 2015 we improved our network's reliability by reducing the average number of outages by 11%

Industry leading safety
Since 2015, we reduced our total recordable injury frequency rate by 71%. It is now at an industry leading level

Genuine engagement with our Customer Consultative Committee
Core group of customer advocates established to challenge our customer and service delivery

Customers directly involved in network investment
Established Network Innovation Advisory Committee to guide our 2019-24 innovation program of $42 million

Improved bushfire preparedness by working with customers
Redesigned approach to rectifying defects on private poles, with strong improvement in customer action (95% of defects rectified)

Updated materials for customers who rely on life support machines
Refreshed materials to reflect customer input, increasing satisfaction from 65 to 77% between May 2020 and March 2022

Adapted to power outages during COVID
Surveyed customers to understand the impact of outages during the high school certificate and worked with 159 customers on the best course of action

Commenced Sydney's first network-run Community Battery trial
Extensive community and council participation to design trial. Potential to save participants up to $200 a year by enabling them to use more rooftop solar

Targeted Culturally and Linguistically Diverse community engagement
Co-designed Train the Trainer program for community leaders to increase energy and bill literacy.
Participants reported more confidence when speaking to their retailer

Addressed long standing concerns about tree trimming practices
Collaborated with City of Newcastle to better plan tree planting activities to deliver urban greening and keep the community safe

Collaborated with emergency services
Hosted a Summer Readiness forum with 91 emergency services and council attendees to review storm protocols and encourage more resilient communities

Energy efficient public street lighting
Worked with 26 councils across Sydney to plan upgrade of 92,000+ main road streetlights with energy efficient LEDs

Improved network planning for 2025-29
Co-designed engagement framework with customers. Voice of Community deliberative panel established with 45 customers over 60 hours across 9 months

Partnered on net zero - International Community for Local Smart Grids
Foundation partner in international collaboration to share knowledge on smart technologies to deliver net zero

IAP2 Organisation of the Year – Highly commended
Recognised for our continued commitment to putting communities at the heart of our business

Pre 2019 | **2019** | **2020** | **2021** | **2022 and beyond**

Reducing our costs
Since 2015, we have reduced our operating costs by over $400 million (more than 50%) and our share of household bills by $241 (30% reduction)

Consulted on network planning for 2019-24
Listened to feedback on quality of customer engagement and commenced journey to improve engagement practices

Removed barriers to service restoration
Worked with the regulator on policy reforms that help vulnerable customers

Joint cross-sector collaboration to improve customer outcomes: the Energy Charter
One of the first businesses to provide transparent reporting on customer outcomes against the Energy Charter principles

Major storm events (2019-20)
140,000 customers without power
Adapted outage information to address customer needs including improved website and SMS

Introduced 'always on'
Voice of Customer Program to capture act on customer and service outcome insights across 25 different channels, increasing customer confidence from 39% to 60% since inception

Improved website experience
Website improvements to make it easier for customers, improving service ease scores from 56 to 70%

Introduced free electric vehicle charging
Extensive community and council participation to install free EV chargers. 15 chargers live; 55.5 tonnes CO_2-e saved; 162,000km of free EV travel

Refreshed Strategy FY22 with customer and employee input
Customer needs and aspirations research, customer advocate input and 200+ employees shaped Ausgrid's future direction

Improved performance in Northern Beaches storm event (12/2021)
(a test of lessons learnt in 2020)
35,000 people without power
68% of customers satisfied with Ausgrid's actions to prepare the community

Leadership in community resilience
Commissioned research on climate impacted areas. Hosted stakeholder forum to identify network solutions, 170 attendees with 82% satisfaction score on the forum

Published Draft Plan for 2024-29
Published our first ever Draft Plan to test our ideas with customers and stakeholders, allowing them to influence our plans for the future, with 30 submissions received

Merriwa Microgrid
Launched our first microgrid project in rural Hunter Valley to help customers most impacted by outages to have alternative sources of emergency electricity

Emissions target
Our emissions target is an 8% reduction by 2023-24, 50% by 2030 and net zero by 2050. So far we are ahead of our plan with a 13% reduction, aligning our own targets with the community's net zero ambition

1.1 Challenges and opportunities for our Regulatory Proposal

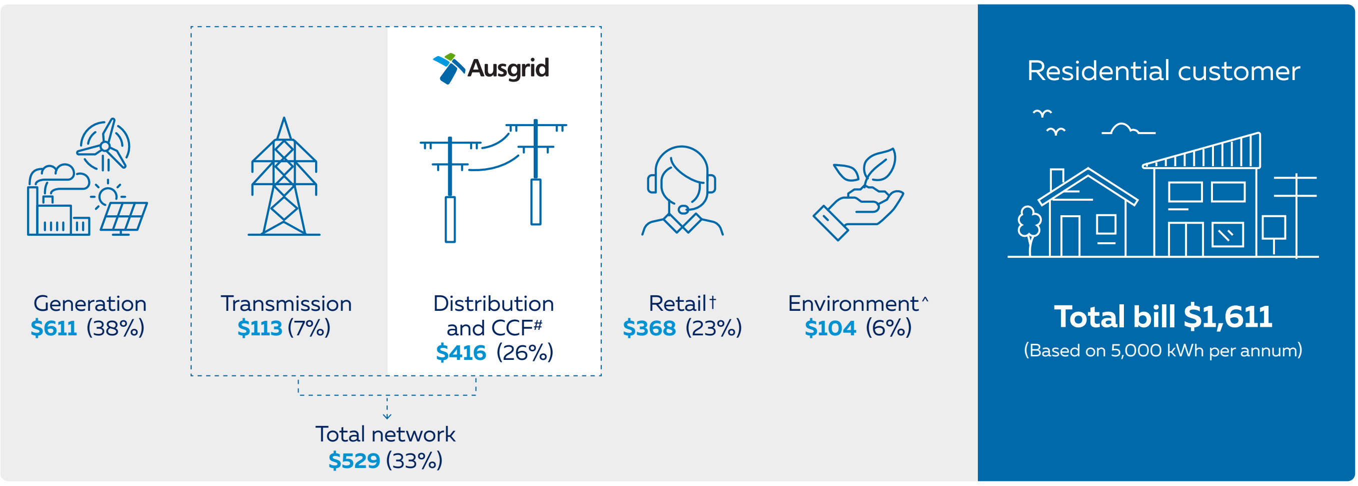
As we look ahead to the 2024-29 period, the challenges and opportunities for Ausgrid and the communities we serve have never been greater:

- **Economic conditions are worsening**. Inflation is at its highest level in more than 20 years. Interest rates are rising and are expected to continue rising over the coming years. This will increase our borrowing costs, and place financial strains on our communities.
- **Climate change** means our poles, wires and other assets must be able to withstand more frequent and extreme weather conditions. At the same time, **cyber attacks** are becoming more frequent and sophisticated. Both of these challenges present growing risks to the resilience of our network services. Without greater network resilience, we could see more frequent and prolonged outages, with significant impacts on lives, livelihoods and safety across our communities.
- The **transition to a low carbon economy** is being spurred on by government commitments to net zero by 2050 and our customers' increased uptake of Customer Energy Resources (**CER**) - such as rooftop solar, household and community batteries, and EVs. Electricity networks like us are an essential platform for the cost effective transition to net zero. We need to be able to accommodate the growing uptake of CER and manage the increasingly complex energy flows this will create. This is both a significant challenge, and an exciting opportunity.
- The **continuing evolution of digital technologies** is expanding opportunities to improve our service delivery, provide innovative service offerings, increase our efficiency in resolving customer concerns, and make it simpler and easier for customers to interact with us.

We are also submitting this Regulatory Proposal at a time when costs in other parts of the electricity supply chain (see **Figure 1.1.1**) are expected to increase. For example, significant investment in transmission infrastructure to connect large-scale renewable generation to the grid will add costs to the system. Generation costs are expected to increase, as could environmental scheme costs under the NSW Government's Electricity Infrastructure Roadmap (see **Section 2.1**).

In this context, it is vital to ensure our investments reflect the priorities and expectations of our communities.

Figure 1.1.1 Breakdown of a typical residential customer bill ($ real FY23)



Notes:

\# Distribution includes NSW Climate Change Fund.

† Retail includes Metering charges.

^ Government environmental schemes.

1. Amounts exclude GST.
2. Ausgrid total network charges include distribution plus pass through of transmission costs and the NSW Climate Change Fund. Our estimate of total network charges for FY24 is $581.
3. Based on tariff EA116.
4. Some Ausgrid revenue is included in the transmission component

1.2 The affordability challenge

Our communities continue to feel the worst impacts of bushfires, floods and severe storms. They are telling us they are frustrated about the lack of co-ordinated action on climate change and are demanding more from governments and businesses alike. At the same time, the impact of the global pandemic has been followed by sharp increases in the cost of living.

As a result, our communities are telling us they want Ausgrid to do more than continue to deliver safe and reliable energy services. They also want a more resilient grid that delivers better value and supports the transition to net zero.

Our Regulatory Proposal, summarised at **Figure 1.3.3**, reflects how we could deliver our customers' evolving priorities. If approved, it would result in our component of bills (the poles and wires) increasing in price by 4.4% for households, 4.3% for small businesses, and 4.7% for large businesses, on average each year over the 2024-29 period (nominal). This is in addition to the external factors that are impacting the cost of living and energy bills like rising interest rates and insurance premiums (see **Section 2.1**).

In **Figure 1.3.1** we depict our price change for households (as an example) in the context of significant reductions since 2014. It shows that a 4.4% per annum increase is equivalent to our share of the household bill rising from $581 in 2023-24 to $723 by 2028-29. While this is a significant increase over the five year period, average bills remain below our average (nominal) charges in 2014.

This $142 increase over the period is comprised of:

- $34 in **savings in response to affordability concerns**, for example, committing to additional efficiency savings (see **Section 5.12**);
- $139 caused by external factors predominantly **outside of our control**, like rising interest rates and insurance premiums. While we are doing what we can to reduce their impact, these factors will still cause bills to rise (see **Section 2.1**); and
- $37 driven by **investment in areas such as climate resilience, cyber security, delivering net zero and digitisation** – reflecting the priorities being communicated to us by our customers.

Our proposed investment in continuing priorities such as replacing ageing assets and responding to growth in peak demand is 6% lower in 2024-29 compared to our current period spend.

As noted in **Section 2.1**, we also expect costs in other parts of the electricity supply chain to increase.

1.3 Changes since our Draft Plan

As detailed in **Chapter 3**, this Regulatory Proposal has been shaped and significantly improved through the input of our customers and stakeholders over the past 18 months.

A central component of our engagement program for this Regulatory Proposal was preparing a 2024-29 Draft Plan for consultation, which we published on our website in September 2022. We were exceptionally grateful to receive 30 submissions on our Draft Plan, covering areas including climate and cyber resilience, net zero, affordability, pricing reform and ongoing partnership opportunities. In addition to receiving submissions, we also re-engaged with the customers who shaped our Draft Plan, to test whether their views had changed and how we should balance competing priorities given escalating cost challenges.

We summarise the key changes we have made to our proposals since the publication of our Draft Plan in response to customer and stakeholder feedback at:

- **Figure 4.1.3** Facilitating an affordable energy transition;
- **Figure 5.5.4** What customers told us about building resilience to support thriving communities;
- **Figure 5.7.7** What customers told us about delivering net zero through CER integration;
- **Figure 5.7.8** What customers told us about delivering net zero by evolving our services;
- **Figure 5.8.4** What customers told us about prioritising innovation;
- **Figure 5.9.8** What customers told us about cyber security and how we are factoring in their views;
- **Figure 5.9.9** What customers told us about the experience they expect when interacting with Ausgrid; and
- **Figure 5.9.16** What customers told us about upgrading our systems to prepare for the future.

Several of these changes have been targeted at the 2024-29 affordability challenge, including:

- Reducing the speed at which we recover our capital investments (the 'depreciation method') – see **Section 4.7**;
- Reducing the speed at which we recover our investment in the Enterprise Resource Platform (**ERP**) program (from 5 to 15 years) – see **Section 4.7.2**; and
- Pre-committing to a 0.5% per annum efficiency saving across part of our capital program – see **Section 5.12**.

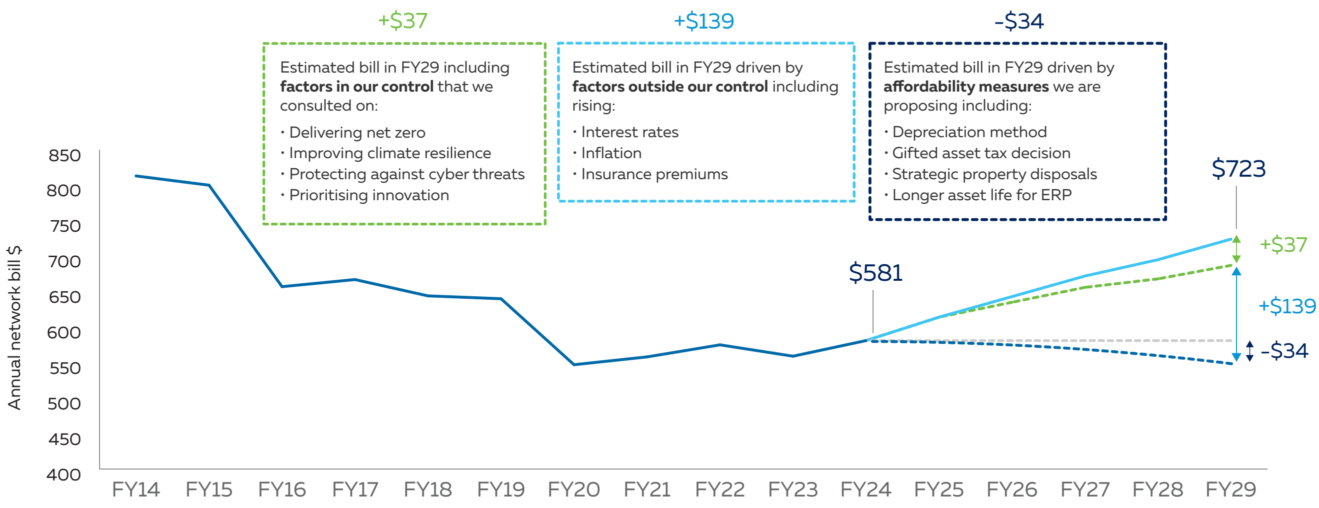
Our Draft Plan consulted on a $38 dollar increase in customer electricity bills from factors within our control and $111 for other factors outside our control. The factors outside of our control continue to increase our forecast revenue compared to our Draft Plan. This is due to interest rates rising further which has increased the rate of return by around 0.1%. We have also seen increasing inflation forecasts for 2023 and 2024. These factors mean that our revenue compared to the Draft Plan has increased by $186 million to $9,714 million.[2]

We have been working hard to limit the impact of these whole of economy pressures on our customers. **Figure 1.3.1** forecasts a $142 increase in customer bills, down from the $149 forecast in our Draft Plan, representing:

- $37 from **factors within our control** but supported strongly by customers through consultation, down $1 from $38 in our Draft Plan;
- $139 from **factors outside of our control**, up $28 from $111 in our Draft Plan; and
- $34 reduction as a result of our **proposed affordability measures** including strategic property disposals and depreciation methods, which translates to lower electricity bills for our customers. These are new measures introduced since our Draft Plan consultation.

2 Other changes have impacted the bill increases since FY24, including updated assumptions for FY24 bill estimates.

Figure 1.3.1 Drivers of potential increases in household network charges ($ nominal, excl GST)



Note:

1. Ausgrid total network charges include distribution plus pass through of transmission costs and the NSW Climate Change Fund. In FY24 our estimate of total network charges is $581.
2. Bill calculated using 5,000 kWh per year, on EA010 to FY23 and EA116 from FY24 onwards.

If our revenue proposal is accepted, we estimate our total network charges (i.e. transmission, distribution and the NSW Climate Change Fund) would increase in real terms (adjusting for inflation) by 1.5% for households, 1.4% for small businesses, and 1.8% for large businesses in each year of the 2024-29 period. Distribution charges alone are expected to increase by 1.6% for households, 1.4% for small businesses (see **Figure 1.3.2**), and 2.4% for large businesses in each year of the period. We have not included the NSW Energy Infrastructure Roadmap scheme recoveries given this information has not yet been provided by the NSW Government. We note that our customer bill impacts assume a full pass through by retailers and for this reason should be considered estimates.

Figure 1.3.2 Estimated annual impacts of our proposal on the distribution component of customer bills over 2024-29 ($, real FY24)

		Residential	Small Business
	FY24	$429	$923
Next Period	**FY25**	$439	$934
	FY26	$447	$955
	FY27	$459	$975
	FY28	$460	$980
	FY29	$465	$989
Average annual increase		**$7**	**$13**

Note: Distribution component only. Some Ausgrid revenue is included in the transmission component of bills. Residential based on EA116 and 5,000 kWh per year usage. Small business based on EA050 and 10,000 kWh per year usage.

Figure 1.3.3 Ausgrid's 2024-29 Regulatory Proposal on a page

Improving customer experience

More timely and accurate outage information

Making connection processes easier and increasing support for our delivery partners

$21m

Transforming the grid

Introducing pricing arrangements that empower customers and support net zero (see our **Tariff Structure Statement**)

Prioritising innovation and continued transformation through modernising our systems

$204m

Delivering net zero

Connecting 620,000 customer energy assets (including rooftop solar systems, batteries and electric vehicles)

Investing to allow another 1 million customer energy assets to connect beyond 2029

$126m

Building resilience

Protecting against cyber attacks by implementing industry best practice safeguards

Reducing the impact of outages caused by severe weather and supporting community resilience

$314m

Safety and reliability

Ensuring the safety of our people and the community

Maintaining the performance of our 5 million network assets

$1,646m

Connecting customers

Expanding network capacity to accommodate growth

Connecting 55,000 new homes and businesses

$190m

Diversity and Inclusion

Delivering our Reconciliation Action Plan (**RAP**)

Improving services for culturally and linguistically diverse (**CALD**) customers

Exceeding our employee diversity targets

Legend

Increasing priorities

Continuing priorities

$m

2024-29 total expenditure

1.4 We consider our proposal is capable of acceptance

The AER's Better Resets Handbook[3] provides guidance for network service providers to develop regulatory proposals that reflect customer preferences and are capable of being accepted by the AER. We have developed this Regulatory Proposal in accordance with the Better Resets Handbook and believe it is capable of acceptance and reflects the preferences of our customers, which we have elicited through extensive and meaningful engagement.

We demonstrate this throughout our Regulatory Proposal, and note that some matters raised in the Better Resets Handbook are addressed in detail in the following chapters of our Regulatory Proposal:

- **Chapter 3** outlines how this Regulatory Proposal is informed by genuine, high-quality engagement with our customers, delivery partners and other stakeholders, and demonstrably reflects what our customers told us through this engagement about their priorities and preferences;
- **Chapters 4 to 6 respectively** outline our proposed revenue, capital expenditure (**capex**) and operating expenditure (**opex**) for the 2024-29 period and reflect the efficient and prudent costs we will incur. Our **Interrelationships across our proposed expenditure** diagram on **pages 62-3** summarises how we have built our proposed expenditure programs;
- **Chapter 7** describes the incentive schemes we propose to apply for the 2024-29 period; and
- **Chapter 8** provides an overview of **Attachment 8.1 - Tariff Structure Statement (TSS) compliance paper** and **Attachment 8.2 - Our TSS Explanatory Statement for 2024-29**. These attachments discuss the potential implications of our pricing structures and demonstrate progressive pricing reform.

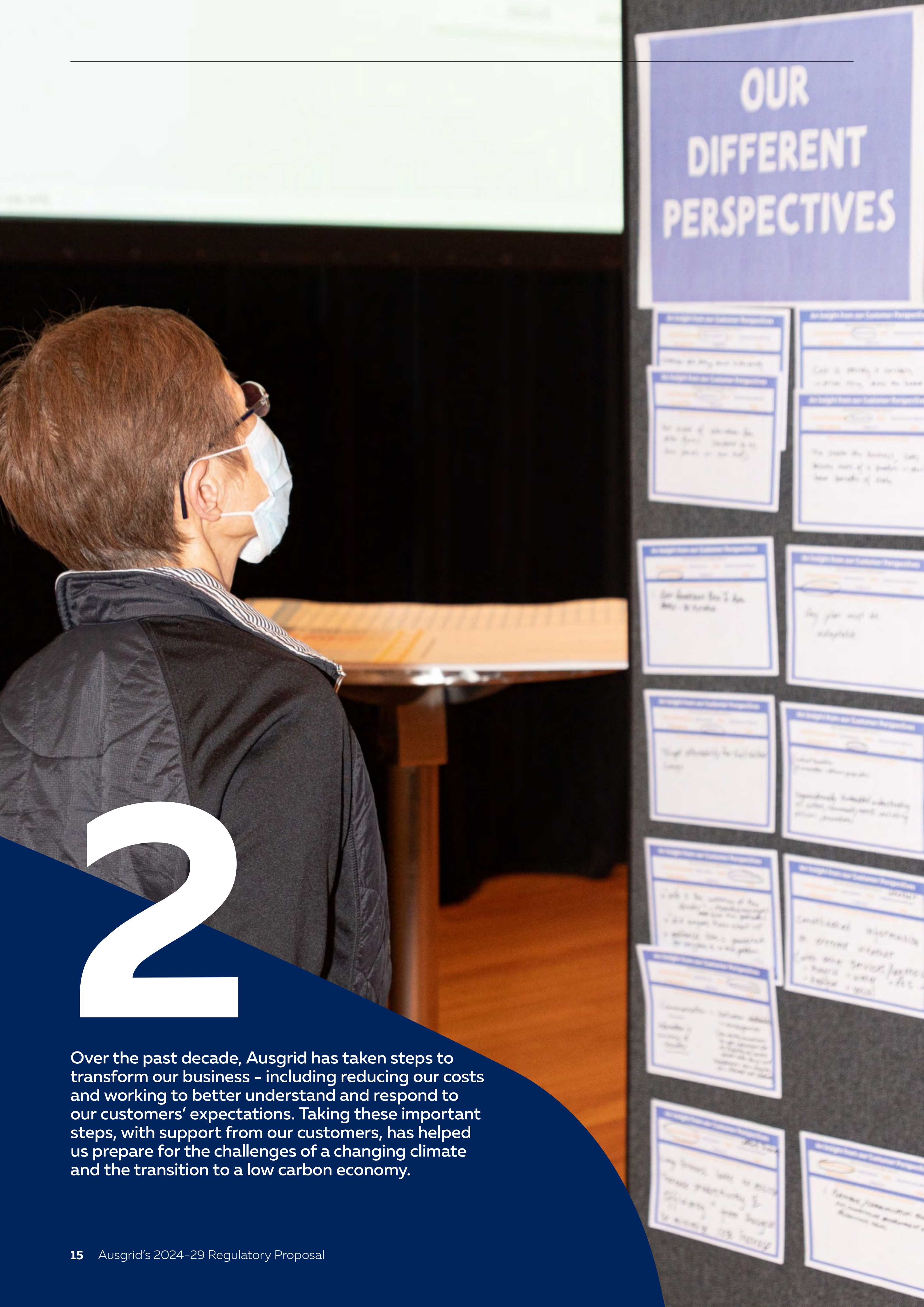
The attachments to our Regulatory Proposal provide further detail to address the requirements of the AER's Better Resets Handbook, provide evidence to support our proposals, and demonstrate that our proposal meets all NER requirements.

To help navigate our Regulatory Proposal and these attachments, we have:

- Included a table at the end of each chapter of this Regulatory Proposal which details the key attachments relevant to each chapter;
- Provided an attachment which provides a summary of all attachments to this Regulatory Proposal (**Attachment 2.1 – Supporting documents list**); and
- Provided attachments summarising how our Regulatory Proposal meets the requirements for regulatory proposals under the NER (**Attachment 2.4 – NER compliance table**) and how we have met the requirements of the Reset RIN Notice Ausgrid received from the AER on 26 October 2022 (**RIN.01 - RIN Response**).[4]

3 AER (2021), *Better Resets Handbook – Towards consumer-centric network proposals* **(Better Resets Handbook)**.

4 Many requirements of the Reset RIN, and the attachments we have prepared in response to the Reset RIN, overlap with the requirements for regulatory proposals under the NER.



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Over the past decade, Ausgrid has taken steps to transform our business – including reducing our costs and working to better understand and respond to our customers' expectations. Taking these important steps, with support from our customers, has helped us prepare for the challenges of a changing climate and the transition to a low carbon economy.

2. Context for our proposal

Our Regulatory Proposal details how we will continue this transformation over the 2024-29 period, in the face of four key challenges and opportunities in particular:

- **Challenging external factors impacting costs** such as high inflation and rising interest rates;
- **Climate change risks** and **other external threats** to our network like cyber attacks;
- The increased pace and urgency of the **transition to a net zero economy**; and
- The continuing **evolution of digital technologies**.

This chapter outlines what these challenges and opportunities mean for our network and customers, and accordingly, our Regulatory Proposal.

2.1 External factors impacting costs

We expect that the following factors (which are largely outside of our control) will increase our costs over the 2024-29 period.

Interest rates

Over recent years, interest rates have been at historically low levels. This has meant that our cost of borrowing has been relatively low, which has helped contribute to lower network prices.

However, economic conditions have now started to change and interest rates are rising. This is demonstrated by the Reserve Bank of Australia (**RBA**) increasing the cash rate in every month since May 2022, and further increases expected.

As interest rates are a major influence on the costs we incur, this will put upward pressure on our prices. More information on our financing costs can be found in **Chapter 4.**

Higher inflation

The cost of living and doing business is rising. In addition, the higher inflation is, the higher our costs, and this will flow through to our network charges. Some of the materials we use to build and maintain the network are increasing by rates much higher than headline inflation. We are absorbing some of these cost increases.

Increasing insurance premiums

Climate change is causing more frequent and severe weather events. This means more frequent damage to electricity networks, which in turn impacts the safety and reliability of supply.

Insurers are limiting their exposure to the energy sector by withdrawing capacity and increasing network businesses' insurance premiums because of the increased risk of extreme weather events.[5]

New costs we must pass through to customers

The NSW Government's Electricity Infrastructure Roadmap aims to deliver significantly more renewable generation capacity by 2030 through five renewable energy zones (**REZs**).

The NSW Government requires Ausgrid and the other NSW distribution networks to pass through a range of costs associated with implementing the Electricity Infrastructure Roadmap (including transmission investment and potential distribution network upgrades) to NSW customers' energy bills from 1 July 2023.[6] While we anticipate that this will impact our future bill estimates, these costs are not reflected in our current estimates because they are not known to us yet.

5 In addition, increased liability claims under Directors and Officers Liability insurance, property bushfire losses under Industrial Special Risks (property) insurance, and the increased potential for claims under cyber insurance have seen our current and forecast insurance premiums for these insurance classes rise significantly.

6 Our customers have told us they want information about what makes up their total retail bill and we are engaging with the NSW Government on how the Electricity and Infrastructure Roadmap's costs and benefits will be communicated.

2.2 Climate risks and other external threats

As the climate changes, our network – like many energy networks around the globe – will continue to face increased risk from extreme weather events like storms, floods and bushfires. At the same time, cyber attacks are becoming more frequent and sophisticated.

More extreme weather

Extreme weather events affect our communities in many ways. They can threaten lives and livelihoods, disrupt support networks for the most vulnerable in society and destroy homes and businesses. When extreme weather events occur, a prolonged outage on our network can compound these impacts. Without the supply of electricity, it may be difficult to use electronic devices to receive critical updates, seek help or check on neighbours. Fallen powerlines also create significant community safety risks.

Extreme bushfires in 2019 and 2020 and floods in 2021 and 2022 have heightened community expectations that governments and essential service providers act to manage climate risk.

For networks like ours, this involves building climate resilience so that our poles, wires and other assets are better able to withstand extreme weather in the most exposed areas. It also involves having adequate community support and recovery resources ready for when major events do occur.

Growing cyber threats

The Australian Cyber Security Centre (**ACSC**) reported receiving over 76,000 cybercrime reports over the 2021-22 financial year (an increase of nearly 13% from the previous financial year), which equates to one report every 7 minutes (compared to every 8 minutes the previous financial year).[7] This report also found that cyber security incidents responded to by the ACSC are growing in severity, that cybercrime has a significant impact on organisations of all sizes, and that cybercrime and cyber security incidents remain underreported. The potential consequences of these threats grow as our own digital footprint expands and more electric devices (such as EVs) interact with our network.

A catastrophic cyber attack on our network (which includes the Sydney CBD) would have social, economic, health and even geopolitical ramifications for Australia. We estimate a complete shut-down of our network would have a total economic impact on our customers of $120 million per hour or approximately $2.9 billion over one full day alone.[8]

To manage cyber threats, NSW regulations require us to use 'best industry practice' to ensure our network and associated information, communications and technology (**ICT**) systems can only be accessed, operated and controlled from within Australia. New requirements now also exist under the recently amended *Security of Critical Infrastructure Act 2018 (Cth)* (**SOCI Act**).

7 ACSC (November 2022), *Annual Cyber Threat Report, July 2021 to June 2022*.
8 Based on the AER's *Value of Customer Reliability* (**VCR**).

2.3 Transition to net zero

While Australia has been transitioning towards a cleaner and more sustainable energy system for some time, the pace and urgency of change is accelerating.

Distribution networks like Ausgrid play a critical role in enabling this transition.

Government policies

The NSW Government is seeking to make NSW a net zero jurisdiction. In addition to the NSW Electricity Infrastructure Roadmap (see **Section 2.2.1**), new policies include the:

- Net Zero Plan 2020 which commits to net zero emissions in NSW by 2050;
- 2021 Electric Vehicle Strategy 2021 which provides $500 million in tax cuts and incentives to increase uptake of EVs in NSW; and
- 2021 Hydrogen Strategy which will result in a significant number of hydrogen electrolysers connecting to our network in the Hunter region.

The May 2022 Federal election showed that the community wants more action on net zero and the new government is reflecting this desire by:

- Rolling out over 400 community batteries across Australia via a budget commitment of $224.3 million;
- A $20 billion 'Rewiring the Nation' plan to accelerate investment in the transmission network and facilitate the growth of large-scale renewable generation;
- Including 'emissions reduction' as a new objective in the National Electricity Objective (**NEO**) via a 12 August 2022 state and federal Energy Ministers unanimous agreement. The draft regulations are currently out for consultation at the time of preparing this Regulatory Proposal, with an indicative timeframe that it will be in effect for our 2024-29 regulatory period; and
- Passing the *Climate Change Act 2022 (Cth)* on 14 September 2022, enshrines into law an emissions reduction target of 43% from 2005 levels by 2030 and net zero emissions by 2050.

Customer investments in CER driving net zero

Households are telling us that they plan to invest more in CER over the forthcoming 2024-29 period and beyond. This is consistent with our forecasts (see **Figure 2.3.1**), which are based on the Australian Energy Market Operator's (**AEMO**) 'Step Change' Scenario.

We expect that by 2029:

- Rooftop solar uptake will nearly double in our network area; and
- The number of home batteries will increase by around 113,000.

Our network will need to evolve to ensure it can efficiently accommodate the increasingly complex energy flows this will create. This has implications for our investment needs over the 2024-29 period.

Figure 2.3.1 Forecast CER uptake in our network area (aligned with AEMO's Step Change Scenario)

Total number on our network (% of total customers)	2022	2029	2034	2039
Rooftop solar systems (% of all customers)	220,000 (12.3%)	400,000 (21.7%)	510,000 (26.3%)	610,000 (30.5%)
Behind-the-meter batteries (% of all customers)	17,000 (0.9%)	130,000 (6.9%)	320,000 (16.7%)	540,000 (27.1%)
Electric vehicles	3,000	370,000	1,110,000	2,050,000
Flexible customer load (e.g. swimming pool pumps and electric hot water systems)	470,000	430,000	410,000	380,000
Total CER assets[9]	**710,000**	**1,330,000**	**2,350,000**	**3,580,000**

9 Refers to number of CER assets not customers.

2.4 The opportunity of digitisation

While we have made significant progress in recent years, Ausgrid and the energy sector more broadly remain out of step with customer expectations for service delivery and automation.

Our goal is to ensure that when a customer interacts with Ausgrid, it is a simple, easy and empathetic experience that exceeds their expectations. To this end, we want to leverage digital technologies to:

- **Offer more innovative services**, such as tailored supply and price offerings to provide customers with more choice and ability to manage their energy costs;
- **Better understand our customers' unique needs** so we can provide high quality, personalised support;
- **Improve how we share data** with our delivery partners, to enable more seamless interactions and smoother service delivery to our mutual customers, and help in rebuilding consumer trust in the energy sector; and
- **Make our processes more efficient**, for example, by automating manual processes to reduce errors, save time and resolve customer issues more quickly.

A cyber-safe digital transformation is critical to keep pace with customers' evolving service expectations while delivering efficiently for customers.

3

Ausgrid is committed to becoming and remaining an industry leader in customer engagement.

3. Our customers' priorities

Over the past three years, we have made significant improvements in our business-as-usual (**BAU**) engagement with our customers, including by establishing our Voice of Community (**VoC**) Program.

Listening and responding to what we have heard through this 'always on' Voice of Community engagement program has helped us to become a better business and deliver better outcomes for our communities (see **Figure 3.1.1**). We have embedded the voice of the community into the heart of our business, co-designing our vision and strategy with our customers as well as engaging on our Regulatory Proposal. Customers have shaped our direction and priorities as well as how we will deliver on these strategic goals in the shorter term.

In designing how we would engage with our customers for our 2024-29 Regulatory Proposal, we built on past improvements and aimed to be ambitious, to take risks and move out of our comfort zone. We did this by partnering with our customers, delivery partners and other stakeholders in our decision-making for this Regulatory Proposal and in the ongoing regulatory process.

3.1 Informed by genuine customer and community engagement and demonstrably reflects what we heard through this engagement

To ensure our proposal responds to our communities' preferences and priorities, we conducted an extensive engagement program over the past 18 months. This program integrated our BAU engagement (through our Voice of Community Program) and our reset engagement across 5 phases:

Phase 1: Establishing the engagement framework (March to September 2021)

We established an independent challenge panel, the Reset Customer Panel to represent the long-term perspectives of customers and challenge Ausgrid on key issues for this reset. We worked with the Reset Customer Panel, as well as our Customer Consultative Committee (**CCC**) and Pricing Working Group (**PWG**), to co-design a framework to ensure our engagement was both deep and broad, and used appropriate methods and channels to overcome barriers to engagement and hear every voice and perspective.

Phase 2: Engaging to inform Draft Plan (October 2021 to July 2022)

We sought community views on the future of the energy industry to identify the main challenges and opportunities we needed to explore when developing our 2024-29 Draft Plan. We then engaged deeply and broadly on these topics over 9 months.

In line with our engagement framework:

- We explored all elements of this Regulatory Proposal with the Reset Customer Panel and the relevant elements with our Pricing Working Group and Network Innovation Advisory Committee (**NIAC**);
- We engaged directly with a wide range of customers, delivery partners and stakeholders through multiple channels including our Voice of Community Panel, using various methods, and analysing data collected through our BAU engagement.

We partnered with independent engagement specialists to ensure transparent and open processes, reduce bias and allow for authentic engagement. We also commissioned the Reset Customer Panel, as part of their role, to have strong oversight of the process and to challenge us on our ambitions and our authenticity.

Phase 3: Engaging to inform regulatory proposal (August to December 2022)

On 1 September 2022 we published our Draft Plan, setting out what we heard through our Phase 2 engagement, the initiatives we were considering in response, and the pricing implications. We invited submissions, and provided multiple additional opportunities for our customers and other stakeholders to provide feedback. We met with our Voice of Community Panel, the Reset Customer Panel and other key customer and stakeholder groups to hear their comments and recommended changes. We specifically tested and retested the affordability of our Draft Plan, including whether our customers were satisfied it provided value for money.

The feedback we received overwhelmingly supported the package of initiatives we included in the Draft Plan. For example:

- Our Voice of Community Panel were reluctant to change anything, as they felt it was 'their' plan and it largely reflected what they wanted;
- Our commercial and industrial customers (**C&I customers**) agreed we had prioritised investment in the right areas, despite the significant challenges of increasing wholesale energy for many of these businesses;
- The level of satisfaction with each element of the plan was high across all customer and stakeholder groups we engaged with; and
- Customers and stakeholders were overwhelmingly positive that the Draft Plan prioritised investments in the areas that matter most to customers, and that it represented good value for money.

Customers and stakeholders made some suggestions to improve the Draft Plan, which we have considered and, in most cases, incorporated into this Regulatory Proposal. **Section 3.6** shows the comprehensive way that customers have influenced this Regulatory Proposal and how we have responded to their feedback.

We consider our engagement to develop this proposal exceeds the AER's expectations as set out in the Better Resets Handbook (see **Figure 3.1.2**).[10]

The sections below outline:

- **How we have engaged** with our communities throughout the reset process;
- **What we heard** through this engagement about our customers' varying priorities and preferences for the reset and beyond; and
- **How we responded** to what we heard.

Figure 3.1.1 Embedding the Voice of Community in our day-to-day business

In 2019 we launched our Voice of Community Program to make engagement with our communities an even more integral part of our everyday business. This engagement occurs across 25 different channels, services and market segments. The Voice of Community Program includes activities such as:

- After every interaction we have with a customer, we ask customers whether their issue was resolved and how easy we were to deal with. If their expectations were not met, we give them an opportunity to request that we re-initiate contact with them to close the loop. To date, more than 108,000 customers have responded to these questions, and we have completed 4,000 close the loop calls.
- We use surveys to measure and evaluate how our communities perceive our performance, and their confidence in Ausgrid as a business. We send surveys to customers in six market segments and to delivery partners in three segments and ask respondents to rate our affordability, reliability, resilience and sustainability. More than 10,000 customers and 1,300 partners have completed these surveys to date.
- We hold regular forums and discussions with key partners and stakeholders, including accredited service providers, energy retailers, and council representatives.
- We participate in industry forums (including the Urban Development Institute of Australia and the National Electrical Contractors Association) and have sought to better serve delivery partners by being more closely involved in the engagement and planning for large infrastructure projects in our area, such as WestConnex.

The Voice of Community Program puts our customers and communities at the centre of our day-to-day decision-making. The insights we receive help us design and deliver improvement initiatives. We harnessed the breadth and depth of these insights to inform the development of our Draft Plan for this regulatory reset.

Phases 4 and **5**: Engagement to inform our Revised Proposal to the AER (December 2023)

After submitting this Regulatory Proposal on or by 31 January 2023, the AER will then consider this proposal and conduct their own independent engagement to seek independent views on our proposal. In parallel with this we intend to continue our engagement with two key aims:

1. Further refine key elements of this plan such as resilience; and
2. Ensure in a changing environment that we remain responsive to our customers' circumstances and can adjust our revised proposal accordingly.

10 AER (2021), Better Resets Handbook p 12-18.

Figure 3.1.2

Our performance against AER's Better Resets Handbook expectations on consumer engagement

	Expectation	Our assessment	Regulatory Proposal reference
Nature of engagement	Sincerity of engagement	Our engagement has been sincere. We have ensured this by giving the independent Reset Customer Panel oversight of our engagement program. This has enabled us to test the questions we sought to ask customers, and methodology used to ensure we knew, before we engaged, how we would use their feedback and respond meaningfully. The Reset Customer Panel were and remain committed to ensure our engagement provide valid and reliable insights. Board-level involvement in our engagement has also been critical in ensuring the buy-in across our organisation to genuine listening and responding. This involved our Chairman and CEO making personal commitments to the Voice of Community Panel that they would listen to and action customer feedback. Materials used in our customer engagement and this Regulatory Proposal showed how we remained transparent and how we incorporated customer feedback.	**Section 3.6** sets out how we have responded to customers' feedback. Customer engagement materials have been shared in **Attachment 3.3a - Customer engagement materials.**
	Consumers as partners	Our engagement framework ensured we partnered with customers in the decision-making process, and that customers continue to be influential in the way we manage our business, as well as the content of our proposal.	**Figure 3.4.1** shows how our engagement framework has been designed to ensure consumers were partners in the process of designing our Regulatory Proposal, including a 10 session deliberative process. **Figure 3.5.2** describes the role of consumers as our partners.
	Equipping customers	We equipped customers by ensuring we engaged early enough to allow time for customers to consider and challenge information presented to them. Customers were able to speak to a range of experts with a variety of perspectives and spoke to experts of their choice. The Reset Customer Panel were funded to enable them to actively participate broadly and deeply in the process, as well as being funded to conduct their own independent research. Materials used in our customer engagement showed how we briefed customers and explained critical concepts, including the questions they asked and responses we gave, and materials provided in their preferred language.	**Figure 3.2.1** sets out our engagement timeline. Customer engagement materials are provided in **Attachment 3.3.a - Customer engagement materials.** **Figure 3.4.1** describes how customers were equipped through the engagement.
	Accountability	We appointed independent community engagement experts who ensured we were transparent in reporting back to customers how we had utilised their feedback and where we had diverged, and why. The Reset Customer Panel observed and reviewed our engagement, as well as the reports provided by our engagement partners. Materials used in our customer engagement showed how we remained transparent and how we incorporated customer feedback.	**Figure 3.4.1** shows how the engagement partners were used to ensure accountability throughout the process. Customer engagement materials are shared in **Attachment 3.3.a - Customer engagement materials.**

Figure 3.1.2
Continued

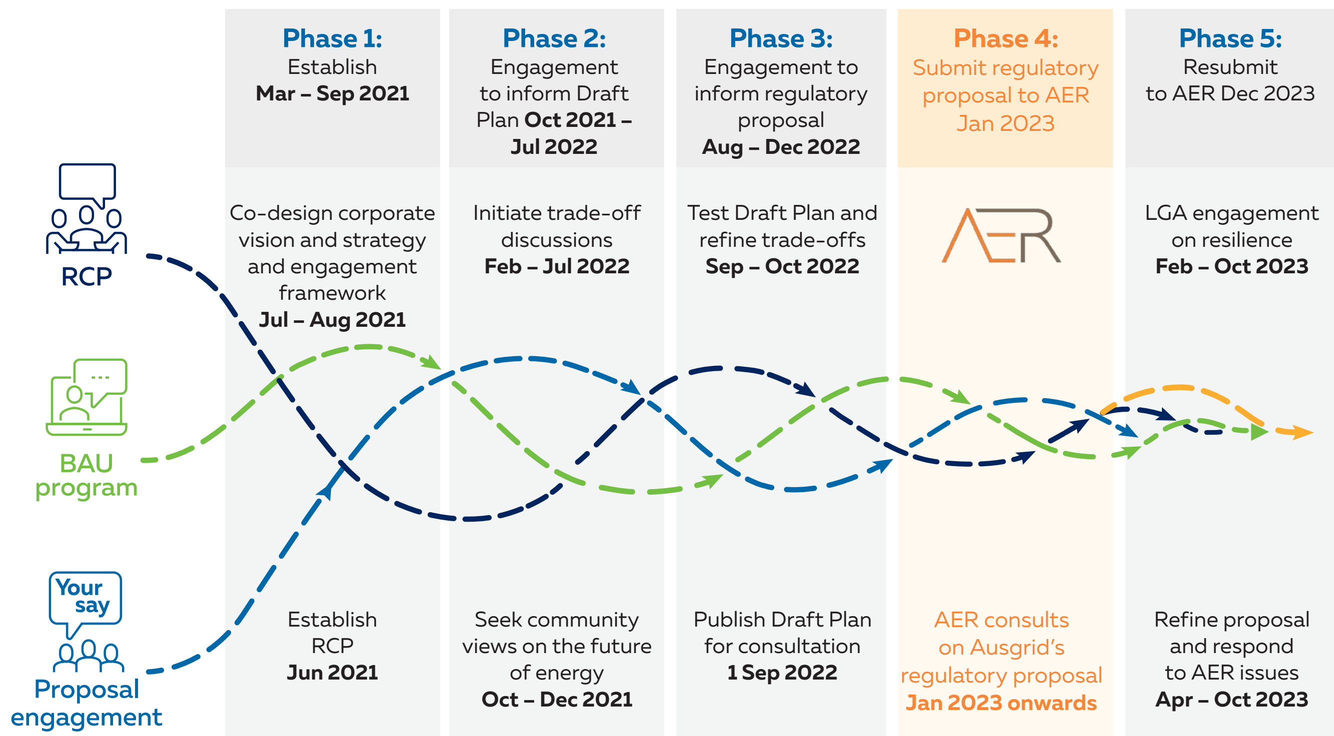
	Expectation	Our assessment	Regulatory Proposal reference
Breadth and depth of engagement	Accessible, clear and transparent engagement	In addition to our face-to-face engagement, our engagement remains accessible through the provision of yoursay.ausgrid.com.au which allows anyone interested to review materials and provide feedback. We also ran a social media campaign promoting the 'Be the Boss' game to reach as many customers as possible and allow them to engage in a simple and fun way. Our engagement was clear and transparent, utilising tools like GroupMap and shared documents that enable customers to give their feedback in their own words. Our engagement was accessible by providing materials and holding dedicated sessions in English and other key languages (Arabic, Vietnamese and Mandarin) to enable a variety of community groups to actively contribute. Materials used in our customer engagement showed how we clearly explained issues to customers, and how we transparently answered their questions, and showed them where and how we had utilised their feedback.	**Figure 3.4.1** describes some of the tools we utilised to ensure transparency. In-language materials produced for Arabic, Vietnamese and Mandarin speaking communities were available **Attachment 3.3.a - Customer engagement materials.** Customer engagement materials are shared in **Attachment 3.3.a - Customer engagement materials**.
Breadth and depth of engagement	Consultation on desired outcomes and then inputs	Our engagement followed a phased approach. Firstly this involved engagement on desired outcomes and priorities, introducing options and trade-offs. It then involved preparing and publishing a Draft Plan to enable transparency of how we would deliver these outcomes and priorities and the inputs required. Finally, we engaged again with customers to inform this Regulatory Proposal. We will continue engaging to shape our Revised Proposal and to ensure we continuously improve our business.	**Figure 3.2.1** shows the phases of this engagement. **Section 3.6** outlines how we moved from desired outcomes to inputs for key themes across the Regulatory Proposal.
Breadth and depth of engagement	Multiple channels of engagement	We implemented 11 new engagement channels for this consultation, in addition to the existing 25 channels already in place through our Voice of Community Program. Many of these channels were also utilised to gather input and feedback for the development of our Regulatory Proposal. We engaged on our Draft Plan and provided customers and stakeholders with multiple ways of providing feedback, including face to face sessions, surveys, submissions tools and emails.	The channels utilised are set out in **Figure 3.4.1** under 'How'.
Breadth and depth of engagement	Consumers' influence on the Regulatory Proposal	Both the Draft Plan and this Regulatory Proposal have been shaped by the priorities and feedback we received from the community and the Reset Customer Panel. We explicitly in our Draft Plan called out those elements which we could control, to enable customers to focus their feedback on areas where their influence would be greatest.	**Section 3.6** details how we have responded to customers feedback and the impact they have had on the proposal. **Figure 3.6.1** shows highlights of the Reset Customer Panel impact on the proposal.
Clearly evidenced impact	Regulatory Proposal linked to consumer preferences	The Draft Plan and this Regulatory Proposal are structured around key themes co-designed with our Customer Consultative Committee, Reset Customer Panel, Pricing Working Group and Network Innovation Advisory Committee members. Our customers have told us they want a resilient, affordable, net zero future, and we have outlined how we propose to deliver this future in later chapters of this Regulatory Proposal.	Our engagement framework **Attachment 3.4 - Engagement framework** sets out the themes, questions and approach codesigned with our consumer advocates. **Section 3.6** details how we have responded to customers feedback and the impact customers have had on our Regulatory Proposal.
Clearly evidenced impact	Independent consumer support for the Regulatory Proposal	We tested our Draft Plan through our independently facilitated engagement (which also had the oversight of our independent panel the Reset Customer Panel), and customers overwhelmingly supported our investment approach and our approach to balancing investment with affordability as set out in our Draft Plan. The Reset Customer Panel noted in its Draft Plan report that: *'Customers .... want Ausgrid to be central to their community's energy future through the deployment and management of community batteries. If this is done well the Panel believes Ausgrid's CER integration program will improve utilisation of the network, make the benefits accessible to many more consumers, reduce energy costs and assist in identifying those customers who, notwithstanding the efforts by Ausgrid to manage fairness, require Government support in the transition.'* [11]	**Figure 3.5.2** shows the level of customer support for the Draft Plan and recommended changes. The Reset Customer Panel have written their own independent report on the proposal **Attachment 3.5 - Independent report on Ausgrid's 2024-29 revenue proposal**.

11 RCP (2022). *Ausgrid's 2024-29 Reset Customer Panel's Draft Report*, p 40.

3.2 How we engaged with our communities

To ensure our Regulatory Proposal responds to our customers' preferences and priorities for the 2024-29 period and beyond, we embarked on an extensive engagement program over more than 18 months. This program integrates our BAU engagement and our reset engagement across five phases (see **Figure 3.2.1**). The sections below outline the key actions we have taken in the first three of these phases, and how we will continue our engagement in parallel to the AER's own consultation.

Figure 3.2.1 Overview of engagement program to inform our 2024-29 regulatory proposal



3.3 Phase 1: Establishment

3.3.1 Co-designing our engagement framework

We worked with our Customer Consultative Committee and other consultative bodies to co-design a framework for our reset engagement program that would facilitate sincere, collaborative engagement with the diverse communities of all different sizes that we serve.

To ensure high quality engagement, we asked an independent consultant (bd infrastructure)[12] to support the co-design process and provide an independent report. This consultant and a range of other specialist organisations also helped to design and deliver key engagement streams and processes.

Most of the co-design work occurred in 2021 and we made refinements throughout 2022 as we implemented the engagement program.

We published our engagement framework in December 2021 and a revised version with our Draft Plan in September 2022. We did this to provide transparency over where we had delivered against the engagement framework and enhance our accountability for any amendments or refinements we made (see **Figure 3.2.1** above and **Attachment 3.4 - Engagement framework** for more detail).

3.3.2 The Reset Customer Panel

Early in the co-design process, we agreed that an independent challenge body was crucial to the engagement, so we established the Reset Customer Panel in June 2021 (see **Figure 3.3.1** below).

The Reset Customer Panel's primary purpose is to represent the long-term perspectives of our customers and to challenge Ausgrid on key issues relating to the 2024-29 period – including our customer and stakeholder engagement, and all elements of our Regulatory Proposal. The Reset Customer Panel is also separately funded to conduct independent research or engagement as it sees fit.

The Reset Customer Panel has been an integral part of our customer and stakeholder governance structure (**Figure 3.3.2**). It reports regularly to the Customer Consultative Committee and ensures alignment and integration with our ongoing key consultative bodies, including our Pricing Working Group and Network Innovation Advisory Committee.

From our perspective, the Reset Customer Panel has been a key influence on our engagement program and the development of our Draft Plan and Regulatory Proposal. The Reset Customer Panel has consistently pushed our business to find better answers to the questions confronting us, and this has resulted in more innovative engagement approaches and a better, more customer-focused proposal. We note that this has required a significant time commitment from Reset Customer Panel members, and corresponding investment from Ausgrid.

We understand that the Reset Customer Panel also considers its involvement in the engagement program to be effective. In its report on the engagement to inform our Draft Plan, Tony Robinson (Chair of the Reset Customer Panel) noted that:[13]

> *'The Panel has been impressed with its access to senior Ausgrid management including the Board, CEO and the executive leadership team. Access has facilitated fulsome and constructive inquiry and dialogue, which Panel members appreciate, as it has allowed a more comprehensive impression of work undertaken on key elements of the revenue proposal. The Panel acknowledges that the commitment given by Ausgrid to engage with, listen to and respond to its customers and the Panel is one that is shared deeply across the business.'*

We also recognise the broader impact the Reset Customer Panel has had on the culture of Ausgrid, including because it has:

- Pushed us to be clearer and more transparent in our communications;
- Assisted us to take real and impactful questions and alternatives to our customers; and
- Encouraged challenge to the status quo, in search for better outcomes for customers.

The Reset Customer Panel comprises six members of our ongoing Customer Consultative Committee and an independent chair. We carefully selected the members to provide deep economic, engineering, policy, legal and engagement expertise, and to represent a range of interests – from commercial to vulnerable and culturally and linguistically diverse (**CALD**) customer groups.

12 See: https://bdinfrastructure.com/.
13 RCP (2022). *Ausgrid's 2024-29 Reset Customer Panel's Draft Report*, p 2.

Figure 3.3.1 Reset Customer Panel

Tony Robinson (Chair)

Tony led the AusNet Services Customer Forum ahead of the distributor's 2019 proposal. He also managed the Brotherhood of St Laurence's financial inclusion department. These appointments followed 13 years in the Victorian Parliament.

Louise Benjamin

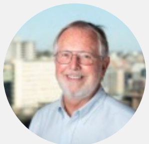
Louise is a commercial and regulatory lawyer with extensive experience in telecommunications and energy regulation.

Gavin Dufty

Gavin is Executive Manager of Policy and Research at St Vincent de Paul Society, Victoria. He undertakes research and policy development in the energy sector.

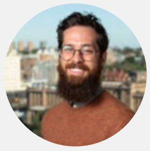
Mark Grenning

Mark is an experienced energy consultant focusing on larger consumers. His work includes advocacy to energy market bodies, networks and governments covering electricity and gas.



Iain Maitland

Iain has worked as the Energy Advocate for the Ethnic Communities' Council of NSW since 2014.



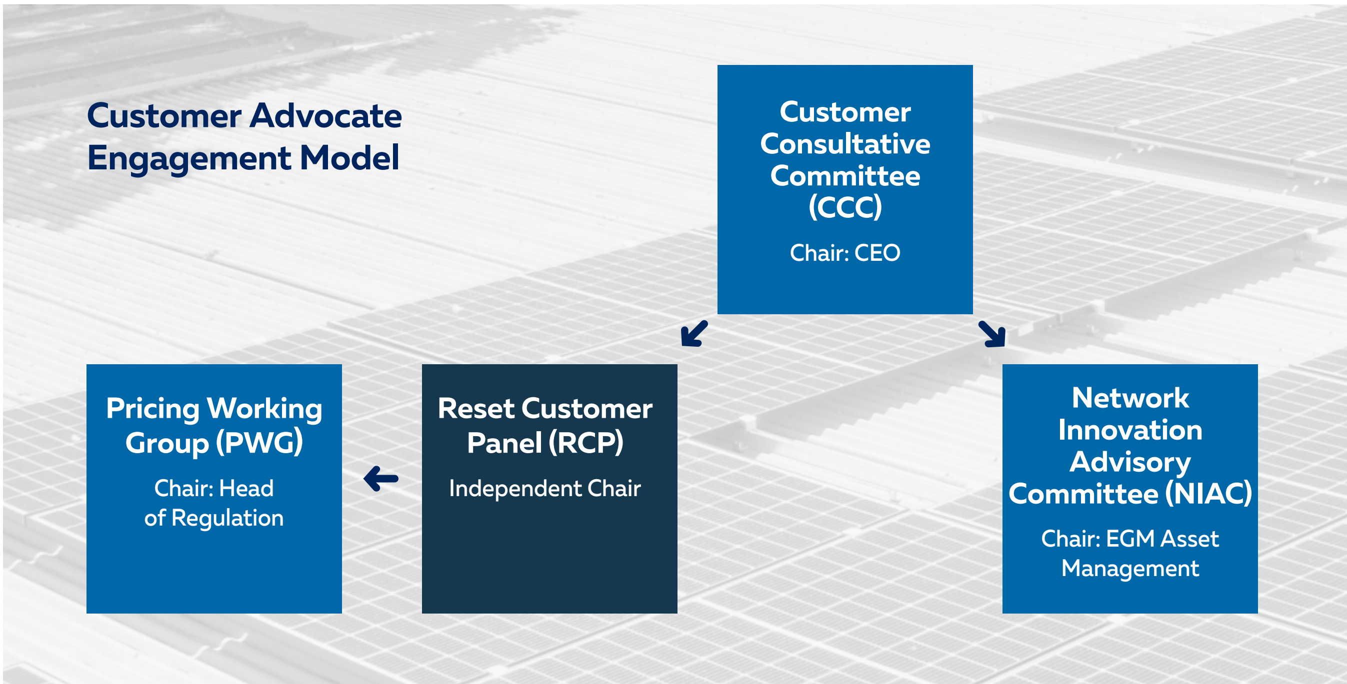
Jan Kucic-Riker

Jan is an energy policy officer with the Public Interest Advocacy Centre. His work seeks to promote sustainable, equitable and affordable access to energy for all people and communities.

Mike Swanston

Mike is a professional engineer with a passion for energy sustainability and a fair deal for energy customers.

Figure 3.3.2 Customer and stakeholder governance structure



- The **Customer Consultative Committee** is our peak stakeholder engagement committee and provides broad customer advocate input to Ausgrid's business planning, customer and business strategy development and implementation;
- The **Network Innovation Advisory Committee** reviews Ausgrid's business cases for planned innovation projects and oversees a $42 million capital funding envelope for approved innovation programs in the 2019-24 regulatory period; and
- The **Pricing Working Group** enables Ausgrid and customer advocates to collaborate on tariff strategies and reforms that promote customer choice and reduce the long-term cost of electricity for customers.
- To inform our 2024-29 regulatory reset we also established the **Reset Customer Panel**. The Reset Customer Panel's role is to help ensure our Regulatory Proposal meets the long-term interests of consumers. The Reset Customer Panel is independent from Ausgrid, well resourced, and able to seek independent expert advice as it sees fit.

Figure 3.3.3 Hearing from vulnerable customers

It has never been more important to lift the voice of vulnerable customers: the impacts of an inflationary environment hit the vulnerable hard, and the extent to which the transition to net zero helps or harms these customers is a measure by which future generations will judge us.

To ensure these critical perspectives are heard, we took a multi-pronged approach:

Understanding the nature of vulnerability

Through our initial research it was clear that the nature of vulnerability is complex, and often compounded by circumstances that for one person may pose no issues but for another exacerbates an already challenging situation. For example, some people living in rural areas enjoy a prosperous life, but for some they have been forced out of the city by high costs of living, which can then lead to increased commute times and costs or lower employment. Additionally, some of the unexpected consequences of rural living (e.g. longer and more frequent outages) can have an increased burden, as it is more difficult for low income groups to recover from consequences of prolonged outages such as a loss of food as they can be less resilient to impacts of these events.

For this reason, we called our vulnerable customers workstream 'Lived Experience' and included not only low-income customers, customers with health needs and elderly customers but also rural and weather event impacted customers, so that we have a more complete picture of how vulnerabilities can play out across our customer base.

Seeking out specific voices and experiences

We sought to hear from a range of different voices in our Lived Experience workstream. We did this by:

- Surveying our own life support customers;
- Hearing from peak bodies representing specific group such as Vision Australia, Deaf Australia, St Vincent de Paul, Uniting Kildonan and others;
- Holding focus groups in geographical areas that had experienced prolonged outages due to extreme weather;
- Holding focus groups with customers living in housing commission housing, elderly customers and customers experiencing low income; and
- Seeking out vulnerable small businesses by conducting interviews in culturally diverse communities and choosing to street walk (walking down a street to speak to available business owners or managers) in areas such as Lakemba where businesses can be more transient.

We also ensured we would hear these voices from the outset by including representatives from St Vincent de Paul and the Ethnic Communities Council of NSW on the Reset Customer Panel.

Creating a holistic community

Hearing and engaging with the specific voices of customers in our community is important and we acknowledge that these customers are an integral part of our communities. We also sought to ensure our Voice of Community Panel was holistic and would represent these lived experience customers as well as the voices of all customers.

We did this by casting the net wide, sending 24,000 letters out to customers. From this, 200 customers applied to be on the Voice of Community Panel. This recruitment process was managed by an independent organisation that specialises in democrative recruitment (Sortition Foundation). Sortition Foundation handled all direct contact with these customers through the recruitment process, and stratified the data – selecting the customers that would go on to be our 45 Panel members.

We are confident that the Voice of Community Panel that was selected by Sortition Foundation is fully representative of the community as bias was removed from the recruitment process.

While we do not know the individual circumstances of each panellist, some panellists did choose to share their stories – which gives us insight into the varied perspectives on the Voice of Community Panel. One individual, who was a strong advocate for her community and other people in her circumstance, shared that she had in the past accessed Energy Accounts Payment Assistance (**EAPA**) vouchers and support from organisations like St Vincent de Paul and that at other times in her life, she had experienced homelessness. Like all our panellists her contribution was extraordinary. Hearing her story reassured us that the Voice of Community Panel was truly representative.

3.4 Phase 2: Engagement to inform our Draft Plan

To inform the development of our Draft Plan, we engaged with the Reset Customer Panel and our other consultative groups to explore and debate all aspects of Regulatory Proposal in depth. We also engaged directly with a wide range of customers and delivery partners to ensure we heard every voice and perspective.

Exploring and debating key issues and inputs with customer advocates

Our engagement with the Reset Customer Panel has been both broad and deep. The panel meets frequently – including independent meetings and meetings with members of the Ausgrid Board, our CEO and our staff to explore, debate and provide customer perspectives on all key components of the Draft Plan and potential trade-offs this may involve. It estimates that its members collectively dedicated over 800 hours to this task in the first 12 months alone.[14]

To guide our work with the Reset Customer Panel, we agreed on four broad workstreams, covering issues related to value for money, network investment, sustainability and the future grid, and customer experience. This allowed Reset Customer Panel members to dive deeply into the areas where they had specific expertise and interest.

We collaborated with the Reset Customer Panel to select, shape and refine potential options that we would then present to our customers throughout the engagement process. This collaboration has been intended to reduce the risk of biasing particular customers and to ensure our engagement was sincere and transparent.

We also engaged deeply with the Pricing Working Group in developing our proposed pricing reforms, which we published in our Pricing Directions Paper in September 2022.[15]

The Pricing Working Group includes a range of customer and electricity industry advocates. For the reset engagement, it was expanded to include energy retailers and aggregators. It met monthly with Ausgrid to discuss topics relevant to the changes and opportunities facing the energy sector, and how our current tariff structures and policies could be reformed to respond to these trends and provide better outcomes for our customers.

In addition, we engaged deeply with our Network Innovation Advisory Committee. The Network Innovation Advisory Committee discussed many of the key issues that were considered in the Draft Plan and are being considered for this Regulatory Proposal, such as net zero technologies, community batteries and resilience, as these programs have strong interconnections to the trials and programs already underway within the Network Innovation Advisory Committee. The Network Innovation Advisory Committee was therefore instrumental in guiding the development of both the engagement on these topics and our proposal.

The Reset Customer Panel was actively involved in supporting our direct engagement with customers and delivery partners. For example, each of the customer and stakeholder groups had a Reset Customer Panel sponsor, and at least one Panel member attended each Voice of Community Panel session, focus group and forum as an observer.

Our engagement meetings and other activities were also open to stakeholders to observe and provide information. We are grateful to the AER and the AER's Consumer Challenge Panel for their participation and observation.

The Reset Customer Panel noted in their report on the Draft Plan[16] that:

> *Having actively assisted the design of a deep, broad and multi-channelled customer engagement framework, the Panel is confident the engagement is delivering accurate and meaningful customer insights that are helping shape the revenue proposal. In particular, the Voice of Community Panel has functioned exceptionally well and delivered an informed set of recommendations.*

14 RCP (2022), *Ausgrid's 2024-29 Reset Customer Panel's Draft Report*, p 15.
15 Ausgrid (2022), *Pricing Directions Paper for 2024-29*.
16 RCP (2022). *Ausgrid's 2024-29 Reset Customer Panel's Draft Report*, p2.

Figure 3.4.1

An engagement framework that facilitates customers as partners

Why

We designed our engagement principles to ensure sincere engagement with a broad range of customers.

Accountable	Inclusive	Collaborative	Dynamic	Transparent

Our objectives ensured our customer advocates (including the Reset Customer Panel) and end customers were partners in the engagement process. They also sought to positively impact staff and the industry.

How

Builds trust and confidence

- Board in attendance
- Transparent engagement tools
- Newsletters – reach multiple people within complex organisations
- Website, **Yoursay.ausgrid.com.au** – access information conveniently and allow feedback from anyone interested
- Map the Indigenous communities, their needs and aspirations
- Data analysis – ensuring customers who provide feedback day-to-day are a central part of decision-making

IAP2 'Inform'

Reaches diverse audiences

- Translation for key language groups
- Games – reach low interest customers
- Surveys – reach low interest time poor
- Street walks – time poor

IAP2 'Involve'

Understand customer aspirations and preference

Interviews –
- Time poor
- Commercially sensitive
- High knowledge

- Forums
- Focus groups
- Round tables

IAP2 'Consult'

Drives cultural change

Industry leading engagement

- Staff involvement
- RCP – Independent challenge and observation through the RCP
- VoC – Citizen's jury (VoC Panel) – access to independent experts, allowing time for conversation, challenge and change

IAP2 'Collaborate'

The success of our engagement framework required knowledgeable engagement partners able to advise the appropriate methodology and ensure delivery in line with our principles and objectives.

nous group	bd infrastructure	Ethnic Communities' Council of NSW Inc.	Indigenous partner	GAUGE Consulting	Edge Red	mosaicLAB
• Review of existing customer literature • Event affected focus groups	• Peak body engagement • Design and oversight of program • Vulnerable / lived experience engagement	• Culturally diverse engagement • Translation of written materials	• Indigenous engagement	• Independent forum facilitation	• API Analysis of BAU data using artificial intelligence	• Deliberative engagement specialists • Independent recruitment of end consumers

When

This approach also necessitated the phasing of our engagement program, to enable the depth of conversations and the cross fertilisation of information between customer groups.

Phase 1

- Co-design of engagement
- Desktop research

Mar-Sep 2021

Phase 2

- Propose alternatives and trade offs
- Project by project bill impacts
- Understand values, preferences, aspirations and needs

Oct 2021 - Jul 2022

Publish Draft Plan for 2024-2029

Phase 3

- Show holistic bill impacts and refine
- Bring together disparate voices

Sep - Oct 2022

Submit Proposal for 2024-2029 to the AER

Phase 4

- AER engagement

Phase 5

- Continue to refine
- Local council area resilience engagement

Feb - Dec 2023

By starting with a review of the existing information available we were able to identify key missing voices and topics. We were then able to match the appropriate methods with each customer group, to meet their needs.

Who

Implementation

Customer numbers and channels

Customer group	Numbers
Commercial and Industrial customers	21, 15
Retailers	24, 70
Councils	33
Accredited Service Providers	209
CALD Households and small businesses	18, 10
Indigenous	3
Small business	30
Vulnerable low income / elderly / event impacted	21, 3,404
Peak bodies and Stakeholders	35
End consumers	2,773, 40,000, VoC 45, 5,744
Reset Customer Panel	RCP

Techniques for making our engagement sincere, accessible, accountable and transparent

Board members and executive staff in attendance

Staff involvement and observation

In language interviews, forums and written materials – to reach non-english speaking customers

Utilise engagement tools that enable customers to write comments directly to reduce interpretation

Reset Customer Panel oversight and observation to ensure transparency

3.5 Phase 3: Engagement to inform this Regulatory Proposal

In September 2022, we published a Draft Plan of our Regulatory Proposal which outlined what we had heard through our engagement up to that date and sought feedback on what we were suggesting to include in our Regulatory Proposal.

The body of this Draft Plan focused on the aspects of our proposal that customers could influence (that is, those expenditure items within Ausgrid's control such as new items of expenditure). It set out our understanding of:

- The key challenges and opportunities facing our business and the energy sector more broadly in the 2024-29 period and beyond;
- What we had heard through our engagement on customers' preferences and priorities in relation to those challenges and opportunities;
- The investments and initiatives we were considering in response to those preferences and priorities and their benefits for customers; and
- The customer benefits and bill implications of these potential responses.

The appendices to our Draft Plan outlined the technical details of our Draft Plan – including our thinking on our proposed revenue for the 2024-29 period, and each of the cost 'building blocks'.

We also prepared and published materials to assist our customers' understanding of our Draft Plan,[17] including:

- Separate papers outlining our then-current thinking on our responses to issues like the impacts of climate change, and alternative control services such as public lighting and metering; and
- Fact sheets that focused on individual elements of the Draft Plan and targeted specific customer or stakeholder groups.

We invited customers and other stakeholders to provide feedback on our Draft Plan, which they could do through a range of channels. These channels included making a formal submission, completing a survey, sending us their thoughts in their own format, playing our 'Be the Boss' game, or attending one of our forums. Written submissions received have been published on yoursay.ausgrid.com.au (where we had permission to do so).

In addition to considering the feedback we received on our Draft Plan, we conducted further engagement with the Reset Customer Panel, the Pricing Working Group and the Network Innovation Advisory Committee, as well as with retailers, councils, peak bodies, our Voice of Community Panel, CALD, small businesses and C&I customers. This engagement was an extension of the conversations we had already begun with these customers and utilised the approach set out in **Figure 3.5.1**.

This further engagement covered key topics, including:

- How the community wants us to evaluate the benefits of solutions such as community batteries where the benefits are not all network based;
- What aspects of our proposed Resilience program do communities most value, and how should we consider where, geographically these investments should occur;
- Whether our Draft Plan got the balance right across investment areas, and whether the cost to customers represented value for money;
- How we should consider phasing bill impacts over the forthcoming 5 year period; and
- Proposed tariff changes, in particular whether an export tariff and reward scheme should be mandated from 2025.

Finally, to ensure a cohesive customer voice we brought together representatives from across all our engagement streams including our Indigenous engagement in a Town Hall meeting. This Town Hall considered:

- Whether the Draft Plan reflected what customers had told us;
- Whether we had the right balance between investing for the future and affordability right now; and, importantly
- How we could ensure, in a rapidly changing environment, that this proposal would also strike the right balance between affordability and delivering customers' expectations.

17 See: https://yoursay.ausgrid.com.au/draft-plan-2024-2029.

Figure 3.5.1

Our Draft Plan engagement journey

Key:

- All
- Voice of Community ongoing engagement program
- Partner and stakeholder engagement
- Customer engagement
- Joint network (DNSP) engagement

September

1st

- Yoursay website: Draft Plan
- Pricing Directions Paper
- Resilience Framework
- Survey
- Submission tool

For: all

2 Sep

Launch event – online
For: all

6th

Resilience framework roadtest
For: RCP

12th

- Publish Metering
- Public Lighting and Ancillary Network
- Services papers

For: all groups

13th

Interview
For: C&I customers

Street walk – Lakemba
For: Small businesses

1 Sep – 14 Oct

Be the Boss game
For: Household customers

14th

Round table.
For: Peak bodies – Lived experience

Interview
For: C&I customers

15th

Street walk – Cessnock
For: Small businesses

16th

Street walk – Cessnock
For: Small businesses

17th

Voice of Community Panel – online
For: Household customers

19th

Street walk – Tuggerah
For: Small businesses

20th

Interview
For: C&I customers

Forum
For: Retailers

Street walk – Tuggerah
For: Small businesses

21st

Round table
For: Peak bodies – Climate response

26th

Interview
For: C&I customers

27th

Forum – Draft Plan.
For: Councils

Interview
For: C&I customers

28th

Interview
For: C&I customers

29th

Forum – Public Lighting
For: Councils

30th

Pricing Working Group – embedded networks
For: Stakeholders

October

5th

Meeting – pricing
For: C&I customers

11th

Submissions received
For: Stakeholders

15th

Town Hall
For: All customers

Glossary

- **C&I customers** – commercial and industrial customers
- **RCP** – Ausgrid's Reset Customer Panel

Ausgrid

Figure 3.5.2 Consumers as partners

When considering how we could or should engage with customers and stakeholders for the purpose of ultimately developing this Regulatory Proposal, we kept the phrase 'Consumers as Partners' (from the AER's Better Resets Handbook) in the forefront of our minds.

We felt our engagement framework needed to have a number of key elements to ensure that we could effectively partner with consumers. Our co-design process resulted in the following key elements:

- **Dynamic/Accountable** – Start early, enabling time to build customers' capacity and knowledge and in time to have a meaningful impact on our plans;
- **Transparent/Collaborative** – Enable access to dissenting or alternative sources of information; and
- **Inclusive** – Meet customers on *their* terms, going to them where possible and/or using techniques that enable them to engage as fully as possible and be deliberate in hearing from and integrating the quiet voices.

Facilitating this multi-faceted engagement required a complex web of engagement with consumers, with the views of different customers being shared with other customer groups for their comment and perspective, enabling a holistic picture of the communities preferences to be built on over time. This is set out in our **Attachment 3.4 – Engagement framework.**

This led us to try a wide variety of approaches:

- A **Voice of Community Panel** – a citizen's jury-style process where our customers form a quasi-jury to prosecute the question 'How can Ausgrid look to the future while being fair to customers today?' To do this, customers on the Voice of Community Panel called on their choice of experts, sought independent advice and spent 60 hours meeting face-to-face as a group, deliberating.
- Launching our '**Be the Boss**' game – which takes only a minute to play – to see if we could capture the attention of those customers that spend around 6 minutes a year thinking about electricity.[18] We managed to reach 2,507 customers, although only 102 stayed for the whole minute.
- We integrated our BAU engagement by running analysis across 40,000 records to draw insights from the written comments and ensure what we were hearing from customers aligned with what we were hearing on a day-to-day basis through our contact channels.

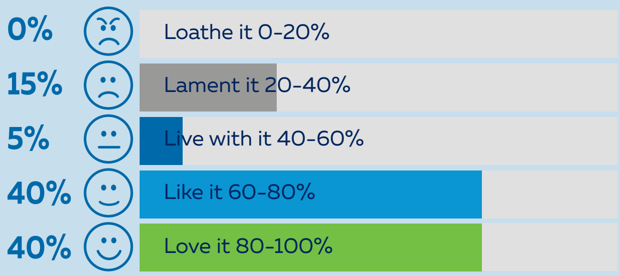
The program was ambitious and challenging, but also rewarding for both the customers and staff involved.

The measure of our success is how well our customers feel we listened to them, and how satisfied they were with our Draft Plan – as indicated by feedback received. While there is always room to improve, our customers have told us that we listened, reflected their feedback and that we are on the right track to deliver the future electricity grid they want, fairly.

Satisfaction with Ausgrid's consideration of participant input

Participants were asked how satisfied they were that Ausgrid had considered what they had told them.

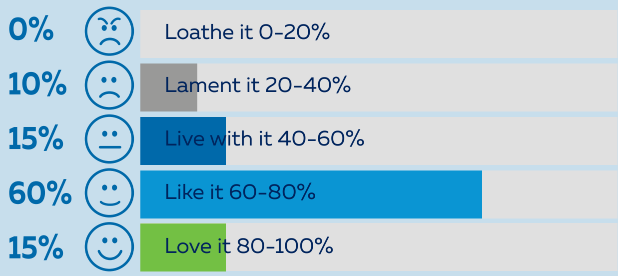
The graph below gives an indication of the spread of response across the 5L spectrum.



Level of comfort with the balance of the Draft Plan

Participants were asked how comfortable they were with how the Draft Plan 'looks to the future whilst being fair to customers today.'

The graph below indicates the overall levels of comfort.



18 See: https://www.greentechmedia.com/articles/read/customers-spend-8-minutes-a-year-interacting-online-with-their-utility#gs.rnx6uc

3.6 What we heard and how we're responding

Throughout our engagement, our customers and delivery partners consistently told us they want Ausgrid to do more than continue to deliver safe, reliable, and affordable energy services over the 2024-29 period and beyond. While meeting these core expectations remains essential, we have learned that our customers and delivery partners also expect us to support the transition to a cleaner, more sustainable energy system and to help them realise their own net zero ambitions and empower them to manage their own energy costs. Our communities' top priorities are discussed further below. **Figure 3.6.2** summarises how the Reset Customer Panel challenged us to do more for our customers.

3.6.1 Facilitating an affordable energy transition

Managing the costs of energy has been a major concern for many in our community, even before the recent wholesale energy price increases and worsening cost of living pressures. While our customers support the energy transition, they have told us that it must be affordable and fair. Our customers have told us they want:

- Better, more transparent information about the different costs driving their energy bills to help them manage their costs;
- More flexible pricing, including two-way pricing, to provide for a fairer transition to net zero; and
- Us to invest to reduce our long-term costs, where it is efficient to do so.

Our engagement with our customers has shown us there is a strong belief in the community that pricing electricity to encourage better utilisation of the grid is the right thing to do, and requires clear and relevant communications that enable customers to make informed investments and energy utilisation decisions.

'Working with government and social housing to help educate everyone including the low income and vulnerable population on how they can be involved in the drive to net zero, how they can get a smart meter, etc.'
– Town Hall customer

Figure 4.1.3 – Facilitating an affordable energy transition in **Chapter 4** summarises how we responded to customer feedback on facilitating an affordable energy transition.

3.6.2 Building the resilience of our network to reduce climate and cyber risks

Managing the impacts of extreme weather events is a unanimous priority across our communities. Our customers and delivery partners told us they support the science on climate change and expect extreme weather events to continue becoming more frequent and intense. We heard that:

- Prolonged outages caused by these events cause major disruptions to the lives and livelihoods of impacted communities, and can have major implications for the safety of life support and other vulnerable customers. These potential impacts are becoming increasingly significant as electricity continues to power more and more aspects of our everyday lives;
- Customers consider the costs they bear during an outage as part of their overall evaluation of the cost of electricity;
- Customers in locations at most risk of climate change impacts should not experience materially worse reliability than others. They want us to prioritise building network and community resilience in these high-risk areas – and they want a say in how we do this;
- When outages do occur, customers want us to improve our emergency response. Information is crucial during outages and customers want us to do better in communicating and engaging with them at these times; and
- Customers expect us to work in partnership with other organisations to play our part in a holistic effort to improve community and individual resilience.

Managing cyber security risks is also important. Communities recognise that keeping our network safe from cyber intrusions is essential for the provision of safe and reliable energy services. However, we heard varied views on whether we need a best-in-class approach to mitigating these risks, given the costs involved. We heard at the Town Hall, that recent high profile cyber attacks across a range of organisations in Australia have heightened the communities' concerns, albeit the risks posed to Ausgrid and our customers vary from other organisations.

'For us certainly the communication piece is the number one because we're large enough that we can organise our own generators and make sure that our stores continue to support the communities that we're in because food is an essential service. So very much like electricity, we need to keep trading to support the communities in which we operate.' ***– C&I customer interview***

Figure 5.9.5 – What customers told us about cyber security and how we are factoring in their views in **Chapter 5** sets out how our customers' feedback has shaped our proposal for building resilience against both the threat of climate change and the threat of cyber attack.

3.6.3 Delivering net zero

Our household, small business and C&I customers have told us they want faster progress towards net zero emissions and that they see Ausgrid as a key enabler of their own and the broader communities' efforts to achieve this. They want us to:

- Proactively prepare our network for net zero to avoid reactive, costly network investments and worsening customer outcomes in the future;
- Prioritise innovations and trials to support the transition; and
- Help them play a key role in the energy transition by providing information and opportunities to do so, including supporting the uptake of lower cost and cleaner energy solutions.

However, customers have told us they are concerned that the transition to net zero needs to be affordable and fair for all – including renters and others who cannot install CER themselves. They want us to find ways to share the benefits across our communities – for example, by advocating for community batteries and other solutions to support equitable access to clean energy in the future.

In particular, community batteries have a lot of support as they provide a means of enabling the storage of rooftop solar generated energy in circumstances where residential customers may have limited ability to self-consume or store their own rooftop solar.

In terms of Ausgrid's own transition to a net zero entity, customers want us to reduce our carbon footprint where this is economically justifiable.

'More education, explanation to the public about how the tariffs contribute to the cost. And why it is a reasonable and fair change. Things to emphasise: customers are not being charged to export, they are just being rewarded a little bit less; and they are being rewarded for shifting their usage and smoothing out load on the grid.'
– Town Hall customer

Our plans for delivering a net zero future, how quickly we progress to this future and the technologies we prioritise in this program have been shaped with our community. We explain how customer feedback has shaped these plans in **Figure 5.7.7 – What customers told us about delivering net zero through CER integration**.

The communities' views on net zero investments were heavily influenced by their views on the introduction of two-way tariffs and the ability of tariffs to drive better utilisation of the existing assets through behaviour change. **Figure 5.7.8 – What customers told us about delivering net zero by evolving our services** shows how customer feedback has been reflected in our Regulatory Proposal.

Customers have also been emphatic on the need for networks and Ausgrid specifically to be more innovative. This is the area where customers would really like to see us do more, and work with market bodies to allow more innovation as part of the regulatory regime. Their feedback has shaped out proposal for the Network Innovation Advisory Committee, and **Figure 5.8.5 – What customers told us about prioritising innovation** shows how the Draft Plan was shaped by their feedback, and their recommendations for this Regulatory Proposal.

3.6.4 Providing a better customer experience

We heard that our customers' interactions with us should be a simpler and easier experience. Our residential customers told us they want to be able to speak to a real person when they contact us, and they want better communications from us during outages. Our delivery partners and C&I customers want us to collaborate more closely, share information more seamlessly and make working with us more efficient.

Our communities also told us our service delivery should be more empathetic to our customers' diverse individual needs, and that they want us to incorporate Indigenous knowledge to better manage our impact on Country and foster better relationships with Indigenous communities.

Figure 5.9.6 in **Chapter 5** outlines **what customers told us about the experience they expect when interacting with Ausgrid.**

Our customers also supported our proposed Customer Service Incentive Scheme (**CSIS**) and agreed that our selected metrics were priorities for our customers.

'We have a major problem with connections across all distributors, the time frames for your new connections are just very lengthy.' ***– Large customer interview***

Following this support we have refined our CSIS metrics based on data availability to set a baseline for customers as outlined in **Section 7.4** and **Attachment 7.1 - Proposed 2024-29 CSIS.**

Figure 3.6.1

Be the Boss

As part of our commitment to try new things, take risks and make it as easy as possible for customers to provide feedback we created a game, Be the Boss.

Be the Boss allowed customers to complete a simple survey in a fun way, asking them to imagine that they were the boss of Ausgrid for the day, and consider what decisions would they make. We promoted the game on social media to encourage those customers who are time poor or uninterested in energy to also have their say.

The results...

The question	Where on a sliding scale did customers land					
Technology is changing quickly, smarter options keep coming. What's your approach to innovation?	Slow and steady	12%	12%	37%	39%	Drive change
Customers tell you they want better customer service, but everyone wants different things. What level of service will you deliver?	Same for everyone	0%	14%	58%	28%	Tailored services
Climate change is expected to cause more extreme weather and that means more outages. What do you do?	Do nothing	0%	3%	55%	42%	Do all you can
The threat of cyber attacks is increasing. So far you've kept them at bay, but there are more than ever. What level of cyber security do you want?	Compliant	6%	–	46%	48%	Advanced
Parts of the network are feeling the strain of more solar. Do you invest to allow customers to continue to export solar, or do you stop people adding solar where the network is congested?	Keep costs low	0%	2%	56%	42%	Invest

2507 people played the game

102 people completed all questions

12 customers with solar

42 homes without solar

11 small businesses

38 apartment dwellers

Without knowing the content of the Draft Plan customers preferences matched the options proposed, with the exception of innovation, where customers wanted more investment. Mirroring the outcomes of the Town Hall and providing confidence that the Town Hall accurately represents the views of broader customer base.

Note: We understand that this methodology lacks the robustness of other parts of our engagement, for example it's not possible to know how many participants were customers or even staff. As such, we would not use this data to justify a Regulatory Proposal, but it is interesting the extent to which this data validates what we have heard across multiple sources of engagement.

Figure 3.6.2 The Reset Customer Panel's impact on Ausgrid and our Regulatory Proposal

Reset Customer Panel challenge	Impact	Regulatory Proposal reference
Embed customer views when building resilience	• We have co-designed a resilience investment framework with the Reset Customer Panel and the Total Environment Centre • The co-designed framework embeds customers' perspectives by implementing additional accountability measures and requiring us to engage with the community at multiple stages in the decision-making process for resilience investments	**Section 5.5.2**
Take a holistic approach to productivity	• We have applied a 0.5% per annum productivity factor to capitalised overheads	**Section 5.12** and **Section 6.7**
Take a non-network approach to net zero, looking to tariff and innovation before network augmentation	• We have prioritised two-way export tariffs, and network innovation as part of a holistic program of net zero investments • Adopted AER's CECV methodology for valuing CER curtailment	**Section 8.5** and **Attachment 8.1 - Tariff Structure Statement compliance paper** **Section 5.7**
Reduce the number of step changes	We did not proceed with proposed step changes for: • The new Software-as-a-Service (**SaaS**) international accounting rule change as it will be treated as a base year adjustment • New CALD, low income and vulnerable customer support programs • New licence conditions that commence on 1 July 2024 which will increase guaranteed customer service level payment thresholds and obligations • New regulatory obligations managing NSW Electricity Infrastructure Roadmap exemptions obligations • New resources and systems to implement Distribution System Operator (**DSO**) and CER obligations under the Australian Energy Market Commision's (**AEMC**) Access, pricing and incentive arrangements for distributed energy resources Rule Determination[19] • New obligations under the AEMC's *Review of the Regulatory Framework for Metering Services* (**Metering Review**) where there was potential that DNSPs would be responsible for site remediations[20]	**Sections 6.3**
Reduce the bill impacts of system upgrades like SAP ERP	• We are proposing an ERP asset life of 15 years, greater than the standard 5 years for ICT projects • We have built a more robust business case for ERP to ensure we have the best understanding possible of the customer benefits and how to deliver them	**Sections 4.7.2** and **5.9**
Access to the Ausgrid Board	• Unlike previous reset processes where our advocates had no access to Board members, the Reset Customer Panel has met regularly with our Chairman and other members of the Board. The Board have also engaged directly with the Voice of Community Panel	**Sections 3.3** and **3.4** **Attachment 3.1 – Engagement overview**

19 This proposed step change evolved into the step change for ICT enablement program for CER integration (as a capex to opex substitution), which we are pursuing.
20 Due to the AEMC's Metering Review being placed on hold until November 2022, we decided to only progress a step change to purchasing smart meter data for visibility.

Continued Figure 3.6.2

Reset Customer Panel challenge	Impact	Regulatory Proposal reference
Robust and transparent ICT governance	• We co-designed ICT governance principles with the Reset Customer Panel which commit us to sharing post implementation reviews and place limitations on the recovery of any cost overruns relating to the ERP program • Limiting the bill impact of our ERP program by recovering the costs of the investment over a longer timeframe	**Section 4.8.2** **Attachment 3.2 – Customer advocate meeting matrix**
Holistic review of key items like insurance	• Challenged us to think more deeply about our overall approach to insurance options by asking probing, detailed questions	**Section 6.6.1**
Improving our fleet modelling	• We have significantly improved our fleet modelling in comparison to previous regulatory processes, during which consumer advocates were concerned that our fleet modelling was not sufficiently robust	**Section 5.10**
Engage jointly with other networks to reduce the burden on consumer advocates	• We engaged jointly with other networks on: – The AER's Framework and Approach – Resilience – Tariffs	**Section 10.2, Section 5.5, Section 6.6.3, Chapter 8** and **Attachment 8.1 - Tariff Structure Statement compliance paper**
	• We also shared a common calendar with other key networks to enable better co-ordination of meetings between networks	**Attachment 3.3 – Customer engagement matrix**
Share openly beyond the reset requirements	• We co-designed our business Vision and Strategy with our customers • We shared our cost allocation methodology (**CAM**) with the Reset Customer Panel • We shared Board-level customer metric reporting	**Attachment 3.2 – Customer advocate meeting matrix**
Enable customers and stakeholders' easy access to the key documents	• We produced an easy to read and customer focused summary of our Draft Plan, as well as information sheets for our customers (some of which we produced in a range of languages)	**Attachment 3.3a - Customer engagement materials**

Figure 3.6.3

Voice of Community Panel

22 Feb	**Meet and Greet:** Meet Ausgrid Board members, CEO and key staff
27 Feb	**Day 1:** Hear from independent experts
15-17 Mar^	**Day 2:** Panel call their choice of experts
22-24 Mar^	**Day 3:** Review insights and develop priorities
30 Apr	**Day 4:** Define fairness and propose initial recommendations
14 May	**Day 5:** Consider options and trade-offs
24 - 26 May^	**Day 6:** Consider recommendations and regional perspectives
4 June	**Day 7:** Agree final recommendations and present report to Ausgrid Chairman and CEO
17 Sep	**Day 8:** Refine Draft Plan: Resilience and net zero
15 Oct	**Day 9:** Provide feedback on the Draft Plan*

^ These days were held in the three different regions of Ausgrid's network.

** The Voice of Community Panel joined with representatives from all of our other end customer engagement streams.*

Attendees

45

Gender

23
51% Female

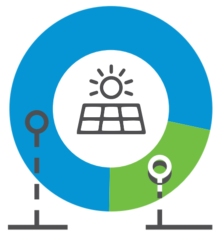
22
49% Male

Own/rent

28
62% Home-owner

17
38% Tenant

Solar panel owner



35
78%
No

10
22%
Yes

Engagement

Face-to-face

60
HRS

Age

4 9%
16-24

7 16%
25-34

15 33%
35-49

7 16%
50-59

6 13%
60-69

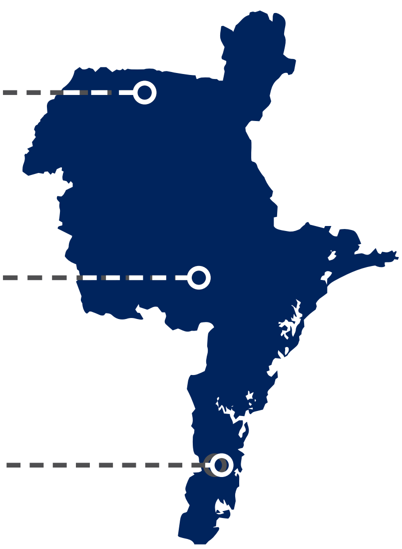
6 13%
70+

Geography

13
29%
Hunter

10
22%
Central

22
49%
Sydney



Meetings

10

Between February and October 2022

Ausgrid

3.7 Supporting attachments relevant to Chapter 3

3.1	Engagement overview
3.2	Customer advocate meeting matrix
3.3	Customer engagement matrix
3.3.a	Customer engagement materials
3.4	Engagement framework
3.5	Independent report on Ausgrid 2024-29 revenue proposal
3.6	Draft Plan for 2024-29
3.6.a	Independent report on Ausgrid's Draft Plan
3.6.b	Draft Plan - submissions received

4

Our proposed revenue is our forecast of the revenue we need to generate over the 2024-29 period to deliver our standard control services (**SCS**) and recover the efficient costs to operate our network.

4. Proposed revenue

Our proposed revenue will be used to maintain and invest in our network and non-network assets to ensure we can continue to meet our regulatory obligations and our customers' expectations now and over the long term.

This revenue reflects our plans for the 2024-29 period, which we developed in collaboration and partnership with our customers, delivery partners and other stakeholders (see **Chapter 3**). These plans respond to our communities' desire for a resilient and net zero future, while balancing their ongoing need for an affordable, reliable and safe energy supply (see **Section 3.6**).

The sections below provide an overview of our proposed revenue, then discuss each of the building block components and key inputs in more detail.

4.1 Overview

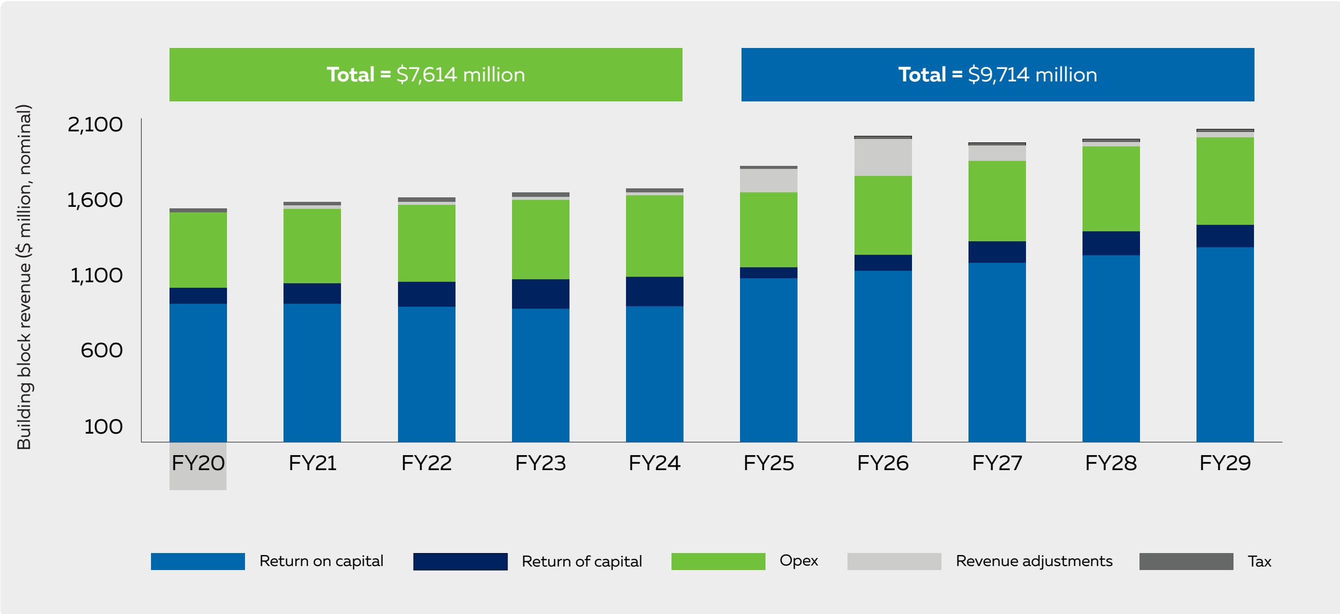
Our proposed total revenue for the 2024-29 period is $9,714 million (nominal). This is 28% higher than our forecast revenue for the current 2019-24 period, and 2% higher than the revenue we included in our Draft Plan. We calculated this revenue using the AER's post-tax revenue model (**PTRM**) and the AER's 2018 rate of return instrument.

Figure 4.1.1 sets out our proposed revenue by building block component. For context, **Figure 4.1.2** compares this proposed revenue to our approved building block revenue for the current 2019-24 regulatory period.

Figure 4.1.1 Proposed revenue and building block components for the 2024-29 period ($m, nominal)

	FY25	FY26	FY27	FY28	FY29	Total
Return on capital	1,060.9	1,109.1	1,159.8	1,210.3	1,263.0	**5,803.2**
Return of capital	72.0	105.8	141.1	157.5	143.3	**619.7**
Opex	486.2	509.2	527.9	547.7	567.8	**2,638.9**
Efficiency Benefit Sharing Scheme (EBSS)	153.5	206.9	63.7	(5.5)	0.0	**418.6**
Capital Efficiency Sharing Scheme (CESS)	(0.2)	35.6	36.6	37.6	38.7	**148.4**
Demand Management Innovation Allowance Mechanism (DMIAM)	1.6	1.8	1.7	1.8	1.8	**8.6**
Shared assets	(2.9)	(3.1)	(3.5)	(3.5)	(3.6)	**(16.6)**
Tax allowance	19.2	18.9	18.4	18.9	18.0	**93.4**
Revenue requirement	1,790.4	1,984.1	1,945.8	1,964.8	2,029.1	**9,714.2**

Figure 4.1.2 Proposed annual revenue for 2024-29 compared to current period ($m, nominal)



Note: Negative amount in FY20 caused by the remittal where revenue was reduced due to over-recoveries in the 2014-19 period.

The biggest drivers of the increase between the current period and our proposed revenue are:

- **Return on asset** – higher interest rates have contributed to return on asset being $1.4 billion or 32% higher than current period;
- **2014-19 remittal** – revenue in the current period was lowered by the repayment of an over-recovery in 2014-19 by $329 million. A similar adjustment does not apply in the 2024-29 period; and
- **EBSS** – significant cost reductions in the current period have resulted in an EBSS carryover of $419 million. There was no EBSS carryover applicable in the current period.

Our revenue proposal reflects our communities' desire to progress towards a net zero and resilient future while balancing the need for affordability. We tested this balance in our Draft Plan and, pleasingly, the overwhelming response was that we had listened well, reflected customer priorities accurately and that the balance between investing for the future and affordability was right. Our customers expect us to continue to engage on our 2024-29 plans throughout 2023, given the potential for further significant changes in the economic environment. **Figure 4.1.3** shows how we have worked with the community to develop our Regulatory Proposal and how our revenue proposal reflects customer feedback.

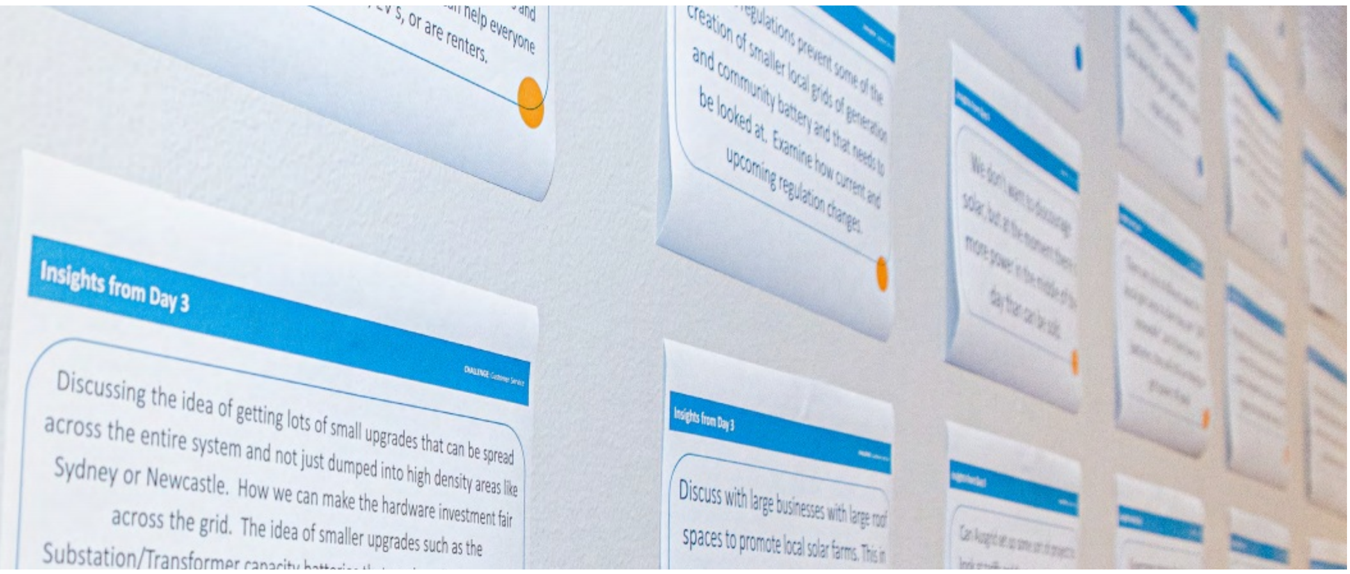


Figure 4.1.3

Facilitating an affordable energy transition

Our engagement journey	Purpose	What we heard from our customers and how we are responding			2029 residential bill impact driven by customer priorities see Section 1.3.
Phase 2 engagement framework	Customer themes	• Energy costs are difficult to manage, so energy needs to be affordable; and • Invest to reduce long-term costs.			
2024–29 **Draft Plan**	Our Draft Plan position	**Building on our significant cost reductions implemented since 2015, by:** • Making an upfront commitment to reduce our operating costs by $32 million over the 2024–29 period; and • Continuing to enhance our investment governance, building on the significant improvements made since 2018. **Taking a risk-based approach to investment that delivers equitable outcomes across generations, by:** • Better understanding the performance of our 5 million assets in service across the grid; and • Maintaining a stable asset base so that investments we make today do not create an affordability challenge for future generations.			**$0** **(these initiatives were factored into our base case)**
		Town Hall (all end use customers)	**Commercial and industrial**	**Councils**	
Phase 3 engagement framework	Customer views on our Draft Plan position	*'Don't lose sight of what's important over the long term even if it takes longer to pay off or see benefits.'*	*'Try and keep your costs low, invest efficiently looking for those sort of operational productivity measures to be in place.'*	*'Acknowledging the rising cost of living, Ausgrid's initiative to facilitate an affordable energy transition as we move toward net zero is supported.'*	
2024–29 **Regulatory proposal**	How we're responding	• Recover the costs of our ERP system program over a 15 year period rather than a 5 year period, reducing the bill impacts of this program in the short term; • Keeping the current depreciation method, which defers revenue to later years and reduces bills in the short term; • Strategic disposal of properties, which reduces bills through a lower Regulatory Asset Base (**RAB**); • Committing to a 0.5% productivity factor for capitalised overheads, reducing our total capex; and • Applying the AER's preferred position on a tax matter related to gifted assets, which reduces tax allowance and lowers bills.			**-$34**

4.2 Regulatory asset base

Our RAB is the unrecovered value of capital invested in our network and non-network assets. It is the basis on which the 'return on asset' building block is calculated, and a key input for calculating the 'regulatory depreciation' building block. This makes it one of the largest drivers of our overall revenue requirement.

To calculate the value of our RAB in the 2024-29 period, we:

- Used the AER's standard models to estimate its opening value (as at 1 July 2024) and to roll this value forward to estimate its closing value (as at 30 June 2029);
- Used placeholder regulatory inflation of 2.87% per annum; and
- Separately accounted for our distribution assets and dual function (transmission) assets,[21] in line with the AER's Framework and Approach (**F&A**) decision.[22] **Attachment 4.1 – 2024-29 Proposed revenue** shows the separate RAB values for these assets.

4.3 Opening value of the RAB

The estimated value of our RAB as at 1 July 2024 is $18.5 billion (nominal) (see **Figure 4.3.1**). This comprises $16 billion attributable to distribution assets and $2.5 billion attributable to dual function assets.

Figure 4.3.1 RAB value at 1 July 2024 ($m, nominal)

	$ million nominal
Opening RAB as at 1 July 2019	15,681.0
Net capex	2,442.4
Straight line depreciation	(2,793.5)
Inflation on opening RAB	3,117.7
Final year adjustment	98.3
Opening RAB as at 1 July 2024	18,545.9

*Includes assets changing classification, see **Attachment 4.1 – 2024-29 Proposed revenue** for more detail.

4.3.1 Property sales strategy to help with affordability

Net capex includes $564 million of property sales – $151 million[23] of which we forecast to accelerate from the 2024-29 period in response to affordability concerns. Customers benefit from property sales because the full disposal value is netted off the RAB. This means any uplift in value compared to the original value recognised in the RAB is fully passed through to customers through lower return on asset. We had identified some properties for disposal in our accommodation strategy that would typically be sold over time. However, we determined that it would be most prudent to achieve the sales as soon as possible, rather than offering the properties for sale over a number of years. This is because:

- Property values are forecast to fall over coming years, therefore we can maximise the value returned to customers by selling over the coming year; and
- The benefit to customers comes sooner if a large portfolio of properties is removed from the RAB in the current regulatory period, rather than phased over the 2024-29 regulatory period.

To achieve the sales quickly, we intend to sell the properties to another company in the Ausgrid group. Being a related party transaction, the highest levels of probity will be adhered to, including procuring independent valuations for the properties to ensure maximum benefit is derived for our customers. We discussed this strategy with the Reset Customer Panel and their view is that disposing of property that we are not using productively, or likely to use productively in the foreseeable future, is in the best interests of customers. The Reset Customer Panel will be kept informed of progress. Sale of the properties also results in a negative step change to opex as discussed in **Section 6.7.8**.

21 See NER, cl 6.24.2.
22 AER (July 2022), *Framework and Approach for Ausgrid, Endeavour Energy and Essential Energy: Regulatory control period commencing 1 July 2024*. p. 54.
23 $158 million of total sales is forecast, however after CAM allocation $151 million is attributable to SCS.

4.4 Value of the RAB over the 2024-29 period

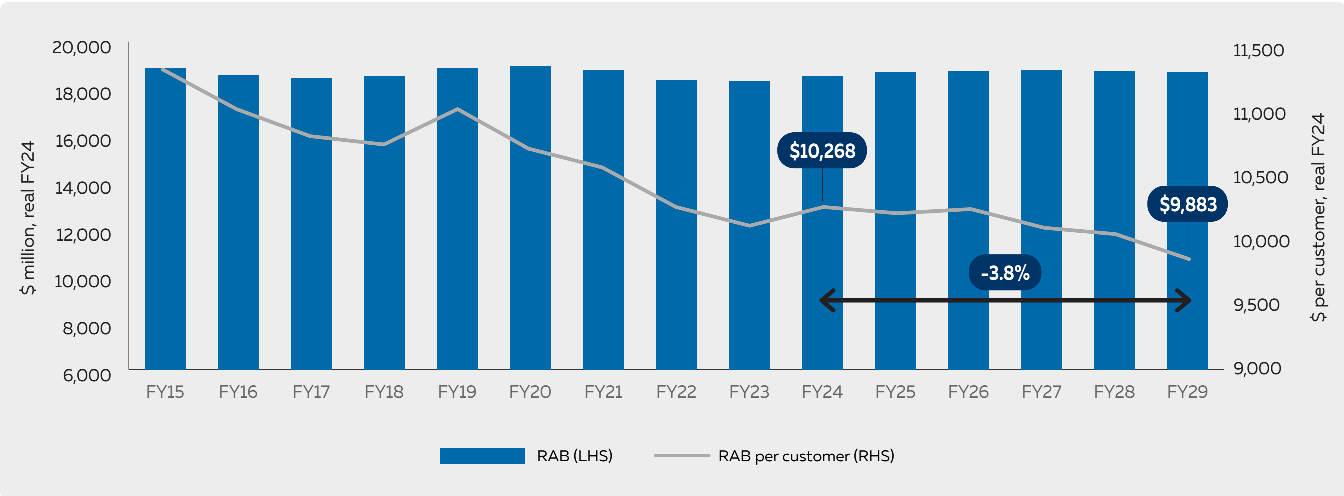
The estimated annual value of our RAB increases to $21.6 billion (nominal) by the close of the 2024-29 period (**Figure 4.4.1**). This represents an average annual increase of 3% over this period.

Figure 4.4.1 Annual RAB values over 2024-29 ($m, nominal)

	FY25	FY26	FY27	FY28	FY29	2024-29 period
Opening RAB	18,545.9	19,222.3	19,840.0	20,429.5	20,994.1	18,545.9
Net capex	748.4	723.4	730.6	722.1	711.0	3,635.6
Straight line depreciation	(605.2)	(658.3)	(711.4)	(744.8)	(746.8)	(3,466.5)
Inflation on opening RAB	533.1	552.6	570.3	587.3	603.5	2,846.8
Closing RAB	19,222.3	19,840.0	20,429.5	20,994.1	21,561.8	21,561.8
Closing RAB – $m, real FY24	18,685.2	18,746.7	18,764.3	18,744.1	18,713.0	18,713.0

Despite this increase, our real asset value per customer is expected to decline by 3.8% over the 2024-29 period, continuing the downward trend since 2014-15 (see **Figure 4.4.2**). This is because the amount of net capex we forecast adding to the RAB is similar, in real terms, to the amount scheduled to be subtracted through depreciation, while our customer numbers are increasing.

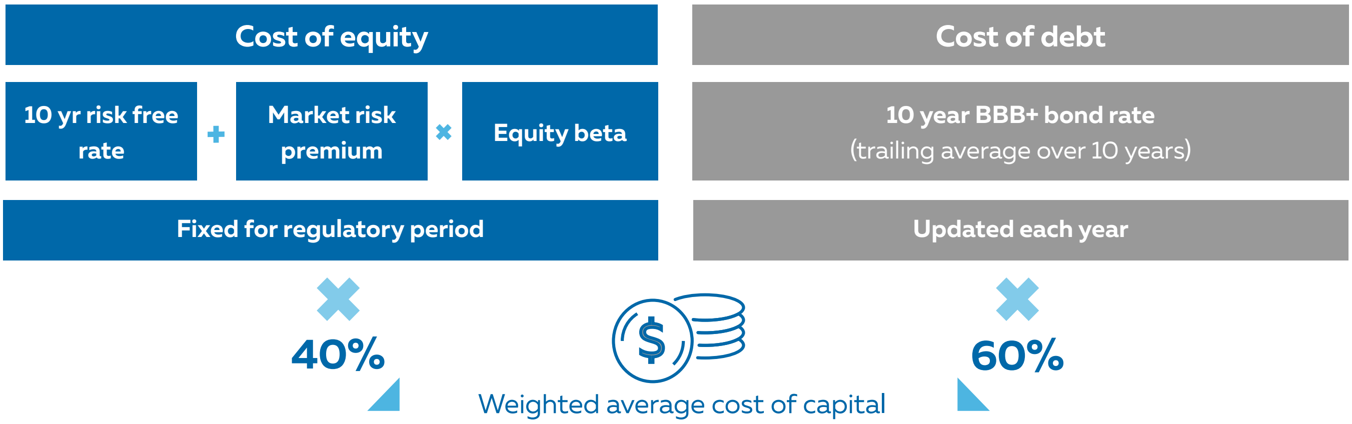
Figure 4.4.2 Asset value and asset value per customer ($m, real FY24)



4.5 Rate of return

The rate of return, or weighted average cost of capital (**WACC**), is used in calculating the 'return on asset' building block. It reflects the cost an efficient network would incur to raise its capital in financial markets. The AER sets the WACC for all distribution network determinations through a separate process which involves estimating the cost of debt and the cost of equity, and combining these estimates using a gearing ratio of 60:80 (see **Figure 4.5.1**).

Figure 4.5.1 AER's approach for calculating the rate of return



Note: This is based on the 2018 rate of return instrument. Subject to change in the 2022 rate of return instrument, expected in February 2023.

We have estimated placeholder values for the risk free rate and cost of debt in accordance with the 2018 rate of return instrument.[24] **Figure 4.5.2** shows the parameters used to build up the rate of return.

Figure 4.5.2 Rate of return

Component	Amount
Risk free rate	3.77%
Market risk premium	6.10%
Equity beta	0.6
Return on equity	7.43%
Return on debt*	4.58%
Gearing	60%
Nominal vanilla rate of return*	5.72%

* First year estimates. Debt is updated each year during the regulatory period. The average return on debt over 5 years is 4.80% and average rate of return is 5.86%.

24 Publication of the 2022 rate of return instrument has been delayed until after this proposal is due, so we must include rate of return parameters aligned with the existing 2018 instrument.

4.6 Return on asset

The return on asset building block is an allowance to fund the efficient costs of debt and provide a reasonable return on equity. This allowance is calculated by multiplying the opening value of the RAB by the rate of return set by the AER in each year of the regulatory period.

In calculating our proposed return on asset, we used the RAB values shown in **Figure 4.4.1**, and the rate of return as calculated in **Figure 4.5.2**.[25] The average rate of return of 5.86% is higher than the average WACC of 5.31% for the 2019-24 period.

Our proposed total return on asset is $5,803 million, which represents 60% of our proposed total revenue for 2024-29. This is 32% higher than our allowance for the 2019-24 period, mainly due to higher interest rates and our higher RAB value. It is 8% higher than we included in our Draft Plan, because of the continued increases in the cost of funds.

25 The rate of return is different in each year due to the trailing average debt methodology.

4.7 Regulatory depreciation

The depreciation building block is an allowance to recover the cost of our efficient and prudent investments in assets over their useful lives. This allowance is calculated using the opening RAB value (as at 1 July 2024), new capex and the economic lives of assets. We then subtract the RAB inflation from this amount so that we are only compensated for actual inflation once (through the return on asset).

Our proposed total regulatory depreciation is $620 million, which represents 6% of our proposed total revenue for the 2024-29 period. This is 21% lower than our depreciation allowance for the 2019-24 period, primarily because RAB indexation, which is netted off straight line depreciation, is significantly higher in the 2024-29 period due to a higher inflation forecast. It is 44% lower than the depreciation we included in our Draft Plan, which was calculated using a different method to calculate depreciation than the method we have used for this Regulatory Proposal.

In the following sections, we discuss our decision to continue using the existing weighted average remaining life (**WARL**) depreciation method for the 2024-29 period and to create a new asset class for our ERP implementation program expenditure.

More information can be found in **Attachment 4.1 – 2024-29 Proposed revenue**.

4.7.1 We propose to continue using the existing 'weighted average remaining life' depreciation method

There are two main methods to calculate depreciation that have been accepted by the AER as meeting the NER requirements:[26]

1. **WARL** – calculated by weighting the remaining lives of assets existing at the start of the period and the remaining lives of new assets rolled into the RAB during the period; and
2. **Year-by-year tracking** – calculates individual straight line depreciation by asset class for each year of capex additions over the life of each asset class.

We currently use the WARL depreciation method and have decided to continue using this method for the 2024-29 period.

We had intended to change from WARL to year-by-year tracking for this Regulatory Proposal and engaged with our customers on this matter. This is because:

- At this point in our investment cycle, WARL results in the dollar value of new assets being given more weight even though the older assets make up significantly more of the RAB in physical terms. This results in the WARL method over-estimating the remaining useful lives of all assets within a particular asset class; whereas
- Under year-by-year tracking, the assets added each year will be depreciated by their actual remaining life, rather than an average including older and younger assets. This better aligns the costs of assets with when they are used which is more equitable for customers over the life of the assets. While both methods recover the same value over the life of an asset, year-by-year tracking more accurately reflects the true straight line depreciation value in each year of the life of an asset class.

We began engaging with the Reset Customer Panel on this topic in late 2021. While the Reset Customer Panel recognised that moving to year-by-year tracking does not increase overall costs to consumers, there was discussion about different segments of customers having different views about whether this change should be implemented. The Reset Customer Panel raised concerns that it would increase prices at a time when other factors would also put upward pressure on prices. Ultimately, because year-by-year tracking is a valid and more accurate depreciation method, the Reset Customer Panel did not object to us proposing to change to this method.

We also discussed this in our Draft Plan, noting that changing methods to year-by-year tracking would result in an overall revenue increase in the 2024-29 period of $42 million.[27] While we did not receive any specific feedback from stakeholders on depreciation methods, we have re-considered our position due to the recent affordability pressures our customers are experiencing. Our position remains that year-by-year tracking is a superior method to calculate depreciation, however we do not think it is appropriate to change to this method at this time. Based on updated data for our Regulatory Proposal, the decision to continue using the WARL method for the forthcoming 2024-29 period results in $97 million lower revenue for this period than year-by-year tracking.

26 NER, cl 6.5.5(b).
27 Ausgrid (September 2022), *Appendices: Regulatory Matters for our Draft Plan for consultation*, p 27.

4.7.2 A new asset class for our Enterprise Resource Platform implementation program expenditure

Our depreciation building block will be impacted by our decision to create a new asset class for our ERP implementation program expenditure.

We are proposing to spend $149 million to refresh and upgrade our business systems and unlock efficiencies through standardised business operations.[28]

This expenditure would normally be allocated to ICT systems or in-house software, both of which have a 5 year life for depreciation. However, when discussing the ERP with the Reset Customer Panel, they noted that there could be an opportunity to lengthen the number of years ERP is depreciated if we replaced our ERP, given that it has not been replaced for over 20 years. This change would reduce the cost impact seen by customers in the 2024-29 period, and would be more reflective of the actual useful life of an ERP.

At our Town Hall on 15 October 2022, the Reset Customer Panel asked Voice of Community Panel members whether we should depreciate ERP over a longer timeframe. Most Voice of Community Panel members supported a depreciation period for ERP that was longer than 5 years.[29]

We assessed this opportunity to ease the bill increase faced by customers in the context of the NER requirements for economic life of assets.[30] ERP systems are long lived assets that are replaced infrequently because of their complexity and the integral role they play in an organisation's core functions. Implementing a modern ERP system will take several years and require significant process re-engineering and system configuration. This will ensure that our customers will continue to derive value from the investment for many years.

We are proposing a new asset class for our ERP with an asset life of 15 years that:

- Reduces the bill impact of ERP in the 2024-29 period;
- Has customer and stakeholder support; and
- Reflects the estimated useful economic life of the implementation.

This decision reduces depreciation in the 2024-29 period by $29 million, and reduces revenue by $32 million.

4.8 Operating expenditure

The opex building block is an allowance to fund the efficient costs of operating and maintaining the network, including corporate support.

Our proposed opex is $2,375 million (real FY24), excluding debt raising costs. We used the AER's preferred method for forecasting opex, the base-step-trend method, to forecast this amount.

Our proposed opex is 14% lower than our current period allowance and 10% higher than our current period forecast spend. This is mainly because we have added some step changes in response to regulatory changes, moved some capex to opex and because of other significant changes in our operating environment that affect our costs. After refining our forecasts, our proposed opex is 5% higher than we included in our Draft Plan. See **Chapter 6** for more detail.

28 See **Attachment 5.1 – Proposed capital expenditure** for more detail.
29 See **Attachment 3.1 – Engagement overview** for more detail.
30 See NER, cl 6.5.5.

4.9 Other revenue adjustments

Our proposed revenue for the forthcoming 2024-29 period includes adjustments for the following which are each addressed in further detail below:

- Two incentives schemes that applied in the current regulatory control period where penalties or rewards are added as revenue adjustments – the EBSS and the Capital Expenditure Sharing Scheme (**CESS**);
- The DMIAM which we propose to apply for the forthcoming 2024-29 period, and adds to our proposed revenue in this period; and
- A negative adjustment for revenue earned from our shared assets.

4.9.1 Efficiency Benefit Sharing Scheme

The EBSS provides network businesses with a continuous incentive to pursue efficiency savings in their operating expenditure and provide a fair sharing of these between a distributor and network users. As **Chapter 6** discusses, we have reduced our opex significantly since 2015 and expect to spend less than our opex allowance for the current 2019-24 period. This means we expect a positive carryover amount in the 2024-29 period.

We have calculated this amount as $419 million, which is 4% of our proposed total revenue, using the AER's model and our forecast opex spend in FY23.

4.9.2 Capital Expenditure Sharing Scheme

The CESS provides network businesses with a continuous incentive to undertake efficient capital expenditure throughout the regulatory control period by rewarding efficiency gains and penalising efficiency losses. We expect our net capex over 2019-24 will be lower than the allowance in this period, mainly because our actual asset disposals have exceeded our forecast. This means we expect a positive carry over amount in the 2024-29 period.

We have calculated this amount as $183 million using the AER's model and our forecast capex for FY23 and FY24. We have also adjusted this amount by negative $35 million to account for our capex overspend in the final year of the previous 2014-19 period.

Our adjustment for the CESS is $148 million, which is 2% of proposed total revenue.

4.9.3 Demand Management Innovation Allowance Mechanism

The DMIAM provides distribution networks with funding for research and development on demand management projects that have the potential to reduce long-term network costs. It comprises:

- A fixed allowance of $200,000 (real FY17), plus 0.075% of the annual allowed revenue for each year;
- Project eligibility requirements; and
- Compliance reporting requirements.

We have calculated our allowance under the DMIAM to be $9 million, which is 0.1% of our proposed total revenue.

4.9.4 Shared assets

The NER provides that we can earn revenue on some network assets that are used for other, non-network purposes. For example, we can receive rent from telecommunications companies that attach their infrastructure to our poles rather than building their own additional poles. If the amount we earn from network assets that are used for other, non-network purposes becomes material, there is a mechanism to return a proportion of the revenue to our customers so that they get some of the benefit of the additional revenue.

We currently expect that the revenue we will receive from these shared assets will become material in the 2024-29 period. Because of this, we have reduced our proposed total revenue by 10% of the forecast shared asset revenue. We have calculated this amount as $17 million (nominal), which represents a 0.2% reduction to our proposed revenue.

4.10 Taxation allowance

The 'taxation' building block is an allowance to meet income tax liabilities, taking into account the benefit that shareholders receive from imputation credits.

In October 2020, the Full Court of the Federal Court of Australia made a unanimous decision relating to the tax treatment of capital contributions in Victoria,[31] under which capital contributions subject to the decision are not added to revenue for the purpose of calculating tax. Consequently, the AER did not allow the relevant capital contributions to be included in the Victorian networks' taxable revenue for the purpose of calculating their tax allowance in the recent decisions.

It is unclear whether the ruling would apply in other jurisdictions. Our expert tax advice indicates that the ruling does not apply in NSW because of the different capital contribution frameworks. However, AER staff have indicated that their preferred approach is not to treat capital contributions as taxable revenue because it is not clear to them that the ruling does not apply in NSW. Given this, we have prepared our proposal using the AER's preferred approach. However given the complexity and significance of this issue (both for Ausgrid and other networks), we believe this is a matter for ongoing consideration. To support regulatory certainty and transparency, the AER may wish to seek (and publish with its draft decision) expert tax advice on the applicability of the VPN decision in each jurisdiction it regulates.

We have calculated the tax allowance using the AER's methodology as $93 million, which is 1% of our proposed total revenue. This includes an adjustment for imputation credits based on the AER's 2018 rate of return instrument value for gamma of 0.585.

31 *Victoria Power Networks v Commissioner of Taxation* [2020] FCAFC 169 (**VPN Decision**).

4.11 Smoothed revenue

Annual revenue requirements might fluctuate from year to year over the course of a regulatory control period, which can cause price volatility. This volatility can be smoothed so that prices do not fluctuate with the timing of expenditure programs during a regulatory period. This smoothed revenue is calculated so that Ausgrid is no better or worse off in net present value (**NPV**) terms as a result of the revenue smoothing.

The AER's standard smoothing method is for the first year revenue to be the same as the building block revenue, and the final year revenue to be no more than 3% different than the building block revenue. If we were to apply the standard method for the forthcoming 2024-29 period:

- There would be a significant increase in revenue between the final year of the current period and the first year of the 2024-29 period; and
- The price increase between FY24 and FY25 would be in the region of 11% nominal, and the following 4 years would be below inflation increases.

We are proposing not to apply this method for the forthcoming 2024-29 period because we do not think it would be appropriate to push through such a material price increase in one year, particularly in the current inflationary environment. We have also considered price movements in other sections of the industry, which could materially impact customers over the coming years. We do not consider a 11% increase in FY25, after forecast heightened wholesale electricity prices in 2023 and 2024,[32] to be a good customer outcome.

Instead of the AER's standard method, we are proposing to smooth revenue so that the annual price increases will be roughly similar each year.

To test our thinking, we raised the prospect of different smoothing methods in our Draft Plan and at our Town Hall on 15 October 2022:

- We did not receive specific feedback to this question in submissions made to our Draft Plan; and
- At the Town Hall, we presented the implications of departing from the standard smoothing method on prices in the forthcoming regulatory period and, importantly, the potential implications for price changes in Year 1 of the subsequent regulatory period (FY30). We noted that – all else being equal – we would expect prices to decrease in the subsequent period because we have recovered more revenue in the later years under our proposed method. 15 of the 21 of the attendees that voted on this matter (71%) agreed with the method we had employed in the Draft Plan to have equal price increase over the period.[33]

Figure 4.11.1 shows the proposed X-factors used to smooth revenue. **Figure 4.11.2** shows building block and smoothed revenue. More detail, including the distribution and dual function asset revenue breakdown is in **Attachment 4.1 – 2024-29 Proposed revenue.**

Figure 4.11.1 Proposed X-factors for the 2024-29 period

	FY25	FY26	FY27	FY28	FY29
Distribution	-3.00%	-3.56%	-3.56%	-3.56%	-3.56%
Dual function	-30.00%	-9.20%	-9.20%	-9.20%	-9.20%
Weighted average	-5.00%	-4.08%	-4.10%	-4.13%	-4.16%

Figure 4.11.2 Smoothed and unsmoothed revenue ($m, nominal)

	FY25	FY26	FY27	FY28	FY29	Total
Unsmoothed revenue	1,790.4	1,984.1	1,945.8	1,964.8	2,029.1	9,714.2
Smoothed revenue	1,694.7	1,814.4	1,943.2	2,081.5	2,230.4	9,764.2
Difference	(95.7)	(169.7)	(2.6)	116.7	201.3	49.9

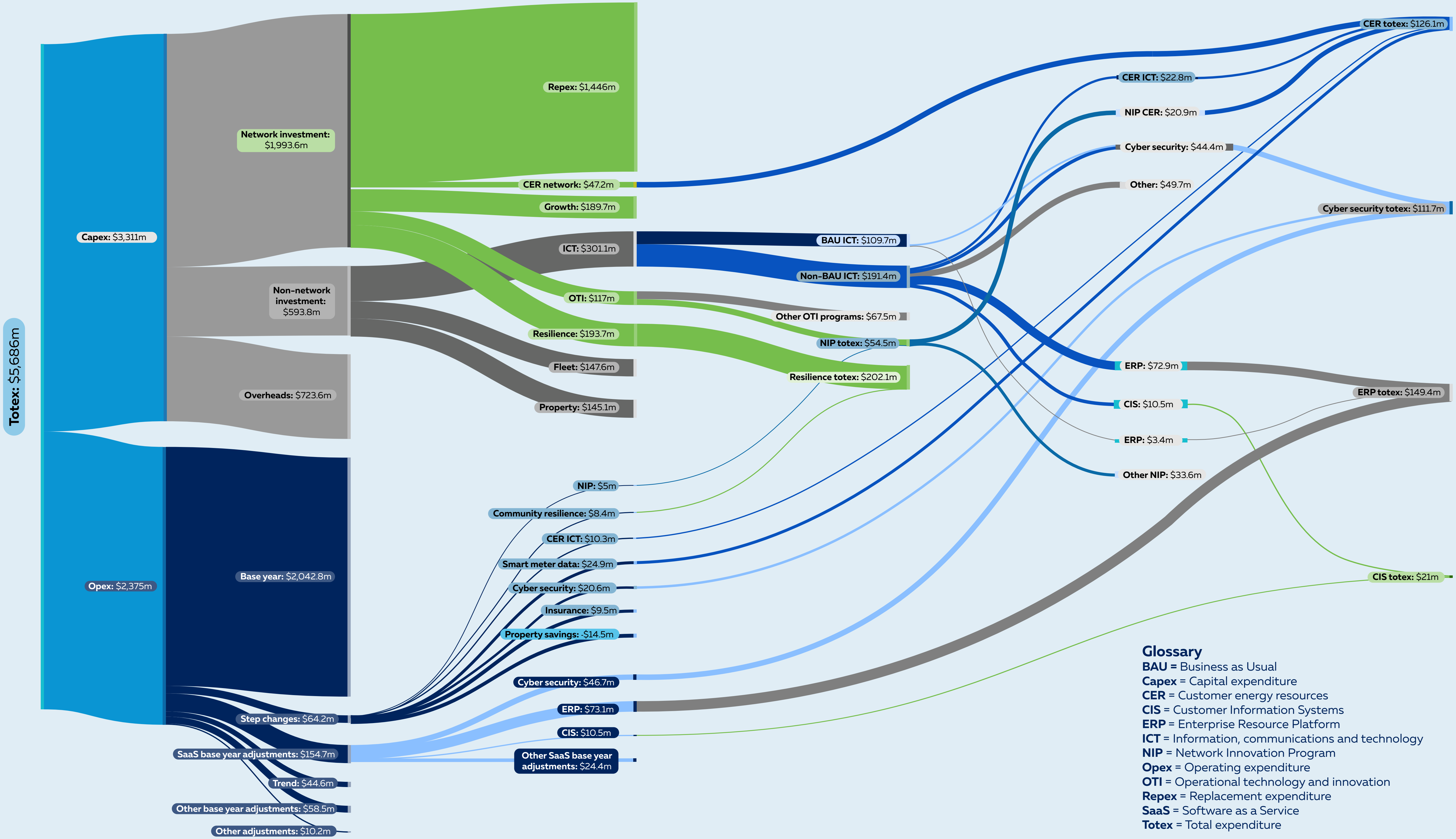
32 AER (November 2022), *Wholesale Markets Quarterly Q3 2022*, p 26.
33 **Attachment 3.1 Engagement overview** by bd infrastructure.

4.12 Supporting attachments relevant to Chapter 4

4.1	2024-29 Proposed revenue
4.1.a	RFM for distribution
4.1.b	PTRM for distribution
4.1.c	RFM for transmission
4.1.d	PTRM for transmission
4.1.e	Depreciation calculation for distribution
4.1.f	Depreciation calculation for transmission
4.1.g	Assets changing classification
4.1.h	FY19 CESS adjustment calculation for distribution
4.1.i	FY19 CESS adjustment calculation for transmission
4.1.j	Rate of return
4.2	Averaging period for cost of equity and debt

Interrelationships across our proposed expenditure

To help you navigate our Regulatory Proposal, this figure summarises where you can find information on each expenditure category and the other matters we are required to address in our proposal.



Glossary

BAU = Business as Usual
Capex = Capital expenditure
CER = Customer energy resources
CIS = Customer Information Systems
ERP = Enterprise Resource Platform
ICT = Information, communications and technology
NIP = Network Innovation Program
Opex = Operating expenditure
OTI = Operational technology and innovation
Repex = Replacement expenditure
SaaS = Software as a Service
Totex = Total expenditure

5

Capex is a significant driver of our component of electricity prices and customer bills. The assets we invest in today can remain in service for 50 years or more.

5. Capital expenditure

Capex refers to our investments in the assets we need to deliver our distribution network services to the standard customers expect from us. It includes investments in both network assets (e.g. poles and wires) and non-network assets (e.g. ICT systems, property and motor vehicles).

Some of the assets we have remain in service for over 50 years. As such, 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. In this way, the cost of an asset built today is not just borne by current customers but also future generations that may use the asset over its useful life.

In developing our capex forecast for the 2024-29 period, we aimed to ensure that the forecast reflects the efficient and prudent costs of achieving our capex objectives and providing safe and reliable distribution services to our customers, in accordance with the requirements of the NER.

We consider our capex forecast meets the AER's expectations, as set out in its Better Resets Handbook (see **Figure 5.0.1**).

The sections below:

- Provide an overview of 2024-29 capex forecast (**Section 5.1**);
- Compare our 2024-29 capex forecast with our recent capex performance trend (**Section 5.2**);
- Provide an overview of our improved capital governance processes (**Section 5.3**);
- Discuss our 2024-29 forecast for each capex category in turn (**Sections 5.4** to **5.12**); and
- List supporting attachments relevant to our capex proposal (**Section 5.13**).

Figure 5.0.1 Our performance against the AER's expectations on capital expenditure proposals

Expectation		Our assessment	Explanation	Where discussed
Top-down testing	Total capex forecast not materially above current period spend	✔	We are forecasting a period-to-period increase of 1%	**Section 5.2**
	Recurrent expenditure components not materially above current period spend	✔	Our replacement expenditure (**repex**) and recurrent ICT capex is 5% and 34% below our current period spend, respectively	**Sections 5.4** and **5.9**
	Non-recurrent expenditure components supported by cost benefit analysis (**CBA**)	✔	Our growth, operational technology, innovation, non-recurrent ICT forecasts, fleet and property forecasts are supported by CBAs	**Sections 5.6, 5.8, 5.9, 5.10** and **5.11**
Prudent decision-making	Key projects / programs needed to meet the capex objectives	✔	We refreshed our investment governance in response to AER feedback during our 2019-24 reset. This put in place arrangements geared towards identifying the most efficient level of investment needed to meet the capex objectives, including portfolio-level challenge and removal of overlapping expenditure	**Section 5.3**
	Project selection supported by CBA	✔	We apply a standardised CBA model across our portfolio which bases option selection on the projects that unlock the most economic value. We apply CBAs to 90% of repex, all non-recurrent ICT investments and most of growth, CER and fleet and property related investments	**Section 5.3.1**
	Trade-offs between capex and opex accounted for	✔	We have traded-off climate resilience investments in favour of more flexible opex based solutions which build resilience through community-based initiatives. We are continuing to engage with our customers about these trade-offs and the optimum mix of resilience solutions	**Section 6.6**
Alignment with standards	Asset management aligned with relevant Australian industry standard	✔	We are certified to *ISO 550001 Assessment Management System – Requirements* and our repex planning approach aligns with the AER's *Industry practice application note for asset replacement planning*[34]	**Section 5.4**
Genuine consumer engagement	Service level outcomes explained	✔	Our 2024-29 capex forecast is expected to maintain existing service levels with a lower level of replacement and network growth investment than we expect to invest in the current period	**Section 5.5**
	Short- and long-term trade-offs explained	✔	Short-and long-term trade-offs have been discussed with the Reset Customer Panel in setting the economic life of major projects such as our ERP replacement (15 years instead of standard 5 years) and in relation to how we prudently manage long-term challenges like climate change	

34 AER (2019), *Industry practice application note: Asset replacement planning*.

5.1 Overview

Our total network and non-network capex forecast for 2024-29 is $3,311 million or $662 million per year (real FY24).[35]

This is:

- 1% higher than our current period capex, excluding SaaS implementation costs which are treated as opex for 2024-29;[36] and
- 2% higher than our Draft Plan forecast. The higher forecast compared to our Draft Plan is principally driven by updated inflation.

Figure 5.1.1 below sets out our capex forecast for 2024-29 and compares it to our actual/estimated spend in the 2019-24 period. To provide a clearer breakdown of the drivers underpinning our forecast, we find it helpful to talk about our investment program in terms of 'continuing' and 'increasing' priorities, as set out in **Figure 5.1.2**.

Our investment on continuing priorities, such as replacing ageing assets and responding to growth in peak demand, is 8% lower in the 2024-29 period compared to our current 2019-24 period spend. Embedding these savings in our forecast promotes affordability at a time of rising cost of living pressures.

We undertook broad and deep engagement with our customers over an 18-month period ahead of lodging this Regulatory Proposal. Through this engagement, we identified a set of increasing priorities that are becoming more important to maintaining existing service levels.[37] These increasing priorities include:

- Building climate resilience;
- Responding to cyber threats; and
- Doing our part to facilitate a net zero future by enabling CER.

Our investment in these areas of increasing importance were subject to the trade-off discussions with customers, including over 10 sessions with our Voice of Community Panel totalling 60 hours. Our 2024-29 period capex also reflects that our internal governance processes are geared towards delivering efficient and prudent outcomes at the lowest long-term cost to customers.

Figure 5.1.1 Network and non-network capex forecast for 2024-29 compared to actual/estimated capex for 2019-24, by expenditure category ($m, real FY24)

Capex category	Section	FY25	FY26	FY27	FY28	FY29	FY20-24 period	FY25-29 period	% change
Replacement	**Section 5.4**	290	277	282	298	299	1,523	1,446	(5)%
Resilience	**Section 5.5**	25	39	48	43	39	0	194	n/a
Growth	**Section 5.6**	49	36	36	36	33	207	190	(9)%
CER integration	**Section 5.7**	8	10	10	9	10	4	47	n/a
Operational Technology and Innovation (OTI)	**Section 5.8**	29	21	20	23	23	204	117	(43)%
ICT	**Section 5.9**	74	98	59	36	34	282	301	7%
Fleet	**Section 5.10**	37	36	30	23	22	138	148	7%
Property	**Section 5.11**	68	15	30	25	8	174	145	(17)%
Overheads	**Section 5.12**	143	147	149	144	141	743	724	(3)%
Total		**723**	**679**	**664**	**637**	**608**	**3,277**	**3,311**	**1%**

35 All dollar numbers discussed in **Chapter 5** are in real FY2024 dollars, unless specified otherwise.
36 Our period-to-period increase in capex is 6.1% if SaaS costs were treated as capex in 2019-24 and 2024-29.
37 More detailed information about the breadth and depth of our engagement is outlined in **Chapter 3**.

Figure 5.1.2

Our capex proposal aims to deliver on our continuing and increasing priorities

Continuing priorities

Repex	Growth	OTI	ICT	Property	Fleet	Overheads	Total
$1,446m	$190m	$117m	$161	$145m	$148m	Capital support	
↓ 5% on 2019-24 spend	↓ 9% on 2019-24 spend	↓ 43% on 2019-24 spend	↓ 17% on 2019-24 spend	↓ 17% on 2019-24 spend	↑ 7% on 2019-24 spend	↓ 3% on 2019-24 spend	
$1,753m			$453m			$724m	$2,930m
↓ 9% on 2019-24 spend			↓ 10% on 2019-24 spend				Our continuing priorities are ↓ 8% on 2019-24 spend

Repex, Growth and OTI: $1,753m, ↓ 9% on 2019-24 spend. ICT, Property and Fleet: $453m, ↓ 10% on 2019-24 spend.

Increasing priorities

Resilience	Network-related CER	Cyber, ERP and CER-related ICT	Overheads (included above)	Total
$194m	$47m	$140m	Note that expenditure associated with 'increasing priorities' attracts overheads (included in the $724m above)	$381m

Total

Our total capex forecast is made up of our continuing priorities ($2,930m) and our increasing priorities ($381m)

$3,311m ↑ 1% on 2019-24 spend

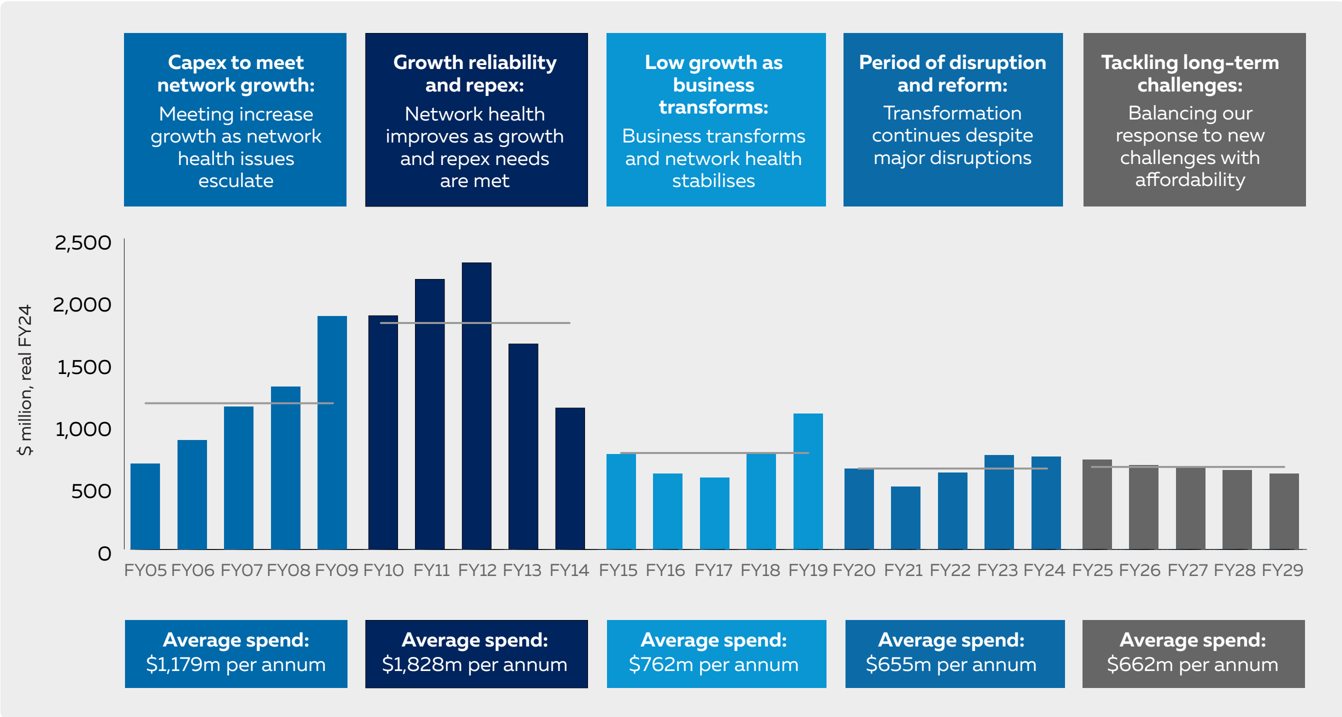
Legend

- Increasing priorities
- Continuing priorities
- $ m: 2024-29 total expenditure

5.2 Capex forecast compared to recent capex performance trend

Our total 2024-29 capex forecast is $3,311 million. While this is 1% higher than our current 2019-24 period spend, it is 40% below our 20 year long-term trend (FY05 to FY24) and 7% below our 10 year trend (FY15 to FY24). Our forecast and historical capex back to FY05 is set out in **Figure 5.2.1**. It shows we are delivering a more sustainable level of spend aimed at keeping long-term bill outcomes stable while maintaining existing service levels and network health.

Figure 5.2.1 Capex forecast for 2024-29 compared with actual/estimated capex for previous periods ($m, real FY24)



During the current 2019-24 period, we took steps to lower our capital cost footprint and implemented reforms to increase productivity. The reforms we introduced will allow us to keep our 2024-29 capex reflective of our recent investment levels while we tackle the challenges of the future. For example, in 2024-29:

- We will spend less to keep average levels of reliability steady under normal operating conditions.[38] Our forecast repex ($1,446 million) and growth capex ($190 million) totals $1,636 million. This is 5% less than the $1,730 million we expect to spend in the 2019-24 period. For customers, we expect this level of expenditure to deliver the same average level of reliability during normal operating conditions at a lower cost;
- Our resilience capex forecast of $194 million is 30% below what our economic modelling indicates we should invest based on customer benefits and the expected growth in our climate related risks. This aligns to the cautious approach we are taking to a new area of investment which will evolve over time, in line with ongoing customer consultation (see **Section 5.5.4** below); and
- We refreshed our approach to investment governance in response to feedback from the AER and its technical consultant, EMCa, at our 2019-24 reset. The improvements we have made ensure we have the right processes in place to deliver prudent investments at an efficient long-term cost.

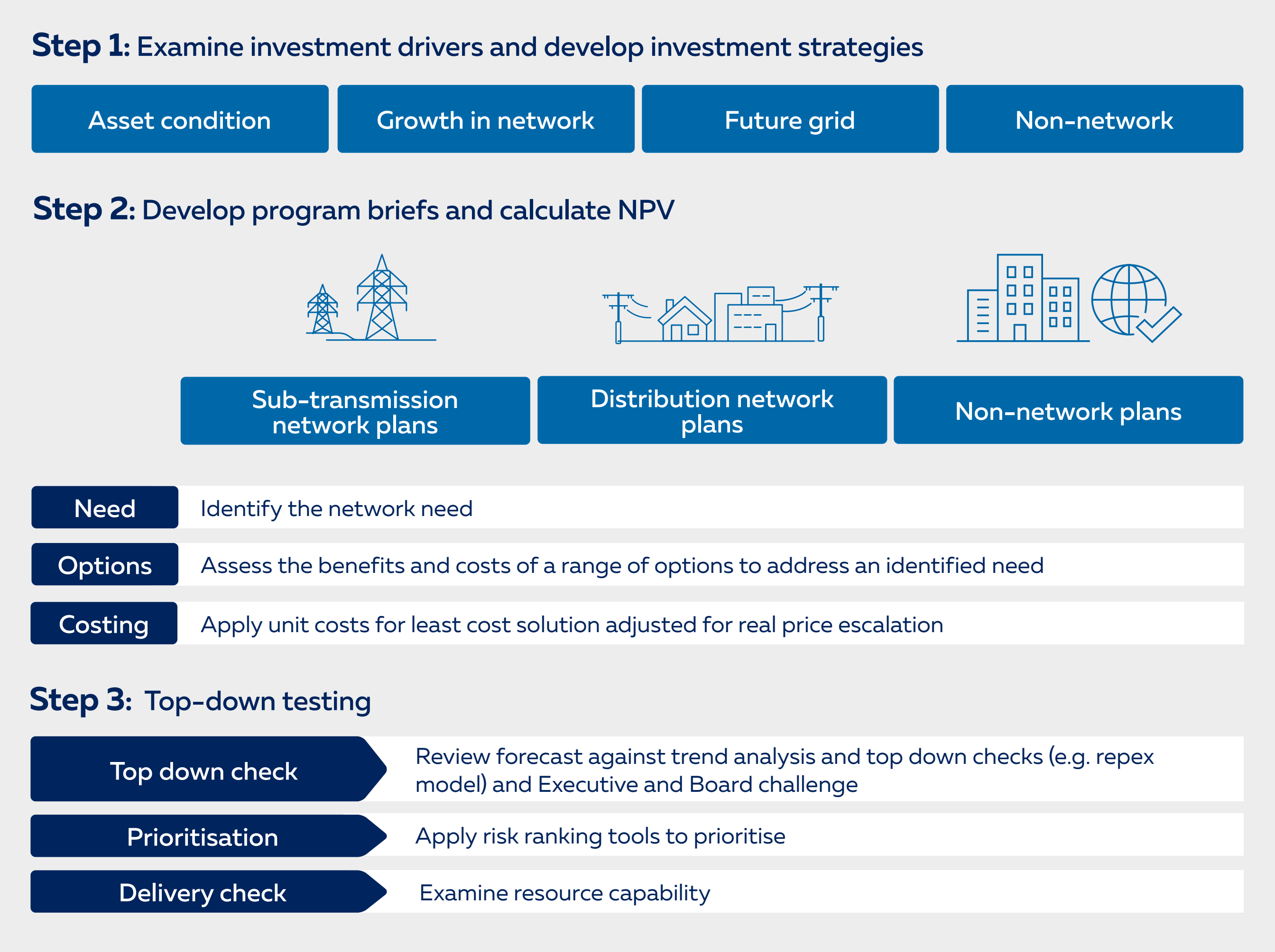
38 That is, when major event days are excluded.

5.3 Our improved capital governance processes

We maintain an investment governance framework that provides clear guidance and accountability with respect to the development, determination and approval of all investments, including network and non-network investments. The investment governance framework supports the selection of investments that deliver value for our customers and provides the basis for making transparent and efficient investment decisions.

There are several embedded stages of internal review of projects to ensure that proposals are appropriately scrutinised as part of our improved investment governance framework (see **Attachment 5.1 – Proposed capital expenditure**). These steps are set out in **Figure 5.3.1** below. They include an assessment of key drivers and strategy development (step 1), development of program briefs and NPV analysis (step 2), and a top-down test at the executive and board level (step 3).

Figure 5.3.1 Our capital planning process



The key improvements we have made in response to the AER's feedback at our 2019-24 reset relate to our NPV modelling and a refresh of our approach to capital prioritisation. We discuss each of these in turn below.

- **We have developed and rolled out a standardised NPV model:** by moving from multiple models to a standardised model, we have sought to improve the robustness of our internal modelling, reduce the scope or potential for error, and ensure a consistent approach to quantifying the net benefits of projects across our capex portfolio.
- **Using quantitative analysis to prioritise our capex program:** our standardised NPV model allows us to directly compare the relative merits of otherwise disparate investments and facilitates the prioritisation of projects based on a common value calculation method.

Our approach to capital planning is stronger in part because of the feedback we received from the AER and its technical consultant, EMCa, at our last regulatory determination. More information about the enhanced capital governance tools we use is included in **Attachment 5.1 – Proposed capital expenditure**.

5.4 Replacement capex

Repex includes capital investments to replace assets that are at the end of their life and pose a risk to safety and reliability. It also includes expenditure to refurbish assets to extend their life.

Our repex programs and major replacement project forecast for the 2024–29 period is $1,446 million.[39] It represents 44% of our total capex forecast, making it our largest capex category (see **Figure 5.4.1**). It is 5% below our 2019-24 expected repex spend and 15% below our 2019-24 repex allowance.

Continuing priority

We replace ageing assets to protect the community and maintain safety and reliability. Our 2024-29 period will continue to prioritise safety and reliability at a 5% reduction in repex relative to the current period.

Figure 5.4.1 Forecast repex as a proportion of total forecast capex

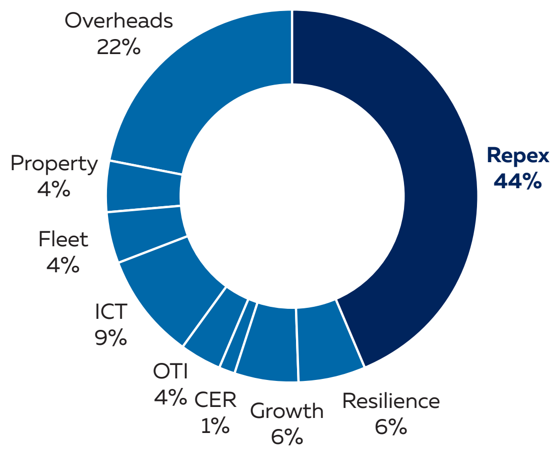
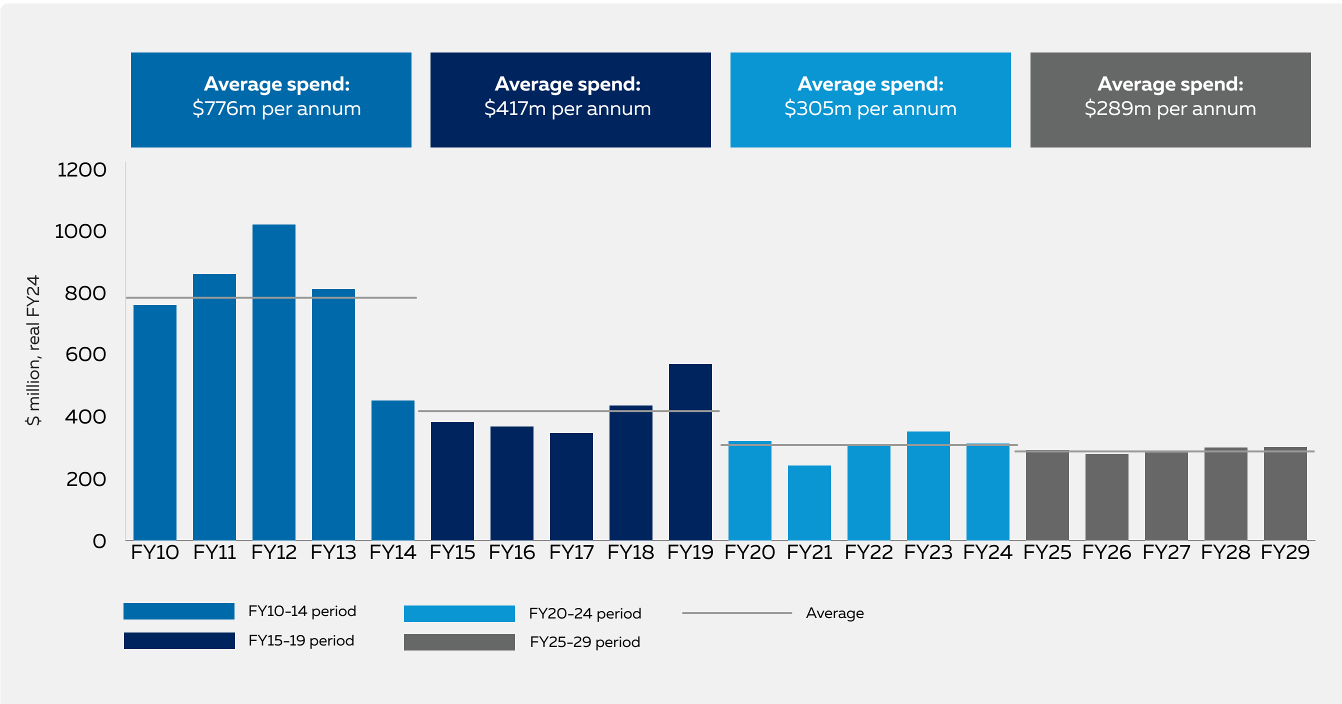


Figure 5.4.2 shows our historical and forecast replacement investment year-on-year and as an average over recent regulatory control periods. Trend analysis highlights a 5% reduction in forecast expenditure relative to our expected spend in the current period.

Figure 5.4.2 Repex trend over a 20-year horizon ($m, real FY24)



39 Excludes resilience-related initiatives which have been separated out as a standalone 'Resilience' cost category for transparency (see **Section 5.5** below).

5.4.1 What we have achieved in the current period and how it benefits customers

We refreshed our forecasting approach for replacement activities in response to feedback received at our last reset. In doing so, we have applied bottom-up and top-down analysis and evaluation tools and strengthened our governance processes. **Figure 5.4.3** summarises these improvements and how they will benefit customers in the 2024-29 period.

Figure 5.4.3 Our recent achievements and how they will benefit customers in the 2024-29 period

	What we achieved in 2019-24	Benefits to customers in 2024-29
Cost benefit	Significantly improved our CBA modelling	Our powerful CBA tools include greater levels of asset risk segmentation, supporting an effective, prioritised bottom-up forecast
Top down challenge	We refreshed our governance processes in response to AER feedback at our last reset	Our repex forecast went through a robust top-down review and challenge
Innovation	We established a Network Innovation Advisory Committee to lead the rollout of innovation technologies on our network	Continued investment in innovation allows us to maintain service levels for customers with a lower repex spend compared to the current period

5.4.2 Incorporating our customers' priorities

For our customers, repex is key to ensuring the safety of our assets embedded within our communities and maintaining our current level of network reliability and performance. We did not focus our engagement with the Voice of Community Panel on repex as it is more recurrent in nature than the other expenditure categories and is driven by complex modelling.[40] However, we engaged with the Reset Customer Panel and the AER on our repex program. The extent of our pre-lodgement engagement on our repex program is summarised in **Figure 5.4.4**.

Figure 5.4.4 Engagement on our repex program

1
AER modelling workshop

6
RCP presentations

10+
Hours of discussion

5%
Reduction on current period spend

40 This aligns with the AER's *Better Resets Handbook*.

5.4.3 Repex forecasting approach

Our bottom-up forecasting using risk-based analysis has improved significantly in recent years. At our last reset, the AER's technical consultant EMCa observed 'only limited application of risk analysis and limited information on Ausgrid's application of predictive modelling'.[41] Since then, we took steps to enhance our approach to CBAs by developing advanced modelling techniques that more accurately predict asset failures.

We have also improved our risk modelling through greater segmentation of consequences against individual assets e.g. utilising granular grid based bushfire modelling to apply fire risk to individual assets or proximity to waterways for heightened environmental risks. In advancing these models, we continue to have regard to the AER's *Industry Practice Note: Asset Replacement Planning* and the prioritises of our customers by valuing customer benefits.

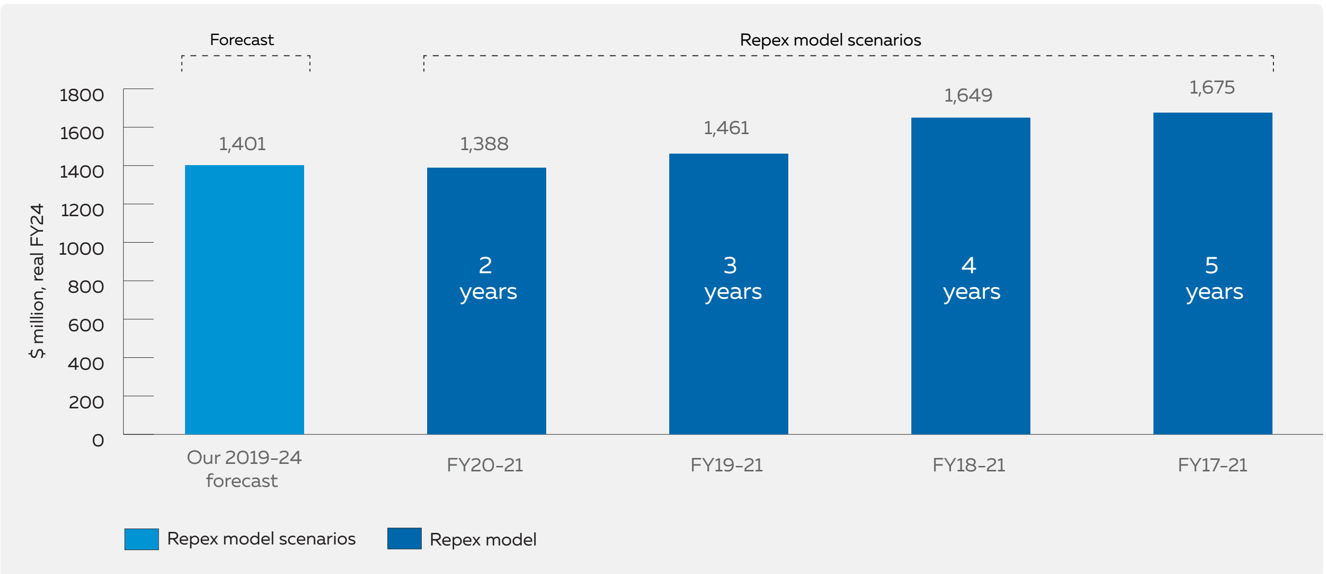
Our CBA now covers much of our replacement expenditure (approximately 90%). Our CBA tools, while highly advanced, are not the only basis on which we have developed our repex forecast. Where our CBA has been applied and has supported a step change in replacement relative to historical expenditure levels, we have considered this against historical investment levels, historical asset performance and associated asset risks before adopting the CBA outcomes. Once our bottom-up forecast was developed, we tested our forecast against the AER's repex evalutation model (**repex model**).

5.4.4 Evidence that our repex forecast is efficient

The AER developed a repex model which considers the age, cost and life of assets for each electricity distributor and applies benchmarking of costs and lives across distributors. These scenarios include a range of historical years to best represent the balance of current asset performance and asset management practices. However, if too short a period is applied, the model is affected by transient factors such as COVID-19, a live work pause and industrial action, as they did to varying degrees in FY20, FY21 and FY22. This results in forecast assets lives that are longer and costs that are higher than expected otherwise.

We have applied the AER's repex model as a further top-down check of the reasonableness of our forecast repex. **Figure 5.4.5** shows, when multiple years are considered, our repex forecast is similar or below the threshold for efficient repex calculated by the model. Note that the proportion of our repex forecast ($1,446 million) which is compared to the repex model scenarios is $1,401 million (as set out in **Figure 5.4.5** below). See **Attachment 5.4a - Asset replacement programs** for more information.

Figure 5.4.5 Forecast repex compared with the AER's repex model scenarios ($m, real FY24)



41 EMCa (Ausgrid2018), *Review of Ausgrid's capex proposal 2019-24*, p iii, paragraph 9.

5.5 Resilience

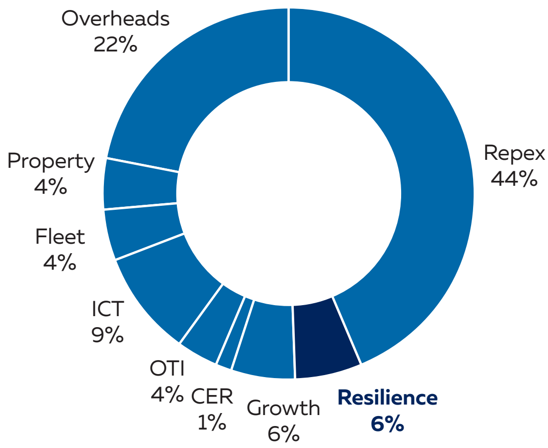
We have always made investments to support the resilience of our network and the supply of energy to customers in difficult operating conditions.

However, climate change means the investments we make in building resilience are now an increasing priority. This reflects our customer engagement to date and the fact that the assets we install in the 2024-29 period are expected to live through potentially dramatic changes in Australia's climate over the coming 30 to 40 years and beyond.

Increasing priority

Our customers told us that they are becoming more concerned about the impacts of climate change and that we should respond by making resilience an increasing priority in the 2024-29 period.

Figure 5.5.1 Forecast resilience as a proportion of total forecast capex



Our resilience capex proposal for the 2024-29 period is $194 million. This is a cautious level of investment, which is nearly 40% less than what our economic modelling suggests we should spend based on customer benefits and the expected growth in our climate risk.

We have had broad and in-depth conversations with customers about resilience. We have hosted over 20 meetings with the Reset Customer Panel and co-designed with customer advocates an investment framework called *Promoting the long-term interests of consumers in a changing climate: A decision-making framework* (**Climate Resilience Framework**).

More recently, we came to the joint view with the Reset Customer Panel that further engagement is needed. This prompted us to develop a plan for implementing our Climate Resilience Framework (**Implementation Plan**), that builds on the conversations we have been having over the past 18 months. The Implementation Plan, summarised in **Figure 5.5.2** below, may lead us to update our current resilience forecast based on the feedback we hear from customers. Any updates will be provided to the AER before its Draft Decision.

Figure 5.5.2 Future engagement planned to implement our co-designed Resilience Framework

5.5.1 What we have achieved in the current period and how it benefits customers

Figure 5.5.3 below outlines key actions on resilience we have taken so far in the 2019-24 period and how they will deliver benefits to customers in the forthcoming regulatory period.

Figure 5.5.3 Our recent achievements and how they will benefit customers in the 2024-29 period

	What we achieved in 2019-24	Benefits to customers in 2024-29
Customer trade-offs	We hosted a Town Hall where our Voice of Community Panel told us about their willingness to pay for building climate resilience	Our resilience investment program is informed by customer trade-offs between price, service levels and fairness
Climate impact study	We implemented a climate impact study that is the first of its kind for an Australian electricity distribution network	The resilience investments customers fund will be based on industry-leading analysis of climate scenarios and their impacts on our ability to maintain current network service levels for our customers
Investment framework	We co-designed an investment framework with our customers to develop and administer resilience investment programs	Our customers have been central to the formation of our resilience program and will have an ongoing role in how it is administered

5.5.2 Incorporating our customers' priorities

We have developed a resilience investment program that aligns with our customers' priorities as evidenced through the feedback we received from the Voice of Community Panel. We listened and in response are doing the following:

- Capping investment at $202 million totex ($194 million capex and $8 million opex) in the 2024-29 period, based on the different options presented to the Voice of the Community Panel and their views on bill impacts; and
- Re-balancing our resilience program to include more flexible opex based, community focused investment solutions (see **Section 6.6.3**)

To embed a customer perspective in our decision-making, we have co-designed our Climate Resilience Framework.

Embedding a customer perspective through a co-design process

The co-design process we used to develop our draft Climate Resilience Framework included multiple in-person workshops involving Ausgrid, the Reset Customer Panel and the Total Environment Centre, and the co-authorship of a written document. We also consulted on the framework when we published our Draft Plan in September 2022.

This process was very different to our traditional approach to developing new policies for managing significant risks like climate change. We believe it will lead to better customer outcomes by embedding customer perspectives in our decision-making at the earliest stage in our resilience planning.

The Implementation Plan we have jointly developed with the Reset Customer Panel will put our Climate Resilience Framework into action through extensive engagement with customers over the coming months.

Our co-designed Climate Resilience Framework has informed our resilience capex forecast and will guide the nature and scale of the resilience investment. The framework requires us to apply scientific evidence, analyse opportunities and options, report back on our findings via accountability measures, and engage with the community at all stages.

Figure 5.5.4 shows multiple phases of engagement we undertook with our Voice of Community Panel, our commercial and industrial customers and councils. What we heard about building resilience to support thriving communities is outlined in more detail along with how we are responding in this 2024-29 Regulatory Proposal.

Figure 5.5.4

What customers told us about building resilience to support thriving communities

Our engagement journey	Purpose	What we heard from our customers and how we are responding	2029 residential bill impact driven by customer priorities see Section 1.3.

Phase 2 engagement framework

Customer themes

- Improved outcomes for those most impacted by extreme weather.
- Improved emergency response.
- A say on how we build resilience.

Options we proposed

In response to customers priorities for mitigating the potentially significant negative experiences of those customers at highest risk and most exposed to the impacts of climate change, we proposed a resilience investment program.

Four options were presented to customers:

- Allow increasing frequency of extreme weather events to degrade reliability over time, with no additional resilience related investment;
- Maintain today's customer experience despite the risk of climate change, investing $25 million per annum;
- Improve the reliability of those at highest risk of increased extreme weather by reducing the number of outages by approx. 13% and the frequency by approx. 11%, with an investment of $40 million per annum; or
- Extend the resilience program to areas with moderate to high impacts from the frequency of extreme weather, through an investment of $80 million per annum.

Based on what we had heard from customers about achieving a fair and equitable access to electricity across the regions but balancing this with the need for affordability we proposed a resilience program of $200 million or $40 million per annum but were keen to understand if we had interpreted customers correctly.

Customer preferences

Voice of Community Panel	Commercial and industrial	Councils
'Agree with investment level of $200m.' *'Pursue an efficient mix of capital and operational investment opportunities to ensure the ongoing reliable provision of electricity.'*	*'Start to be proactive, think about the long term – start to rebuild more resilient.'*	*'Nominated resilience localised community centres for people to go to.'*

Draft Plan for 2024–2029

Our Draft Plan position

Partnering with customers to decide what climate resilience investments we make, by:

- Supporting affordability by spending no more than $204 million on climate resilience initiatives over the 2024–29 period; and
- Developing our draft climate resilience framework alongside customer advocates.

Making investments that meet different customer needs, by:

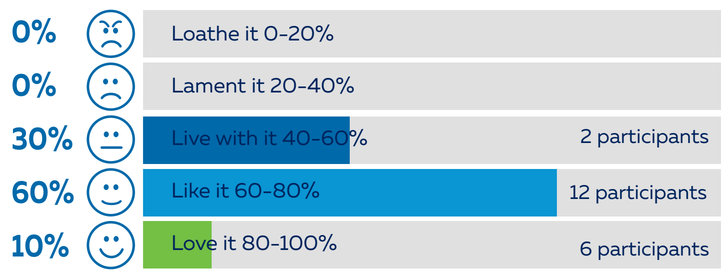
- Installing stronger powerlines in areas with large amounts of vegetation, potentially in partnership with councils;
- Maintaining our current storm response capabilities, by taking 5 years of data into account when forecasting these costs which adjusts for unusually low or high storm activity in a single base year; and
- Rolling out up to five community resilience vans so that our customers have a place to charge their phone and connect with loved ones when they lose supply.

Bill impact 2029: $5 of the $38

Phase 3 engagement framework

Customer views on our Draft Plan position

Town Hall (all end use customers)



'Urban areas already well served – so prioritise non urban areas.'

'Partnership is a way to save money to get better and cheaper outcomes.'

Councils

'SSROC supports the continued participation of customer advocates in developing resilience. The electricity grid infrastructure is essential to the effective functioning of society today, and in some instances is critical to human health. Its resilience is of great importance and SSROC is generally supportive of improvement measures.'

2024–2029 Regulatory proposal

How we're responding

- Proposing a balanced mix of network capex ($194 million) and opex based ($8 million) community resilience initiatives; and
- Continuing to engage with the community through an Implementation Plan that seeks the views of our customers in LGAs most at risk of extreme weather events due to climate change.

+$6 of the $37

* For the average customer using 5000kWh per annum.

5.5.3 Resilience expenditure forecasting approach

Our resilience expenditure forecast is based on analysis that models future climate scenarios and their impact on electricity distribution network infrastructure. This analysis is the first of its kind in Australia.

Using the outcomes from our climate modelling, we calculated the impact of extreme weather events on our network. The risks we considered involved higher failure rates, the cost of responding to damage on our network, and estimated unserved energy (the time that customers would be without supply). The results showed the anticipated average cost each year associated with growing climate risk.

5.5.4 Evidence our resilience expenditure forecast is efficient

We have aligned our forecasting approach to the AER's *Network resilience: A note on key issues* guidance note (**AER Resilience Note**).[42] It sets out three key expectations for resilience funding to be considered efficient. Each of these expectations are considered below.

Expectation 1: There is a causal relationship between the proposed resilience investment and the expected increase in the extreme weather events

We have used risk-based quantification analysis to develop a potential suite of resilience initiatives. It applies climate change forecasts with engineering information about our network to establish a causal link between these initiatives and the ability to mitigate the risk associated with expected increase in climate events.

The time horizon over which this causal link is assessed is important. This is because over a 40-year time horizon, which corresponds to most network assets, a resilience initiative will accumulate benefits. These benefits may be an improvement in safety or a reduction in the length of network outages.

We have run quantitative analysis to calculate the pay back period (costs = benefits) from our resilience program. Identifying that our planned investments will deliver net benefits to customers provides a strong basis on which to test the causal link between our proposed resilience expenditure and the expected increase in extreme weather events. We will revisit this quantitative analysis as part of our Implementation Plan.

Expectation 2: The proposed expenditure is required to maintain service levels and is based on the option that likely achieves the greatest net benefit of the feasible options considered

Our total 2024-29 capex program aims to maintain existing levels of service for customers. The resilience initiatives within our total program (6% of total capex) contribute to this outcome by containing the expected increase in climate-related risks that could lead to longer customer outages or safety hazards.

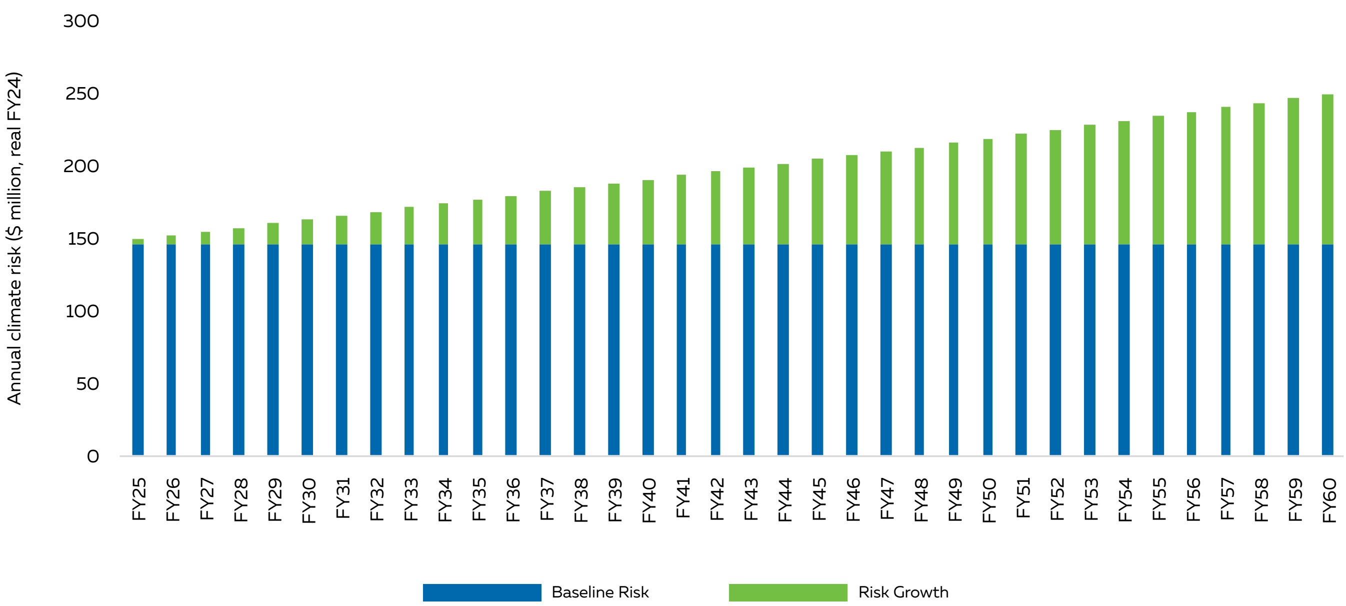
Our approach to quantifying the expected growth in climate risk, which could lead to a degradation in existing services, involved calculating:

- Our baseline level of climate risk in 2020; and
- The change in risk in a 'do nothing' scenario, modelled over low, medium and high carbon emission pathways (whereby emissions pathways are greenhouse gas concentration trajectories adopted by the Intergovernmental Panel on Climate Change).

42 AER (2022), *Network resilience: A note on key issues.*

Figure 5.5.5 below sets out the growth in risk ($m) for the Emissions Pathways modelled under a 'do nothing' scenario. It shows that future customers would face materially higher climate risks, and ultimately poorer service levels, if we do not act today to tackle the long-term challenge of climate change. Our analysis uses an AER input called the Value of Customer Reliability (**VCR**) which allows us to calculate the equivalent dollar impact of network outages. Using VCRs allows us to translate the customer impact of a network interruption due to more extreme weather into a dollar value ($m) which we can then compare with the cost of acting.

Figure 5.5.5 Growth in climate-related risk compared to our 2020 baseline ($m, real FY24)

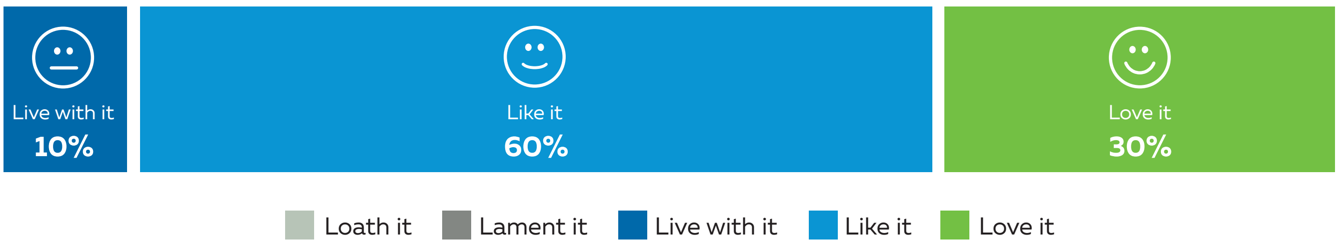


Our modelling of the aggregate growth in our climate risk is $1.64 billion by 2050. To address this growth in climate risk via a smooth investment profile, an investment of $65 million per annum or $325 million over the 2024-29 regulatory period would be required. Our current forecast takes a more cautious approach by investing less ($40 million per annum) than our economic modelling indicates would be required to mitigate all projected risk growth. Our forecast is also in line with the $200 million cap on investment the Voice of Community recommended.

Expectation 3: Consumers have been fully informed of different resilience expenditure options, including the implications stemming from these options, and are supportive of the proposed expenditure

We have tested our resilience investment program with our customers. Over 10 sessions held in-person and via videoconference and totalling 60 hours, we fully informed the Voice of Community Panel of the different resilience options available to us. This culminated in a survey which revealed that 90% of the customers making up our Voice of Community Panel either liked or loved our resilience investment program, with the remaining 10% saying they are able to 'live with it' (**Figure 5.5.6**).

Figure 5.5.6 Voice of Community Panel comfort levels with our resilience investment program



Our conversations with customers about building resilience remain ongoing. Together with the Reset Customer Panel, we have developed an Implementation Plan (see **Section 5.5**) which will be integrated into a July 2023 submission, directly targeted at meeting the AER's expectation that customers are fully informed of all resilience options, their implications and are supportive of our proposal.

5.6 Growth

Growth capex includes two components:

1. **Augmentation capex (augex)** – includes capital works on our shared network which are needed to meet increases in demand for energy; and
2. **Connection capex** – includes investment in new installations to provide reliable supply to customers who want access to the shared network.

We also manage our reliability compliance program through our growth capex spend, which is targeted at addressing localised parts of the network that exhibit poor reliability.

Our growth capex forecast for the 2024–29 period is $190 million – including augex of $138 million and connections capex of $51 million. It accounts for 6% of our total capex forecast (see **Figure 5.6.1**).

Continuing priority

We will continue to prioritise our network growth needs but at a lower cost to customers with our forecast 9% below our current period spend.

Figure 5.6.1 Forecast growth capex as a percentage of total capex

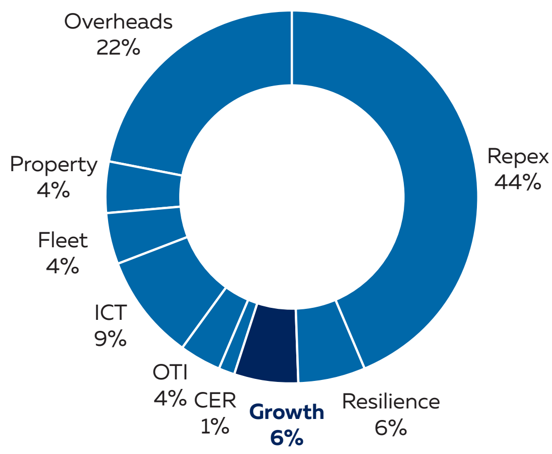
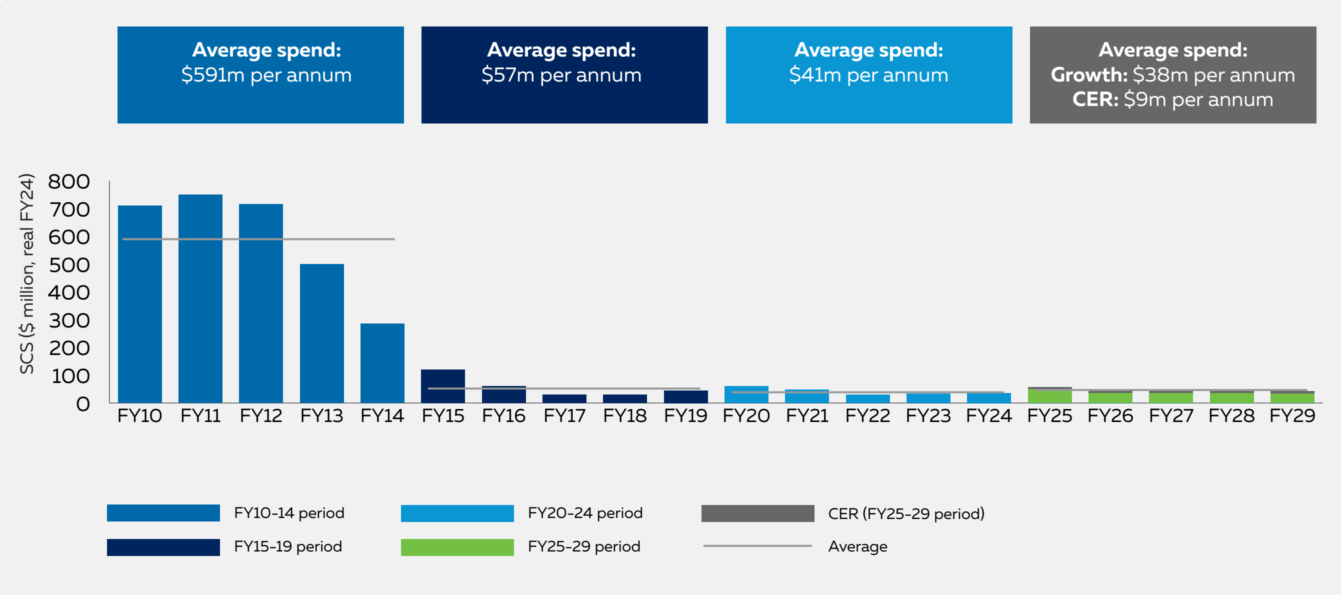


Figure 5.6.2 sets out our trend in growth capex over a 20-year horizon. It shows that our spend is well below our peak levels of investment.

There is a relationship between our growth capex and CER integration capex because our CER capex enablement program (discussed in **Section 5.7**) will deliver more capacity to the grid, complementing our traditional growth capex needs. Due to this relationship, we have set out our growth capex and CER integration investments together in **Figure 5.6.2** below.

Figure 5.6.2 Growth capex trend over a 20-year horizon ($m, real FY24)



5.6.1 What we have achieved in the current period and how it benefits customers

We are continually refining our forecasting approach for growth-related capex. **Figure 5.6.3** sets out a summary of recent changes we have made and how these improvements will unlock customer benefits into the 2024-29 period. As peak demand is a key input into our investment needs, many of our improvements relate to how we forecast this investment driver.

Figure 5.6.3 Our recent achievements and how they will benefit customers in the 2024-29 period

	What we achieved in 2019-24	Benefits to customers in 2024-29
Agent-based modelling	Our forecast of demand recognises that many of our customers can now generate and store energy. To account for this when forecasting demand, we have developed sophisticated modelling techniques that assign 'agent types' to each customer where variations in load are expected due to CER (see **Section 5.6.4**)	Improvements in our forecasting approach mean that customers will not pay more than is necessary for augmentation of the shared network
Strengthened governance	We have strengthened our governance processes, including applying an independent review of our peak demand forecast	Customers can have confidence that our forecast has been subject to a prudent review and challenge process, including independent review of key inputs
Electric vehicles	We modelled the impact of EV charging on our network and surveyed 130 EV customers to identify typical charging patterns	Our understanding of EV charging behaviour will inform efficient network tariffs that defer or avoid growth-related investment

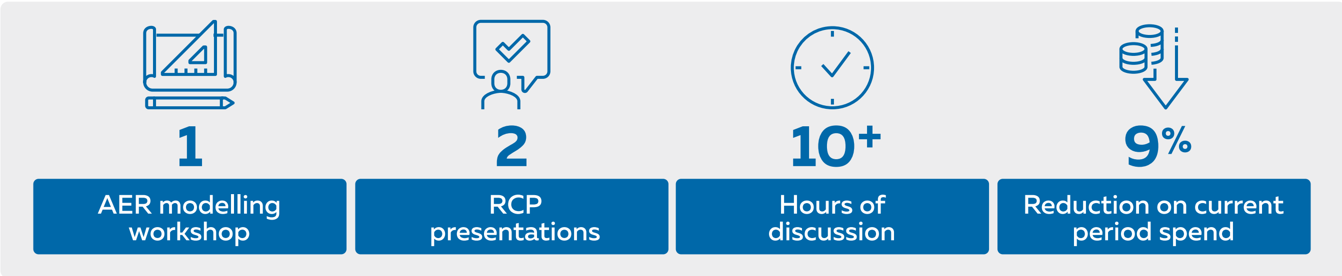
5.6.2 Incorporating our customers' priorities

Responding to peak demand and connecting new customers to our grid through growth-related investment is a continuing priority for our customers in the 2024-29 period.

In seeking to identify our customers' views, we focused our attention on deep-diving into technical matters with the Reset Customer Panel. This included in-person sessions during a two day workshop, in addition to multiple Reset Customer Panel presentations.

Our engagement (summarised in **Figure 5.6.4**) underscored the importance of promoting affordability. In line with this, our 2024-29 forecast would save a typical residential customer $0.19 per annum compared to if we trended forward our current period spend. Though a small annual saving, it reflects an avoided cost to our customer for 50-60 years which, when combined with other efficiencies, has a material long-term impact.

Figure 5.6.4 The breadth and depth of our engagement on our growth capex program



5.6.3 Growth forecasting approach

Our growth capex enables new customers to connect to our infrastructure and for our network to meet peak demand from customers. Our approach to forecasting peak demand is based on our share of the inputs and assumptions in AEMO's 2022 Integrated System Plan (**ISP**).[43] Ausgrid supplies approximately 40% of NSW peak demand and around 36-38% of energy delivered in NSW each year.

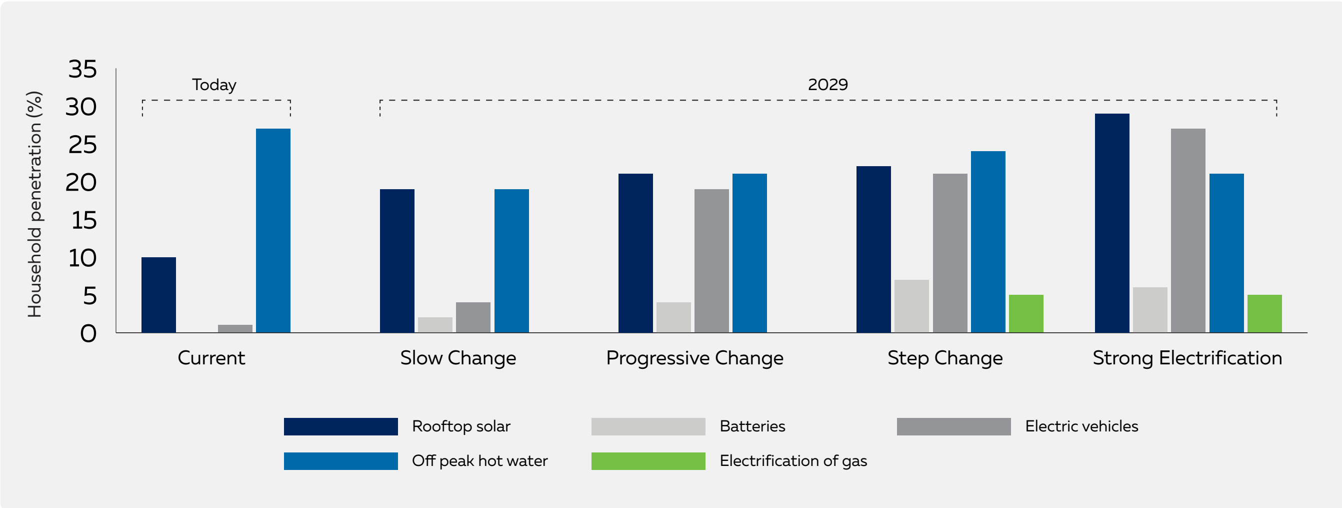
AEMO's 2022 ISP includes the following Scenarios:

1. **Slow Change:** Challenging economic environment with slower net zero emissions action. Slow Change would not reach the decarbonisation objectives of Australia's Emissions Reduction Plan;
2. **Progressive Change:** Delivers the decarbonisation objectives of Australia's Emissions Reduction Plan, with a progressive build-up of momentum ending with deep cuts in emissions across the economy from the 2040s;
3. **Step Change:** Moves much faster initially to fulfilling Australia's net zero policy commitments that would further help to limit global temperature rise to below 2°C compared to pre-industrial levels. Rather than building momentum as Progressive Change does, Step Change sees a consistently fast-paced transition from fossil fuel to renewable energy in the NEM; and
4. **Strong Electrification:** Consistent with strong global action on climate change and significant technological breakthroughs to achieve an even more rapid transition to net zero than Progressive Change or Step Change Scenarios.[44]

43 AEMO (2022), *2022 Integrated System Plan (ISP)*.
44 Ausgrid selected AEMO's Strong Electrificiation sensitivity modelling as the alternative Scenario to AEMO's Hydrogen Super Power Scenario. This is due to how the Strong Electrification Scenario impacts the low voltage network relative to the Hydrogen Super Power Scenario. See, AEMO (2022), *2022 Integrated System Plan (ISP)*, p. 92.

Figure 5.6.5 below summarises the customer technology adoption assumptions for our network as applied to each of the AEMO Scenarios. We have adopted the 'Step Change' Scenario when developing our peak demand forecast. The 2022 ISP process identified this Scenario as the most likely based on ageing generation plants, technical innovation, government policies and consumer choice.

Figure 5.6.5 Customer technology adoption assumptions within our network context

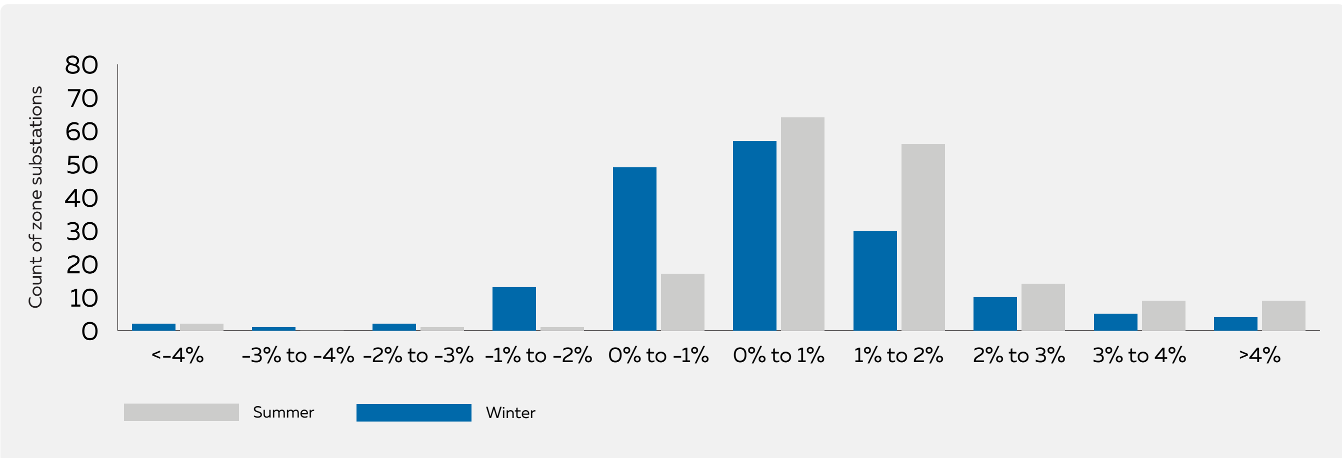


Based on the Step Change Scenario, the compound annual growth rate (**CAGR**) for peak demand on our network is 1.1% per annum for both summer and winter peak demand during the 2024-29 period. Steady growth in summer maximum demand is underpinned by continuation of elevated levels of C&I customer connection activity, population growth and EV uptake. This uplift in demand is offset by energy efficiency impacts and strong growth in rooftop solar uptake.

While overall maximum demand growth provides a helpful, macro view of the rate of demand growth, it is important to note that constraints on the network are highly variable depending on location and the network assets used to supply an area.

Figure 5.6.6 shows the distribution of demand growth across 180 Ausgrid zone substations.

Figure 5.6.6 Zone substation demand growth



Our analysis at the zone substation level shows that demand at some parts of our network is growing quickly. For example, data centres, which are among the largest new energy users connecting to our grid, can trigger the need for investment by causing 'spot' load growth in small, localised areas on our network. Other major customers connecting to our grid include large road and rail infrastructure projects. Our forecasting approach for growth capex applies these localised forecasts of demand.

5.6.4 Evidence our growth forecast is efficient

Our demand forecast underpins our investment strategies and ensures that we are investing the right amount in the right locations. Given uncertainty in the pace of change towards greater electrification, our demand forecast considers various scenarios incorporating different emissions pathways, and informs least regrets investments.

Factoring in the impact of CER

There is a relationship between our growth capex and CER integration capex. This is because our CER enablement capex program (discussed in **Section 5.7**) will deliver more capacity to the grid, complementing our traditional growth capex needs. Our growth capex forecast takes this into account through our agent-based modelling.

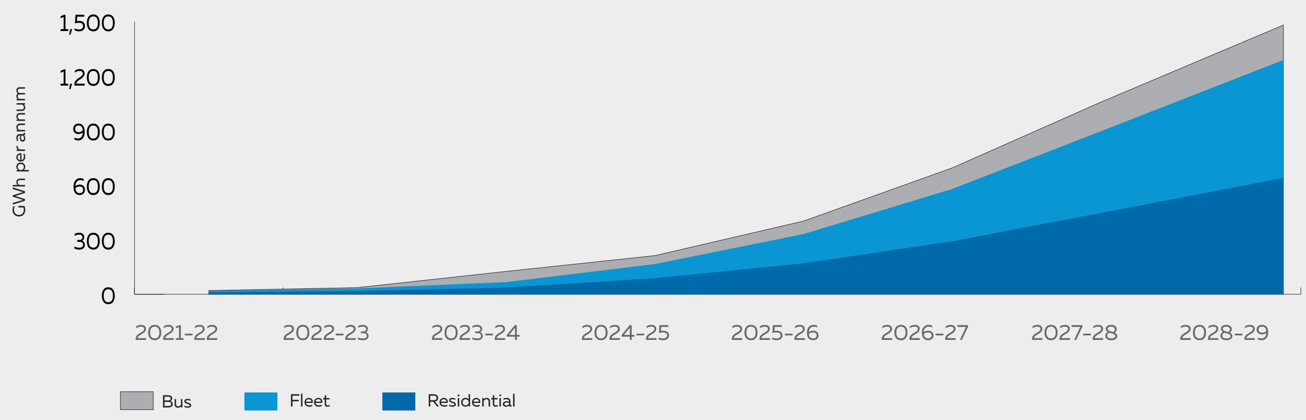
Under this approach, an agent type is assigned to each customer where variations in load are expected due to CER-related elements including rooftop solar, customer batteries, EVs, shifting off-peak hot water loads (solar soak) and electrification of residential gas. Loads which do not vary with these factors are not assigned agents but are treated as fixed loads for the purposes of this model. Our agent-based approach provides a clearer picture of demand and our growth capex needs. More information can be found in **Attachment 5.7 – CER integration program**.

Managing demand through cost reflective tariffs

The Step Change Scenario in AEMO's 2022 ISP forecasts that annual electricity consumption from the grid will double by 2050 as transport, heating, cooking and industrial processes are electrified.

In terms of transport, we expect to see significant growth in the number of customers owning EVs in our network area over the 2024-29 period and beyond. **Figure 5.6.7** below shows that we forecast that the annual energy consumption from EV charging to increase from around 20 GWh today to over 1,500 GWh by the end of the forthcoming 2024-29 period.

Figure 5.6.7 Forecast EV energy consumption in Ausgrid's network



Charging EVs can use a lot of electricity over a very short period. For example, we are already seeing chargers on the market with substantial capacities that could lead to significant new demand peaks on the network, including:

- Commercial chargers with up to 350 kW capacity; and
- Home smart chargers with a typical capacity of 7 kW.

The time of day when customers charge their vehicles will be crucial, in addition to the location where this occurs – for example, at home, at a public charging station, or in an area of the network with a lot of solar generation.

We recognise that our tariffs need to send efficient price signals about the different costs of charging EVs at different times so that EVs do not lead to a significant uplift in growth capex. We are already taking these prudent steps. Our residential demand and time of use (**TOU**) tariffs signal the higher costs of charging in the evening peak period and encourage charging overnight when network demand is low. Our proposed changes to the charging windows (see **Attachment 8.2 - Our TSS Explanatory Statement for 2024-29**) for these tariffs will strengthen these signals.

5.7 CER integration expenditure

CER includes rooftop solar, customer owned batteries, EVs and and unlocks the potential for innovative pricing arrangements.

Our network, ICT and innovation capex programs all include elements of CER integration. We also plan to employ opex based initiatives, innovative tariffs and dynamic connection agreements to efficiently integrate CER.

The following section of our Regulatory Proposal focuses on our planned CER integration investments that are network-based, which total $47 million in the 2024-29 period (see **Figure 5.7.1**).

Our CER integration program split by capex, opex and driver is set out in **Figure 5.7.2** below. CER is a priority for our customers and our modelling, based on AEMO's Step Change Scenario, forecasts an almost 90% increase in CER in our network by 2029.

It is important to note that all programs within the CER integration expenditure category are interdependent. That is, if the network capex elements in this section are approved and the ICT enablement program in **Section 5.9** and the smart meter data opex in **Section 6.6.6** are not approved, or vice versa, this will impact our low voltage network visibility and so we will not be able to deliver the CER integration program benefits.

Increasing priority

Our customers told us that we should be preparing our network for a net zero future by ensuring that we are proactively planning for and accommodating the forecast increased in CER on our network and not working reactively.

Figure 5.7.1 Forecast CER as a proportion of total forecast capex

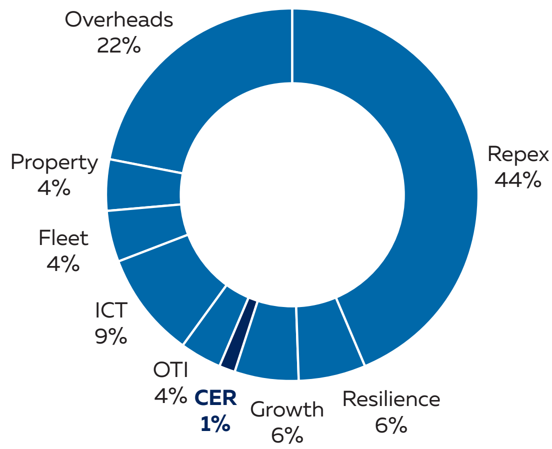
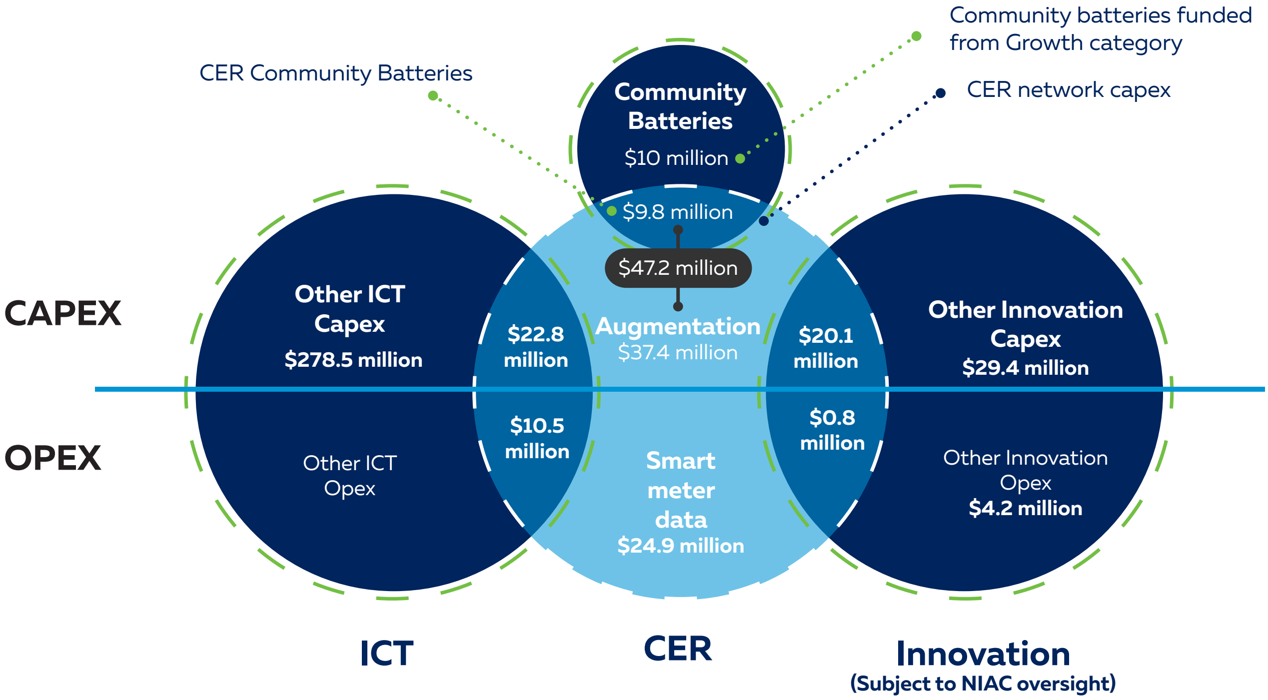


Figure 5.7.2 Our breakdown of CER integration expenditure ($m, real FY24)



CER totex = $126.1 million

5.7.1 CER integration forecasting approach

We have applied the AER's *CER Integration Expenditure Guidance Note* (**CER Guidance Note**) to develop our CER capex forecast. This involves the following three steps outlined below.

Step 1: Problems with integrating CER

The first step in the CER Guidance Note is to identify the problem which we are seeking to address.

While CER provides significant benefits to customers, it can present technical challenges for our infrastructure. These stem from the original design of our network which was built for one-way energy flows rather than the mass adoption of rooftop solar and flexible loads such as batteries and EVs. The main technical challenges we face are outlined in **Figure 5.7.3** below.

Figure 5.7.3 Technical challenges arising due to CER-led transformation of our network

	Problem	Impact
Hosting capacity	High voltage levels at times of peak exports from rooftop solar	Solar customers are unable to export energy back to the grid, preventing them from achieving the full benefit of their investment
Network overload	Concentrated areas of CER exports or loads, such as electricity vehicles and batteries, causing overload of the network	Loss of supply due to failure of the network

We have run extensive modelling to forecast the extent of these technical challenges. Our analysis incorporates AEMO's 2022 ISP which forecasts plausible futures for the energy industry which vary based on emission reductions, electricity demand and decentralisation of generation. Of these plausible futures, AEMO considers the Step Change Scenario to be the most likely, which is described as a 'rapid consumer-led transformation of the energy sector and co-ordinated economy-wide action'.[45]

Our CER Integration Strategy (**Attachment 5.7 - CER integration program**) elaborates on the technical challenges that the CER-led transformation of our network is presenting. This includes network voltage analysis and CER penetration forecast over the medium to long term. We also explain how we will manage CER integration through other strategies besides investment, such as innovative tariffs and dynamic operating envelopes which allow customers to change, their use of our network depending on whether we have the available capacity at the time.

45 AEMO (2022), *2022 Integrated System Plan (ISP)*, p 31.

Step 2: Potential solutions

We have considered a range of potential solutions to respond to the challenges and opportunities that CER presents for our network and customers. These are set out in **Figure 5.7.4.**

Figure 5.7.4 Hierarchy of potential responses to CER challenges

1 Innovative pricing options

Providing incentives for customers to use energy in ways that put less pressure on the grid

2 Education and collaboration

Providing information to customers about their role in the transition and how to make the most out of their CER and community batteries

3 Network visibility

Leveraging network and customer data (including from smart meters) to help us pinpoint constraints on the network, to ensure our solutions are as targeted as possible

4 Better Voltage Management

Using network assets and customer devices to dynamically manage voltage across the network

5 Tailored connection agreements

For customers with significant flexibility in how they use the network, offering tailored connection agreements that deliver win-win outcomes for them and the grid

6 Network augmentation

Upgrading network capacity to alleviate inefficient constraints

7 Curtailment

Selectively restricting customer exports where options are inefficient or unavailable

Step 3: Assess cost and benefits

We have applied economic modelling techniques to quantify the costs and benefits associated with a range of options for integrating CER on our network. A summary of our approach is included in **Figure 5.7.5** below. We quantified more values than those listed, yet these are the ones which are relevant to our network-based CER solutions.

Figure 5.7.5 Approach to quantification of CER benefits

Benefits Area	Approach to Quantification
Customer export curtailment value (CECV)	We adopted the AER's calculated CECV which is a modelling input that places a value on the economic cost from the curtailment of rooftop solar exports
Value of customer reliability (VCR)	We used the AER's calculated VCR to value the benefit of alleviating unserved energy from the load impact of electric vehicles
Deferred investment	Our modelling has assessed the scope to defer investment through alleviating CER curtailment via other means

5.7.2 How our CER forecast responds to customers' priorities

Our Voice of Community Panel sessions, as well as submissions to our Draft Plan, confirmed that customers and stakeholders want us to proactively prepare to deliver net zero so we can avoid reactive, costly network investment and worsening customer outcomes in the future. **Figure 5.7.6** provides an overview for how we engaged with stakeholders on our proposed CER investment.

Figure 5.7.6 How we engaged on our CER integration forecast

1	12	10+
AER modelling workshop	RCP presentations	Hours of discussion

Figure 5.7.7 shows how customers told us that they support a proactive approach to CER integration in our network that enables them to invest in CER and directly access and share its benefits with all customers. This aligns with customers' desire for the network to prepare for the future and enable the rapid transition to net zero.

Figure 5.7.8 shows how we plan to enable successful CER integration so that our network effectively uses our customers' two-way power flows while efficiently managing the network reliability and power quality. It also demonstrates how we plan to ensure that customers are not unnecessarily restricted in their choices about how they export electricity using their CER, while contributing to the net zero transition.

Figure 5.7.7

What customers told us about delivering net zero through CER integration

Our engagement journey	Purpose	What we heard from our customers and how we are responding	2029 residential bill impact driven by customer priorities see Section 1.3
Phase 2 engagement framework	Customer themes	• Prioritise innovations that support the transition; • Proactively prepare the network for net zero; and • Reduce Ausgrid's carbon footprint where economically justifiable.	
	Options we proposed	Customers were clear that we should prioiritise supporting their investment in net zero ahead of reducing our own emissions. **We tested with customers how proactive our approach should be by presenting four options:** • Take a gradual approach, prioritising curtailment to reduce the need for investment; • A moderate approach, investing where we see issues emerge on the network; • A proactive approach, investing where practical to remove the constraints to increased solar or other technologies before they appear (where the benefits are greater than the costs); or • Accelerate the transition to net zero by investing to eliminate all barriers to customers adding new CER to the network. We estimated a proactive approach would be roughly $150 million and would facilitate the curtailment free addition of 85% of new CER over the 2024-2029 period.	
	Customer preferences	**Voice of Community Panel:** *'Ausgrid should introduce a pro-active and targeted mixed investment plan between $100-$150 million to achieve net zero and minimise barriers for 85% of impacted customers.'* **Commercial and industrial:** *'Assisting the customers on their emissions reduction is going to have a greater impact on the absolute value of the greenhouse gas emission globally than emissions reductions in Ausgrid's own business.'* **Councils:** *'Would like to see more projects like solar gardens, community batteries, eg trial area of all electric homes..'*	
Draft Plan for 2024-2029	Our Draft Plan position	**Evolving how we deliver and charge for services, by:** • Partnering with councils and retailers to: – Support us deliver community batteries and other local energy solutions that could help save customers up to $200 per year on their bill; and – Advocate for regulatory changes that would help us more effectively manage the network, and offer tailored solutions to our customers. **Investing to support higher uptake of CER, by:** • Implementing a range of new processes and tools, including upgrading our ICT systems to give us better visibility of all parts of our network, through an investment of $153 million; and • Better understanding two-way energy flows across the network and monitor potential electrical faults that can cause safety hazards, by investing $24 million in smart meter data. **Reducing our own carbon footprint cost- effectively, by:** • Electrifying our vehicles as options become more affordable and available; and • Finding ways to avoid using equipment containing sulphur hexafluoride (SF6) (a greenhouse gas).	**Bill impact 2029: $6 of the $38**
Phase 3 engagement framework	Customer views on our Draft Plan position	**Town Hall (all end use customers):** 0% Loathe it 0-20% 0% Lament it 20-40% 17% Live with it 40-60% — 3 participants 61% Like it 60-80% — 11 participants 22% Love it 80-100% — 4 participants *'Suggestion to prioritise community batteries in areas with high density, heritage limitations, lots of renters, … so that they can benefit from renewables and reduced cost.'* **Councils:** *"Council supports the expenditures for network enhancement to be able to incorporate more CER.'*	
2024-2029 **Regulatory proposal**	How we're responding	Customers supported the initial forecasted expenditure of $153 million, however after refining the modelling based on the AER's guidance note (including AER CECV), it resulted in lower value of $126 million.	**+$7** of the $37

Figure 5.7.8

What customers told us about delivering net zero by evolving our services

Our engagement journey	Purpose	What we heard from our customers and how we are responding	2029 residential bill impact driven by customer priorities see Section 1.3

Phase 2 engagement framework

Customer themes

- Find a way (for those who can afford to) to contribute more; and
- Flexible two way pricing provides a fairer transition t net zero emissions.

Options we proposed

After deciding that keeping net zero costs down was a priority, customer agreed that driving behaviour change through flexible two ways tariffs was the right approach.

We proposed three ways that we could do this:

- Implement new export and reward tariffs for all customer immediately – so that everyone is subject to the same pricing signals;
- Introduce the tariffs but allow customer to either opt-in or opt-out; or
- Only apply the new tariffs to people adding new CER, so that those who have already invested in solar or other systems aren't impacted by the change.

Customer preferences

Voice of Community Panel	Commercial and industrial	Councils
'Net zero investment plan may be offset by the introduction of an [opt in or opt out] two-way tariff system.'	*'The benefits of charging for exporting into the grid should be allocated to all the customers of the grid.'*	*'[Councils] are concerned at penalising solar owners who invest in solar in good faith to cut their energy bills and do their part for the environment.'*

Draft Plan for 2024–2029

Our Draft Plan position

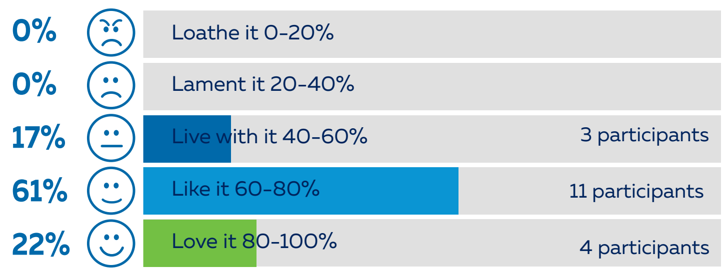
Evolving how we deliver and charge for services, by:

- Introducing pricing arrangements that encourage customers to export energy to the grid between 3pm and 9pm, when demand is highest.

Phase 3 engagement framework

Customer views on our Draft Plan position

Town Hall (all end use customers)



'More education, explanation to the public about how the tariffs contribute to the cost. And why it is a reasonable and fair change.'

'Things to emphasise: customers are not being charged to export, they are just being rewarded a little bit less; and they are being rewarded for shifting their usage and smoothing out load on the grid.'

Retailer

'Retailers will make competitively rational decisions in response to their customers' preferences and the network costs incurred. This will mean that some retailers will choose not to pass on multiple changes to export charging, or will implement it in a manner that will result in only one change to both their systems and customer tariffs.'

2024–2029 Regulatory proposal

How we're responding

- Based on customer preferences we are proposing to introduce export pricing on an opt-in basis in July 2024, with mandatory assignment from July 2025; and
- We also propose to support introducing export pricing by providing targeted information to customers on how they can manage their bills through flexible use of the grid.

5.7.3 Evidence our CER forecast is efficient

Our CER integration capex forecast of $47 million is based on the AER's CER Guidance Note requirements and rigorous cost benefit analysis. This approach has arrived at an efficient forecast which has resulted in the selection of the investment option which unlocks the most benefits for customers.

Figure 5.7.9 below summarises the options we considered, together with their costs over the 2024-29 period and respective NPV outcomes. The total costs across all capex streams (network, ICT and innovation) along with the associated opex is shown. We have selected Option 3 (proactive investment) because it will deliver the highest net benefits. In this way, it is the optimal response to the technical challenges we face in integrating CER into our network.

Figure 5.7.9 CER integration investment options ($m, real FY24)

Option	Description	Total Cost 2024-29	NPV FY24
Option 1 Base Case	• Address CER with our current capabilities and static network settings • Most investment is through traditional network augmentation	$50.3	(2.9)
Option 2 Preparatory Investment	• Improved network visibility to manage complex power flows through better understanding of the network and optimising network investment • Digital tools that improve the experience of connecting CER and network information available • Customer education resources to improve customer literacy about technology, services and benefits • Primarily traditional network augmentation where economically justified	125.0	48.8
Option 3 Proactive investment (proposed)	• Providing incentives to customers through innovative connection and pricing options to use their energy in ways that puts less pressure on the grid • Improved network visibility to manage complex power flows through better understanding of the network and optimising network investment • Customer education resources to improve customer literacy about technology, services and benefits • Deploying a mix of traditional augmentation and flexible network solutions. This includes distribution substation tap changes, phase balancing, distributor augmentation, STATCOMs and community batteries	126.1	169.4

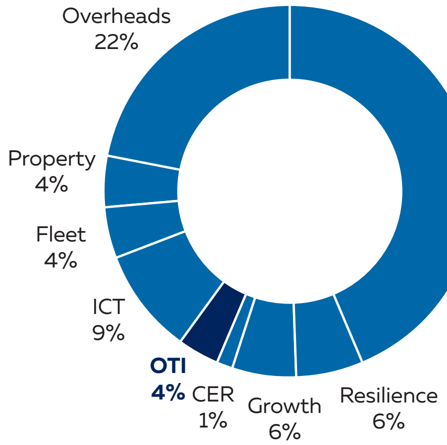
5.8 Operational technology and innovation

Our capex forecast for OTI totals $117 million in the 2024-29 period. This is 43% lower than the $204 million we expect to spend in the current period. It accounts for 4% of our total capex forecast (see **Figure 5.8.1**).

Operational technology (**OT**) enables us to directly monitor and control physical devices and processes on our network and to automate manual processes. Our forecast OTI capex also includes an innovation program that covers a range of network technology related research, trials and pilots.

Continuing priority
Our customers want us to continue prioritising smart grid technologies and innovative trials and pilot programs that help us keep costs down in other areas of our business, such as repex.

Figure 5.8.1 Forecast OTI capex as a percentage of total capex



5.8.1 What we have achieved in the current period and how it benefits customers

We established a Network Innovation Advisory Committee during the current 2019-24 regulatory control period to help guide our innovation investment decisions.

The Network Innovation Advisory Committee, which first met in July 2019, consists of customer advocates, technology experts from industry and academia, and Ausgrid staff. It has supported innovative trials including pole-mounted batteries, standalone power systems (**SAPS**) and a microgrid in the township of Merriwa.

The Network Innovation Advisory Committee is among our biggest achievements in the 2019-24 period, in terms of driving customer centric network investment decisions, ensuring we maintain close relationships with customers and meeting their expectations throughout the delivery period. This is noted in **Figure 5.8.2** below.

Figure 5.8.3 outlines the three workstreams that make up the innovation program subject to Network Innovation Advisory Committee's oversight.

Figure 5.8.2 Our recent achievements and how they will benefit customers in the 2024-29 period

	What we achieved in 2019-24	Benefits to customers in 2024-29
NIAC	We were the first network in Australia to establish a customer-led investment committee focused on innovation	The continuation of the NIAC will maintain customer centric in the rollout of our innovation program
ADMS rollout	We are set to complete Phases 1 and 2 of our Advanced Distribution Management System (**ADMS**) rollout	Our ADMS provides greater visibility and control of our network which has helped us put downward pressure on other parts of our capex program, like repex
Cyber risks	Managing the increasing cyber security threat landscape to our operational technology without a major incident	We have built a solid cyber security foundation to protect our grid and impacts to customers as the threat landscape increases further

Figure 5.8.3 The three workstreams that make up our innovation program

	CER support and enablement	• New, untested technology that helps integrate and support more CER to connect to the Ausgrid network – enabling customers to extract more value from their CER assets.
	Community resilience	• New, untested technology that helps to increase the resilience of our network and our communities to severe weather events and other incidents such as bushfires.
	Safe, intelligent networks	• New field assets that deliver safe, reliable and sustainable energy for our customers; and • Technology and capability that helps us to better plan, maintain and operate the network. This improves our capability to use the increasing quantum of data available to us through customer and network devices.

5.8.2 Incorporating our customers' priorities

Engagement on our OTI program focused on innovation and its role in facilitating a safer, more decentralised, resilient and intelligent network. When discussing the trade off between lower bills and higher innovation investment, the Voice of Community Panel told us to prioritise additional investment, totalling $80 million in capex in the 2024-29 period.

Figure 5.8.4 sets out the themes and priorities explored with our customers over the different phases of our engagement. We have kept our innovation investment steady at $54.5 million (including opex step change of $5 million) rather than the Voice of Community Panel's recommended $80 million. We still believe that our proposal gives effect to the Voice of Community Panel's feedback because there are elements of innovation throughout other parts of our capex program, besides OTI.

Figure 5.8.4

What customers told us about prioritising innovation

Our engagement journey	Purpose	What we heard from our customers and how we are responding	2029 residential bill impact driven by customer priorities see Section 1.3
Phase 2 engagement framework	Customer themes	Prioritise innovations that support the transition	
	Options we proposed	Customer emphatically pushed us to increase and incorporate innovation, partnering with others, looking for cost efficient and smart solutions and looking trial technology and fail fast. In response we proposed changes to our existing Network Innovation Advisory Committee innovation program to enable Ausgrid to innovate on new technologies to support customers: • Maintain the current level of NIAC funding of $8 million per annum capex; • Increase funding to $12 million per annum capex and $1.5 million per annum opex, to allow for trials of community-based initiatives; or • Increase funding to $16 million per annum capex and $12 million per annum opex. We proposed to customers that an investment of $12 million per annum capex and $1.5 million per annum opex would meet their need for increased innovation.	
	Customer preferences	**Voice of Community Panel** *'We want Ausgrid to move from the proposed increase in spend ($12 million per annum capex + $1.5 million per annum opex) to the higher increased spend ($16 million per annum capex + $2 million per annum opex) to achieve increased innovation.'* *'Faster roll out of new technology across the network. Great to see trials of community batteries but need to keep up with the community demand for this technology.'* **Councils** *'Faster roll out of new technology across the network. Great to see trials of community batteries but need to keep up with the community demand for this technology.'*	
Draft Plan for 2024–2029	Our Draft Plan position	**Investing to support higher uptake of CER, by:** Testing new technology that supports CER uptake via our industry-leading innovation program (resulting in a total innovation investment of $50 million over the 2024-29 period.	**Bill impact 2029: $2 of the $38**
Phase 3 engagement framework	Customer views on our Draft Plan position	**Town Hall (all end use customers)** 0% Loathe it 0-20% 20% Lament it 20-40% 4 participants 5% Live with it 40-60% 1 participant 50% Like it 60-80% 10 participants 25% Love it 80-100% 5 participants *'Innovation can significantly reduce cost in the long term. Resilience and cost are equally important.'* *'Spend more in accelerating decarbonisation.'* *'Trialling should consider geographic and social economic focus.'* **Councils** *'The Draft Plan prioritises innovation which can have many benefits such as reducing emissions through maximising solar use, creating additional storage and improved network resilience. Adopting new and emerging technologies play a significant role in our communities' transition to net zero.'*	
2024–2029 **Regulatory proposal**	How we're responding	We are increasing our Network Innovation Program in response to include $54.5 million in innovation totex plus and additional $10 million in community batteries funded through our CER program but still subject to Network Innovation Advisory Committee oversight. **Innovation is not restricted to the Network Innovation Program, we have elements of innovation throughout our investment program including:** • Innovative customer solutions in our customer service investments $10 million; and • Our totex resilience program of $202.1 million is by it's nature innovative, and includes many new initiatives to drive smarter and more efficient use of the network as well as delivering better outcomes for customers.	**+$2** of the $37

5.8.3 Evidence our OTI forecast is efficient

Our 2024-29 period OTI forecast is 43% lower than our expected spend in the current period. The reduction reflects our OTI investment cycle which peaked in the 2019-24 period with our ADMS rollout. In the 2024-29 period, we do not have the same level of investment to sustain customer benefits.

Our remaining OTI investments are relatively stable and have been adjusted to reflect the underlying works required during the 2024-29 period and maximise the outcomes for customers. We will achieve this by investing in those projects that have the greatest benefit for customers and by deferring investments that have marginal benefits in favour of those with more favourable outcomes.

OT security program

We are forecasting $25 million in OT security investment in the 2024-29 period.

Our OT system comprises of field devices and communication networks used to monitor and control the flow of electricity. The increasing digitalisation and automation of these systems, while delivering significant benefits to customers, gives rise to a heightened risk of cyber attack. The widespread adoption of CER within our distribution network has also increased the entry points and methods for gaining access to our infrastructure.

Our forecasting approach for OT security is efficient because it is based on balancing cost with delivering the most capability and benefits for customers. We achieved this through NPV modelling targeted at identifying the investment option the mitigates our cyber and other risk so far as is reasonably practicable (**SFAIRP**) while meeting our licence conditions that require 'best practice' management of our OT security. The program will also implement controls that enable our business to achieve Security Profile 3 (**SP-3**) (as defined in the Australian Energy Security Cyber Security Framework).

Innovation program

Our planned innovation program totals $49.5 million. It tests advanced and emerging technologies that have the potential to deliver significant benefits to our customers and the wider market. It does this by efficiently demonstrating the benefits of emerging technologies through trials and pilots rather than full scale deployments.

We forecast our innovation needs by developing a pool of potential project ideas in consultation with customers and subject matter experts. Costs and benefits for these projects are then estimated to calculate a NPV for each option, as outlined in **Figure 5.8.5** below. See **Attachment 5.8a – Network innovation program** for more information.

Figure 5.8.5 Our assessment of innovation options, costs and NPV ($m real, FY24)

Option	Description of Option	Capex	Opex	NPV
1: Do nothing	• Cease Network Innovation Program and undertake traditional network investment only	0	0	0
2: Full network innovation program	• Undertake 100% of identified projects and all customer research across the three workstreams in order to maximise the total benefits • This results in a proposed program that has a split between 60% trials and 40% pilots	82.3	5.4	70.4
3: Optimised network innovation program (proposed)	• Undertake approximately 60% of identified projects and customer research across the three workstreams, prioritising those that have the largest expected cost benefit • This results in a proposed program that has a split between 70% trials and 30% pilots	49.5	5.0	81.8
4: Maximised breadth of innovation program	• Undertake approximately 70% of identified projects and customer research across the three workstreams, prioritising the largest breadth of Network Innovation trials • This results in a proposed program that has a split between 80% trials and 20% pilots	59.5	5.1	79.8

We selected Option 3 because it has the highest NPV through the optimisation of potential benefits. The size of the program is also similar to our program for the 2019-24 period. This will promote affordability at time of increasing cost of living pressures.

5.9 Information, Communications and Technology

We envision a future where customers can flexibly respond to dynamic tariffs using smart devices, can choose from a range of innovative technologies connected to the grid, and have access to new services, like community batteries, which help facilitate a net zero future while keeping bills low.

ICT is the key enabler of this future. Our proposed ICT program for the 2024-29 period is targeted at keeping pace with the digital transformation of the energy system, maintaining existing service levels through periodic upgrades and responding to changing expectations from our customers, including those from CALD backgrounds.

There are also challenges that we must meet. Cyber threats are growing in frequency and severity. Our responsibility to our customers and our obligations under new legislative arrangements have encouraged us to prudently invest in mitigating the risk of potentially catastrophic cyber attacks.

Our ICT program makes up 9% of our capex forecast, as set out in **Figure 5.9.1**. This excludes SaaS implementation costs which are currently recognised as capex, but due to accounting treatment changes will shift to opex in the 2024-29 regulatory period.

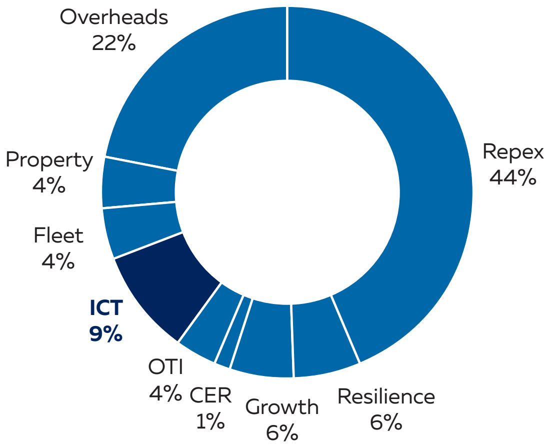
Continuing priority

Our BAU investments in ICT systems will be 18% lower than our 2019-24 spend.

Increasing priority

Cyber security, CER and the replacement of our ERP are increasing priorities that make up nearly 60% of our 2024-29 ICT forecast.

Figure 5.9.1 Forecast ICT capex as a percentage of total capex



About 40% of our ICT capex program is made up of a BAU component. The other roughly 60% consists of three large projects relating to cyber security, the replacement of our ERP and CER related ICT. This is shown in **Figure 5.9.2** below. For completeness, the SaaS opex component of each project is shown.

Figure 5.9.2 Forecast ICT capex as a percentage of total capex

	Category	FY25	FY26	FY27	FY28	FY29	Total
BAU ICT component							
Geographical Information System (**GIS**)	Capex	1	7	6	-	-	14
	SaaS opex	-	-	-	-	-	-
Data & analytics	Capex	10	11	6	2	1	30
	SaaS opex	-	-	-	-	-	-
ICT & infrastructure management	Capex	13	18	13	9	13	65
	SaaS opex	1	1	1	0	1	5
Minor projects	Capex	10	10	6	8	7	41
	SaaS opex	5	3	4	3	4	18
Customer information systems	Capex	3	3	2	2	2	11
	SaaS opex	3	3	2	2	2	11
Subtotal	Capex	36	49	33	20	23	161
	SaaS opex	9	7	7	5	6	34
	Totex	45	55	40	25	29	195
Cyber, ERP and CER component							
Cyber security	Capex	9	9	9	8	9	44
	SaaS opex	10	9	9	10	9	47
ERP	Capex	21	33	15	6	1	76
	SaaS opex	21	32	15	5	0	73
CER related ICT	Capex	7	7	2	2	1	20
	SaaS opex	0	1	0	1	1	3
Subtotal	Capex	38	50	26	16	11	140
	SaaS opex	31	42	24	16	9	123
	Totex	69	92	50	32	20	263
TOTAL	Capex	**74**	**98**	**59**	**36**	**34**	**301**
	SaaS opex	**40**	**49**	**31**	**21**	**16**	**157**
	Totex	**115**	**147**	**90**	**57**	**49**	**458**

Figure 5.9.3 below sets out the long-term trend in the BAU component of our ICT program. It shows that, inclusive of SaaS implementation costs, this part of our forecast is reflective of our historical spend over a 20-year time horizon and trending lower towards the later years of the 2024-29 period. Our 2024-29 BAU ICT capex is 18% below our estimated 2019-24 BAU ICT capex.

Figures 5.9.4 to **Figure 5.9.6** provide the same analysis for our cyber security, ERP and CER-related ICT projects. The spend profile in these areas reflects the growing integration of digital technologies into all areas of our business, resulting in fundamental changes in how we operate our network and deliver value for our customers. It also reflects the emergence of completely new types of services, such as the use of digital tools to integrate up to 620,000 new CER into our network by FY29.

Figure 5.9.3 Actual and forecast ICT capex excluding cyber, ERP replacement and CER ($m, real FY24)

Figure 5.9.4 Actual and forecast cyber security capex ($m, real FY24)

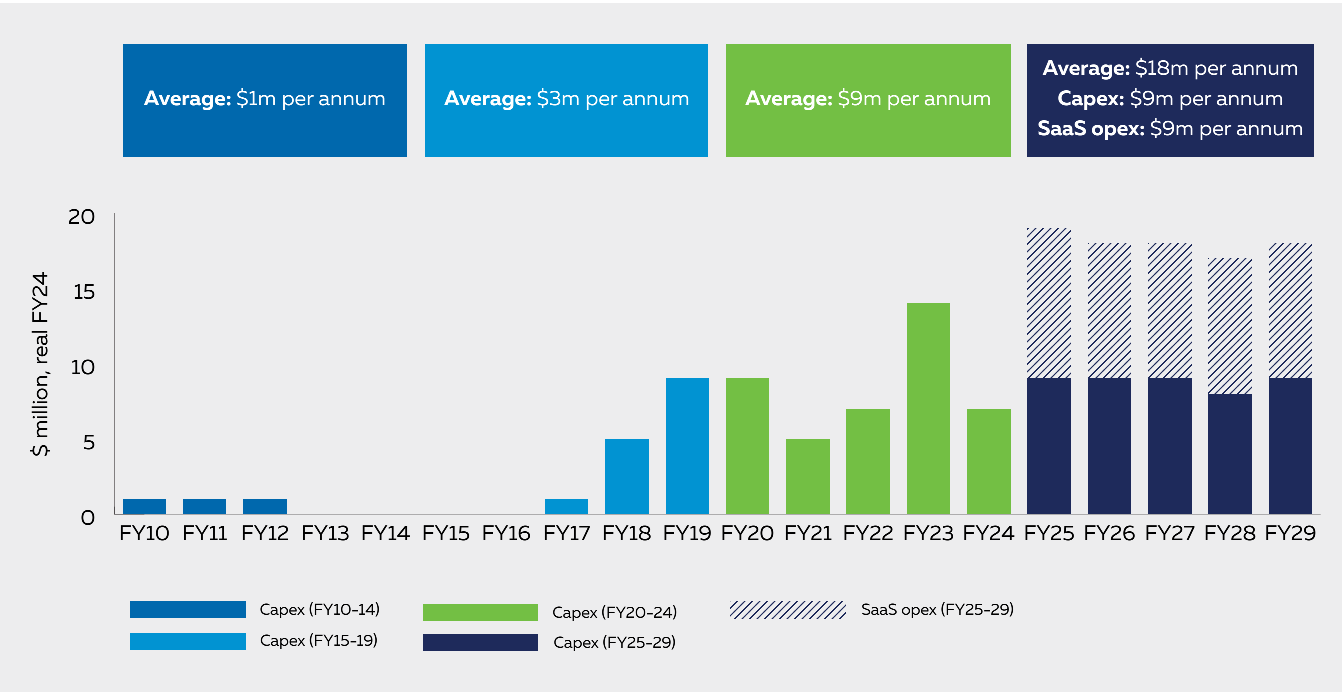


Figure 5.9.5 Actual and forecast ERP replacement capex ($m, real FY24)

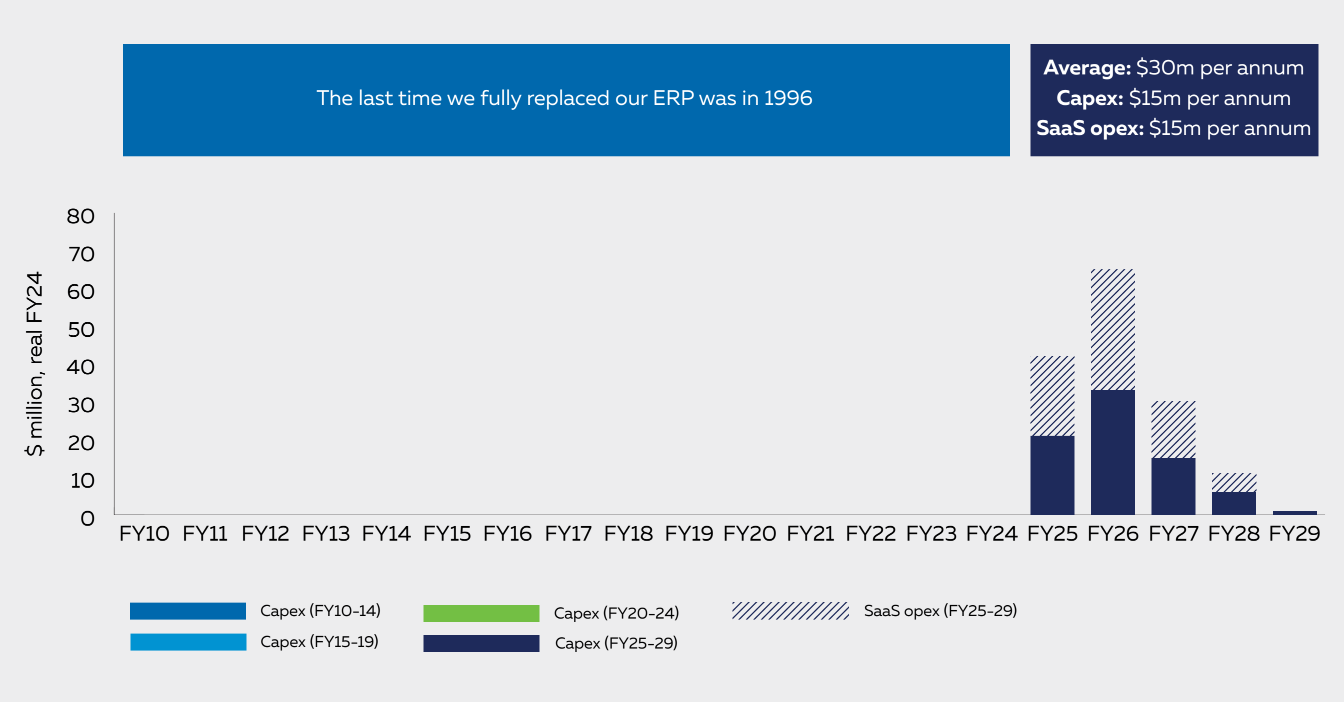
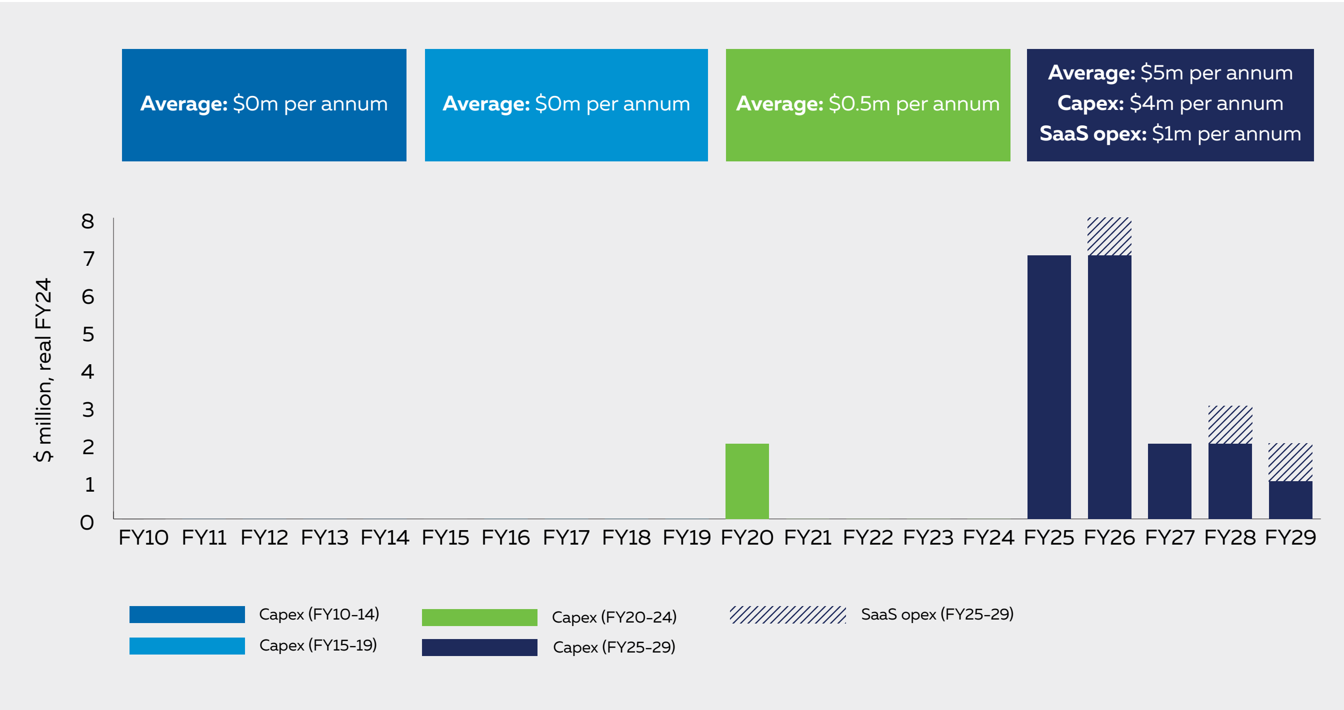


Figure 5.9.6 Actual and forecast CER related ICT capex ($m, real FY24)



5.9.1 What we have achieved in the current period and how it benefits customers

Our ICT investments in the current 2019-24 period have laid a foundation for ongoing benefits for customers. **Figure 5.9.7** shows we have invested in the cyber security protections needed for the current threat landscape and taken steps to keep pace with our customers' evolving expectations in how they interact with us. We have also implemented workforce management systems that, along with other investments, help us apply a 0.5% productivity efficiency factor to our forecast of 2024-29 capitalised overheads.

Figure 5.9.7 Our recent achievements and how they will benefit customers in the 2024-29 period

	What we achieved in 2019-24	Benefits to customers in 2024-29
Cyber security	We have defended our ICT systems from perimeter scans and other threats looking for weaknesses in our cyber protections	Our commitment to defending our systems from cyber threats maintains the supply of electricity to our customers and other critical infrastructure providers
Customer experience	We successfully rolled out a new Customer Relationship Management (**CRM**) platform	We will build on our CRM rollout by introducing self-service portals for councils and an upgrade to our portal for connections and disconnections
Workforce improvements	We implemented a new Integrated Works Management system to improve scheduling of field crews and other critical staff	Our capitalised overhead forecast incorporates a 0.5% p.a. productivity efficiency factor in recognition of technology and other improvements

5.9.2 Incorporating our customers' priorities

The Reset Customer Panel challenged us to find ways to deliver greater customer confidence in our ICT investments and the realisation of benefits. This led to us committing to a set of ICT investment governance principles.

ICT Governance Principles

We worked with the Reset Customer Panel to design a set of ICT investment governance principles which commit Ausgrid to:

- Sharing post implementation reviews with our Customer Consultative Committee; and
- Excluding ERP program costs in our 2029-34 regulatory proposal which were reasonably foreseeable at time of our initial business case.

The Customer Consultative Committee is our peak customer engagement panel which will assess our performance against these principles.

Our Regulatory Proposal is informed by multiple trade-off discussions with the Voice of Community Panel on ICT expenditure. These focused on cyber security and how to best use digital technologies to improve customer experience. **Figures 5.9.8** and **5.9.9** set out what we heard on these topics and our planned response in the 2024-29 period, respectively.

Our customers, via the Voice of Community Panel, supported Ausgrid moving to a higher cyber security maturity level and told us to make prudent investments in improving customer experience. We have responded by putting forward a cyber security program target at reaching SP-3 (highest maturity) within the 2024-29 period and by transforming our ERP to lay the foundation for innovative services.

Figure 5.9.8

What customers told us about cyber security and how we are factoring in their views

Our engagement journey	Purpose	What we heard from our customers and how we are responding	2029 residential bill impact driven by customer priorities see Section 1.3

Phase 2 engagement framework

Customer themes

Improved cyber security

Options we proposed

Customers were clear that in the face of increasing cyber threats we should invest to improve cyber security.

We proposed three options to do this:

- Investing to maintain current cyber levels with $37.3 million ICT capex and $910,000 opex;
- Improve cyber security by implementing Security Profile 2 (**SP-2**) with $76.2 million ICT capex and $18.7 million opex; or
- Implementing SP-3, the highest level of cyber security, with $91 million ICT capex and $18.7 million opex.

Just as our Board debated these options, our customers also hotly debated these options.

Customer preferences

Voice of Community Panel	Commercial and industrial
'Preference for investment to achieve Standard SP-2, giving Ausgrid the option to go to the AER to shift up to greater investment if it's needed in order to protect the grid.' *A minority report was also written saying: 'We recommend Ausgrid implements the best in class cyber security protection.'*	*'We expect best in class on all our essential utilities, especially in a rapidly changing landscape of cyber threats.'*

Draft Plan for 2024-2029

Our Draft Plan position

Keeping pace with the growth in cyber security threats, by:

- Ensuring our safeguards align with industry best practice by investing $106 million.

Bill impact 2029: $11 of the $38

Phase 3 engagement framework

Customer views on our Draft Plan position

Town Hall (all end use customers)

%	Response	Participants
0%	Loathe it 0-20%	
10%	Lament it 20-40%	2 participants
10%	Live with it 40-60%	2 participants
37%	Like it 60-80%	7 participants
42%	Love it 80-100%	8 participants

'Ausgrid should ensure the cyber protection processes are well-researched and transparent to customers and stake holders.'

'Invest now, to prevent a greater spend later. Prevention is better than a cure!'

Councils

'The above initiatives to build resilience in response to climate change and cyber security threats is strongly supported. Council is working on its own locally appropriate initiatives and responses ...council has developed a cyber-security strategy and 3-year improvement program which aligns with NSW cyber security policy, ISO27001 and other standards.'

2024-2029 Regulatory proposal

How we're responding

Staggering our cyber investment to begin improving in the short term, reaching SP-2 by FY27 and further progressing to SP-3 by FY29.

+$8 of the $37

Figure 5.9.9

What customers told us about the experience they expect when interacting with Ausgrid

Our engagement journey	Purpose	What we heard from our customers and how we are responding	2029 residential bill impact driven by customer priorities see Section 1.3

Phase 2 engagement framework

Customer themes

- Enhance our communications as outage information is crucial;
- Being able to speak to a real person is important;
- Services need to be simple and easy to engage with; and
- Improved engagement and processes with delivery partners will be more efficient for all.

Options we proposed

To respond to customers desire for improved services we presented three options:

- Maintain the status quo and avoid increased bills and prioritise affordability, noting the improvements already made to the service provided to household customers in particular;
- Minimal investments to upgrade and maintain key customer service systems for $7 million ICT capex; or
- Invest $26.3 million ICT capex in innovative solutions such as:
  - Early warning alerts;
  - Chat bots and increased self service;
  - Improved presentation of outage information; and
  - Direct data transfer of outage data to key stakeholder like NBN.

Customer preferences

Voice of Community Panel	Commercial and industrial	ASP's
'Reduce spending to $7 million.'	*'Would like distributors to be more customer focused and responsive to customer issues.'*	*'We would like to have access to information about the network directly, so we can provide it to clients without having to ask Ausgrid for the information each time.'*

Draft Plan for 2024–2029

Our Draft Plan position

Making the customer experience simpler and easier by:

- Improving the timeliness of outage communications through a $14 million additional investment in our ADMS;
- Improving the quality of outage information so delivery partners (such as retailers) can better communicate with customers during an outage;
- Maintaining the quality of service delivered by our contact centres;
- Proposing that the AER apply a CSIS to us from 1 July 2024;
- Improving the complex customer connection process via a $7.5 million investment in our customer information systems; and
- Introducing fast, easy digital self-service options for delivery partners and C&I customers, via an investment of $10 million.

Engaging more effectively with our delivery partners and C&I customers, by:

- Delivering better-tailored services to our customers via a $2.5 million investment to improve our contact centre, website and SMS communications.

Bill impact 2029: $1 of the $38

Phase 3 engagement framework

Customer views on our Draft Plan position

Town Hall (all end use customers)

0%	Loathe it 0–20%	
19%	Lament it 20–40%	3 participants
37%	Live with it 40–60%	6 participants
19%	Like it 60–80%	3 participants
25%	Love it 80–100%	4 participants

'Need to ensure human customer service experience. If cuts need to be made, this area should be reduced in funding.'

'Would like to know that the investment is being used to significantly improve customer satisfaction.'

ASP

'For services to complete contestable works or gain access to the network or a customers installation safely, there must be a greater focus on the customer service.'

Councils

'A customer service incentive scheme would in principle help to encourage improvements to customer services. The proposed revenue at risk seems to be a small percentage, but it is acknowledged that it could provide an incentive.'

2024–2029 Regulatory proposal

How we're responding

We have adjusted the initiatives making up our Customer Information Systems forecast to deprioritise 'Chat Bots' in favour of ICT solutions that make the human customer experience better. While our forecast of $21 million (including SaaS implementation opex) is higher than the Voice of Community Panel recommended at the Draft Plan stage, it aligns to subsequent feedback from all end use customer who revealed during a Town Hall discussion that most (81%) could at least 'live with' our proposal.

+$2 of the $37

5.9.3 ICT forecasting approach

Our capital planning for ICT programs delivers efficient outcomes for customers by:

- Using a range of forecasting tools (see **Figure 5.9.10** below); and
- Considering key drivers of investment (see **Figure 5.9.11** below).

Figure 5.9.10 Investment drivers and how they are evolving in the 2024-29 period

	Trend analysis	Benchmarking	Top down challenge	Risk based CBA modelling
Recurrent investment	✔	✔	✔	
Non-recurrent investment			✔	✔

Figure 5.9.11 Investment drivers and how they are evolving in the 2024-29 period

Driver	Our assessment	Impact on our forecast
CER	We forecast that an additional 620,000 rooftop solar systems, batteries, EVs or controlled load are expected to connect to network over the 2024-29 period	We are investing in digital systems that give us greater visibility of CER while reinforcing our cyber protections to secure the additional entry points that CER potentially offers cyber criminals
Customer expectations	C&I customers have requested technology integration with our systems	We are investing in Application Programming Interfaces (**APIs**) that personalise the experience C&I customers have with Ausgrid
CALD customers	We provide an essential service to one of the most culturally and linguistically diverse communities in Australia	We are simplifying our CALD customer experience and plan to introduce CALD friendly systems and personalisation that remembers CALD customer preferences
Regulatory changes	The regulatory landscape is changing to facilitate a two-way market and strengthen cyber security protections	We are investing in the highest cyber security maturity levels and taking steps to keep pace with regulatory reforms that aim to deliver new services to customers

5.9.4 Evidence that our ICT capex forecast is efficient

We set out below how we have used different forecasting tools and incorporated key investment drivers to develop an efficient ICT capex forecast for the 2024-29 period.

Cyber Security

We are proposing $91 million in cyber security capex. This is made up of $44 million in capex and $47 million in SaaS implementation costs which from the 2024-29 period will be recognised as opex.

Cyber attacks are on the rise in Australia. The recent Medibank incident saw four million customers have their personal information leaked, while the Optus breach exposed personal details of 10 million Australians.

Figure 5.9.12 Investment drivers and how they are evolving in the 2024-29 period

There have also been attacks on JBS Foods which paralysed a company that employs 11,000 Australians across 47 sites and on Nine Entertainment which disrupted the network's ability to broadcast. In Australia, there is now a cyber attack reported every 8 minutes.[46]

We have a duty to our customers to protect their data and safeguard our systems from vulnerabilities to cyber attacks that in a worst case scenario, such as in the Colonial Pipeline incident in the USA, could lead to a shutdown of our network. There are also regulatory requirements under the recently amended SOCI Act which place new and enhanced obligations on Ausgrid. These include a requirement to implement and maintain a Risk Management Program that addresses a range of prescribed risks, including cyber security. The Risk Management Program must:[47]

- Identify hazards that present a material risk to the availability, integrity, reliability and confidentiality of critical infrastructure assets, or information about, or stored in, those assets;
- Mitigate risks to prevent incidents (so far as it is reasonably practicable to do so);
- Minimise the impact of realised incidents (so far as it is reasonably practicable to do so); and
- Implement effective governance and oversight procedures, including testing and evaluation, relating to security.

Our plan for the 2024-29 period is to invest in the capabilities needed to reach a maturity level known as SP-3. It will best prepare Ausgrid and our network to implement and maintain the required Risk Management Program in the SOCI Act and respond and, in line with our duty to our customers, minimise our exposure to cyber risks in the first place.

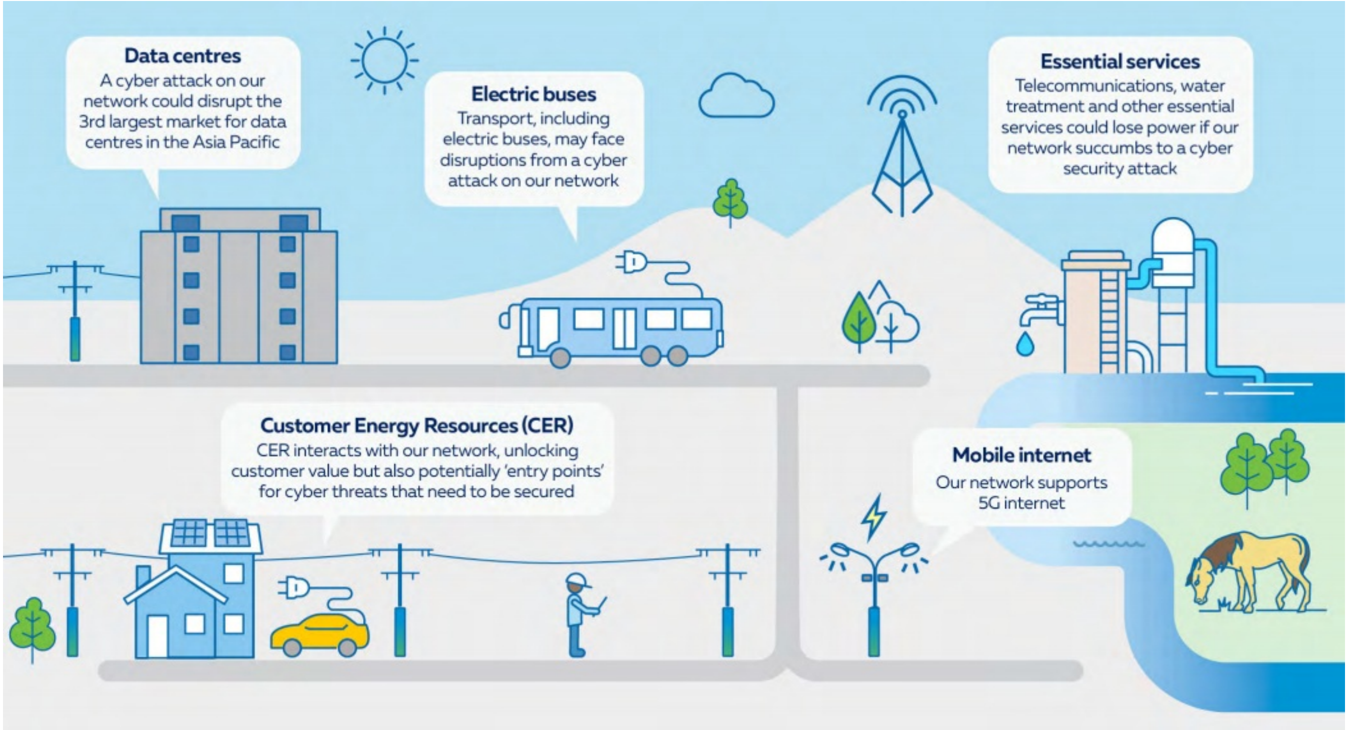
We note the AER's recent Draft Decision on Transgrid's transmission revenue determination for the 2023-28 period[48] states:

> *'We agree with Transgrid and consider it prudent for Transgrid, as a transmission network service provider, to uplift its security and particularly to achieve SP–3 maturity. This is also supported by our consultant, Energy Market Consulting associates (**EMCa**), who provided expert advice on the assessment of this step change. EMCa considers that it is appropriate for Transgrid to achieve an AESCSF maturity indication level of SP–3 based on the combination of legislation, appropriate risk management, and the urgent request of the Australian Cyber Security Centre to adopt an enhanced cyber security posture.'*

46 ASCS (November 2022), *Annual Cyber Threat Report, July 2021 to June 2022.*
47 SOCI Act, sections 30AC-30AF.
48 AER (2022), *Transgrid 2023-28 – Draft Decision – Attachment 6 – Operating expenditure – September 2022*, p 22.

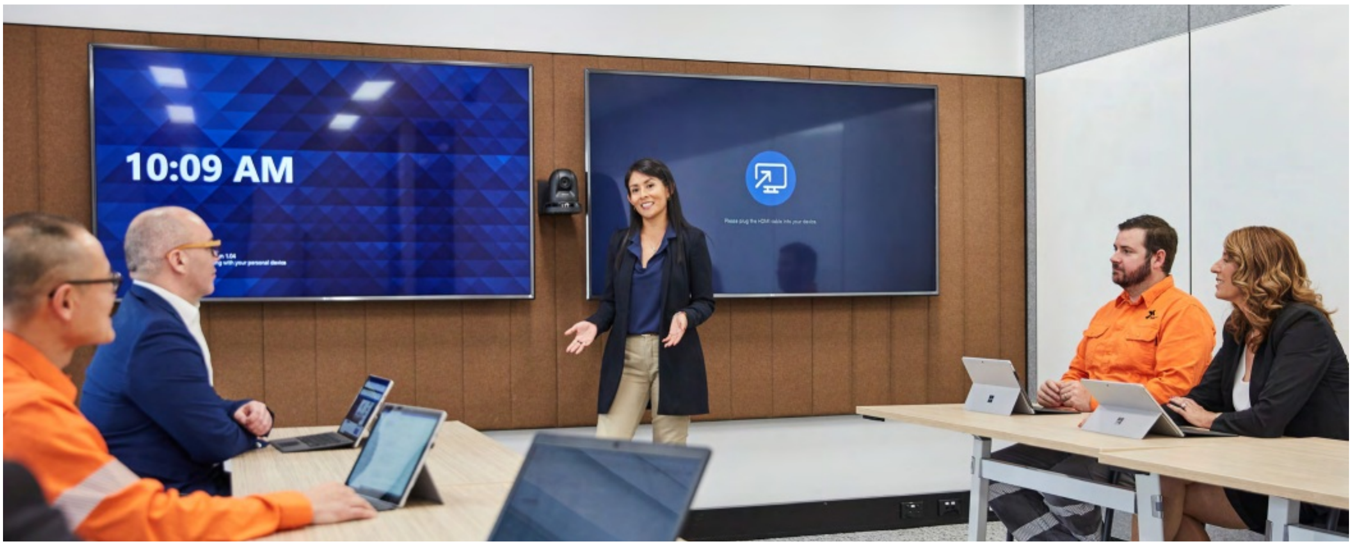
It is also prudent to move to SP-3 from a customer impacts perspective. Our network powers essential services, like wastewater treatment and telecommunications infrastructure, and supplies an area recognised as the third largest market for data centres in the Asia Pacific region and the 8th largest internationally.[49] This is indicative of the compounding impacts of a cyber attack. They threaten not just the disruption of our electricity network but other critical services, as outlined in **Figure 5.9.13** below.

Figure 5.9.13 Why keeping our network cyber safe is critical to the community



We estimate a complete shut-down of our network would have a total economic impact on our customers of $120 million per hour or approximately $2.9 billion over one full day alone.[50]

To calculate our efficient level of investment in cyber security protection, we have applied economic analysis. Our approach considered the consequences of a successful cyber attack, the likelihood of specific events, and the risk we can 'buy down' through investment. More information about our approach is set out in **Attachment 5.9.c – Cyber security program**.



49 Cushman & Wakefield (2022), *2022 Global Data Center Market Comparison Report*.
50 Based on the AER's *Values of Customer Reliability* (**VCR**).

ERP replacement

We are forecasting $149 million for the replacement of our existing ERP platform in the 2024-29 period.

Our existing ERP was initially deployed in 1996 and parts of it will have been in operation for 31 years by the time of its planned replacement date in 2027. Many of our digital ambitions for customers – from cost reflective pricing, to handling customer complaints in a timely manner – depend on not only replacing the ERP but also transforming it.

Figure 5.9.14 outlines the reasons why our ERP transformation program is important to our business. These benefits range from securing technical support which, for our current ERP version, expires in 2027 and unlocking efficiencies through standardised business operations. The customer benefits of replacing our ERP are more wide-ranging and are set out in **Figure 5.9.5** below.

Figure 5.9.14 Why transforming our ERP is important to our business

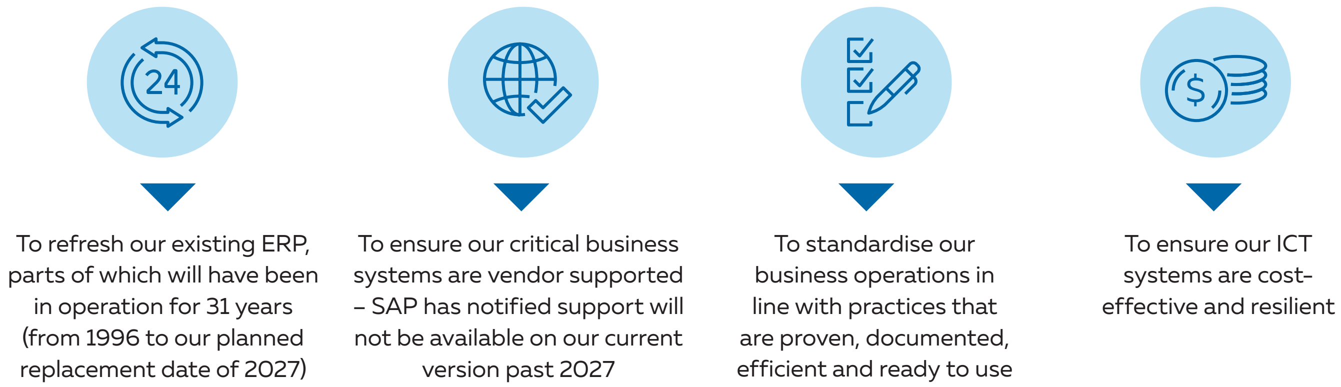


Figure 5.9.15 How transforming our ERP will benefit our customers

51 $2.7 million per annum in avoided repex.

Figure 5.9.16

What customers told us about upgrading our systems to prepare for the future

Our engagement journey	Purpose	What we heard from our customers and how we are responding	2029 residential bill impact driven by customer priorities see Section 1.3.
Phase 2 engagement framework	Customer themes	• Energy costs are difficult to manage, so energy needs to be affordable; • Invest to reduce long-term costs; and • Flexible two-way pricing provides a fairer transition to net zero emissions.	
2024–29 **Draft Plan**	Our Draft Plan position	Investing $149 million in upgrading our ERP system to enable us to**:** • Provide more innovative services offerings, such as dynamic supply and pricing options; • Improve our network planning and investment decision-making; • Improve customer experience by supporting simpler internal processes with fewer handovers between teams; and • Ensure our ERP supplier is still able willing to provide us with technical support if needed.	**Bill impact 2029: $12 of the $38**
Phase 3 engagement framework	Customer views on our Draft Plan position	**Town Hall (all end use customers)** 0% Loathe it 0-20% 0% Lament it 20-40% 16% Live with it 40-60% 3 participants 53% Like it 60-80% 10 participants 31% Love it 80-100% 6 participants *'Support longer depreciation to reflect longevity of investment.'* *'We can't afford to not upgrade system.'* **Councils** *'It is recommended that Ausgrid work with the NSW Government to identify a fair way to fund higher costs in the short term that will improve intergenerational equity without adding costs to customers in addition to other inflationary pressures.'*	
2024–29 **Regulatory proposal**	How we're responding	• Invest $149 million for the replacement of our existing ERP platform in the 2024-29 period, to enable future efficiencies and deliver smarter tariffs. • Commit to ICT investment governance principles including: – Sharing post implementation reviews with our Customer Consultative Committee; and – Excluding ERP program costs in our 2029-34 regulatory proposal which were reasonably foreseeable at time of our initial business case. • Recover the costs over a 15 year period rather than a 5 year period, reducing the bill impacts of this program – see **Figure 4.1.3** to see how this change impacts customer bills	**+$12** of the $37

5.10 Fleet

Our forecast fleet and plant capex of $148 million in the 2024-29 period is 7% higher than the $138 million we expect to spend in the current period. It represents 4% of total capex (**Figure 5.10.1**).

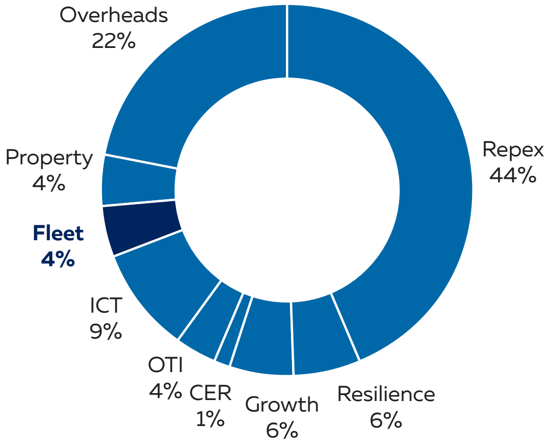
Our fleet of vehicles and trucks support our operations in the field by providing a safe and reliable mode of transportation. 'Plant' assets refer to the equipment we use in the field— such as elevated work platforms (**EWPs**), vehicle loading cranes and pole installation equipment.

Our goal in the 2024-29 period is to reduce our total fleet and plant-related costs, including the economic cost that is incurred when a fleet or plant asset is broken down and cannot be used to provide critical customer services. To reduce total costs, we are targeting efficiencies in maintenance and improvements in the productivity and reliability of our fleet and plant equipment.

Continuing priority

Our commitment to a safe, reliable fleet is a continuing priority in the 2024-29 period as we take steps to move towards a more sustainable investment profile going forward.

Figure 5.10.1 Forecast fleet capex as a percentage of total capex



5.10.1 What we have achieved in the current period and how it benefits customers

We faced challenges in the delivery of our 2019-24 fleet program as supply chains were disrupted due to the COVID-19 pandemic. When these disruptions eased, we could secure build slots for EWPs so that our investment in these key fleet assets could be more efficiently profiled across the 2019-24 and 2024-29 regulatory control periods.

Figure 5.10.2 below sets out our key achievements in the 2019-24 period in relation to fleet and how they will continue to benefit customers.

Figure 5.10.2 Our recent achievements and how they will benefit customers in the 2024-29 period

	What we achieved in 2019-24	Benefits to customers in 2024-29
Build slots	We have secured build slots for the delivery of new EWP vehicles	Our fleet investment profile will follow a smoother profile with investment in EWPs more evenly spread across the 2019-24 and 2024-29 periods
Replacement lifecycles	We apply a 15-year replacement lifecycle for EWPs which means our customers have funded the replacement of these assets less often than other networks	Our continuation of a 15-year replacement lifecycle remains the most efficient outcome for customers, although we may explore the benefits of a 10-year lifecycle in the future
Fleet reductions	We have reduced our fleet by 18% from 1,769 vehicles in FY19 to 1,452 in FY22	We have right sized our fleet to efficiently meet our customers' needs and maintain current service levels
Finnancial modelling	In response to Reset Customer Panel feedback we improved the rigour of our fleet modelling approach	Our investment analysis is based on robust modelling of the least cost options that unlock the most benefits for customers

5.10.2 Incorporating our customers' priorities

Our approach to continuing priorities in the 2024-29 period, such as our fleet investment program, focused on technical matters through deep engagement with the AER and customer advocates sitting on the Reset Customer Panel.

Figure 5.10.3 sets out a summary of this engagement which included a modelling workshop with AER staff, multiple presentations to the Reset Customer Panel and more than 10 hours of discussion.

Figure 5.10.3 The breadth and depth of our engagement on our fleet capex program

1
AER modelling workshop

5
RCP presentations

10+
Hours of discussion

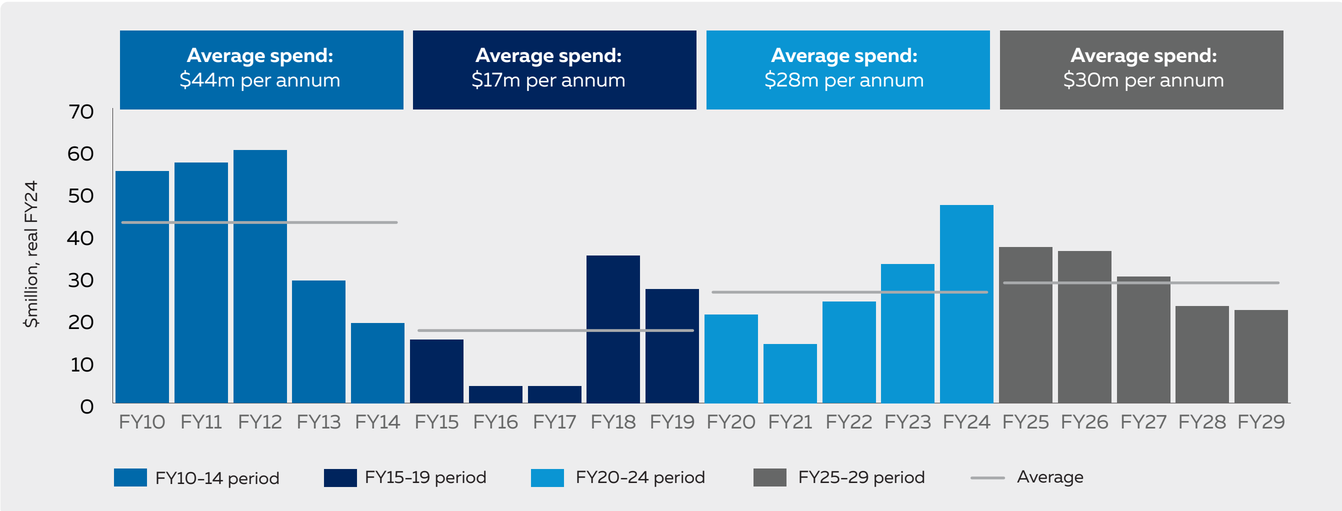
5.10.3 Fleet forecasting approach

Our 2024-29 fleet and plant capex forecast is 7% higher than our current actual/estimated spend. This increase reflects historical events within the current 10-15 year investment lifecycle. Specifically, we are:

- **Exiting a trough in our investment cycle** which was driven by the suspension of capital spend as we pursued an aggressive fleet reduction program between FY15-17; and
- **Entering a catch up period** needed to address recent underinvestment and transition to a smoother investment profile in the later years of the 2024-29 period and beyond.

Figure 5.10.4 below sets out our fleet and plant capex forecast. This shows the peaks and troughs of our investment cycle and that our fleet and plant spend has oscillated from an average annual spend of $44 million per annum in the 2009-14 period to as low as $17 million per annum in the 2014-19 period. Relevantly, the high volume of assets acquired in the 2009-14 period, particularly plant assets such as EWPs and crane borers, will reach the end of their technical life in the forthcoming 2024-29 period. This will lead to a peak in our investment cycle before it transitions to a smoother capex profile going forward.

Figure 5.10.4 Our fleet and plant capex forecast ($m, real FY24)



5.10.4 Evidence our fleet and plant forecast is efficient

Our fleet of motor vehicles is efficiently sized for our mix of network characteristics which stretches from the Sydney CBD to low density, rural terrains in the Upper Hunter.

Figure 5.10.5 shows that we have 1,452 vehicles in operation or 44% less than the 2,572 we had in FY15. This is a significant reduction in line with the broader transformation of our business since the partial long-term lease of Ausgrid in 2016. We have tested the efficiency of our motor vehicle count relative to our peers: **Figure 5.10.6** shows that our fleet count also benchmarks well on a per employee basis.

Figure 5.10.5 Our fleet of motor vehicles is now efficiently sized

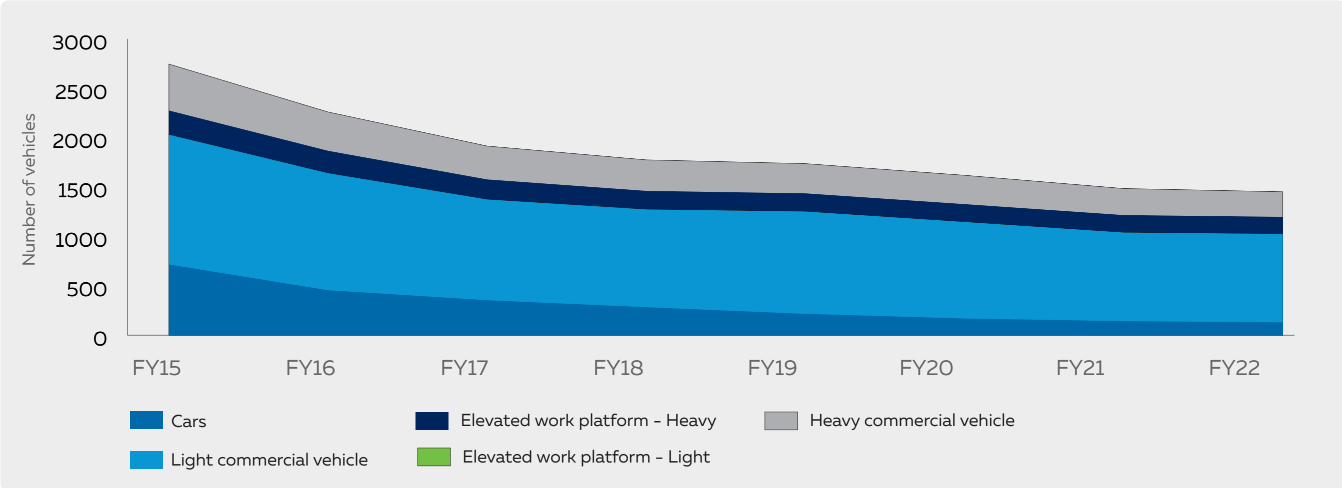
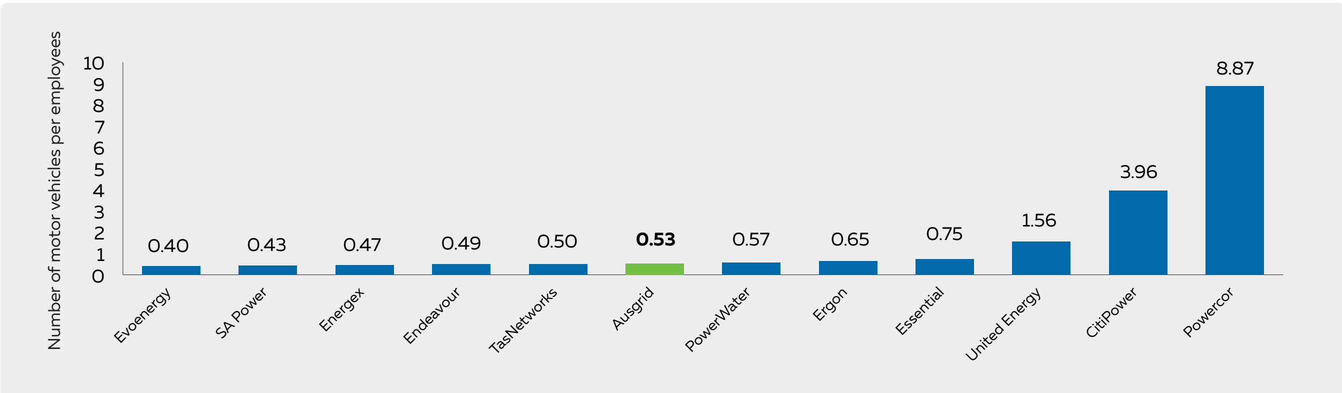


Figure 5.10.6 Our motor vehicle count per employee benchmarks well against our peers



Source: AER (2022). FY21 Category analysis Regulatory Information Notice).

Our fleet replacement program will unlock productivity gains for our network capex program by introducing EWP assets with greater manoeuvrability and shorter setup/pack-up times, while also improving safety by reducing worker twist/strain injuries. From an accounting perspective, most of these benefits will flow to capex given that EWPs and other heavy vehicles are used for capital programs (e.g. installing/replacing assets).

5.11 Property

We are forecasting $145 million in non-network property capex for the 2024-29 period. This makes up 4% of our total investment in **Figure 5.11.1.**

Our planned capex program aims to deliver a property portfolio which, by FY29, will be flexible and adaptive to rapid shifts in customer requirements, while also maintaining safety for our workforce and the community.

Figure 5.11.2 below sets out the trend in our non-network property capex. It shows that our 2024-29 forecast aligns with our spend in recent years.

Continuing priority

Our non-network property forecast is 17% less than our 2019-24 expected spend. We will continue to prioritise safe, productive workplaces at this lower level of investment.

Figure 5.11.1 Forecast property capex as a percentage of total capex

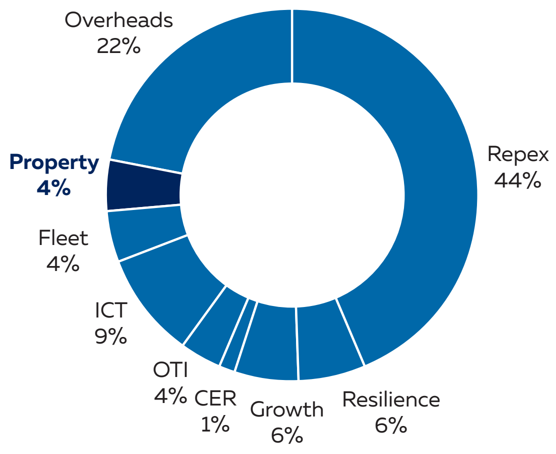
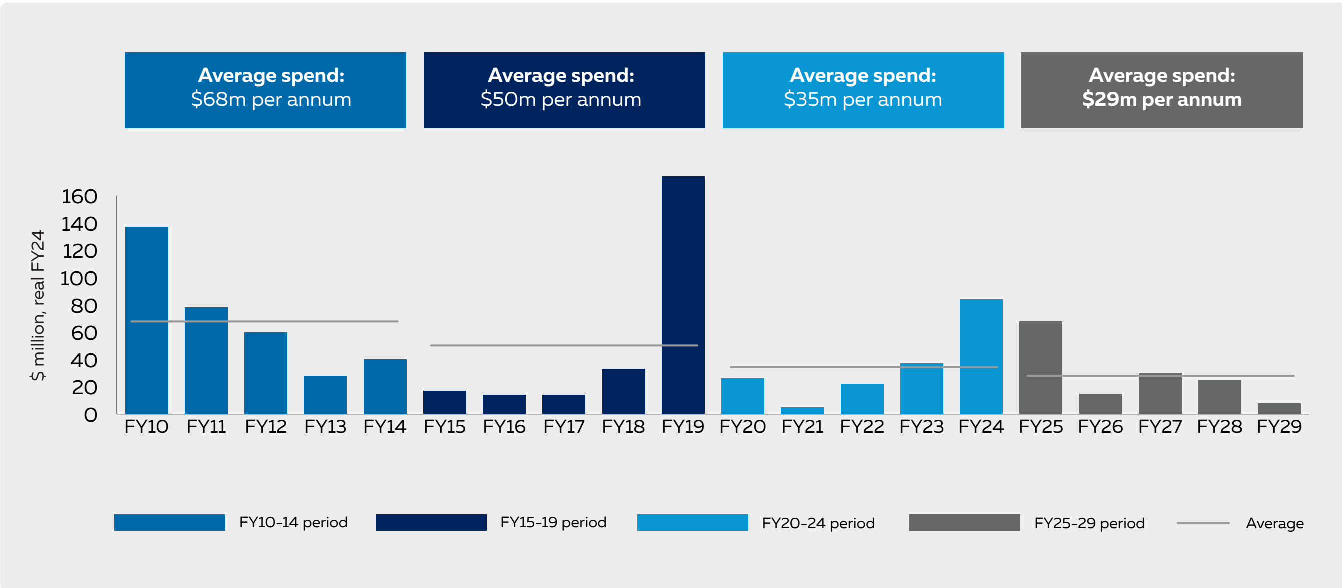


Figure 5.11.2 Our forecast non-network property capex is lower than our recent level of investment



5.11.1 What we have achieved in the current period and how it benefits customers

Figure 5.11.3 below sets out our key achievements in the 2019-24 period and how they will continue to benefit customers.

Figure 5.11.3 Our recent achievements and how they will benefit customers in the 2024-29 period

	What we achieved in 2019-24	Benefits to customers in 2024-29
Property sales	We have consolidated our property requirements by disposing of assets in the 2019-24 period	The sale of property in the 2019-24 period leads a lower RAB value for customers to fund, leading to savings on customer electricity bills
Accomodation strategy	We have maintained the safety and security of the accommodation our staff use every day they are at work	Our track record for safety and security has helped us put forward a non-network property forecast that is 17% below our expected spend in the 2019-24 period

5.11.2 Incorporating our customers' priorities

We focused our engagement with customers on technical matters relating to our non-network property investment needs. **Figure 5.11.4** sets out a summary of this engagement which included multiple presentations to the Reset Customer Panel and more than 10 hours of discussion on issues relating to health and safety and the quantification of benefits from our property investment plans..

Figure 5.11.4 How we engaged on our non-network property forecast

3 RCP presentations

5+ Hours of discussion

5.11.3 Our forecast approach produces an efficient forecast

Our 2024-29 non-network property forecast is based on regulatory obligations, guidelines and policies, including:

- **Regulatory compliance obligations** – such as the *National Construction Code*, the *Australian Standards*, the *Building Code of Australia standards*, the *Workplace Health and Safety Act 2011 (NSW)*, the *Environmental Planning and Assessment Act 1979 (NSW)*, the *Heritage Act 1977 (NSW)*, and the *NSW Government Workplace Guidelines*;
- **Ausgrid policies** – such as the Health and Safety Management System – previously known as 'Be Safe', COVID-19 Protocols and Electrical Safety Rules; and
- **Ausgrid Guidelines** – such as the Health and Safety Strategy, which has the key objective of 'continually improving control effectiveness to reduce the health and safety hazards and risks across our operations so far as is reasonably practicable'.

We have applied our BAU investment governance processes in the development of our non-network property forecast. These processes are geared towards selecting the most efficient solutions by considering factors such as security of tenure, asset life cycles, and any efficient capex and opex tradeoffs that may be present when making investment decisions impacting our non-network property portfolio.

We have also applied our standardised NPV model, which we use across our capex portfolio, to identify the most efficient options. This approach applies quantitative analysis which considers benefits such as safety and reliability.

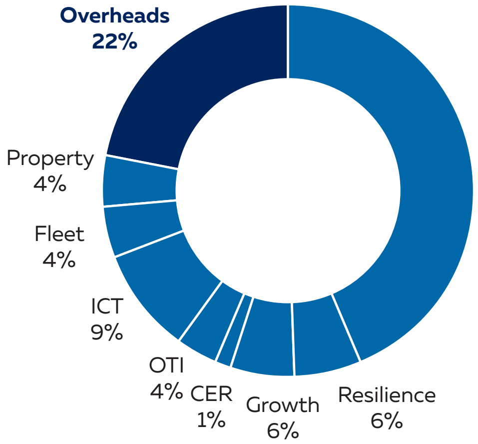
5.12 Capitalised overheads

Capitalised overheads include the indirect costs we incur in the delivery of both our network and non-network capex programs. It includes the costs associated with planning, managing and supervising the capex program and a portion of administrative/corporate support costs including safety, ICT, human resources and finance functions.

Although these costs support the delivery of the capex program, they cannot be directly attributed to specific projects or programs. As a result, these costs are bundled together as capitalised overheads.

As shown in **Figure 5.12.1**, our capitalised overheads make up 22% of our total forecast capex in the 2024-29 period.

Figure 5.12.1 Capitalised overheads as a proportion of total capex



5.12.1 Evidence our capitalised overheads forecast is efficient

The AER's standard method to calculate capitalised overheads involves using the historic proportion of capitalised overheads to direct capex and trending this forward. The forecast for capitalised overheads is calculated by assuming that for every 4% change in direct capex, capitalised overheads change by 1%. This methodology is based on the assumption that capitalised overheads are 75% fixed and 25% variable.

We have developed a capitalised overhead forecast that applies the AER's standard method.

In response to customer feedback, we are also seeking to promote affordability by applying a 0.5% productivity growth adjustment. This commits our business to unlocking efficiencies in the costs making up our capital overheads with the full benefit passed onto customers.

5.13 Supporting attachments relevant to Chapter 5

Overview	
5.1	Proposed capital expenditure
5.1.a	Capex model – FY23-24
5.1.b	Capex model – FY25-29
5.2.a	Network strategy
5.2.b	Investment governance framework
5.2.c	Customer value framework
5.2.d	Principles of CBA
5.3.a	Resourcing and delivery strategy for 2024-29 period
5.3.b	Cost estimation approach
5.3.c	Master list of network SCS capital projects
Replacement capex	
5.4.a	Asset replacement program
5.4.b	Major projects – 11kV Switchgear replacement
5.4.c	Major projects – Sub-transmission cable replacement
5.4.d	Major projects – other replacement
5.4.e	CBA approach for replacement program
5.4.f	CBA approach for major projects
Resilience	
5.5.a	Resilience implementation plan
5.5.b	Climate impact assessment
5.5.c	Climate resilience framework
5.5.d	Climate resilience CBA model
Growth	
5.6.a	Maximum demand forecast
5.6.b	Maximum demand forecast and DER integration model review
5.6.c	Major projects – augex and connections
5.6.d	HV & LV augmentation programs
5.6.e	Reliability program
5.6.f	Connection policy
5.6.g	Macquarie STS Tx3 CBA model
5.6.h	HV & LV augmentation CBA model
5.6.i	Forecast new connections model – SCS customer contribution
5.6.j	Forecast new connections model – SCS
CER integration expenditure	
5.7	CER integration program
Operational technology and innovation	
5.8.a	Network innovation program
5.8.b	Network innovation program mid-term review
5.8.c	Control system core refresh program
5.8.d	Operational technology program
5.8.e	Network digitisation program
5.8.f	Network innovation CBA model
5.8.g	Network digitisation CBA model
5.8.h	Feedback on innovation program

5.13 Supporting attachments relevant to Chapter 5

Continued

	ICT
5.9	Technology plan 2024-29
5.9.a	Geographic information systems program
5.9.b	ERP upgrade program
5.9.c	Cyber security program
5.9.d	Customer information systems program
5.9.e	ICT & infrastructure program
5.9.f	Data & analytics program
	Fleet
5.10.a	Elevated work platform program
5.10.b	Light commercial vehicles program
5.10.c	Heavy commercial vehicles program
5.10.d	Crane borer program
5.10.e	Fleet CBA model
	Property
5.11	Property plan for 2024-2029
	Capitalised overheads
5.12	Capitalisation policy

6

Our opex for the 2024-29 period builds on significant cost reductions implemented since 2015, by making an upfront commitment to reduce our operating costs by $35 million over the 2024-29 period.

6. Operating expenditure

In general, opex reflects our activities and costs that are recurrent. It includes the costs of operating and maintaining our physical assets (such as our poles, wires and substations, monitoring and control systems), responding to emergencies (such as fallen trees on our power lines), undertaking customer-related functions (such as providing call centre services) and back office functions.

In developing our 2024-29 opex forecast, we have used the AER's preferred 'base-step-trend' method and have also sought to meet the AER's other expectations on opex forecasts in regulatory proposals as set out in the AER's Better Resets Handbook (see **Figure 6.0.1**).

The sections below provide an overview of our opex forecast (**Section 6.1**), and then outline:

- How we have recently transformed our business to reduce our opex (**Section 6.2**);
- How our opex forecast responds to customer priorities (**Section 6.3**);
- Our opex forecasting method (**Section 6.4**) and application of its key steps – Base (**Section 6.5**), Step (**Section 6.6**) and Trend (**Section 6.7**); and
- List the supporting attachments relevant to our opex proposal (**Section 6.8**).

Figure 6.0.1 How our opex forecast meets the AER's expectations[52]

Expectation		Our assessment	Explanation	Where discussed
Forecasting approach	Base-step-trend method	✔	We have used the base-step-trend method	**Section 6.4**
Forecasting approach	Base year	✔	We have used the base year for which there will be audited actuals for the final decision	**Section 6.5**
Forecasting approach	Trend	✔	We have met one or more of the AER's categories for step changes, including being supported by customers	**Section 6.7**
Forecasting approach	Step changes	✔	We have met one or more of the AER's categories for step changes, including being supported by customers	**Section 6.6**
Forecasting approach	Category specific forecasts	✔	We have limited our category specific forecasts to categories previously agreed in AER decisions	**Section 6.6**
Genuine consumer engagement	Impact on service level outcomes	✔	We have not proposed any cost changes that would compromise our current level of service delivery	**Section 6.5**
Genuine consumer engagement	Consistency with consumer preferences	✔	We have consulted on cost increases and aligned with customer preferences	**Section 6.6**
Genuine consumer engagement	Deviation from base-step-trend	✔	We do not propose any deviations from the base-step-trend approach	**Section 6.4**

52 As set out in the AER's Better Resets Handbook, section 5.2.

6.1 Overview

Our opex forecast for the 2024-29 period is $2,375 million, excluding debt raising costs[53] (see **Figure 6.1.1** below). This is:

- 14% lower than our current period opex allowance;
- 10% higher than our current period forecast spend; and
- 5% higher than the opex we included in our Draft Plan.

If the impact of the changed accounting treatment of SaaS ICT solutions is excluded from our forecast opex,[54] our forecast is 2% higher than the current period spend.

Our opex forecast also includes an upfront $35 million ($, real FY24) productivity saving, which is fully passed through to customers.

Figure 6.1.1 Forecast opex, 2024-29 ($m, real FY24)

Opex	FY25	FY26	FY27	FY28	FY29	Total period
Opex excluding debt raising costs	463.6	472.1	475.8	479.9	483.7	2,375.0
Debt raising costs	9.0	9.1	9.1	9.1	9.1	45.4
Total opex	**472.6**	**481.2**	**484.9**	**489.0**	**492.8**	**2,420.4**

6.2 We have transformed our business

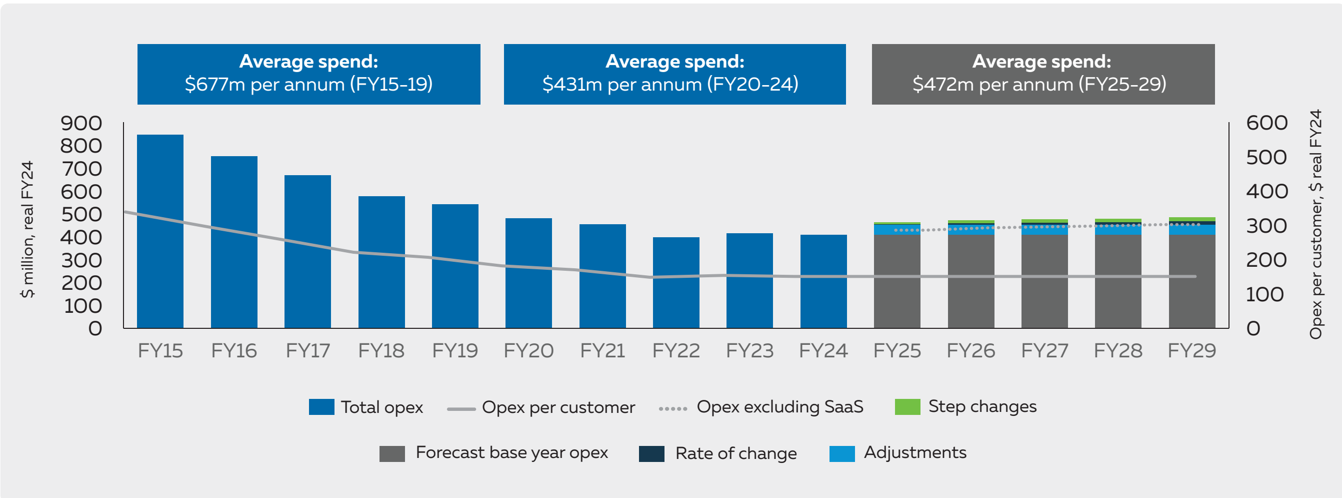
Over the current regulatory period, we have undergone significant transformation which has reduced ongoing opex and is passed through to customers through lower costs in the next regulatory period. We have:

- Reduced the number of full time equivalent employees from 3,576 to 2,908; and
- Achieved other significant cost reductions through the implementation of non-labour transformation initiatives including ICT licence cost reductions, savings in vegetation management and reductions in fleet costs.

While we have achieved significant costs savings, our opex forecast for the 2024-29 period indicates that we expect our costs to increase compared to the current period. This is mainly due to:

- The change in accounting treatment for SaaS ICT solutions (as outlined in **Section 6.5.3**);
- Step changes (as outlined in **Section 6.6**); and
- Changes to our CAM which allocate more indirect costs to SCS compared to the current regulatory period (as outlined in **Section 6.5.3**).

Figure 6.2.1 Forecast opex for 2024-29 compared to actual/estimated opex for 2015-19 and 2019-24 ($m, real FY24)



53 Debt raising costs are added to total opex to cover, for example, arrangement fees, credit rating fees, and issuer legal counsel fees associated with raising debt.
54 In April 2021, the IFRIC decided the costs associated with configuring and customising SaaS ICT solutions must be treated as opex, rather than capex as previously was the case. We have included these costs in our forecast opex as a base year adjustment.

6.3 How our opex forecast responds to customer priorities

In our engagement to inform our Draft Plan, our customers and stakeholders told us that:

- Energy costs are difficult to manage, so energy needs to be affordable;
- We should invest to reduce our long-term costs;
- We should improve our climate and cyber resilience; and
- We should prioritise innovation that supports the energy transition.

We discussed step changes with the Reset Customer Panel in detail several times over 2021-2022. In these discussions, we explored a range of step changes – some of which we have included in this Regulatory Proposal (see **Section 6.6** below). **Figure 6.3.1** below outlines step changes we considered and decided not to progress after consultation with the Reset Customer Panel.

Figure 6.3.1 Step changes considered, but not progressed

Step change considered	Why not progressed further
New CALD, low income and vulnerable customer support programs	While this was a strong theme within submissions to our Draft Plan and from Voice of Community Panel customers, the Reset Customer Panel did not support a specific step change. We note the AER's gamechanger initiative is yet to be finalised and may have implications for our Revised Proposal
New license conditions obligations from 1 July 2024 that increase guaranteed customer service level payment thresholds and obligations	The Reset Customer Panel asked us to absorb any incremental costs
New regulatory obligations managing NSW Electricity Infrastructure Roadmap exemptions obligations	Any incremental costs associated with administering this scheme (for example, managing exemptions data and contribution orders, and communications) will be absorbed
New resources and systems to implement DSO and CER obligations under the AEMC's access, pricing and incentive arrangements for CER rule determination	As there was no strict obligation from this rule change, this proposed step change was initially rejected by the Reset Customer Panel, however in refining analysis it evolved into the step change for ICT enablement program for CER integration as a capex to opex substitution (see **Section 6.7.7**)
New obligations under the AEMC's Metering Review where there was potential that DNSPs would be responsible for site remediations	Given that the AEMC paused its Metering Review we only progressed with a step change for purchasing smart meter data for network visibility (see **Section 6.7.3**). We will await the outcomes of the review early in our 2024-29 period
SaaS implementation costs	International accounting guidance released in FY21 requires the cost of configuring and customising software within SaaS arrangements to be expensed rather than capitalised. We consulted on this as a step change in our Draft Plan, however subsequent discussions with AER officers indicates we should treat this as a base year adjustment

In our Draft Plan, we outlined potential responses to feedback we had received from customers about our plans for the 2024-29 period.[55] The responses indicated we should:

- Invest in smart meter data and real-time smart meter functionality to enable more efficient growth capex, lower opex, and enhance safety benefits and outcomes for CER customers;
- Improve our communities' climate resilience, for example by employing new staff to run outreach programs, provide information about climate resilience and support communities during prolonged outages caused by extreme weather events;
- Invest in a cyber security program that would enable us to adopt practices and protections in line with industry best practice (SP-3 of the Australian Energy Cyber Security Framework); and
- Add a $5 million opex allowance to our current Network Innovation Program to allow us to select the most efficient energy technology options for customers, and conduct ongoing research on community attitudes, expectations and preferences on issues relevant to this program, as well as contribute to long-term capex savings.

We included some step changes in the Draft Plan to address this feedback, sought comment on them and tested them further with the Reset Customer Panel (particularly the ICT enablement program for CER integration).

We have made some adjustments to our forecasts in response to this feedback and based on further development of forecasts as shown in **Figure 6.3.2**.

Figure 6.3.2 How we responded to customer feedback in developing our step change proposal ($m, real FY24)

	Draft Plan ($)	Regulatory proposal ($)	Difference ($)	Reason for change
Insurance premiums	27.8	9.5	(18.3)	Adjusted based on renewal negotiation outcomes
Smart meter data	23.5	24.9	1.4	Update reflects inflation
Community resilience	25	8.4	(16.6)	Updated analysis, feedback from Voice of Community Panel and storm costs moved into base year adjustments
Cyber security	18.3	20.6	2.3	Update reflects inflation
Network Innovation Program	5	5	No change	No change despite strong support by Voice of Community Panel to increase (see **Section 6.6.5**)
ICT enablement program for CER integration	N/A	10.4	10.4	New step change that evolved as CER analysis progressed but included within $126.1 million CER totex
Property step change	N/A	(14.5)	(14.5)	Reduced land tax and other costs associated with property sales

55 See Ausgrid (September 2022), *Appendices: Regulatory Matters for our Draft Plan for consultation*, pp 22-23.

6.4 Forecasting method

To develop our opex forecast, we applied the base-step-trend methodology for most operating cost categories. For the remaining costs – debt raising costs - we used a specific or bottom-up forecasting approach that better reflects the nature of these costs. **Figure 6.4.1** provides an overview of our methodology.

Figure 6.4.1 Overview of methodology used to forecast opex for 2024-29

Start with the efficient base year

We selected actual opex in FY23 as the proposed base year as the most recent year of actual financials by the time of our final decision. We consider that this is representative of the efficient annual costs needed to operate and maintain the network.

▼

Adjust the base year

We adjusted the base year for any non-recurrent costs (if there are any) which are not reflective of ongoing opex requirements. We also adjusted the base year for other changes that affect our future opex.

▼

Trend the base year forward

We trended base year opex forward by taking into account expected growth in input prices, such as labour (0.6% per year on average), output (0.5% per year on average) and productivity gains (0.5% per year).

▼

Adjust for step changes (positive or negative)

We adjusted the efficient base year to account for identified step changes, which reflect changes in costs relating to a change in regulatory requirements, or other external factors outside of management control, or where there is an efficient trade-off between opex and capex.

▼

Add category specific forecasts

We added debt-raising costs (around $9 million per year) using a specific forecasting approach, which better reflects the nature of these costs.

▼

Forecast opex for the 2024-29 period

6.5 Base year

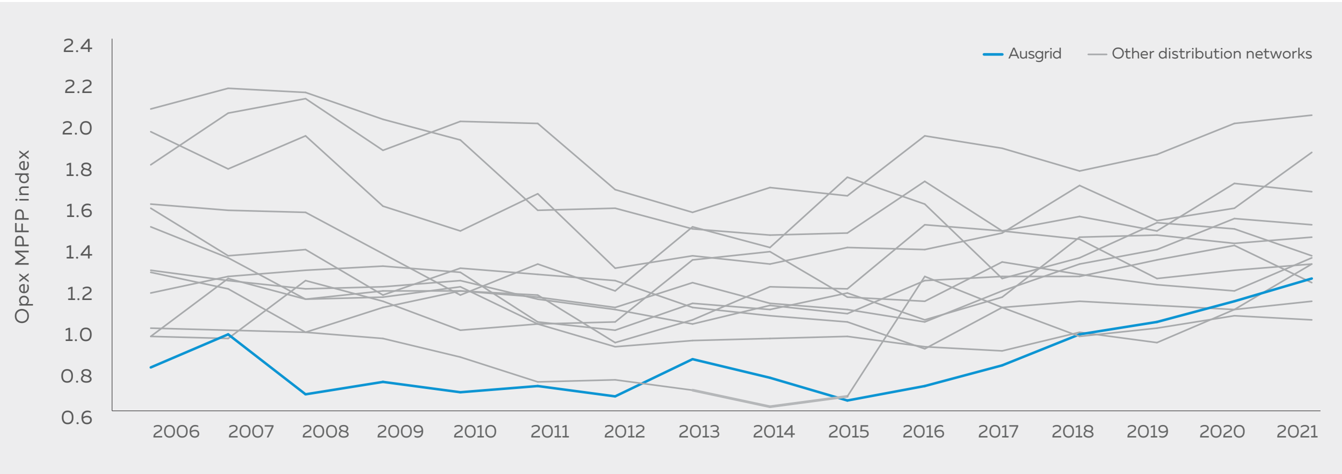
6.5.1 Benchmarking performance

Our benchmarking analysis is based on the AER's 2022 annual benchmarking report.[56] While our historical opex compares poorly to other network businesses, Ausgrid has become the most improved in the AER's opex multilateral partial factor productivity (**MPFP**) in recent years as a result of our efforts to reduce opex in the current and previous regulatory periods.

In particular, we note:

- While we were in the bottom three network businesses for opex MPFP between 2006 and 2018, we have shown significant improvement since 2015;
- Our MPFP performance improved by 9% in 2021 compared to 2020;
- We have consistently been one of the most improved DNSPs since 2015; and
- In 2021 we improved our MPFP ranking to 10th place, and are expected to continue to improve this ranking again based on our actual opex for 2022 (see **Figure 6.5.1** below).

Figure 6.5.1 Ausgrid opex MPFP continues to improve



Source: AER 2022 Benchmarking Report

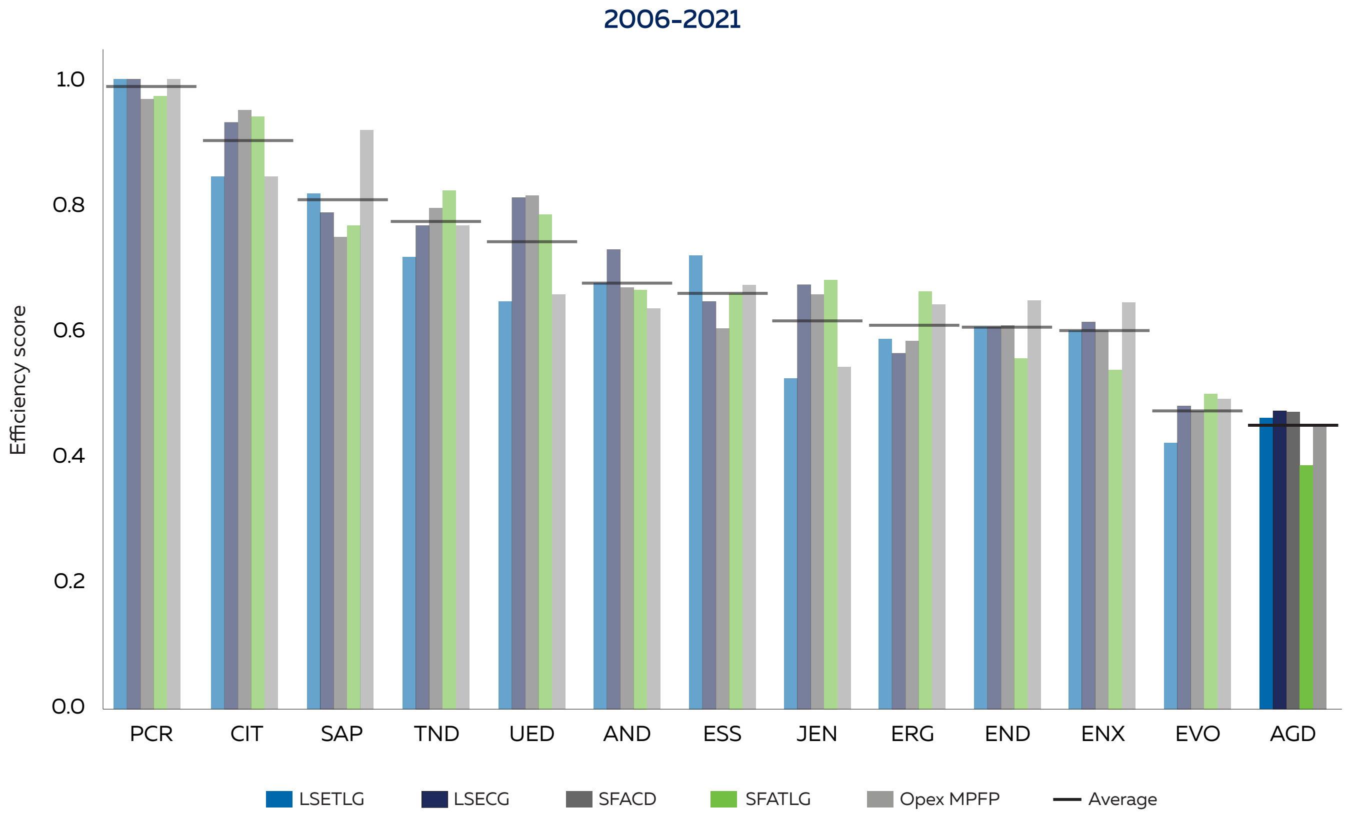
6.5.2 Efficiency of the base year

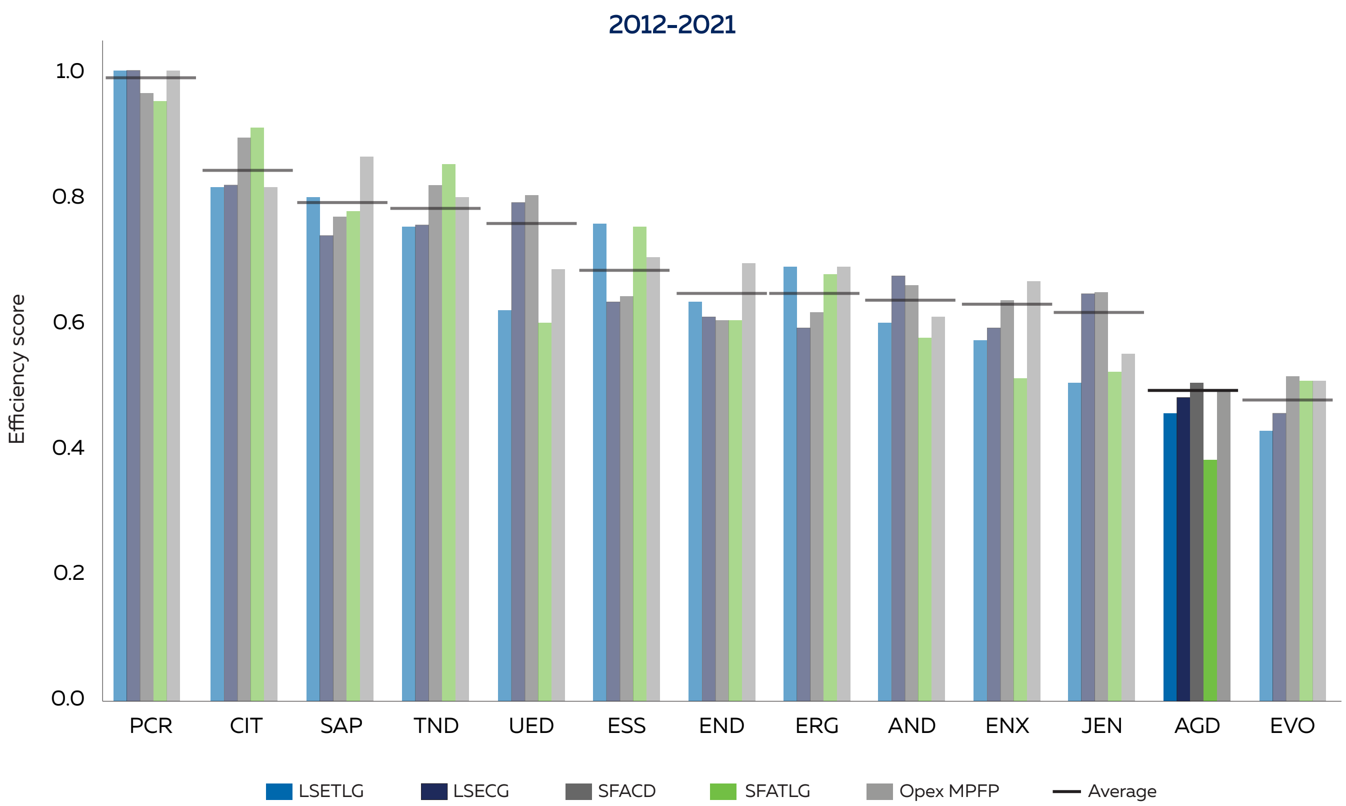
The AER's opex econometric models are the most critical of the AER's benchmarking techniques as they are used deterministically when assessing revealed costs, or substituting a DNSP's opex.

The results of econometric benchmarking are similar to the results of opex MPFP, as shown in **Figure 6.5.2** below. **Figure 6.5.2** shows that Ausgrid performs better in the shorter (2012-2021) period because – as noted earlier – it takes some time for efficiencies to be reflected in outcomes. Our significant improvements in opex began in 2015, so the results are still influenced by the years prior to 2015. We recognise that Ausgrid's opex performance appears inefficient, however when considering other benchmarking tools and metrics, and the significant improvements since 2015, we believe our base year is efficient.

56 AER (2022). *Annual benchmarking report – Electricity distribution network service providers.*

Figure 6.5.2 DNSP opex efficiency scores – econometric models and MPFP





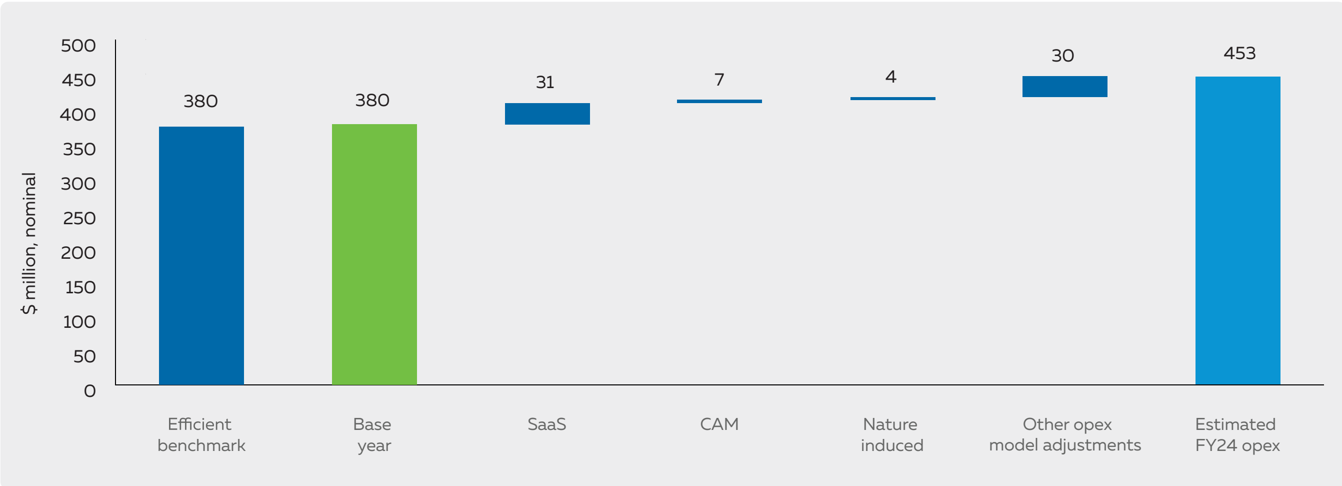
Source: AER 2022 Annual Benchmarking Report

We selected FY23 as the base year for our opex forecasts for 2024-29 because:

- It is the most recent regulatory year for which audited regulatory accounts and other financial information will be available when the AER makes its final decision in April 2024;
- We consider it best represents our underlying operating conditions in the current 2019-24 period, and the conditions we expect for the 2024-29 period. To date, it has not included unusual events or factors that indicate it will not be reflective of our normal operating environment; and
- While we do not yet know our actual opex in FY23, our base year estimate is our latest forecast. We have used the AER's opex roll forward models, and the latest benchmarking results, to estimate whether our base year can be considered efficient, or not materially inefficient, according to the AER's preferred methodology.

Our own estimate of the efficiency of this forecast opex (based on currently available information) indicates it is within 0.2% of the AER's benchmark opex level (**Figure 6.5.3**). We consider this estimate demonstrates that our FY23 opex is efficient based on the AER's methodology. In pre-submission engagement, AER staff indicated informally that our proposed FY23 forecast opex is likely to be considered not materially inefficient.

Figure 6.5.3 Ausgrid estimate of the efficiency of our base year opex and estimate of FY24 opex ($m, nominal)



6.5.3 Base year adjustments

After selecting FY23 as our base year, we then estimate FY24 opex as the starting point for trending forward opex to the next period. We have made the following adjustments to our base year to estimate FY24 opex:

1. **Updated CAM** – to represent the movement of costs as a result of a new CAM approved by the AER in October 2022;
2. **Updated emergency response** – to account for emergency response costs on the basis of a 5 year average, rather than a single year estimate; and
3. **Updated SaaS** – to reflect the change in accounting guidance which recognises some software implementation costs as opex rather than capex and treating it as a base year adjustment over a step change, per advice from AER officers (more details on this adjustment below).

Other adjustments to estimate opex in the final year of the current period include adjusting for inflation and adding the difference between the AER's allowances between the base year and final year onto our efficient base year operating expenditure, as per the AER's opex model.

6.6 Step changes

Step changes refer to increases or decreases in our opex associated with meeting new or changed regulatory obligations, major external factors or opex/capex trade-offs. These factors represent required opex not captured by the base year expenditure or trend escalation, and therefore they are added to or subtracted from the trend-adjusted base year.

Figure 6.6.1 summarises our seven proposed step changes and categorises each as falling under one of the AER's step change categories (as set out in the AER's Better Resets Handbook).[57]

Figure 6.6.1 Proposed opex step changes 2024-29 ($m, real FY24)

Step change	Description	AER category
Insurance premiums	Risk management to address increasing insurance premiums due to climate events such as bushfires and floods causing more damage to our network	Major external factor
Community resilience	Investigate community solutions other than network capex through community engagement, coordination with other resilience actors, and research / trials for alternate solutions	Capex to opex
Smart meter data	We need to purchase smart meter data that is not in our base year due to increased smart meter uptake on our network as a result of the AEMC's smart meter review	Major external factor
Network Innovation Program	Replacing Network Innovation Program capex for opex to enable research and development through partnership	Capex to opex
Cyber security	Uplift our capability to respond to the frequency and severity of cyber attacks	New regulatory obligation
ICT enablement program for CER integration	Delivering some projects in the ICT enablement program for CER integration as opex rather than capex	Capex to opex
Property strategy	Remove opex associated with property disposals in the current period	Negative step change

The following sub-sections describe our proposed step changes, how we explored them with customers and demonstrates how we are not double counting costs.

We note these step changes were selected as a result of detailed engagement with the Reset Customer Panel and that we also proposed several other step changes for inclusion in this Regulatory Proposal that we did not progress further (see **Section 6.3** above).

57 AER (2021), *Better Resets Handbook*, p 28.

6.6.1 Higher insurance premiums

Insurance costs are increasing. For us, key drivers of these increases are climate change, which is causing more damage to networks, and the significantly higher risk of cyber security breaches.

Our insurance premiums have increased by 87% over the last two years and are forecast to increase another 46% between now and FY29, even with concerted efforts to manage these costs. For this reason, we have included a step change of $9.5 million to our insurance costs so we can continue to appropriately manage risk at the lowest sustainable cost.

Justification for the step change

We obtained a report from our insurance consultants Marsh which provides detailed information on the market for all insurances obtained by Ausgrid – see **Attachment 6.3 - Marsh insurance report (Marsh Report)**. Marsh has also forecast our insurance costs to FY29, and these forecasts form the basis of our step change amount.

We included an insurance premium opex step change of $27.8 million in our Draft Plan. The step change in the proposal has reduced by $18.3 million to $9.5 million due to:

- Advice from the AER that the step change should be calculated relative to our insurance spend in FY24, rather than our base year FY23 ($6.2 million);
- Updated forecasts by Marsh, taking account of the outcomes of our FY23 renewal negotiations ($7.6 million);
- Excluding RAB growth from forecasts related to asset growth ($1.7 million); and
- Changes to inflation forecasts ($2.8 million).

This step change is driven by a major external factor outside of our control and does not include (i.e. double count) forecast growth that is already accounted for in the trend factor.

What customers said

Due to the commercial-in-confidence nature of our insurance premiums we did not discuss or share the Marsh Report with Voice of Community Panel members. We engaged the Reset Customer Panel in detailed briefings on this step change, including conducting dedicated Q&As on the Marsh Report and understanding the ways in which Ausgrid could mitigate increasing insurance premium risks over time. The Reset Customer Panel robustly challenged our approach to insurance by challenging the value customers receive from insurance and asking Ausgrid to think about alternative ways of mitigating or managing risk in the face of increasing premiums. The Reset Customer Panel did not indicate concerns with the level of the step change.

6.6.2 Smart meter data

We plan to invest $24.9 million in smart meter data and real-time smart meter functionality that will enable us to better understand two-way energy flows associated with CER and monitor potential electricity faults that can cause safety hazards.

Justification for the step change

Currently Ausgrid is only receiving data from 20,000 smart meters under the Network Innovation Program to test safety outcomes for customer installations, service connections and the network. We explored three scenarios for purchasing smart meter data based on our forecast understanding of smart meter uptake in our network and the corresponding cost to purchase smart meter data. We selected the scenario that provided greatest value for money to improve our network visibility.

This step change will enable more data and real-time smart meter functionality so we can:

- Implement more efficient growth capex through more granular and timely information about CER assets. This will result in faster and more accurate decision-making to integrate CER into our network so that these assets are better utilised and we can reduce the risk of curtailing CER;
- Have additional growth benefits through connectivity validation, voltage compliance and dynamic network management;
- More efficient use of resources through a reduction in customer callouts, outages and safety incidents; and
- Enhanced safety benefits through neutral integrity monitoring and life support validation.

What customers said

In our engagement to inform our Draft Plan, our customers and stakeholders told us we should proactively prepare our network for net zero and invest to reduce our long-term costs. Some stakeholders indicated that we should look to purchase all available data, which could in turn be provided to customers in a meaningful format. In response, our Draft Plan indicated that we were considering this investment in smart meter data and functionality, but only to a level that would still provide demonstrable benefit to customers. The costs and benefits of this investment will be reviewed on an ongoing basis to ensure that this remains appropriate.

In our engagement to inform this Regulatory Proposal, customers told us they agreed with the level and scope of investment we proposed in order to prepare the network for net zero and to help facilitate customers to do the same. In response to this feedback, we have not changed the level of expenditure that informs this step change.

6.6.3 Community resilience

In response to the increasing intensity and frequency of extreme weather events, we have planned a range of initiatives to improve our climate resilience. Forecasting the cost of these initiatives started with developing an efficient level of capital expenditure needed to address our expected growth in climate related risk (see **Section 5.5.4** above). In line with the AER's Better Reset Handbook, we then considered the scope for prudent trade-offs between capex and opex. This has led us to propose a $8.4 million opex step change for the implementation of community-based resilience initiatives, fully offset by a reduction to our 2024-29 capex forecast.

The opex based solutions making up our proposed step change predominately involve the cost of new staff with a specialist skillset. These new staff would run resilience education and grant style programs, help communities with resilience planning, do further research on vulnerable communities and extreme heat, and support the communities we serve after an extreme weather event.

Our proposal aligns with the engagement we have had with customers to date. The Voice of the Community Panel told us that they wanted a spectrum of resilience solutions which included a mix of capex initiatives partnered with more flexible opex solutions that support communities before, during and after an extreme weather event.

More recently, we came to the joint view with the Reset Customer Panel that further engagement is needed. This prompted us to develop a plan for implementing our Climate Resilience Framework, that builds on the conversations we have been having with customers. This implementation plan is summarised in **Section 5.5.4**. The feedback we hear from customers may lead us to update our proposed opex step change, with any updates to be provided to the AER before its Draft Decision.

Justification for the step change

Our resilience program is an increasing priority for our network and customers. The step change can be justified as an efficient capex to opex trade-off or as a major external factor category due to climate change. It is also strongly supported by customers who requested a balance of capex and opex based resilience solutions during extensive consultation, including workshops, joint consultation papers with other DNSPs and Voice of Community Panel discussions.

Our total forecast proposed community climate resilience programs expenditure of $8.4 million is based on customer feedback that the bill impact of total resilience expenditure should be split 40:60, whereby 40% of our resilience spend is for community-based resilience opex programs and 60% is based on network investments (capex).

What customers said

Customers were very clear that we need to respond to the impacts of climate change to communities and risks to our network. This included feedback that we need to:

'Start to be proactive, think about the long term – start to rebuild more resilient.' ***– C&I Customer***

'Pursue an efficient mix of capital and operational investment opportunities to ensure the ongoing reliable provision of electricity.' ***– Voice of Community***

'[Provide] nominated resilient localised community centres for people to go to.' – ***Councils***

Our Voice of Community Panel confirmed that their desire is for Ausgrid to provide support during major weather events which we are proposing to deliver through this step change. In submissions to our Draft Plan, councils were particularly supportive of these initiatives and welcomed the opportunity to engage with Ausgrid further to develop community-based resilience programs.

6.6.4 Cyber security

In response to the frequency and severity of cyber attacks, we plan to invest in a cyber program that would enable us to adopt practices and protections in line with industry best practice – SP-3 of the Australian Energy Sector Cyber Security Framework.

Justification for the step change

We aim to deliver an experience for our customers that takes advantage of digital technologies, while still maintaining a reliable network service with robust protections against the growing risk of cyber security breaches.

There are requirements under the recently amended SOCI Act which place new and enhanced regulatory obligations on Ausgrid. It requires Ausgrid and other entities to implement and maintain a Risk Management Program that addresses a range of prescribed risks, including cyber security.

It is also prudent to move to SP-3 from a customer impacts perspective by virtue of the interdependencies across sectors and potential for cascading consequences to other critical infrastructure assets and sectors if disrupted. Our network powers essential services, like waste water treatment and hospitals, and supplies an area recognised as the third largest market for data centres in the Asia Pacific region and the 8th largest internationally.[58]

We consider that this assessment, combined with the recent increase in high profile cyber attacks on Australian communities and businesses, means that this step change meets the AER's requirements for a regulatory requirement step change and a major external factor step change.

What customers said

In our engagement to inform our Draft Plan, our customers and stakeholders were unanimous in their view that we should improve our resilience to cyber attack. However, they did not initially reach a consensus on the appropriate level of protection for our business by the time we went out for consultation on our Draft Plan. Only the Reset Customer Panel and some members of our Voice of Community Panel considered SP-3 was necessary. Other members of the Voice of Community Panel were not convinced given the cost of this level of protection.

In our engagement to inform this Regulatory Proposal, we continued to consult our key customer and stakeholder groups on this issue. As shown in **Section 5.9.2** our Voice of Community Panel formed a consensus to support SP-3.

Given this customer and stakeholder support, we have included a step change of $20.6 million in addition to our recurrent cyber security costs so that we can improve our cyber protections in line with industry best practice and achieve SP-3. The cost of the forecast step change is primarily based on additional cyber software licencing and resourcing costs in line with the incremental cyber controls based on typical delivery team resource requirements and partner costs. We will take a staggered approach, reaching SP-2 in FY27 and progressing to SP-3 by FY29.

58 Cushman & Wakefield (2022), 2022 Global Data Center Market Comparison Report.

6.5.5 Network innovation

As discussed in **Attachment 5.1 - Proposed capital expenditure**, the Network Innovation Program comprises a range of trials and pilots covering leading edge energy technologies to support the rapidly evolving electricity sector, for a total capital investment of $49.5 million over 5 years.

For the 2024-29 period, we plan to add an opex allowance to the program.

Justification for the step change

The opex innovation allowance will enable us to:

- Select the most efficient innovation options for customers, particularly where service offerings (typically opex) may be more efficient than product offerings (typically capex); and
- Conduct ongoing research on community attitudes, expectations and preferences related to issues relevant to the Network Innovation Program, including solution options and equipment standards.

The expenditure is also expected to create long-term capex savings through the application of innovative solutions. The opex is not for increased internal resources for innovation at Ausgrid.

What customers said

We consulted on the totex Network Innovation Program in our Draft Plan, including the $5 million for opex, and received strong feedback from our Voice of Community Panel that this planned level of expenditure was insufficient. We explained that the amount we spend on innovation is constrained by the number of personnel that we have to deliver these programs and our ability to prioritise innovation projects over BAU service delivery projects.

We also consulted with our Network Innovation Advisory Committee to determine their recommended option out of a range of four. The Network Innovation Advisory Committee supported the $5 million option due to the proposed expenditure enabling them to oversee research into customer preferences and partner with specialist researchers.

The $5 million opex combined with the $49.5 million capex expenditure for the Network Innovation Program, is expected to deliver $81.8 million in benefits.

6.6.6 ICT enablement program for CER integration

In our Draft Plan, we proposed expenditure to invest in supporting higher uptake of CER. Some of this included upgrading ICT systems to enable CER integration, which was included as capex in our Draft Plan forecasts. We have since refined our strategy because we believe we can deliver a better and cheaper outcome by delivering some of these projects as opex rather than capex.

In the Draft Plan, we included $34 million for ICT enablement capex for CER integration. We now propose $10.4 million of ICT enablement expenditure to be opex, and included it as a step change because we do not have any expenditure of this nature in the FY23 base year. Therefore, while this is a new step change compared to our Draft Plan, it does not add to our total expenditure (**totex**) for CER integration.

> It is important to note that all programs within the CER integration expenditure category are interdependent and critical to one another. That is, if the capex elements are approved and the ICT enablement program and smart meter data opex are not approved, or vice versa, this will impact our low voltage network visibility such that we will not be able to deliver on the overall CER integration program.

Justification for the step change

Our ICT enablement program for CER integration over the 2024-29 period aims to build foundational capabilities needed to become a dynamic platform. This includes:

- **Making improvements to our connections** processes to support the anticipated increase in the number and types of CER customers we will connect to our network;
- **Uplifting our modelling and forecasting capabilities** to allow us to make as much network capacity available to customers as possible without breaching network limits. This will also take advantage of increased low voltage network visibility due to purchasing smart meter data as outlined in **Section 6.6.2** above; and
- **Providing customers with more flexible network services options** that rewards them for their flexibility through investing in dynamic operating envelopes and dynamic network pricing.

To identify and quantify this step change, we scoped the ICT requirements internally. Our ICT team then did an international provider scan to determine who would be able to deliver this work. We then had discussions with the two providers that our ICT team determined would be able to deliver the work. We sought informal quotes from them and tested them for their ability to be able to deliver the work. The proposed provider for the step change demonstrated an ability to understand and deliver to the project requirements relative to their counterpart. They were able to provide an upfront cost compared with a subscription based cost so we could better determine which approach would meet our needs. As a result, this was the most prudent and efficient provider based on market testing.

We asked the preferred provider for options to deliver the work program. The option with a larger amount of capex and smaller amount of opex (Option 2) is $15.9 million more expensive over the period. Option 1 also is our preferred option because it relies more heavily on SaaS solutions. This is preferable because it:

- Will allow us to leverage capabilities other networks have already developed and ensure any enhancements made for Ausgrid remains accessible to other networks,
- Presents a lower risk to customers than upfront investment if two-sided markets take longer to develop, and
- Has a lower spend profile over 2024-29 of $15.9 million, which will help with affordability in the short term.

Further detail on the elements of the ICT enablement program we're proposing to utilise a SaaS solution for can be found in **Attachment 6.1 – Proposed operating expenditure**. Although we are currently conducting a trial (Project Edith) to test and demonstrate these capabilities, it is funded through network innovation program capex and not included in our base opex.

What customers said

As discussed in **Section 5.7** customers told us that we should be supporting a proactive approach to CER integration in our network that enables them to invest in CER and directly access and share its benefits with all customers. We did not specifically consult with customers on this step change in our Draft Plan as we had not yet received quotes from providers on how to deliver this work. However, customers consistently told us that they are supportive of us undertaking foundational investments to enable CER integration.

Additionally, this steps change enables us to enact the Reset Customer Panel's and Pricing Working Group's support for introducing dynamic pricing.

6.6.7 Property strategy (negative step change)

The property strategy negative step change arises from property sales in the current 2019-24 period that reduce land tax and other costs associated with properties sold.

Justification for the step change

This is a negative step change to reflect lower costs due to the sale of properties in the current period.

Customers benefit from property sales because the full disposal value is netted off the RAB. This means any uplift in value compared to the original value recognised in the RAB is fully passed through to customers through lower return on asset.

When preparing this Regulatory Proposal, we identified several properties that could be rationalised. We determined that it would be most prudent to achieve these sales as soon as possible, rather than offering the properties for sale over a number of years, including because:

- Property values are forecast to fall over coming years, therefore we can maximise the value returned to customers by selling over the coming year; and
- The benefit to customers comes sooner if a large portfolio of properties is removed from the RAB this regulatory period, rather than phased over the following regulatory period.

To achieve the sales quickly, we will sell the properties to another company in the Ausgrid group. Being a related party transaction, the highest levels of probity will be adhered to, including procuring independent valuations for the properties to ensure maximum benefit is derived for our customers .

Each property owned by Ausgrid carries a certain level of opex, including land tax and maintenance costs. As we are forecasting to sell $151 million worth of properties, we have identified recurrent costs associated with those properties that we will not incur once they are sold. This is estimated at $14.5 million over 5 years, which will be updated in our revised proposal to reflect the actual sales outcome.

More information can be found in **Attachment 4.1 – 2024-29 Proposed revenue.**

What customers said

We consulted with the Reset Customer Panel on this step change, which was supported as it results in a negative step change and reduces prices in the 2024-29 period.

6.7 Trend

To 'trend' our base year opex forward to account for changes over the 2024-29 period, we considered:

- **Real price growth** – to reflect expected changes in the price of our cost inputs, including our labour costs;
- **Output growth** – to account for changes in costs based on how much output we expect to deliver; and
- **Productivity growth** – to reflect expected industry-wide improvements in finding more efficient ways of delivering services.

For each of these trend factors, we forecast the annual rate of change over the 2024-29 period, and applied it to our base year expenditure. **Figure 6.7.1** summarises these forecast rates.

Figure 6.7.1 Forecast rates of change used to trend base year opex, year on year (%)

Trend factor	FY25	FY26	FY27	FY28	FY29
Price	0.98%	0.89%	0.39%	0.30%	0.42%
Output	0.29%	0.37%	0.44%	0.84%	0.79%
Productivity	(0.50)%	(0.50)%	(0.50)%	(0.50)%	(0.50)%
Total change	**0.76%**	**0.75%**	**0.33%**	**0.63%**	**0.71%**

To forecast these rates, we used approaches consistent with those specified in the Better Resets Handbook. In summary:

- **To forecast price growth** – we used an average of two NSW-specific utilities industry wage price index growth forecasts of real labour inflation. To obtain the first forecast, we asked BIS Oxford Economics to forecast the electricity, gas, water, waste services wage price index for NSW. As a placeholder for the AER's consultant forecast we have used the KPMG NSW utilities forecasts provided for Transgrid's draft decision.[59] This does not cover the last year of our current 2019-24 regulatory period, so we have carried forward the FY23 forecast for FY24. We have applied real labour escalation to 59.2% of opex, aligned with the AER's methodology.
- **To forecast output growth** – we have forecast output growth consistent with the AER's preferences in the Better Resets Handbook, and applied the weightings produced by the AER's 2022 benchmarking;[60] and
- **For productivity growth** – we included a productivity factor of 0.5% which aligns with the AER's expectations in the Better Resets Handbook. We consulted on this with the Reset Customer Panel who undertook a holistic evaluation of productivity of our overall proposal (see **Attachment 6.1 – Proposed operating expenditure**). We also included a 0.5% productivity factor to capitalised overheads to reflect that productivity gains made in opex overheads would also flow to capex.

We expect to update our opex forecast with the latest forecasts for price and output growth in our revised proposal.

59 KPMG (14 September 2022), *Wage Price Index Forecasts.*
60 AER (2022), *Annual benchmarking report – Electricity distribution network service providers.*

6.8 Supporting attachments relevant to Chapter 6

6.1	Proposed operating expenditure
6.1.a	Opex model
6.1.b	Step changes model
6.2	Network maintenance program
6.3	Marsh insurance report

7

Our Regulatory Proposal includes incentive schemes that cover expenditure, service performance, customer service and demand management. Our Regulatory Proposal also includes four pass through events to ensure we can respond to certain circumstances, such as natural disasters.

7. Incentive schemes and pass through events

Incentive schemes are crucial elements of our Regulatory Proposal. These schemes help us achieve our goal of delivering value for money for our customers, without compromising on reliability or customer service. The schemes give us consistent incentives to identify more efficient alternatives to building new infrastructure and seek other cost reductions, which benefit customers.

Our customers will benefit from each of the incentive schemes that will apply during the 2024-29 regulatory period:

- The EBSS and the CESS each give our customers about 70% of any cost reductions we can achieve;
- The Service Target Performance Incentive Scheme (**STPIS**) gives us an incentive to improve our reliability;
- We are proposing a new CSIS which we have designed through close customer engagement to further deliver customer service improvements; and
- The demand management incentive scheme (**DMIS**) and DMIAM encourage us to implement lower-cost, non-network solutions consistent with our customers' expectations.

In the following sections we provide an overview of how we propose to apply each of these incentive schemes in the 2024-29 period[61] and highlight areas where our proposed approach differs from that of the AER's approach.[62]

61 The NER require that our Regulatory Proposal contain a description, including relevant explanatory material, of how we propose any incentive scheme that has been specified in the F&A paper should apply (NER, cl 6.1.3).
62 The AER sets out its approach in its F&A for Ausgrid, Endeavour Energy and Essential Energy: Regulatory control period commencing 1 July 2024, July 2022. The AER is required to publish its approach under NER clause 6.8.1(b)(2).

7.1 EBSS

By applying the EBSS our customers will benefit from around 70% of any opex cost savings, improving affordability.

The EBSS provides an incentive to improve affordability by continuously reducing our operating costs and giving our customers a fair share of any savings that we achieve as a result of the scheme.

The AER applied the EBSS to Ausgrid for the 2019–24 period, and we have earned an EBSS reward by lowering our opex (discussed in **Chapter 4** and **Attachment 4.1 – 2024-29 Proposed revenue**).

In its F&A decision paper, the AER indicated it proposes to apply the EBSS as part of its determination on our revenue proposal for the forthcoming 2024-29 period, provided the AER is satisfied the scheme will fairly share efficiency gains and losses between Ausgrid and consumers.[63] The AER has indicated this will only occur if our opex forecast for the following period is based on our revealed costs.

As explained in **Chapter 6**, we have delivered substantial opex savings during the current regulatory period. These savings, together with our good benchmarking performance, should give the AER confidence that our proposed FY23 base year opex is an efficient 'base' for applying its 'base-step-trend' forecasting methodology. As such, we propose that the AER also apply the EBSS in the 2024–29 regulatory period, as it is an integral component of the AER's framework for driving efficient opex outcomes over time, subject to the exclusions outlined in **Section 7.1.1** below.

7.1.1 Cost exclusions

In deciding how the EBSS should apply, Ausgrid has the option of proposing that certain cost categories be excluded from the AER's calculations of efficiency gains or losses for the EBSS reward or penalty.

Under the EBSS, certain categories of opex may be excluded if doing so better achieves the scheme's objectives. This approach leads to fairer sharing of the efficiency improvements between Ausgrid and our customers and also prevents windfall gains or losses.

The current version of the EBSS already specifies several adjustments, which Ausgrid agrees should be made.[64]

In addition, Ausgrid proposes excluding:

- **Debt raising costs** – we have calculated debt raising costs by applying a benchmark debt raising unit rate to the debt portion of our RAB. This is consistent with the AER's approach. We propose that debt raising costs should be excluded from the EBSS calculation because the cost is set based on a benchmark debt raising allowance rather than our revealed costs.
- **Costs associated with the DMIAM** – under the DMIAM arrangements, any underspend must be returned to customers in full. In this case, we propose these costs should not be subject to the EBSS so that customers retain the full amount of any underspend.
- **Innovation expenditure** – we have proposed a $5 million step change for innovation to complement the capex innovation program and allow a broader range of projects to be pursued that may have an opex component. The Reset Customer Panel has raised with us the option of proposing innovation opex to also be excluded from EBSS. We consider this to be appropriate because the amount is not based on our revealed costs and propose that it is excluded from the EBSS.
- **Community resilience expenditure** – The Reset Customer Panel has also raised with us that it may be appropriate to exclude community resilience expenditure from the EBSS. Like innovation, this is another expenditure type that is not based on revealed costs, therefore we we also propose excluding community resilience expenditure from EBSS.

63 AER (2022), *Framework and Approach for Ausgrid, Endeavour Energy and Essential Energy: Regulatory control period commencing 1 July 2024*, pp 44, 47; NER, cl 6.5.8(a).
64 AER, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, November 2013, clause 1.4.

7.2 CESS

Like the EBSS, the CESS will allow our customers to benefit from improved efficiencies through lower regulated prices in future periods. The CESS shares efficiency gains 70:30 between our customers and us.[65]

The AER intends to continue to apply the CESS in the forthcoming 2024-29 period.[66] In calculating any capital underspend or overspend, the AER takes into account the financing benefit or cost to the distributor of any underspend or overspend amounts. The AER can also make further adjustments to account for deferred capex and *ex-post* exclusions of capex from the RAB.

In the current period we proposed, and the Reset Customer Panel agreed, that innovation capex be excluded from CESS, and this is how we have approached our CESS calculation. We encourage the AER to consider continuing this exclusion for the 2024-29 period, aligning with treatment of the innovation allowance in the current period.

The Reset Customer Panel also considers that resilience capex on top of capex allowed under the AER's repex model should be excluded from CESS. This is to ensure customers do not pay a reward for expenditure that is supported by a resilience business case in our proposal, but does not occur. We also encourage the AER to consider applying this exclusion from CESS for the 2024-29 period.

We note that the AER has commenced a review of its incentive schemes and has released a position paper in relation to the CESS, which indicates that it is considering reducing the network share of the ratio from 30% to 20% in certain circumstances.[67] Ausgrid proposes that the mechanism for calculating the penalty or reward under the scheme is calculated in accordance with the AER's CESS Guideline that applies at the time of the AER's Final Determination.

7.3 STPIS

The STPIS will help us maintain and improve our service performance and ultimately deliver better outcomes for customers, including in relation to reliability.

The STPIS works by providing rewards or penalties, depending on whether we meet specified reliability and customer service targets (through an 's-factor' adjustment to our revenue). The rewards allow us to fund reliability improvements. The penalties hold us to account if we do not maintain our current level of performance.

Consistent with the AER's proposed approach,[68] we propose that the maximum we can be rewarded or penalised in the forthcoming 2024-29 period is 4.5% of our revenue. The STPIS scheme may also include a guaranteed service level (**GSL**) component composed of direct payments to customers experiencing service below a predetermined level. However, GSLs already apply to Ausgrid through a jurisdictional scheme, so we do not propose they apply as part of the STPIS.

In the current period we included a telephone answering metric as part of STPIS to encourage improvements in customer service. We are developing a new approach to measuring customer service performance under the new CSIS, as discussed below. **Attachment 7.1 – Proposed 2024-29 CSIS** includes our full CSIS proposal for the forthcoming 2024-29 period.

65 AER (2022), *Framework and Approach for Ausgrid, Endeavour Energy and Essential Energy: Regulatory control period commencing 1 July 2024*, pp 44, 47.
66 AER (2013), *Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, cl 1.4.
67 AER (2022), Position paper - Review of incentive schemes: Options for the Capital Expenditure Sharing Scheme.
68 AER, *Framework and Approach for Ausgrid, Endeavour Energy and Essential Energy: Regulatory control period commencing 1 July 2024*, July 2022, 46.

7.3.1 Reliability

The STPIS will help us maintain and improve our service performance and ultimately deliver better outcomes for customers, including in relation to reliability.

Calculation of scheme parameters

We have calculated our STPIS incentive rates, reliability performance targets and historical reliability performance as per the AER's 2018 version of the STPIS.[69] This information is set out in **Figures 7.3.1** to **7.3.3** below.

Figure 7.3.1 – STPIS incentive rates

	SAIDI incentive rate	SAIFI incentive rate
CBD	0.00833%	1.75559%
Urban	0.08402%	6.33749%
Short rural	0.01134%	1.04134%
Long rural	0.00009%	0.02114%

These incentive rates are based on the formula specified in the Explanatory Statement to the AER's 2018 STPIS.[70] As required, we have based our reliability targets (see **Figure 7.3.2** below) on an average of our last 5 years of historical reliability performance (see **Figure 7.3.3**).

Figure 7.3.2 Proposed reliability performance targets for the 2024-29 period

	SAIDI target (minutes)	SAIFI target (interruptions)
CBD	13.2180	0.0418
Urban	67.0179	0.5923
Short rural	133.3093	0.9682
Long rural	729.0270	1.9833

Figure 7.3.3 Historical reliability performance

		FY18	FY19	FY20	FY21	FY22	Average
SAIDI	CBD	12.6837	24.863	3.6245	18.7698	6.1492	13.2180
	Urban	64.4837	65.7878	80.9539	60.7763	63.0881	67.0179
	Short rural	114.0159	131.6741	160.6341	129.5830	130.6394	133.3093
	Long rural	349.8913	465.9028	652.5282	613.6509	1563.1616	729.0270
SAIFI	CBD	0.064	0.1123	0.0051	0.0190	0.0087	0.0418
	Urban	0.6494	0.6026	0.6374	0.5181	0.5541	0.5923
	Short rural	0.9817	1.0416	1.0134	0.8735	0.9308	0.9682
	Long rural	1.5897	2.2222	2.0542	2.0083	2.0421	1.9833

69 AER (2018), Service Target Performance Incentive Scheme v 2.0 - updated 13 December 2018.
70 AER (2018). Explanatory Statement - *Amending the Service Target Performance Incentive Scheme (STPIS) and establishing a Distribution Reliability Measures Guideline (DRMG).*

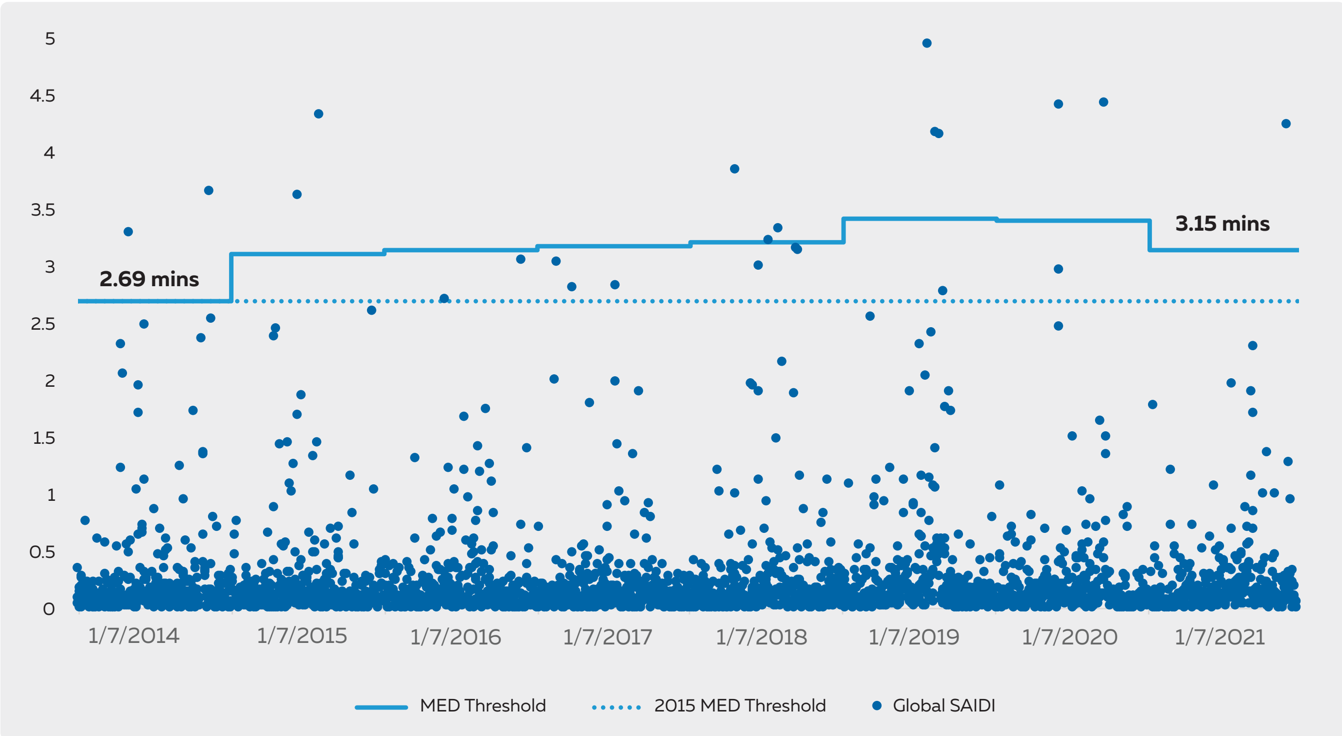
Ongoing work on major event day exclusions

Major event days (**MEDs**) are a key component of the STPIS methodology. These exclude extreme events like major storms from the calculation of the rewards and penalties we receive under the STPIS. However, this does not adjust for the impact of extreme events in calculating the MED threshold itself, which can have a distortionary impact.

The impact of including major events in calculating the MED threshold is shown in **Figure 7.3.4**. Significantly, it shows that:

- Under the AER's method, the MED threshold has increased from 2.69 minutes in FY15 to 3.15 minutes in FY21; and
- There have been nine major events on our network since FY15 that would have been excluded under the FY15 threshold, but are included in our current 3.15 minute MED threshold.

Figure 7.3.4 Major event day threshold plotted with network wide (global) SAIDI performance



We are continuing to investigate this issue. One option may involve the exclusion of 'catastrophic' weather events from how our MED threshold is calculated. This would provide greater stability in the operation of the STPIS and focus reliability incentives on normal operating conditions. However, at this stage we are not proposing any amendments to how the MED threshold is calculated.

7.3.2 Customer service

We propose that our CSIS (a new scheme introduced since our last determination) replaces the customer service element of the current STPIS.

7.4 CSIS

We are proposing a new CSIS to the AER which we have developed with our customers to drive improvements in our service delivery performance and to focus on areas of service that are most valuable to our communities. Under this scheme, we would risk losing up to $44 million in regulated revenue over the 2024-29 period if we do not improve our performance in key service areas over the period.

In close collaboration with the Reset Customer Panel and through significant engagement with our customers, we have identified four service areas that we believe our customers would most value improvement in and a mix of operational and sentiment metrics that will challenge us to do better in these areas. **Figure 7.4.1** below provides a summary of our proposed CSIS metrics.

The total value of the revenue we would risk is +/- 0.5% of our annual revenue for the 2024-29 period. This equates to around $9 million per year. We have split the incentive weightings evenly across the services.

We present our CSIS proposal in **Attachment 7.1 – Proposed 2024-29 CSIS.**

Figure 7.4.1 Proposed Customer Service Incentive Scheme metrics

Customer priorities for the CSIS			Baseline	Dead band (only applies to increase in performance)	Incentive rates	Proposed revenue at risk p.a. (+/–)
Cores services	Planned outage service ease	Urban	63.7%	0	0.025	0.125%
		Regional	69.2%	0	0.025	0.125%
Enabling services	Connection project timeframe		177 days	0	0.0125	0.125%
Customer care	Website satisfaction rate		41.2%	8.8%	0.025	0.125%

In close collaboration with the Reset Customer Panel and through significant engagement with our customers, we have identified four service areas that we believe our customers would most value improvement in and a mix of operational and sentiment metrics that will challenge us to do better in these areas. These are summarised in **Figure 7.4.2** below.

Figure 7.4.2 Proposed Customer Service Incentive Scheme metrics definitions

Proposed CSIS metrics			Definition
Core services	Planned outage service ease	Urban	Level of ease in the service experience for customers on a planned outage, which is a prearranged interruption to supply where affected customers are given advanced notification. This interaction includes both short sustained and general interruptions to customers' electricity supply. Service ease will be measured separately for urban and regional customer groups.
		Regional	
Enabling services	Connection project timeframe		The median timeframe within which all connections projects in each financial year are energised, following the later of: **a.** Acceptance of a connection offer; or **b.** Appointment of an accredited service provider (**ASP**) construction partner.
Customer care	Website satisfaction rate		Communication metric to measure whether customers were able to achieve the intent of their visit to the website

These performance parameters are key interactions or experiences that customers have with us and will benefit a large number of customers. For example, around 400,000 sites (**NMI**s) are affected by planned outages each year, but within those NMIs dozens, 100s or 1000s of individuals may be affected due to the NMI representing embedded networks, shopping centres, hospitals and other critical services. Our decision to adopt these particular parameters was based on consultation with our Voice of Community Panel, large business customers and the Reset Customer Panel to understand the areas where customers value improved service delivery, and our assessment of the parameters against the requirements in the AER's CSIS.

We are proposing a CSIS which has been developed with our customers to enhance customer service and to focus on areas of service that are most valuable to our communities.

7.5 DMIS and DMIAM

In its F&A, the AER stated that it intends to apply the DMIS and DMIAM to the NSW distributors for the 2024-29 period. We support this and include both in our proposal. The DMIS and DMIAM will help us to identify more efficient alternatives to building new infrastructure and provide funding to test new demand management options. Together, the DMIS and DMIAM aim to reduce network costs over time and lower prices in future regulatory periods.

We consider that applying the DMIS and DMIAM in the forthcoming 2024-29 period will meet the NEO set out in the NEL and the individual objectives of the DMIS and DMIAM as set out in the NER.

The DMIS and DMIAM focus on better managing customer demand to reduce network costs over time and may involve research or technology trials using customer side technology.

We note that these programs differ from our Network Innovation Program which focusses on research, trials and pilots of new network technology that are aimed at creating safe, intelligent networks, better enabling CER and increasing customer resilience. The Network Innovation Program aims to test advanced and emerging technologies on the distribution network in order to efficiently demonstrate the potential of these technologies to deliver significant benefits to our customers and the wider energy market if deployed at scale.

7.5.1 DMIAM projects

The DMIAM will give us additional funding to trial innovative demand management projects with the potential to reduce long-term network costs. The DMIAM will only be used where we are not able to obtain funding for research and development through other means.

We will publicly share our findings and learnings in relation to our proposed demand management projects. This will allow the industry and our customers to understand and benefit from our project learnings, which in turn will contribute to achieving the NEO.

Figure 7.5.1 summarises recent demand management projects financed through the innovation allowance.

Figure 7.5.2 identifies future demand management innovation projects we are proposing for the forthcoming 2024-29 period that will help improve the range and cost effectiveness of non-network options to better reflect network needs. We are currently considering these projects, which may be fully or partially implemented during the 2024-29 regulatory period.

Figure 7.5.1 Summary of recent demand management projects

Project name	Project description
Demand Management (DM) for replacement needs	Most of Ausgrid's network capital investment expenditure over the next 5-10 years relates to the retirement or replacement of aged assets. This project explored important demand management capability to test the viability of using non-network options to defer or manage the load at risk associated with network investments that involve retiring / replacing aged assets. The learnings from this trial are now being used to inform demand management assessments of major capital projects.
Future trends research (DEF)	This is a 3-year research project being led by Monash University that aims to understand and forecast customers' changing digital lifestyle trends and their impact on future household electricity demand, including at peak times. The learnings from this social research fills a significant gap in networks' understanding of changing customer behavioural trends and has broad and far-reaching benefits in being able to inform demand forecasts, demand management modelling, customer engagement strategies and more. Ausgrid is supporting this project through co-funding and an in-kind contribution in partnership with Energy Consumers Australia and Ausnet Services.
Battery demand response (VPP)	Ausgrid's Battery Demand Response (Virtual Power Plant (**VPP**)) trial explored whether battery VPP's can provide reliable and cost competitive sources of demand reductions or voltage support services to defer network investment. The project explored how the grid can integrate renewables and partner with industry and customers to maximise grid efficiency benefits and reduce costs for customers. The project successfully tested various modes of demand response by orchestrating numerous residential batteries together to simulate network support services scenarios.
Peak time rebate (Retailer DR)	Ausgrid explored the cost-effectiveness of a peak time rebate as a demand management solution in localised areas of the Ausgrid network area. The project explores whether a rebate offer with customers on peak demand days can be used to alleviate location specific short-term network constraints to defer or reduce the need for longer term network infrastructure upgrades.
EV dynamic charging	This project explores the future impacts of EV charging on the Ausgrid network and the viability of, and customer response to, various demand management interventions. The project developed understanding of electricity demand impacts from electric vehicle charging on network assets and included participation in EV trials to investigate the potential demand management options for addressing future network investment needs.
SAPS sizing & costing tool	This project developed a sizing and costing tool to inform whether SAPS are a suitable alternative to conventional poles and wires for supplying Ausgrid's 'fringe-of-grid' customers. This project used industry-standard software for SAPS sizing and leveraging internal asset risk models to deliver a quantitative cost-benefit assessment tool which is now being used to inform locational suitability for SAPS that are being trialled under the Network Innovation Program in the current regulatory period.
Cost-reflective network pricing (CRNP) research	This project explored the benefits of cost-reflective pricing. It developed a methodology to quantify the peak demand reduction benefits derived from introducing CRNP to residential customers to better understand the effectiveness of these pricing structures as a targeted demand management tool for network investments. The project highlights complementary measures which can be used to increase the effectiveness of network pricing signals and to inform future tariff design.
Community battery feasibility study	This project investigated the potential for locally based community batteries paired with an innovative business model to offer both a competitive alternative to traditional local network investment and introduce a novel way to markedly improve equitable access to energy storage for customers. The project involved a feasibility study on the engineering, regulatory and commercial aspects of the community battery concept and included research to explore customer response, awareness and interest in the concept to inform the development of a potential trial. Over the course of the trial, the project was supported with ongoing activities to maintain customer engagement and customer experience-related activities. Community batteries are now being trialled under the Network Innovation Program in the current regulatory period as a result of this study.
Hot water load control	This project was developed to understand the current and future capability of dynamic load control as a demand management solution appropriate for the Ausgrid network and to explore how Ausgrid, retailers and customers can collaborate to optimise operation of the load control system for the benefit of all consumers. This project involved moving a portion of overnight hot water electrical input energy into the daytime. This can alleviate network issues caused by high amounts of distributed solar systems. The trial successfully demonstrated that this solution can achieve its stated objectives. The next steps are to roll out this project more broadly across our customer base.

Figure 7.5.2 Proposed demand management projects for the 2024-29 period

Project name	Project description
Customer CER research	Projects will develop research to study the opportunities and barriers for demand management participation across different customer, technology and industry stakeholders. Projects will aim to develop new engagement techniques or collaborative partnerships that help to improve equitable access to demand management participation. These techniques and partnerships will aim to support increased scale of participation for demand management trials and test innovative solutions or cost-reflective pricing in different customer segments. Data capture will guide the effectiveness of novel solutions for providing efficient or low-cost demand management and response.
Smart energy technology solutions and trials	Projects will investigate novel smart solutions to enable CER with a focus on addressing opportunities or challenges across the urban and rural network environment. This could include areas such as multi-occupancy apartment units or offices. Projects will identify and collaborate with partners to study the scale of demand management opportunities provided by emerging or innovative solutions. Demonstration trials will include exploring the integration of electric vehicles at increasing scale (including smart charging technology) and different demand management solutions across residential and business fleet customer groups. These trials will aim to explore the impact of new customer technologies such as EVs and determine where they could provide efficient demand management solutions in the future.
Business customer demand flexibility studies and trials	Projects will explore innovative low- or high-tech, temporal or spatial, and collaborative demand flexibility solutions and opportunities to support existing or newly connecting business customers. Projects will study and inform where the greatest potential for business customer demand flexibility might exist. Proposed solutions could efficiently provide grid support or demand management services, including increased CER hosting capacity. Projects will help to identify what is needed to implement and standardise successful solutions for customers.
Dynamic network management and data	Projects will focus on identifying demand management requirements and use cases that are supported by increasing availability of data and improving low-voltage network visibility through smart meters and behind-the-meter partnerships. Projects will explore data processing techniques and capabilities that support demand management and forecasting needs. Projects will aim to highlight how increasing availability of data and improving network visibility can support improved or new demand management or customer participation opportunities.

7.6 Cost pass throughs

We propose including four pass through events for the 2024-29 regulatory period and amending the definition of 'natural disaster' to:

'Natural disaster events will include, but may not be limited to, natural disasters declared by a relevant government authority. Where a government authority has made a declaration that a natural disaster has occurred, the temporal and geographic scope of the natural disaster event will be defined by reference to the terms of that declaration.'

The pass through event mechanism provides additional (or reduced) funding, subject to AER approval, to cover any significant increases (or decreases) in costs as a result of a pre-defined event. Cost pass through events are an important part of the incentive framework as they allow for price adjustments to be made in response to large, unexpected and uncontrollable events that result in cost changes. Without pass through events, we would need to inefficiently invest to avoid the impact of these events on our network potentially reducing costs elsewhere (such as reducing maintenance costs), which could increase risks and/or costs in the long term or increasing overall costs for customers. Cost pass through events also allow us to return funding to customers that we no longer require where they meet pass through event criteria.

To avoid constant changes in funding, we can only ask to adjust funding if the change in cost exceeds a materiality threshold of 1% of our annual revenue.

The NER specifies that any of the following is a cost pass through event for a distribution determination:

- A regulatory change event;
- A service standard event;
- A tax change event;
- A retailer insolvency event; and
- Any other event specified in a distribution determination as a pass through event for the determination.[71]

After reviewing our risk management processes and systems, we have decided to propose the following four additional pass through events so that we can respond to and address the consequences of unlikely, but high-cost events that are outside management's control:

- Insurer's credit risk;
- Insurance coverage;
- Natural disaster; and
- Terrorism.

The AER has previously approved these four events for Ausgrid. We propose substantive changes to the definition of 'natural disaster event' and minor adjustments to the other definitions so that they better reflect more recent AER decisions. We discuss the need for changes to the definition of 'natural disaster' event below and provide the drafting provisions for the pass through events in **Attachment 7.2 – Nominated cost pass through events**.

In the lead up to our Draft Plan, we engaged with our communities and heard from customers that they are interested in how the regulatory framework can be reviewed to ensure it better considers the impacts of climate change. Customers also told us that they want us to prioritise building climate resilience.

In response to this, we recommended revisiting the cost pass through framework to accommodate natural disaster events that are a series of cumulative events (rather than one large, isolated event such as a cyclone). Our Draft Plan included the above definition of the 'national disaster' pass through event and asked stakeholders for their views on this definition.

We developed this definition to provide greater certainty in the administration of the pass through applications. The current 2019-24 definition of a 'natural disaster' does not address how the temporal or geographic scope an event should be defined. This has resulted in electricity distributors engaging scientific experts to support pass through applications, and the AER being forced to make meteorological findings in the exercise of its decisions as an economic regulator.

Our view is that the most objective way to determine if a natural disaster event has occurred is by examining whether a government authority has declared an event as such. These government authorities are impartial and resourced with the expertise to decide if a natural disaster event has occurred. Their declarations also include a finding regarding the dates that encompass the natural disaster event and the locations impacted.

71 NER, cl 6.6.1(a1).

7.7 Supporting attachments relevant to Chapter 7

7.1	Proposed 2024-29 CSIS
7.1.a	Proposed CSIS metrics model
7.1.b	Proposed CSIS compliance model
7.2	Nominated cost pass through events

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Full details of our tariff proposal can be found in our Tariff Structure Statement Compliance Paper (**TSS**) and Our TSS Explanatory Statement for 2024-29.

8. Network tariffs

8.1 Our current network prices

We have different network prices for our residential and small business customers and for our medium and large business customers.

For residential and small business customers, retailers package up our prices with the other costs of electricity supply (including wholesale, environmental and retail costs). A retailer may have pricing structures that mirror the structure of our network prices, or may have another structure entirely.

Historically, most of our residential and small business customers have been on network prices with a flat energy-based structure, which means they paid a fixed rate for every kilowatt hour (**kWh**) of electricity they used. This is because older electricity meters only recorded the amount of energy used over time.

This flat tariff structure:

- **Is not cost-reflective** – given that our costs are driven by how much energy our customers use **at the same time** (the peak demand on our network), not by how much energy our customers use over time. We also expect our costs to be increasingly driven by the amount of energy customers export to the grid at the same time with further CER integration on our network; and
- **Does not give customers much control over their bills** – given that the only way customers can lower the network cost component of a bill that uses a flat energy-based structure is to lower their overall energy usage.

As metering technology has improved, we have been able to implement several pricing reforms to make our residential and small business tariffs more cost-reflective and to give our customers more power to influence their bills, including introducing:

- **TOU pricing** for small customers with interval ready meters in 2003. These prices have a range of 'charging windows', so customers pay a higher rate for energy used during the periods of peak demand on our network; and
- **Demand pricing** for new residential and small business customers with smart meters in 2019. These tariffs apply to a customer's metered peak demand that occurs over a month and within the peak period window.

If passed on by their retailer, our TOU and demand tariffs can provide price signals to customers about how the timing of their energy use influences our network costs, which can allow customers to lower their bills by shifting some of their energy use to when network demand is low. Importantly, if customers respond to these price signals, these tariffs can help us reduce the overall costs of providing the energy services to the community. This also helps us control the growth in our network costs – reducing the overall costs of providing the community energy services

Almost half a million residential and small business customers are on our TOU tariffs, and more than 160,000 are on demand tariffs. This is nearly one-third of all our residential customers and more than half of all our small business customers.

For large C&I customers, our network prices are typically itemised on their bill so they can see the contribution of our network prices to their overall electricity costs and are better able to respond to their price signals. Our existing tariffs for these customers include capacity charges, which are applied to the highest peak demand that occurs over 12 months that falls within the peak period window.

Information on our proposed tariffs structures can be found in our **Attachment 8.2 - Our TSS Explanatory Statement for 2024-29.**

8.2 Our pricing principles

We need to continually reform our pricing so we can meet the challenges – and capture the opportunities –facing the energy sector and our customers. We are expecting significant changes over the forthcoming 2024-29 period to the way our customers use the network as a result of CER uptake and EV charging.

Our proposal positions us well to meet these changes and manage future risks and uncertainties. We have developed a set of reforms to implement in the 2024-29 regulatory period, as well as undertaking tariff innovation to inform further reforms in future periods.

Our TSS provides details of how our proposed prices comply with the pricing principles in the NER.

We have also developed the following three Ausgrid pricing principles in consultation with our Pricing Working Group (see **Section 3.1**) to guide us further:

1. **Efficiency** – our prices should efficiently reflect the overall costs of operating the distribution network and the costs associated with providing different network services at different times of the day and year. Efficient cost-reflective tariffs can signal the costs of distributing electricity to customers – enabling customers to decide whether the benefits they get from the electricity (consumed or self-generated) outweigh the costs;
2. **Flexibility** – our prices should reward customers for being flexible in when and how they use energy. Prices that encourage customers to consume energy at times of low network demand and export energy at times of peak network demand can improve the overall utilisation of the grid. This can reduce the need to augment the network and limit network charge increases for everyone in the long term. It also supports customer choice, facilitates innovation and creates win-win outcomes across customer segments; and
3. **Fairness** – our prices should recover our costs in a way that is fair and equitable to all customers. For example, our prices should not create an unfair burden on customers who have less ability to control their network charges (such as those renting and living in apartments) and/or who may be unable to invest in CER (such as rooftop solar and battery storage systems). In addition, our approach to price setting should be technology-neutral to promote innovation and remain relevant as technology evolves. It should also consider customer impacts, and significant changes should be supported by complementary measures to minimise these impacts if necessary.

We consider our pricing reforms for 2024-29 effectively balance these three principles.

8.3 Stakeholder consultation

We have been engaging extensively with our customers and other stakeholders to develop the pricing reforms we are including in our January 2023 proposals to the AER. We will continue our engagement as we refine our proposed reforms and prepare our regulatory and TSS proposals. This will be through our Pricing Working Group and retailer forums, and individual meetings with customers and retailers.

In this section, we provide an overview of our engagement on pricing reforms to date.

8.3.1 Pricing Working Group

We continue to work closely with our Pricing Working Group to develop our proposed pricing reforms.

The Pricing Working Group comprises a range of customer and electricity industry advocates, as well as energy retailers and aggregators. It met 15 times in the 2023 calendar year and discussed a wide range of topics relevant to the changes and opportunities facing the energy sector, and how our tariff structures and policies could be reformed to respond to these trends and provide better outcomes for our customers.

For example, the diverse members of the Pricing Working Group provided their perspectives on our pricing principles, and the options for – and trade-offs involved in:

- Introducing and designing export pricing;
- Changing our charging windows and our controlled load tariffs;
- Streamlining our residential and business tariffs;
- Reforming our policies for assigning customers to these tariffs; and
- Introducing EV charging tariffs and embedded network tariffs.

Representatives from the AER and the NSW Government also attended most of the Pricing Working Group meetings to observe and provide comments.

We greatly appreciate each Pricing Working Group member's insights, contributions and assistance in developing our initial pricing reform proposals.

8.3.2 Voice of Community Panel

To help us understand the experiences and perspectives of our residential customers, we established the Voice of Community Panel from 45 randomly selected members of the public that represent the diverse range of households our network serves across the Hunter, the Central Coast and Greater Sydney.

The feedback we have received from the Voice of Community Panel is helping us to test whether our proposed pricing reforms reflect our customers' expectations for fairness and value for money. It is also helping us to gauge the extent to which customer behaviour could be influenced by price signals and pricing reforms that aim to optimise electricity supply and demand – balancing time of use, time of export, and reliability.

In the Town Hall meeting on 15 October 2022 we heard further feedback from the community on our export tariff proposal. Stakeholders emphasised that more customer education was required, particularly on how the export tariffs contribute to the cost. This includes explaining to customers that they are unlikely to be charged to export (they are just being rewarded a bit less on their existing retail feed-in tariff) and they are also being rewarded for shifting their usage and smoothing out load on the grid.

8.3.3 Interviews and forums with large and medium business customers

To better understand the perspectives of our large commercial and C&I customers, we:

- Interviewed representatives from several large business in both March 2022 and September 2022. In these interviews we found support for the proposed changes to the tariff charging windows and component structures, and for a price trajectory that is even across the 2024-29 regulatory period; and
- Held two forums for C&I customers in May 2022 to get their input and test our thinking on reforms, such as moving the peak period to later in the day and combining the existing shoulder and off-peak charging windows into a new off-peak window.

8.3.4 Small business interviews

In September 2022, we visited several small businesses in Lakemba, Cessnock and Tuggerah and asked them for their views on our proposed pricing reforms. These interviews established that small businesses did not expect to be impacted greatly by our charging window or export tariff reforms. However, some small businesses seek a closer alignment of retail prices and charging components across residential and business tariffs.

8.3.5 Retailers and aggregators

In 2022 we invited retailers to have one-on-one discussions with us on our reset, and to attend our Pricing Working Group meetings and two retailer forums to discuss our proposed pricing reform.

Unfortunately, there was not a strong interest in one-on-one discussions on the reset, and the Pricing Working Group meetings were not regularly attended by retailer representatives. However we pleasingly had more than 40 attendees at both retailer forum meetings.

Overall, the feedback we received was relatively limited. We received a submission from Red Energy which raised a number of concerns with our proposed reforms. Feedback from three other retailers was focused on specific reforms (either embedded network tariffs or energy storage tariffs). **Attachment 8.2 - Our TSS Explanatory Statement for 2024-29** details our responses to this feedback.

8.4 Pricing Directions Paper

We released a Pricing Directions Paper in early September 2022 which contained our proposed pricing reforms for the 2024-29 period.

We consulted extensively with our stakeholders, including our customers, retailers, industry and consumer associations, and the AER. The consultation on our Pricing Directions Paper received a total of 19 submissions. **Figure 8.4.1** lists some of the organisations who provided submissions.

Figure 8.4.1: List of Pricing Directions Paper submissions

- City of Newcastle
- City of Sydney
- Compliance Quarter
- Electric Vehicle Council
- Energylocals
- Firm Power
- GoEvie
- Northern Beaches Council
- Inner West Council
- NSW Caravan & Camping Industry Association
- Origin Energy
- Public Interest Advocacy Centre
- Red Energy/Lumo
- Shell Energy
- Shopping Centre Council of Australia
- Total Environment Centre
- Uniting
- Willoughby Council

The feedback we have received through this process and the amendments we have made to our proposal in response to this feedback is included in **Attachment 8.2 - Our TSS Explanatory Statement for 2024-29.**

8.5 Our proposed pricing reforms for 2024-29

In response to the changes and opportunities ahead for the energy sector, and to what we are hearing in our engagement with our customers and communities, we propose to reform our standard tariff offerings for the 2024-29 period. We are proposing six main changes:

1. **Introducing export pricing for residential and small business customers after a 1-year transition period** to reflect the increasing costs that receiving CER customers' exports imposes on the network and provide an incentive for CER customers to self-consume or time their exports to minimise these costs and maximise the benefits they receive;
2. **Introducing tariffs for embedded network operators** that will better reflect the costs (over a transition period) that these business customers impose on our network, so they make a fairer contribution to funding these costs;
3. **Streamlining our existing tariff offerings and tariff assignment policies for our customers** to make it easier for retailers to respond to or pass through our price signals to our customers**;**
4. **Simplifying and updating the charging windows for our demand, capacity and TOU tariffs** to make it easier for retailers to pass through our price signals to customers, and ensure peak charges apply when demand on our network is highest;
5. **Introducing pricing for utility scale storage facilities** to enable large batteries connect to our network and create a level playing field for projects located in the distribution network; and
6. **Updating our controlled load tariffs for residential and small business customers** to reflect changes in the times of day when demand on our network is lowest, and allow our 470,000 controlled load customers to operate their hot water systems during the day when solar energy production is highest.

We think our proposed reforms would make our tariffs more efficient, flexible, fair, and sufficiently caters for the anticipated electrification of transport. The sections below discuss each of the changes we are proposing in more detail and set out the questions we seek comments on.

8.6 Energy affordability and bill impacts

After a period when our customers saw their bills go down, a range of factors are now putting upward pressure on the costs of supplying electricity, and thus on its affordability for our customers. These factors are largely outside of Ausgrid's control or affect the non-network components of electricity bills. For example:

- Rising interest rates and higher inflation are increasing our network costs, as well as the overall cost of energy supply, while also increasing our customers' cost of living;
- Disruptions in the energy supply chain due to gas shortages and an aging fleet of coal fired power stations are factors which are driving up the generation component of bills; and
- Significant investments in transmission infrastructure are expected to increase the transmission component of bills.

Many of our proposed pricing reforms (see **Section 8.5** above) aim to support an affordable transition by giving our customers more choice and control over their energy services and bills. For example, our tariff assignment policy moves customers (with capable metering) to demand tariffs with the option to opt out to TOU tariffs. Our Regulatory Proposal also sets out a range of response to ensure customers pay no more than necessary for our network services, and facilitates an affordable transition to net zero.

The bill impact analysis supporting **Attachment 8.1 - Tariff Structure Statement compliance paper** is based on an estimate of total network charges for the FY25 year. It includes our proposed distribution and transmission revenues, and an estimate of the Transgrid revenues and NSW Climate Change Fund. We have not included the NSW Electricity Infrastructure Roadmap scheme recoveries as a projection for FY25 has not been provided by the NSW Government.

The full details of the bill impacts (by tariff) are included in **Attachment 8.3 – Network bill impacts**.

8.7 Alternative control services

Detail on Ancillary Control Service (**ACS**) can be found in **Chapter 9, Attachment 9.1 - Public lighting services**, **Attachment 9.2 - Metering services** and **Attachment 9.3 – Ancillary network services**.

8.8 Supporting attachments relevant to Chapter 8

8.1	Tariff Structure Statement compliance paper
8.2	Our TSS Explanatory Statement for 2024-29
8.3	Network bill impacts
8.4	Long run marginal cost import model
8.5	Long run marginal cost export model
8.6	Long run marginal cost import methodology report
8.7	Price and asset linkages
8.8	Transmission pricing methodology
8.9	Methodology for avoided TUOS
8.10	Standalone avoidable cost model
8.11	Indicative pricing schedule – ACS
8.12	Demand forecast volumes and customer numbers
8.13	Pricing Directions Paper
8.14	Submissions on the Pricing Directions Paper
8.15	Indicative pricing schedule – DUOS
8.16	Trial tariffs for FY25
8.17	Indicative pricing schedule - NUOS

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Our ACS include public lighting, metering and ancillary network services.

9. Alternative control services

9.1 Public lighting

9.1.1 Overview

Ausgrid is one of the largest providers of public lighting services in Australia. We own, operate and maintain more than 260,000 public lights across our network area, which spans 22,275 square kilometres and encompasses 33 council areas.

Councils are our key public lighting customers – representing over 99% of public lights on our network. Public lighting is an essential service that promotes safety of communities and roadway users. We aim to deliver an effective and efficient service meeting today's needs and enabling future needs.

9.1.2 Customer engagement

To develop our 2024-29 Regulatory Proposal on public lighting services, we reviewed our current services and prices. As part of this process, we engaged with our public lighting customers to get their feedback on the services we offer and our pricing.

In our engagement to date on public lighting services we have heard that councils want:

- A faster transition to LED luminaires – including the introduction of smart controllers (devices that can be fitted to individual LED luminaires). Smart controllers would enable public lighting to be controlled and monitored remotely and could provide for other smart city solutions and services; and
- To make the process of having public lighting minor capital works approved and delivered easier, faster and cheaper for them.

In relation to public lighting pricing, these customers generally want greater transparency and simplicity and they support changes to simplify prices provided they do not significantly reduce cost-reflectivity and are clearly explained.

Figure 9.1.1 summarises the specific feedback we have heard, and how we are proposing to respond.

Figure 9.1.1 What we have heard on public lighting, and how we are proposing to respond

	What we have heard ...	We are proposing to ...	For our customers, this would mean...
Pricing	Our pricing, including any changes in pricing, should be transparent Price rationalisation is supported provided that bill impacts are negligible Moving to simpler (weighted average) pricing is supported, provided that the prices for the most commonly used products are cost-reflective	• Rationalise existing public lighting charges where feasible • Continue our consultations with councils and their representatives such as Southern Sydney Regional Organisation of Councils (**SSROC**) on our proposed pricing approach	A simpler, more transparent list of public lighting prices so they can find pricing information relevant to them more quickly and easily Greater understanding of, and confidence in, the methodology used to calculate our prices
	Customers would like to have flexibility in paying their pre-2009 capital charges	• Provide an option for councils to accelerate payment of remaining pre-2009 capital values during the 2024-29 period so they are fully paid off by the end of 2028-29	Flexibility to manage public lighting expenditure to suit their funding profiles over time
Transition to LED and smart city solutions	The transition to LED public lighting and introduction of smart controllers to facilitate smart city applications should be accelerated	• Accelerate the rollout of LED replacements on major roads by 30 June 2026 • Install smart controllers as part of the rollout of LED streetlights on minor roads (when councils choose this option) • Start the rollout of LED decorative lighting and floodlights in 2024-29 period • Extend our smart control rollout to residential and decorative luminaires	More reliable, energy efficient and affordable public lighting Ability to build on installed sensors to enable broader smart city solutions (e.g. air quality monitoring, traffic counting)
	The AER's annual price setting process delays the adoption of new technologies and pricing	• Consult with councils when sourcing new lighting technologies/ products • Seek approval for a pricing approach which allows new public lighting technology to be adopted sooner, without needing to wait for annual price reviews	Ability to adopt new and more efficient technology sooner, resulting in more timely cost savings and lower carbon emissions
Minor public lighting projects	For public lighting minor capital works projects, the approval process should be simpler, the time required to install light poles should be shorter, and the pricing should be more transparent.	• Review the end-to-end process for customer requests for public lighting minor capital works (up to 10 lights) to commence in FY23	A cheaper, faster, and overall improved experience for customers requesting public lighting minor capital works

9.1.3 Regulatory modelling

Our 2019-24 Regulatory Determination used the following modelling approach for public lighting prices:

- Assets constructed prior to 1 July 2009, using an asset roll forward model;
- Prices for services provided after that date were derived using an annuity model; and
- Operation and maintenance costs.

Ausgrid proposes to retain the form of modelling for this proposal. Model inputs will be updated to reflect changes that have taken place in the intervening period.

For the 2024-29 period, the AER has requested that the three NSW network businesses use a standardised model to calculate the installation costs included in their proposed post-2009 capital charges. We note that not all of the functionality of the model applies to how we price our public lighting services. Therefore, we are only using it to the extent required to build-up capital and opex costs in a similar way to the AER's 2019-24 Regulatory Determination.

Pre-2009 capital charge

In 2009, the AER made a change to the way our public lighting capital charges are calculated, based on when the assets were installed. For assets installed before 1 July 2009, the charge is calculated based on a return *on* capital invested (to recover our ongoing financing costs) and return *of* capital invested (or depreciation, to recover the cost of the asset over its useful lifespan).

The AER determined the value of our public lighting asset base as at 30 June 2009, by customer and by asset category. The value of this asset base is updated each year, reducing in value to account for depreciation (based on the average age of assets within each category). The value is also adjusted each year to remove the residual capital value of assets replaced or removed in the previous year.

By 1 July 2024, the value of the pre-2009 asset base will have reduced from $111.3 million in 2009 to an estimated $9.7 million. This is because the capital value of pre-2009 public lighting assets will be almost fully recovered. For example, all luminaires will be fully depreciated, and assets in other categories will be mostly depreciated.

However, poles will not be fully depreciated until 2044 – which means that some councils will continue to pay a small annual pre-2009 capital charge for another 22 years.

In our customer engagement, some councils indicated that they would like flexibility in their pre-2009 asset charges and more transparency. In response to this feedback, we are proposing to provide councils with the option to accelerate payment of remaining pre-2009 capital values during the 2024-29 period so that all assets are paid off by 30 June 2029. Councils would pay the same amount in NPV terms whether they bring payments forward or continue to pay until 2044. However, bringing payment forward would simplify their future public lighting bills, and may provide other benefits.

We expect that whether this option makes sense for a council will depend on its individual financial circumstances and preferences. We received responses from 14 councils, with 11 in favour of bringing payments for the pre-2009 asset base forward so they are fully paid off by the end of 2028-29. As a result, we have only applied accelerated depreciation to the 11 councils that responded positively.

Post-2009 capital charge

Ausgrid proposes to retain the methodology for capital build up and pricing used for the 2019-24 determination. Assets installed post-July 2009 are priced using a cost build up model which then calculates an annuity based on the expected life of the asset. This means it is calculated so that our one-off installation costs and our ongoing financing costs are recovered over the asset's expected life.

We have responded to council feedback that our capital price lists are confusing. In our consultation with councils in May 2022, we raised the possibility of rationalising these price lists by introducing some weighted average prices for similar products. Councils indicated that they would support this approach, provided that:

- The most commonly used products are properly cost-reflective (i.e. not included in a weighted average price);
- Rationalising the costs of luminaires with like luminaires does not drive unintended outcomes (e.g. no incentive to minimise the luminaire utilised as the costs are the same as larger luminaires); and
- The impacts on prices are marginal.

We took this feedback into account in developing our final price lists for our post-2009 capital prices and propose the following:

1. **Rationalise the bracket capital price list**

   We are proposing to rationalise the current legacy bracket capital price list from 26 to six categories of bracket. Prices for legacy brackets are rolled forward based on the Consumer Price Index (**CPI**). In addition, five new prices will be included for new bracket categories included in the LED roll-out. These will be priced based on latest contract prices and will only apply to new or replaced brackets.

2. **Rationalise legacy decorative and floodlight luminaire prices**

   In light of councils' feedback that luminaire prices should be properly cost-reflective, we are not proposing to rationalise luminaire pricing. We note that the price list for luminaires will reduce over the 2024-29 regulatory period, as legacy luminaire types are replaced as part of our LED replacement program.

   We have also reviewed the descriptions for each LED luminaire price and updated the descriptions to be more flexible so that they apply to equivalent luminaires in terms of functionality and price in the future.

Maintenance charge

The cost of scheduled and unscheduled maintenance services is priced via an annual maintenance charge. The average charge reflects the average time taken for each activity, a labour rate, and the materials required. Maintenance charges apply to both pre- and post-2009 capital assets.

We currently have 50 maintenance prices. Several of them are the same as, or only slightly different to, another price. Councils have indicated that the prices could be rationalised without material impact on their charges. In response to this feedback, we are proposing to rationalise maintenance prices for luminaires by grouping similar luminaires together and calculating one maintenance price for each group. This will reduce the number of maintenance prices from 50 to six.

In addition, we are introducing four new maintenance prices for our new LED luminaires with smart controllers, which will have lower prices than the equivalent category of luminaire without smart controller. A separate charge to cover the smart controller licence and maintenance fee (introduced in the FY23 annual pricing) will also apply to luminaries with smart controllers. No changes are being proposed for the maintenance 'connections' price categories.

More information is contained in **Attachment 9.1 – Public lighting services**.

9.2 Metering services

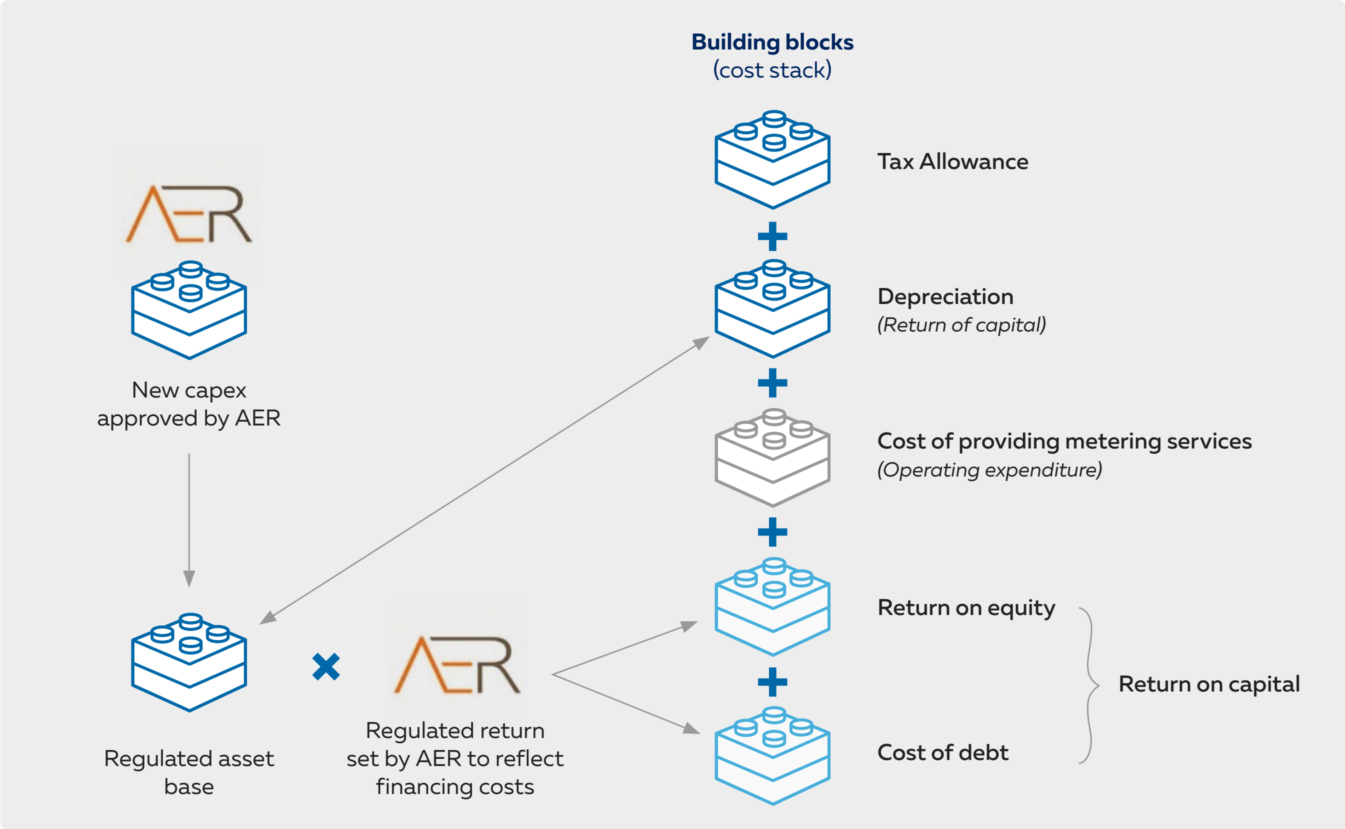
9.2.1 Overview

With the commencement of the Power of Choice metering reforms, our customers now have the option to leave our type 5 and 6 metering service by taking up a retailer offering that is inclusive of an advanced interval meter or 'smart meter'.

Our proposal reflects the efficient costs of continuing to operate our fleet of type 5 and 6 meters for customers who stay with our service.

To calculate our proposed prices for type 5 and 6 metering, we used the 'building block' approach, consistent with AER guidance and the previous regulatory period. This involves calculating and adding the individual cost inputs or 'blocks' that feed into the running of our type 5 and 6 metering operations (see **Figure 9.2.1**). Once the building blocks have been developed, the revenue required to provide metering services is then forecast to reflect declines in meter numbers and any increase in the unit cost of providing metering services.

Figure 9.2.1 **Metering price building blocks**



9.2.2 Metering reforms – AEMC draft report

The AEMC published its a draft report on its Metering Review in November 2022 (**Draft Metering Report**).[72] The Draft Metering Report made the following preliminary recommendations:

- A target of 100% uptake of smart meters by 2030 in NEM jurisdictions;
- New arrangements for network businesses to develop a legacy meter retirement plan and replace meters by 2030 (in consultation with retailers and metering businesses);
- Measures to support customers through the rollout, including greater transparency, access to quality information and safeguards; and
- Harnessing the opportunity for customers, network businesses and retailers to have guaranteed access to smart meter data.

We have considered the findings in the Draft Metering Report and have had regard to them when developing our proposal. This is particularly in relation to our forecast of type 5 and 6 meter volumes in the 2024-29 period.

72 AEMC (2022). *Draft report – Review of the regulatory framework for metering services.*

9.2.3 Forecast type 5 and 6 meter volumes

We are forecasting a decline in the number of our type 5 and 6 metering customers over the 2024-29 regulatory period.

The AEMC's Draft Metering Report recommends a target of 100% uptake of smart meters by 2030 in the NEM jurisdictions. Our smart meter forecast assumes that 90% of our customers will have a smart meter installed by 2032. We believe that this timeframe is a prudent projection given the AEMC's Metering Review is still underway and the details of the legacy retirement plan are still to be finalised.

We also understand that despite the AEMC's 2030 target, there will still be some type 5 and 6 meters remaining beyond that timeframe, the management of which is unclear at this time.

Our forecast assumes that until AEMC's final decision, the smart meter uptake will be in line with recent trends at 58,000 per year. The legacy meter retirements are expected to accelerate in FY25 upon AEMC's final decision on smart meter roll-out and reach a plateau in FY27 at 102,000 per year. The customer-initiated meter upgrades are expected to be at the same level throughout the forecast period at 47,000 per year. As a result, the share of type 5 and 6 meters drops from 80% in FY21 to 31% in FY29 and 10% in FY32.

Figure 9.2.2 below sets out our forecast change in type 5 and 6 metering customers at the end of each financial year from 2021 to FY29 by NMIs.

Figure 9.2.2 Forecast change in type 5 and 6 metering customers at the end of each financial year (NMIs)

	2021 (actual)	2022 (actual)	2023	2024	2025	2026	2027	2028	2029
Type 5 and 6 meter upgrades	65,392	50,053	57,829	57,829	88,302	118,776	149,249	149,249	149,249
Customer initiated	57,020	37,499	47,319	47,319	47,319	47,319	47,319	47,319	47,319
Legacy meter retirement	8,372	12,554	10,510	10,510	40,983	71,457	101,930	101,930	101,930
Remaining type 5 and 6 meters	1,429,886	1,349,858	1,292,029	1,234,200	1,145,898	1,027,122	877,873	728,624	579,374
Share of type 5 and 6 meters	80%	76%	72%	68%	63%	56%	48%	39%	31%

9.2.4 Our proposed type 5 and 6 metering prices

Figure 9.2.3 below sets out our proposed type 5 and 6 metering prices.

We have calculated capital and non-capital components of our charges as per the AER's 2019-24 Regulatory Determination. The non-capital charge covers the operating costs associated with metering which, broadly speaking, should be avoided when a customer leaves our type 5 and 6 metering service. Calculating the capital and non-capital components of our charges separately allows our customers who leave our metering service to discontinue paying the non-capital component.

Figure 9.2.3 Proposed metering prices ($nominal)

Tariff	Component	FY25	FY26	FY27	FY28	FY29
EA010 - Residential flat	Non-capital	14.43	15.98	17.70	19.61	21.72
	Capital	13.29	13.64	14.00	14.37	14.75
EA025 - Residential TOU	Non-capital	37.30	41.32	45.77	50.70	56.16
	Capital	14.79	15.18	15.58	15.99	16.41
EA111 - Residential demand (introductory)	Non-capital	-	-	-	-	-
	Capital	14.79	15.18	15.58	15.99	16.41
EA116 - Residential demand	Non-capital	-	-	-	-	-
	Capital	14.79	15.18	15.58	15.99	16.41
EA030 - Controlled load 1	Non-capital	1.22	1.35	1.50	1.66	1.84
	Capital	7.37	7.56	7.76	7.96	8.17
EA040 - Controlled load 2	Non-capital	1.22	1.35	1.50	1.66	1.84
	Capital	7.37	7.56	7.76	7.96	8.17
EA050 - Small business flat	Non-capital	14.89	16.49	18.27	20.24	22.42
	Capital	20.31	20.85	21.40	21.96	22.54
EA225 - Small business TOU	Non-capital	36.96	40.94	45.35	50.23	55.64
	Capital	14.11	14.48	14.86	15.25	15.65
EA251 - Small business demand (introductory)	Non-capital	-	-	-	-	-
	Capital	14.11	14.48	14.86	15.25	15.65
EA256 - Small business demand	Non-capital	-	-	-	-	-
	Capital	14.11	14.48	14.86	15.25	15.65
EA302 - low voltage up to 160 MWh	Non-capital	65.77	72.85	80.69	89.38	99.00
	Capital	18.38	18.87	19.37	19.88	20.40
EA305 - low voltage 160-750 MWh (system)	Non-capital	65.77	72.85	80.69	89.38	99.00
	Capital	18.38	18.87	19.37	19.88	20.40
Generator tariff	Non-capital	3.84	4.25	4.71	5.22	5.78
	Capital	7.61	7.81	8.02	8.23	8.45

9.3 Ancillary network services

9.3.1 Overview

Ancillary Network Services (**ANS**) are non-routine services Ausgrid provides to individual customers on an 'as needs' basis. For example, they may only be needed when a customer is making changes to their property or their connection to our network. In this way, they are different from other services, such as network services, that are provided to our broad customer base.

The services fall into 14 broad categories (see **Figure 9.3.1** below).

Figure 9.3.1 Our ancillary network service categories[73]

To recover our costs associated with providing ANS, we levy fees on the requesting party. The fees that we charge may be either:

- **A fixed fee** – based on the average time required to deliver the service; and
- **A quoted fee** – which is subject to variance depending on the task, materials and time involved in performing the service.

We currently provide over 100 distinct ANS with either a fixed or a quoted price (see **Figure 9.3.2**). Where feasible, we provide both a fixed and quoted fee for a service. In these cases, the fixed fee applies to jobs deemed 'simple' (based on the time typically required), and the quoted fee applies to 'complex' jobs.

Figure 9.3.2 Fixed and quoted fees for providing ANS

Fee type	Description
Fixed fees	• Are applied to services where delivery involves a consistent level of effort each time (e.g. special meter reading) • Are based on the average time required to deliver the service and the hourly rates for each category of Ausgrid staff involved in delivery
Quoted fees	• Are applied to services where the delivery time varies significantly, depending on the size and complexity of the work involved (e.g. complex access permits) • Are based on the estimated time required to deliver the service, and the labour rates and estimated hours for each category of Ausgrid staff involved in delivery

73 Notification of arrangements refers to the provision of written notification to councils confirming necessary arrangements have been made to supply electricity to a development. Training refers to network related access/compliance training for ASPs.

9.3.2 Customer engagement

For the current 2019-24 period we made extensive changes to our ANS – including simplifying our fees for these services to better reflect how we deliver these services and by reducing the number of distinct services from 148 to 108.

As part of preparing for our proposal for the forthcoming 2024-29 period, we engaged with our communities to inform our review of our list of services and fees to ensure that they align with our customers' and partners' needs, are fair and transparent, and reflect our costs to provide the service.

In our engagement on ANS, our customers and delivery partners who interact with us regularly on ANS told us they want us to improve our service delivery. They want the experience of requesting an ANS and moving through the process required to get the job done to be simpler, easier and more efficient. Price certainty is also important to them – and they want this certainty as early in the process as possible.

In response to this feedback and our ongoing review of our current ANS and fees, we are proposing to make a range of changes to improve our services and service delivery in this area. We think these changes will make our ANS pricing more visible and transparent, our list of ANS and associated fees simpler and easier to understand, and our processes more efficient. **Figure 9.3.3** below summarises the specific feedback we have heard, and how we are proposing to respond.

Figure 9.3.3 What we have heard on our ancillary network services, and how we are responding

	What we have heard...	We are proposing to...	For our customers, this would mean...
Pricing (C&I customers, ASPs, retailers)	Price certainty is important	Convert quoted fees to fixed fees where possible	• ANS prices are more accessible and transparent, and total costs are known earlier in the process
	For new connections, indicative costs of the whole job should be provided at an earlier stage in the process	Investigate the possibility of providing 'typical' average costs as well as a low to high range for common types of connection projects, prior to the official quote stage	
	Individual service elements included in our quotes should be more accurate and comprehensive of all costs – including overtime hours and rates if overtime is expected	Implementing more frequent reviews of completed jobs to better inform assumptions and improve accuracy for future quotes	
	Disconnection and reconnection fees should be charged independently and not as a combined fee	Ausgrid has considered this request and is not proposing to change how this fee is charged. The reasons for this decision are: • We believe the retailer requesting the disconnection is incurring the cost and will receive all the benefits. Further, there is not always a reconnection for every disconnection and so the majority costs are associated with the disconnection; and • There are other options available that a retailer could utilise which are potentially more cost effective	• Shorter price lists that include only the ANS relevant to them, making them simpler and easier to understand • Clearer service descriptions so it is easier to understand which fees may apply to different situations
	The list of ANS fees should be simpler and more transparent and descriptions of services should be clearer	• Remove or combine some fees • Publish the ANS fee lists on our website where links to ANS are provided • Publish customer/partner specific listings of ANS on our website, rather than only one full list • Update ANS descriptions and definitions so they are clearer	• Shorter price lists that include only the ANS relevant to them, making them simpler and easier to understand • Clearer service descriptions so it is easier to understand which fees may apply to different situations
	For customer-funded contestable projects, the connection process should be made easier	• Create dedicated strategic engagement resources to work with large businesses (building on the creation of a dedicated inbox for technical connection enquiries in FY22) • Migrate service delivery onto a central CRM platform to enable ANS delivery progress to be visible to the customer, improve communications and provide a choice for digital self-service options	A simpler and easier process for customer-funded contestable projects, leading to: • Improved service delivery • Quicker response times • Better visibility of progress • Fewer cancellations of scheduled outages for contestable connections and asset relocations
	ASP-3s should have direct access to our network data at no additional cost – particularly technical data for new connections (substation rating and maximum demand). Other distributors offer this	Replace our current network data platform (Web GIS) to improve functionality and enable us to provide partners with different levels of access to data based upon the intended connection and associated works	• ASP-3s would be able to directly access specific network data when they need it — resulting in cost and time savings
	Certification of designs should be taken out of DNSPs' hands and a private certifier regime established	N/A We note that design certification is not part of the AER's remit in a determination process. Our view is that design certification needs to remain regulated to ensure safety and reliability of the network.	N/A

9.3.3 Forecasting approach

The AER applies a price cap to our ANS. For services offered on a quoted basis, the AER sets a schedule of labour rates for the first year of the regulatory control period. We have applied a 'bottom up' approach to develop our proposed prices for ANS fixed fees by applying a labour rate to the estimated time taken to deliver a service.

For the subsequent years of the regulatory control period, labour rates and fixed fees are escalated annually using a formula.

Labour rates

Almost all ANS fees are based on labour rates. As part of its determination process, the AER reviews the reasonableness of these labour rates, including benchmarking them against the rates used by other network businesses and the wider industry.

Ausgrid has experienced significant cost pressures driven by labour shortages in the utilities sector in recent years. These pressures are expected to continue through the 2024-29 period, driven by two main factors:

1. Workforce shortages associated with Australia's closed borders during the first years of the COVID-19 pandemic; and
2. Increased demand for skilled labour caused by high levels of investment in the utilities sector – for example, electricity-related engineering construction is forecast to be 48% higher in 2029 than it was in 2021.[74]

In developing this proposal, we have undertaken a thorough review of our labour rates. We engaged CutlerMerz to benchmark our current approved rates to comparable market rates, including:

- **NSW contestable market rates for similar services** – using ASP rates, CutlerMerz developed minimum, maximum and median benchmark rates for each ANS labour category to represent the rates that businesses servicing the NSW utility industry (electricity, gas and water) are charging for similar services that Ausgrid provides through ANS;
- **Interstate and intrastate peer DNSPs** — based on equivalent labour rates in the most recent distribution determinations; and
- **Developing benchmark rates using Hays' FY22 energy sector and office support salary data** – using the same methodology employed by the AER's consultant in previous labour rates reviews.

CutlerMerz found that some of our labour rates are below the median for comparable skills in NSW, suggesting that these rates do not reflect current labour market circumstances. Importantly, the CutlerMerz analysis is based on NSW overall, which does not take account of the premium associated with a workforce based predominantly in the Sydney region. This would push the comparison labour rates for Ausgrid higher than those in the report.

We are proposing to increase our ANS labour rates for the 2024-29 regulatory period, in light of the identified cost pressures on labour rates. **Figure 9.3.4** below shows our proposed labour rates to be used in calculating our maximum fees for the first year of the 2024-29 regulatory period. These rates are inclusive of on-costs and overheads.

Figure 9.3.4 Proposed labour rates ($ per hour, real FY24)

	Proposed FY25 hourly labour rate (excl GST)
Admin **(R1)**	130.21
Technical specialist **(R2)**	197.01
Engineer / Senior Engineering officer **(R3)**	237.68
Field worker **(R4)**	191.78
Senior Engineer **(R5)**	283.79
Engineering Manager **(R6)**	328.29

74 RIN.04 - Real materials and land escalation report, p 3.

9.3.4 Proposed changes to ANS

Our aim is to have an appropriate mix of fixed and quoted fees to provide price certainty for as many ANS as possible, while also allowing us to fairly recover the costs of complex jobs that require differing levels of effort. As a result, for the 2024-29 period, we are considering introducing a small number of new ANS and increasing the proportion of services for which a fixed fee is offered. Some ANS are no longer required and we are proposing to remove them.

Overall, we are proposing 108 discrete ANS. Of these services, 63 have a fixed fee, 44 have a quoted fee and there is one for ASP material sales. This increases the proportion of fixed fee services from 52% in the current period to 58% in the 2024-29 period. The fee for ASP material sales would continue to be based on material price plus overhead margin. **Attachment 9.3 – Ancillary network services** 'summarises the ANS fee changes and new ANS and fee types we are proposing for the 2024-29 period, and the reasons for the changes.

9.4 Supporting attachments relevant to Chapter 9

9.1	Public lighting services
9.1.a	Public lighting - pre-2009 'fixed charge' model FY24-29
9.1.b	Public lighting model FY24-29
9.2	Metering services
9.2.a	Metering RFM 2024-29
9.2.b	Standardised metering capex and opex model 2024-29
9.2.c	Standardised metering pricing model 2024-29
9.2.d	Metering PTRM 2024-29
9.2.e	Independent estimate of diseconomies of scale
9.3	Ancillary network services
9.3.a	Standardised ancillary network services model
9.3.b	NSW ANS labour rates review

10

This section discusses Ausgrid's proposed approach for other regulatory matters including control mechanisms, service classification, and negotiation framework and criteria.

10. Other regulatory items

10.1 Control mechanisms

10.1.1 Revenue cap for standard control services

On 29 July 2022, the AER published the final F&A for Ausgrid for the 2024-29 period commencing 1 July 2024. The F&A maintains the same revenue cap control formulae as the current period, except for minor adjustments for the application of service target performance incentive scheme Version 2.0 (**STPIS 2.0**). We agree with the revenue cap control formula provided in the AER's F&A and have applied the formula in setting prices for the 2024-29 period.

We note that the variable 'I' for incentive schemes is to be decided in the AER's determination. Ausgrid proposes the following definition based on the incentive schemes we have proposed to apply in **Chapter 7**. We note that EBSS and CESS are applied in the building block revenue calculation and therefore do not appear in the control mechanism formula.

I_t *= the sum of payments relating to:*

- The STPIS version 2.0;
- The CSIS (H-factor) in relation to year t-2;
- The demand management incentive scheme and innovation allowance adjustments relating to:
  - The final carryover amount from the application of DMIAM. This amount will be deducted from/added to allowed revenue in the 2025-26 pricing proposal (t=2); and
  - Approved DMIS amounts from year t-2.

10.1.2 Side constraint

The NER pricing principles require that annual network pricing proposals demonstrate compliance with a side constraint mechanism. In general terms, this side constraint mechanism allows the distribution revenue per tariff class to change annually by no more than the revenue path plus 2%.

On 17 November 2022, the AER released its final position paper to review the application of the side constraint mechanism.[75] This paper sets a single mechanism to be applied in all DNSPs' determinations to ensure consistent interpretation and application of the side constraint. Specifically, the AER's final position is as follows:

- Maintain the current format of the side constraint mechanism for presentation purposes;
- Include a Q factor in the mechanism for changes in price attributable to movements in quantities from the preceding year;
- Not introduce an explicit treatment of new/trial tariffs as these are accommodated through the Q factor; and
- Include a D factor in the mechanism to ensure the tariff class revenues are comparable to the (1+CPI)(1–X)(1+2%) threshold.

Ausgrid participated in the AER's consultation on the development of the amendment to the side constraint formula. We agree that the proposed formula is less likely to result in the side constraint binding in an environment of falling volumes, and consider it to be an improvement to the existing formula.

Consistent with the AER's final position, we will apply the new side constraint formula in annual distribution network price proposals for the 2024-29 period.

75 AER (2022), *Annual pricing process review - Final position paper - Side constraint mechanism.*

10.1.3 Alternative control services

The final F&A also maintained the same price cap formulae as the current period for alternative control services. For metering, public lighting and fee based ancillary network services the price cap formula is of a standard CPI – X form. We do not propose any changes to the formula in the F&A and have applied the formula in setting prices for the 2024-29 period.

For quoted ancillary network services the price cap formula in the Framework and Approach is:

$$Price = Labour + Contractor\ Services + Materials + Margin + Tax.$$

Margin and tax has been added to this formula since the 2019-24 decision. While we do not propose any changes to this formula, we have not added margin or tax for quoted services to our prices at this time.

See **Attachment 9.3 - Ancillary network services** for more detail.

10.2 Service classification

While Ausgrid accepts the AER's final F&A decision and commends the AER on the thorough and open consultation process it undertook to develop it, we note that a material change in circumstances (**MCIC**) may need to be triggered at the draft or final determination stage due to the rapid rate of energy transition regulatory reform underway in the NEM.

As we noted in our submission to the AER's F&A Preliminary Position Paper 'the MCIC provisions provide the AER, DNSPs and customers with the flexibility needed to be responsive to the current significant rate of innovation and change' in the NEM.[76]

Ausgrid is grateful that the AER's F&A decision foreshadowed that the rate of change from the energy transition may trigger a MCIC for system support services.[77]

We consider the AER may also need to trigger a MCIC due to recent and foreshadowed developments in relation to:

1. Community batteries;
2. Metering services; and
3. Reliability and Emergency Reserve Trader (**RERT**).

We address each of these developments in turn below.

10.2.1 Community batteries

For Ausgrid's 2019-24 regulatory period, the AER approved an innovation allowance which we used to trial community batteries via our Network Innovation Program funding and in consultation with our Network Innovation Advisory Committee. Ausgrid now has three trial community batteries and plans to expand this trial to a pilot.

On 25 October 2022 the Federal Government announced its plans to provide $224.3 million over 4 years from 2022 to deploy 400 community batteries. In the round 1 funding, six of the 58 already announced community battery locations are within Ausgrid's network area. We also expect some of the remaining 342 community batteries for the Australian Renewable Energy Agency's round 2 to be within Ausgrid's network area. The AER is currently consulting on a class ring fencing waiver for DNSPs to be able to become proponents for this funding.[78]

Ausgrid intends to apply for these funding rounds for community batteries within our network area and subject to receiving the waiver, plans to be installing the six announced community batteries in the current 2019-24 regulatory control period. Our Network Innovation Advisory Committee will have an oversight role of this project.

If Ausgrid is successful in being awarded tranche 2 funding then we anticipate this would occur in the current 2019-24 and the 2024-29 period.

Given the potential for community batteries in the NEM, the following may occur between now and 1 July 2024 when our next regulatory period commences:

1. Based on the findings from community batteries installed and waivers obtained to date, the AER triggers the MCIC provisions and allows Ausgrid to offer leasing out spare capacity in batteries as a SCS; or
2. NSW derogates from the AER's electricity distribution Ring fencing Guideline (version 3) by preparing regulations for NSW DNSPs to deliver community batteries under new regulation making powers in section 192A of the *Electricity Supply Act 1995* (NSW).[79]

76 Ausgrid (20 May 2022), *Submission to the AER's F&A Preliminary Position Paper*
77 AER (2022), *Final framework and approach for Ausgrid, Endeavour Energy and Essential Energy for the 2024-29 regulatory control period*, p. 2.
78 AER (2022), *Batteries funded under the Commonwealth Government's Community Batteries for Household Program – Ring-fencing class waiver.*
79 This law enables the NSW Government to make regulations for DNSPs to own and operate community-scale batteries, limited to batteries or a series of inter-connected batteries not exceeding 30 megawatts storage capacity.

What customers have told us on community batteries

Voice of Community Panel

Ausgrid conducted extensive engagement via the Voice of Community Panel to understand whether our communities value Ausgrid delivering community batteries, and – if so – why.

Customers told us they valued Ausgrid delivering community batteries because they support wider renewable energy development and because they reduce the need for new poles and wires.

Our customers told us:

'Supports the drive to net zero carbon'

'If we are moving to net zero, we need to start here'

'Good to see you are working on this'

'Look back 20 years ago with how solar panels were and look at now with where they are. The technology has gotten better, cheaper, and more reliable. Community batteries are new like solar was decades ago'

This engagement showed us that customers want Ausgrid to expand our existing community battery trials.

Newgate Research customer survey

In the lead up to our community battery trial we engaged Newgate Research to conduct a customer survey on community batteries for our current regulatory period community battery trial.[80]

This research found that 69% of customers surveyed were comfortable with DNSPs like Ausgrid delivering community batteries compared to councils, electricity retailers, local residential advocacy groups and a private battery company. These findings helped motivate us to pursue expanding our community battery trial as part of this Regulatory Proposal.

80 Newgate Research (2021), *Ausgrid's Community Battery Concept: Customer Survey Report*, p 38.

10.2.2 Metering services

On 3 November 2022 the AEMC published its Draft Report on its Metering Review. The Draft Metering Report suggests it is likely that DNSPs in NEM jurisdictions will need to develop legacy meter retirement plans. We anticipate this would be a SCS.

10.2.3 RERT services

Ausgrid strongly supports the AER's 14 December 2022 decision to grant a class ring fencing waiver that allow DNSPs to offer RERT services for voltage management as an unregulated service. This will reduce the cost of AEMO's RERT payments for customers and allow for a more seamless and integrated approach during system security and reliability events.

Ausgrid will consider whether and how it will offer these services in our 2023 revised proposal to the AER. Therefore it may be more appropriate for the AER to enable NSW DNSPs to offer these services within its service classifications for the 2024-29 period at the final determination stage through the MCIC provisions (over a waiver). Waivers are an unsustainable approach to service classification especially when considered with our proposed approach to classifying system support services in **Section 10.2.4**.

10.2.4 System support services

System support services would be a new service provided by Ausgrid to AEMO and potentially to transmission network service providers (**TNSPs**) in the future. Ausgrid will provide details about the system support services it intends to offer in the 2024-29 period in our 2023 revised proposal and we support the AER using the MCIC provisions in its final determination.

To date, the AER has assessed the provision of system support services on a case-by-case basis during the F&A process. However, we expect these services will be increasingly needed by AEMO to support system security in the NEM given the increasing role for distribution networks as DSOs. These system support services are unique to distribution networks and there is therefore a low risk of harm for competitive markets from classifying such services.

We suggest the AER should classify system support services in the three ways outlined in **Figure 10.2.1** below. It is important that system support services can be classified in all three ways so that DNSPs can leverage existing network capabilities depending on the type of system support services.

Classification	How services should be classified	How this could be delivered
1. SCS	As inputs to SCS, with revenue recovered from customers via tariffs	By creating and listing local use of service (**LUoS**) tariffs to support specific energy schemes. General Distribution System Operator (**DSO**) functions and capabilities would be SCS, which would not require amendment as they are an input to common distribution services that we provide. Note: services that are a discrete and billable services to AEMO or a TNSP require ANS classification under classification 2
2. ACS	As an ACS provided to AEMO and TNSPs with a regulated price list. This could include, for example, compliance checks of third parties bidding into the AEMC's proposed Operating Security Mechanism	Ausgrid could have contracts with AEMO to conduct compliance checks as an ACS service to ensure that third parties bidding into the AEMC's and AEMO's proposed operating security mechanism meet the necessary standards set. As Ausgrid has been contracted to provide these services under – for example, the operating security mechanism – a regulated price list would ensure transparency for consumers
3. Unregulated	As an unregulated distribution service making use of shared assets with unregulated prices which are instead services negotiated between Ausgrid, AEMO or a TNSP directly)	These services would be discrete and billable to AEMO or a TNSP directly by making use of distribution assets and are, accordingly, best suited to being an unregulated distribution service. These services require the use of assets and systems that are inextricably linked to, and form part of how distribution networks operate. We acknowledge that providing services to AEMO during market contingency events is not well suited to direct control regulation

What customers have told us on system support services

In September 2020, the New South Wales, Australian Capital Territory, Tasmanian and Northern Territory DNSPs (Ausgrid, Endeavour Energy, Essential Energy, EvoEnergy, TasNetworks and NT PowerWater Corporation) jointly consulted on service classification.

This included consulting on what role DNSPs should play in enabling and – increasingly, offering – platform services for CER both for customers and AEMO. We were told in submissions that:

PIAC submission:

'PIAC considers these functions will likely be a mix of input and services, for example, DSO functions such as dynamic operation of the network and visibility are unlikely to be able to be provided to a customer individually and are therefore inputs, whereas dynamic connection agreements and associated export services are more likely to be services'

SSROC submission:

'Re-framing the network as a platform for the provision of a range of services is fundamentally a move in the right direction. DNSPs are right to examine each of the services that can potentially be delivered using that platform'

10.3 Proposed approach for a negotiating framework

This section describes Ausgrid's proposed negotiating framework and criteria that would apply to any of Ausgrid's services classified as negotiated distribution services.

Negotiated distribution services require a less prescriptive regulatory approach because all relevant parties have sufficient market power to negotiate the provision of those services. Prices for negotiated distribution services can be negotiated between Ausgrid and our customers according to a prescribed framework, with the AER providing arbitration if required.

Historically, Ausgrid has not had any of its services classified as negotiated services. The AER again proposes in its final F&A decision that none of Ausgrid's services will be classified as negotiated services for the 2024-29 regulatory period.[81]

10.3.1 Proposed negotiating framework

If Ausgrid is required to provide negotiated distribution services in the forthcoming 2024-29 period, we will apply our proposed negotiating framework (see **Attachment 10.3 – Proposed negotiating framework**). Our proposed negotiating framework has been prepared to comply with the requirements of Part D of Chapter 6 of the NER.[82]

10.3.2 Proposed approach to negotiated distribution service criteria

In addition to considering the negotiating framework, NER clause 6.12.1(16) requires the AER to make a constituent decision as part of its distribution determination on Ausgrid's negotiated distribution service criteria. These criteria are to be applied by Ausgrid in negotiating terms and conditions of access and by the AER in resolving any access disputes.

NER clause 6.7.4 requires that the negotiated distribution service criteria must give effect to and must be consistent with the negotiated distribution service principles set out in NER clause 6.7.1. Ausgrid supports the AER in maintaining the current negotiated distribution service criteria.

81 AER, *Final framework and approach for Ausgrid, Endeavour Energy and Essential Energy for the 2024-29 regulatory control period* (2022) p. 6.

10.4 Supporting attachments relevant to Chapter 10

10.1	Request for a new Framework and Approach
10.2	Submission to the AERs Framework and Approach preliminary position paper
10.3	Proposed negotiating framework

Glossary

2024-29 Period – 2024-29 regulatory control period
ACS – Alternative Control Service
ACSC – Australian Cyber Security Centre
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
AMS – Asset Management System
API – Application Programming Interface
ARP – Asset replacement planning
ASP – Accredited Service Provider
BAU – Business-as-usual
BCR – Benefit to Cost Ratio
CALD – Culturally and Linguistically Diverse
capex – Capital expenditure
CBA – Cost-benefit analysis
C&I - Commercial and Industrial
CCC – Ausgrid's Customer Consultative Committee
CCF – The NSW Government's Climate Change Fund
CCP – AER's Consumer Challenge Panel
CECV – Customer Export Curtailment Values
CER – Customer Energy Resources
CESS – Capital Expenditure Sharing Scheme
CPI - Consumer Price Index
CRM – Customer Relationship Platform
CRNP – Cost-reflective network pricing
CSIS – Customer Service Incentive Scheme
DER – Distributed energy resources (now commonly referred to as CER)
DMIAM – Demand Management Innovation Allowance Mechanism
DMIS – Demand Management Incentive Scheme
DNSP – Distribution Network Service Provider
DOE – Dynamic Operating Envelope
DSO – Distribution System Operator
EBSS – Efficiency Benefit Sharing Scheme
Emissions Pathway – greenhouse gas concentration trajectories adopted by the Intergovernmental Panel on Climate Change).
ERP – Enterprise Resource Planning
ESA – Electricity Supply Act 1995 (NSW)
ESOO – Electricity Statement of Opportunities
ESS – Energy Savings Scheme
EV – Electric Vehicle
EWP – Elevated Work Platform
F&A – Framework and approach
FTE – Full-time equivalent
GDF – Grossly Disproportionate Factor
GDP – Gross domestic product
GIS – Geographical Information System
GSL – Guaranteed Service Level
GSP – Gross State Product
ICT – Information, communications and technology
IFRIC – International Financial Reporting Standards Interpretation Committee
ISP – Integrated System Plan
LGA – Local government area
LHS – Left hand side
MEDs – Major Event Days
MP – Member of Parliament
PFP – Multilateral Partial Factor Productivity
NECF – National Energy Customer Framework
NEM – National Electricity Market
NEO – National Electricity Objective
NER – National Electricity Rules
NIAC – Network Innovation Advisory Committee
NIP – Network Innovation Program
NMI – National Metering Identifier
NPV – Net present value
OEF – Operating Environment Factors
opex – Operational expenditure
OT – Operational Technology
OTI – Operational Technology and Innovation
PaaS – Platform as a Service
PDRS – Peak Demand Reduction Scheme
PTRM – Post-Tax Revenue Model
PWG – Pricing Working Group
RAB – Regulated Asset Base
RAP – Reconciliation Action Plan
RERT – Reliability and Emergency Reserve Trader
RBA – Reserve Bank of Australia
RCP – Reset Customer Panel
repex – Replacement expenditure
REZ – Renewable Energy Zone
RHS – Right hand side
RIN – Regulatory Information Notice
RoRI – Rate of Return Instrument
SaaS – Software as a Service
SAIDI – System Average Interruption Duration Index
SAIFI – System Average Interruption Frequency Index
SAPS – Stand-Alone Power System
SCS – Standard Control Service
SFAIRP – So Far As Is Reasonably Practical
SoNS – Systems of National Significance
SP-2 - Security Profile 2
SP-3 - Security Profile 3
SSROC - Southern Sydney Regional Organisation of Councils
STPIS – Service Target Performance Incentive Scheme
TSS – Tariff Structure Statement
TNSP – Transmission Network Service Provider
totex – Total expenditure
TOU – Time of use

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